Meeting name	BSC Panel
Date of meeting	10 April 2008
Paper title	Report on Issue 30 'Cashout Issues'
Purpose of paper	For Information
Synopsis	Issue 30 was raised to consider certain areas of cashout that were identified during the Ofgem-led cashout review as potentially sub-optimal. The Group has discussed a range of topics under this Issue. The Group has provided some further areas for consideration, were any participant minded to raise a related modification. This paper is presented to the Panel for information.

1 Introduction and Issue Scope

1.1 Standing Issue 30 was raised by Utilita (the 'Proposer') on 2 November 2007 for consideration by the Pricing Standing Working Group (the 'Group'). The Group held 4 meetings over a 3 month period to discuss 6 broad cashout related topics.

1.2 This paper summarises the key conclusions of the Group at its four meetings. The Group notes in Section 2 of this paper the subjects which may warrant further work and a general set of conclusions based on their discussions. Additionally, this report highlights, for each topic, some questions the Group believes should be addressed if any participant was contemplating raising a modification in one of the areas discussed.

1.3 The 6 topics identified by the Proposer and discussed by the Group were:

- Single vs Dual Pricing - (see discussions in Appendix 1);
- Spread (between the main and reverse price) - (see discussions in Appendix 2);
- Balancing Services Adjustment Data (BSAD) - (see discussions in Appendix 3);
- Residual Cashflow Allocation Cashflow (RCRC) - (see discussions in Appendix 4);
- Gate Closure - (see discussions in Appendix 5); and
- Introduction of a Half Hourly Energy Balancing Market (see discussions in Appendix 6).

1.4 The appendices contain a summary of the topic discussions followed, where appropriate, by any further discussions.

1.5 At its first meeting, the Group set itself Terms of Reference to guide its discussions in regard to each of these topics. This is included as Attachment 1. Throughout the consideration of Issue 30, the Group welcomed comment and participation from the whole industry. The Group published topics and discussion slides in ELEXON's Newscast publication in advance of the meetings. However, there were no views or feedback from the wider industry and this report therefore only reflects the views presented by members of the Issue 30 Group.

1.6 In addition, and at the request of the Imbalance Settlement Group (ISG), the Group considered the Reverse Price. This was following the most recent ISG review of the Market Index Definition Statement (MIDS). The Groups discussions on Reverse Price can be found in Appendix 7. A list of background documentation that the Group considered or referred to is included in Appendix 8.

2 Key messages

The key messages of the Group which may warrant further analysis and investigation are:

- There is the potential for market benefits from improving the Contract Notification process and/or reducing Gate Closure. Therefore, a potential area for a Modification is to extend the current Contract Notification process to allow for notifications to occur after Gate Closure and/or to shorten Gate Closure;
- The Reverse Price could potentially be improved by considering and analysing different weightings toward short duration trades. This could be when the ISG next considers the MIDS; and
- BSAD has the potential to distort the Imbalance Prices. There are some aspects of how BSAD is calculated, and incorporated into the Imbalance Prices, which are not consistent with other areas of the Imbalance Price calculation.

Other key messages of the Group based on the topics of discussion are:

- The aim of cash out prices should be to reflect the short term costs of the SO balancing energy on the system such that these costs can be targeted onto those Parties who are out of balance. This would provide the correct incentives on Parties to trade and attempt to balance to an efficient level;
- Economic theory for a normal commodity suggests that a single marginal price would produce the most efficient market outcomes. There are, however, a number of characteristics of electricity, plus the specific electricity market design that mean that a single marginal price might not be the best solution for a residual balancing electricity market;
- Spread is a side effect of having a dual cashout arrangement and should not be considered an issue in itself. This is essentially a consequence of how the main and reverse prices are calculated;
- There was Group consensus that the current RCRC mechanism is fit for purpose, and achieves what it was designed to do. There was a minority view that the RCRC mechanism could be used to artificially correct existing distortion. The Group noted that the current size of RCRC (currently over £100m annually), and believed this to be a symptom of having a dual cash out arrangement, and the way in which those cash out prices are calculated;
- There may be merit in bringing BSAD and BSC under single governance. However, this is likely to take significant legal unpicking of the Transmission Company's licence. The Group noted that further BSAD work would be best considered after the Governance Review and SO Incentives review; and
- A Half Hourly Balancing Energy Market (BEM) needs to be assessed in terms of whether the long term benefit to competition and efficient investment that might accrue under a BEM, outweigh the increased SO balancing costs and any other identified detriments. Significant analysis would be required prior to being able to take a definitive view on a BEM, potentially utilising academia. However, in regards to the straw man BEM model discussed by the Group, (which attempted to create a clear differentiation between a price for half hour energy balancing and all other SO activities to balance the system), the majority of the Group believed that this is unlikely to produce a fairer differentiation of system and energy

actions than the current arrangements. When looking at the BEM on its own it could be argued that certain benefits would accrue for the market. However, when looking at the market as a whole (including forward markets, spot market and the Balancing Mechanism (BM)), any currently existing imperfections may not necessarily be resolved. They could simply be moved elsewhere. Additionally, the BEM concept, whilst being afforded more definition under the Issue Group, would still require significant development into a workable solution for which useful analysis could be undertaken;

- Some useful insights can be gained from observing other markets. However, the physical attributes of the GB system and those in other markets should be considered in order to understand if they would be appropriate for the GB market;
- Industry currently has to consider different areas of governance separately. It would be useful to have a forum where the 'bigger picture' view could be taken. The Group noted, for example, potential changes to Transmission Access under the Connection and Use of System Code (CUSC) is fundamental to the whole market. The Group noted that Ofgem has instigated the Governance Review;
- The Group suggests analysis would be required to support any fundamental changes to the arrangements. Such analysis is likely to be very significant, and therefore requires a clear mandate, and would potentially benefit from assistance from academia; and
- There are currently two open pricing/cashout Modifications, with ongoing work in regard to the cashout arrangements[1]. Any Modifications raised will be assessed against the current baseline, so any proponent of a new pricing/cashout Modifications should consider the existing Modifications and the impact of the timings of these.

3 Recommendations

3.1 The Panel is invited to:

a) **NOTE** the discussions of the Issue 30 Group;

b) **NOTE** the key messages of the Issue 30 Group; and

c) **NOTE** that, following the submission of this report, Issue 30 will be closed.

Chris Stewart

List of attachments:

Attachment A: Issue 30 Terms of Reference.
Attachment B: 'Issue 30 BSAD analysis' - Presentation from Ofgem.
Attachment C: 'Allocation of Reserve Option Fees to Cashout' – Presentation from Libby Glazebrook.
Attachment D: 'Issue 30 RCRC analysis' - Presentation from Ofgem.
Attachment E: 'Issue 30 – Balancing Markets' - Presentation from Ofgem.
Attachment F: 'Balancing Energy Market – Straw man' – Presentation from Ian Moss.

[1] These are P217 'Revised Tagging Process and Calculation of Cashout Prices' and Modification P211 'Main Imbalance Price based on an Ex-Post Unconstrained Schedule'. Background documentation is available at: ELEXON - Modification Proposal P217 and ELEXON - Modification Proposal P211

Appendix 1 - Single vs Dual Price

Issue Group Summary

The Group considered the benefits and dis-benefits of each of dual and single pricing regimes. These are included in Appendix 2 along with more detailed Group discussions. The Group noted that the specific benefits and dis-benefits depend on the market structure associated with either of the regimes. Therefore, the Group were of the view that the question of single vs dual pricing is larger than just considering the cashout arrangements.

For example, the impact of having participants in the Balancing Mechanism (BM) paid for their bids or offers that were accepted by the SO at the price they offer into the BM (known as 'paid as bid'), as opposed to paid the price of the last action taken by the SO to resolve the imbalance (known as 'paid as cleared' – i.e. a marginal price), changes the incentives faced by Parties. Whether a single pricing regime had a 'paid as bid' or 'paid as cleared' arrangement would change the merits of such a regime.

The Group agreed that economic theory for a 'normal' commodity suggests that a single marginal price would produce the most efficient market outcomes via providing the correct incentives. There are, however, a number of characteristics of electricity[2], (plus the specific electricity market design) that mean that a single marginal price might not be the best solution for the GB market (as a residual balancing electricity market). There is currently a dual pricing regime in place which is, in part, due to the fact that the characteristics of electricity lend themselves toward such a regime.

The Group felt that the key aim of the cashout arrangements should be to create a price that reflects the short term cost of energy balancing and then targeting those costs onto those Parties that causes the SO to take energy balancing actions. Therefore, analysis should try to establish how good a proxy the Imbalance Price calculation (under a single or dual regime) is for the short term costs of energy balancing.

The Group felt that any future proponents of a single Price should consider and, where necessary, seek analysis on:

- Will the arrangements produce an Imbalance Price that reflects the short term costs of energy balancing?
- Will a single pricing regime produce a more efficient market outcome in the GB electricity markets?
- How does electricity differ from other commodities and do these characteristics support a single or dual pricing regime?
- Will a single price alter Parties incentives to balance?
- There are many variants of a single price regime (for example, marginal price, average price, price average reference (PAR) or a price based on forward markets). Therefore consideration would need to given as to which is the most appropriate price construction;
- The implications that a single price will have on the BM;
- The effect on new entrants, market power, and different types of Party/Traders;

[2] For example, the inability for electricity to be stored; the Transmission System; trading a continuously delivered product in Half Hourly blocks; and the requirement for ancillary services (such as frequency keeping). These do not lend themselves toward a perfect competition model in which a single marginal price would, in economic theory, be considered an efficient market price.

- Impact on liquidity;
- Impact on SO costs and potential for greater ‘rents’ in the BM;
- Implications of single pricing when BM Bid or Offer Acceptances are settled ‘paid as bid’ i.e. the incentives to spill; and
- Potentially consider a hybrid type approach where there is a ‘single price’ with a small fixed spread (e.g. 5%).

Issue Group Further Discussions

Potential benefits of Single Pricing identified

The list of single pricing benefits includes:

- Economic theory suggests that, at any one time, there is only one market price for a commodity;
- Provides a single reference for financial transactions;
- Encourages financial hedging instruments (e.g. Contract for Differences (CfD));
- Potential reduction in transaction costs; and
- Potentially better overall system balancing due to reduced incentive to be long.

Potential Dis-benefits of Single Pricing identified

The list of single pricing dis-benefits includes:

- The potential to reduce forward trading (and therefore a resultant forward price);
- Incentive to spill when the system is short;
- Potential for the volatility of Final Physical Notifications (FPN’s) increases;
- Parties have less incentive to balance by the half hour;
- Those who are in imbalance in the opposite direction to the system effectively benefit; and
- A single price with an artificial spread would favour those Parties who have greater control over their imbalance positions (generally generators).

Potential benefits of Dual Pricing identified

The list of dual pricing benefits includes:

- Providing incentives to forward trade to avoid spread;
- Providing appropriate incentives on long and short Parties;
- Ensures imbalance in the opposite direction to the system is not unduly compensated;
- Incentive to be long creates incentive for Parties to provide their own reserve; and
- Potentially mitigates against market power abuse.

Potential Dis-benefits of Dual Pricing identified

Note that some of the dis-benefits below may be attributable to how the main and reverse prices are calculated rather than dual prices per se. The list of dual pricing dis-benefits includes:

- The degree of complexity (some Group members noted that this could potentially a red herring);
- Difficulties to forecast price and therefore hedge against it;
- The market is restricted to pre-Gate Closure trading; and
- The RCRC mechanism is required (and exaggerated by the degree of spread).

Group Discussion

The Group noted that when evaluating the merits of a single price, the benefits will depend on the detailed methodology for calculating that price. For example, a single price that is calculated from forward trades (i.e. based on the current market price) would have a very different impact than a single price calculated from Bid Offer Acceptances (BOAs). Similarly, if the regime changed from one where BOAs were 'paid as bid' to 'paid at cleared price' then the benefits of a single price would differ. Therefore the group highlighted that any change to a single price may require additional market restructure.

The Group noted that the aim of cashout prices should be to reflect the short term costs of the SO balancing the system so that these costs can be targeted onto those out of balance. This would provide the correct incentives on Parties to trade and attempt to balance to an efficient level.

The Group considered that a single marginal price, that fully reflects market information, is the most efficient price for a commodity where there is 'perfect competition'. However, the nature of electricity as a commodity is different to most others, and does not necessarily lend itself to a 'perfect competition' model. Electricity:

- Cannot be stored;
- Currently incorporates Gate Closure to enable the System Operator (SO) to balance the system;
- System balance is achieved by SO actions. Each action may be taken for one, or a multitude of reasons;
- Requires many ancillary products; and
- Is a product that is continuously delivered, but is traded in (currently half hour) blocks.

Therefore, these characteristics of electricity do not necessarily favour single marginal price models as a best solution. Indeed, the difficulty in establishing what actions should be included in a 'price stack' to establish a marginal price (as seen in recent cashout modifications debates), might steer an optimal solution away from a pure marginal price.

A single price would facilitate simplification of the market by having one price to reference forward trades and financial hedges against. A single price is likely to reduce transaction costs as well as the costs of managing risk, and therefore increase the ease of doing business. This might be beneficial to new entrants, although the Group noted it is still possible to establish a reference price under a dual pricing regime.

Under a single pricing regime there would be a reliable reference price against which financial trades can be settled. Financial hedging instruments and risk management tools (such as Contract for Differences (CfD)), may further develop as a consequence. This could lead to efficiency gains. Conversely, there is the potential for a reduction in liquidity and efficiency in the forward and spot markets as CfDs are would move volume away from these markets. An increase in the number of CfDs might therefore move trading away from forward and spot markets. The Group also noted that it is likely that a premium will be associated with forward contracts based on a single price.

Additionally, the Group noted that a single price would impact Parties balancing behaviour and overall system balancing. This is due to a potentially reduced incentive for Participants in the market to be long, given Parties would be less concerned with avoiding SBP. If the perceived volatility of SBP is reduced, then Parties would seek to come closer to balance in each Settlement Period, bringing the market as a whole closer to balance in each Settlement Period. A counter argument is that, with no reverse price, this would increase the price received for spill and could encourage Parties to maintain length.

However, an increase in the proportion of CfDs at the expense of forward contracts may also alter the incentives on Parties balancing behaviour. This is due to the nature of CfDs providing less incentive to balance in individual half hours, provided the Party can balance across a longer time period (e.g. a day).

The Group queried whether it would be appropriate to have a pricing regime (such as a single price) where a Party can benefit from inadvertently being in the opposite direction to the system. Additionally, a single price regime where one price[3] that is applied to Parties imbalances, regardless of whether their imbalance is in the same direction as the system, might encourage Parties to speculate on system length (whether the system is long or short). Once a Party had taken a view on the direction of the system, there would be incentive to take a position contrary to the overall system balance.

For example, if a Party believed the system would be short, and all imbalances were to be cashed out at SBP, then there is incentive to spill on to the system and receive SBP for that volume. The reverse might also occur when the Party believes the system is going to be short. The result would be swings in individual imbalances from long or short dependent on their view of the system imbalance. The Group highlighted that the Information Imbalance charges, which are currently set at zero, could be used to address this issue.

The Group discussed what impact a single price might have on Party submission of ‘Physical Notifications’ (PNs). Where a Party speculates on the system direction (as identified above), they are taking a risk that their speculation proves to be wrong. Therefore, a Party will make its assessment of system direction as close to Gate Closure as possible. This could result in Parties revising their PNs frequently in the run up to Gate Closure. Such revisions could also be significant if a Party wishes to alter their position from one of spill to under provision (as their assessment of system direction has changed). This would not assist the SO’s ability to balance or its own forecast of the net Imbalance volume. It could also result in National Grid having entered into unnecessary PGBTs.

The Group discussed that there would be little incentive to submit contract notifications under a single price regime. This is because the net combined cashflow of two contracting Parties would be zero, and one could pay the other without the need to inform central systems. The Group was unsure whether this would happen in practice. The Group believed that this would be an outcome from single pricing but acknowledged that arguments could be made as to whether this is a benefit or a dis-benefit.

The Group noted that in a residual balancing market, you can always split the market into two types of Party: those who are long, and those who are short. Therefore, it could be considered appropriate that these different types of Party face different prices (i.e. a dual pricing regime).

A dual price does not reward Parties being out of balance in the opposite direction to the system to the same degree that a single price would. One member commented that a dual price is about the need to have a reverse price which ensures Parties are not unduly rewarded for spilling onto the system.

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[3] SBP when system is short, and SSP when the system is long.

The Group noted that a dual price can have opposing impacts on Party incentives. There is an incentive to go longer than under a single price regime because of the threat of SBP. Thus Parties are effectively providing their own reserve under a dual pricing regime. The Group questioned whether this was more or less efficient than the SO providing this reserve. The opposing impact is that the reverse price by its nature reduces the price for spill thus providing less incentive to be long. The Group could not determine without analysis which impact is likely to dominate.

The Group also believed that a dual price helps to mitigate against market power that could exist under a single marginal price regime. Market power could be wielded when a Party realises that they are the marginal unit available to the SO in the Balancing Mechanism. The Party could then price more keenly to take advantage of this. It is this price, strongly influenced by the marginal unit, that sets the Imbalance Price for the entire market under the single marginal price regime. Such a regime is likely to favour generators as they have greater ability to participate in the BM.

The Group noted that there was a view that a dual pricing regime would be more complex than a single regime. However, the Group noted this could be a red herring because ultimately it would depend on how a single or dual price is constructed.

It was agreed that, whilst not impossible, it is more difficult to establish a reference price from a dual regime from which to form a hedging strategy around. This is because it is expected to be more difficult to forecast dual prices than a single price. This is likely to be a bigger issue for new entrants than established Parties. The Group also acknowledged that a dual price is likely to favour vertically integrated Parties given that their risk and exposure to volatility apparent in a dual pricing regime is reduced.

Finally, the Group noted that dual pricing means that an RCRC type mechanism is required, and this favours those Parties who are better at balancing. However, the Group believed that it was true of any market that those who are less able to forecast well will have to pay more. This provides incentive to invest in forecasting, flexibility and reliability that benefits the market as a whole.

Appendix 2 – Spread

Issue Group Summary

Spread is the difference between System Buy Price (SBP) and System Sell Price (SSP) (of which one is the 'main' price and one the 'reverse price' depending on the length of the system).

The Group noted that spread is a side effect of having a dual cashout arrangement and should not be considered an issue in itself. If the degree of spread is considered to be inappropriate by any Party, then the Group believed this is essentially an issue with how the main and reverse prices are calculated and focus should be on getting these 'right'. Some members believed that spread is representative of a current market reality, which is that it is more expensive to increase generation than it is to decrease it. For example, a gas fired generation plant that is running below capacity would be required to burn additional fuel to increase its output. Regardless of the efficiency of the plant, the added fuel burnt is an added cost. However, in order to decrease its output, the plant saves on the fuel it does not use.

In particular, the Group queried whether the current calculation of the reverse price, which is based on short term trades in the forward market, is appropriate. The fundamental question of 'what is the purpose of the reverse price?' needs to be addressed. The market price does not, on average, fully move to the level of the main Imbalance Price because of the uncertainty (of price and system direction) associated with trading 1.5 hours prior to the start of the Settlement Period.

Currently, the purpose of the reverse price is to be an indifference price to what a Party could have traded in the within-day markets if that Party could have traded forward with perfect knowledge. The Group believed that there could be merit in challenging whether this is the correct principle for the reverse price. For example, the principle could be to have a reverse price that was incentive related, or reflective of SO costs, and therefore result in a different calculation. As a side effect of a new methodology to calculate the reverse price, spread could be reduced.

If the current principle of an indifference price is believed to be the correct one, then the current MIDS could be reviewed to put more weightings on those actions that occur closer to real time. Additionally, moving Gate Closure closer to real time would, on average, be likely to result in market prices that are closer to the main Energy Imbalance Price (due to the increased ability to forecast accurately as you get closer to real time).

No Group members indicated that, taken on its own, spread was detrimental. The Group agreed that spread actually provided an incentive to contract ahead of Gate Closure. Reducing this incentive could result in less liquidity in the forward market, and it is the liquidity that helps Parties to manage their risk. Promoting forward trading also reduces perceived market power.

The Group recognised that there might be some Parties who were not represented on the Group who see spread as detrimental. Therefore, some Group members attempted to put themselves into the shoes of other Parties. Such Parties might find it more difficult to access the balancing services they require within day and therefore receive, or pay, relatively unattractive prices for output/purchases. The members suggested that the issue is not so much one of spread, but that SBP is too high, too volatile, and therefore it detrimentally impacted some participant's businesses.

Additionally, concern had been raised from certain Parties, that there was insignificant liquidity to be able to purchase the required volumes for these participants to balance. This has therefore left them exposed to the imbalance costs. Again, the Group believed that this was not an issue with spread but was fundamentally about getting the cashout prices as accurate as possible.

Appendix 3 - BSAD

Issue Group Summary

A presentation was provided by Ofgem to promote discussion. This is included as Attachment 2.

The Group noted that BSAD is an important element of Energy Imbalance Prices and if it was not as accurate as possible, then this has the potential to distort the Imbalance Prices and have perverse impacts on the market.

The Group discussed whether reserve option fees should be fully charged to out of balance Parties, fully socialised, or somewhere in between (as at present). The majority view was that, in principle, reserve availability fees should be fully targeted on those out of balance. However, practically it was unlikely to be possible to have full targeting, and therefore some form of partial recovery through cashout is appropriate. The current arrangements provide for partial recovery, but some members queried whether the current amount partially recovered could be considered the 'right' amount'. A minority view was that, because of economies of scale, it is cheaper and more efficient for the SO to procure reserve on behalf of individual Parties. This is similar to an insurance policy which benefits the market as a whole and therefore this cost should be socialised.

The Group noted that the Buy Price Adjuster (BPA) is designed to inflate SBP to reflect those short term costs attributable to option fees and BM start up costs. However the BPA and Bid Offer Acceptances (BOAs) are not treated consistently in cashout prices. BPA's are calculated based, in part, on historic utilisation[4], and targeted into Settlement Periods of expected usage, whereas BOAs are the actual volumes used in a particular Settlement Period. It was noted that the BPA is only added to the SBP when the system is short, and there could be an argument for applying this to SBP when the system is long (and SBP is the reverse price) such that short Parties still have these costs targeted on them.

One member provided an alternative way in which option fee allocation could be incorporated into cashout through the BPA (see presentation included as Attachment 3).

The proposed methodology would alter the current allocation of reserve option fees from one which is based on historic utilisation to one which is based on expected utilisation. The SO would have to identify the top 100 super peak hours and next 400 peak hours in advance. The cost of the option fees would therefore be allocated into these periods based on a specified methodology. In this way, the cost allocation would be known in advance.

The Group believed that such a methodology could have merit although it was noted that in order to obtain an expected usage, this is likely to be based on historic patterns. This would essentially not be much different from the existing methodology.

The Group then discussed BSAD governance. Imbalance Prices are impacted (sometimes significantly) by certain variables[5] that are produced under the BSAD Methodology Statement which are inputs to the price calculation. The BSC Modification Process can alter how, and which of, these variables is included in the Imbalance Prices. However, BSAD Governance administered by National Grid is the only route to change the calculation of those variables.

[4] Short term Operating Reserve (STOR) is based on historical utilisation, whilst BM start up in based on the actual requirements on the day.

[5] This includes the BPA, SPA, the energy Buy and Sell Price cost adjustments (EBCA and ESCA respectively), the energy Buy and Sell Price volume adjustments (EBVA and ESVA respectively), and the system Buy and Sell Price volume adjustments (SBVA and SSVA respectively)

The Group agreed that there could be merit in bringing BSAD and BSC under single governance. However, this is likely to take significant legal unpicking of the Transmission Company's licence. Additionally, there were also complex practical issues around the IT systems and around how the changes to this would be paid for.

The Group noted that, since a major difference between current BSAD and BSC governance is that Parties cannot bring forward change proposals to BSAD governance as it can under the BSC, the BSAD change process is not as robust. Some of the Group believed that, as a minimum, it would be useful for the BSAD change process to have a requirement for a BSC impact assessment. It was also noted that the Transmission Company had proposed that any issues associated with BSAD should be debated within the BSC framework in the event that any issues or modifications regarding cash out prices were raised there.

The Group agreed that the Ofgem led Governance Review that was initiated in November 2007 was of particular relevance and noted there was some desire within the Group to bring the BSAD and elements of the BSC under single governance. Support for this would depend on the detail of how this was achieved, and therefore the Group believed it would be useful to wait until the outcome of the Governance review before pursuing BSAD governance changes further.

Issue Group Further Discussions

Ofgem provided a presentation to promote discussion on BSAD. This is included in Attachment 2. There were 2 main areas identified by Ofgem for consideration. These were reserve availability fees and reserve creation. Reserve availability fees are the option fees that the SO has to pay to ensure that plant is available should they want to bring it onto the system within agreed timescales. Reserve creation is where the SO buys energy in the BM to get the plant in a position to provide reserve. Crudely speaking, the SO buys reserve to the level they believe the market will be out of balance[6]. The SO bases the requirement on historic analysis and products are bought based on NGs economic and efficient licence obligations.

Ofgem have estimated that only 27.5% of reserve availability fees were recovered through cashout in 2006-07. There were 3 potential reasons for this. First, that the Buy Price Adjuster (BPA) is only added to SBP when the system is short. This was only 26% of periods in 2006/07. Second, not all contracted reserve is utilised. Finally, the BPA excludes BM start up that is used for constraint management. The presentation queried whether there should be full, partial, or no recovery through the cashout arrangements, and whether the current methodology is appropriate.

The presentation queried whether a revised BSAD methodology could be developed to improve cost targeting for reserve creation. It highlighted that cost targeting is problematic for reserve creation. Specifically, costs of creating reserve might be incurred in Settlement Periods prior to the period in which reserve is utilised. Therefore the costs might be being reflected into cashout, but into the wrong Settlement Periods. This poses the question, if reserve is not targeted into the right Settlement Periods and onto the right Parties, then should the cost be socialised? Further, the presentation queries whether it is appropriate to target all reserve creation into cash out as some reserve creation might also have system balancing elements. The presentation noted that analysis for January to September 2007 indicated that 42% of Offers and 48% of Bids taken for reserve are also taken for other balancing purposes.

The Group's initial discussion was based on this presentation and whether reserve should be included in cashout prices or not. One Group member noted that, when the system is short, reserve creation also resolves energy imbalances, and therefore should be reflected in the main Energy imbalance Price calculation. Additionally, it was their view that, in principle, reserve availability fees should be fully targeted on those out of balance. However, practically it was unlikely to be possible to have full targeting and

[6] Technically the SO buys reserve to 2.78 times the standard deviation in the forecast error.

therefore some form of partial recovery through cashout is appropriate. Because some reserve is required for intra half hour purposes, and the targeting of this is not going to be perfect based on half hourly Imbalance Prices, the pragmatic approach is to not attempt to fully recover the reserve availability costs.

One member noted that because of economies of scale, it is cheaper and more efficient for the SO to procure reserve on individual Parties behalves. This is similar to an insurance policy which benefits the market as a whole and there is an argument that could be made that this should be socialised.

Another member believed that, using the insurance policy comparison, a higher premium is usually paid by the higher risk party covered by the insurance. Insurance products are dependent on the risk profile of the purchaser. Expanding on this analogy, a Party that is out of balance more often, and at periods where the cost of reserve is greater, would expect to have to pay proportionally greater insurance premiums than the norm. Therefore, by socialising the costs of reserve, those Parties that are less able or willing to balance their energy positions are effectively being subsidised by those that do balance their energy positions more fully.

A further view was that reserve is required because Parties cannot balance in real time. If all Parties balanced there would no need for reserve. A Group member disagreed and believed that reserve would still be required by a prudent SO even if all Parties balanced perfectly because there was always a risk that a Party would not balance. The member believe that if there is still a cost for reserve when all Parties are in balance, then this should be a socialised cost as it benefits all participants.

One member believed it was important to differentiate between cost recovery and cost reflectivity. Cost recovery occurs via Balancing Services Use of System (BSUoS) charges. However, in terms of the main Energy Imbalance Price, this should reflect the short term costs of balancing. The BPA mechanism is designed to inflate SBP to reflect those short term costs attributable to availability fees and BM Start Up costs.

However the BPA and Bid Offer Acceptances (BOAs) are not treated consistently in cashout prices. BPA's are calculated based on historic utilisation of STOR and on actual incurred BM start up costs and targeted into Settlement Periods of expected usage, whereas BOAs are the actual volumes used in a particular Settlement Period. The member also noted that the BPA is only added to the SBP when the system is short, and there could be an argument for applying this to SBP when the system is long (and SBP is the reverse price) such that short Parties still have these costs targeted on them.

One member provided an alternative way in which option fee allocation could be incorporated into cashout through the BPA (see presentation included as Attachment 3). The member noted the principles of option fee allocation should be that it is well signalled, it should reflect actual usage, and should allow for prompt price reporting. The member added that the elements of being well signalled and reflecting use are difficult to align.

The proposed methodology would alter the current allocation of reserve option fees from one which is based on historic utilisation to one which is based on expected utilisation. The SO would have to identify the top 100 super peak hours and next 400 peak hours in advance. The cost of the option fees would therefore be allocated into these periods based on a specified methodology. In this way, the cost allocation would be known in advance.

The Group believed that such a methodology could have merit although it was noted that in order to obtain an expected usage, this is likely to be based on historic patterns. This would essentially not be much different from the existing methodology.

The Proposer's representative highlighted that the Proposer of Issue 30 had raised the issue of BSAD from the perspective of governance being an area which might benefit from improvement. He stated that there needed to be an efficient change process and there should not be fragmented governance.

The Group noted that BSAD governance was pursuant to the Transmission Company's licence conditions. Imbalance Prices are impacted (sometimes significantly) by certain variables[7] that are produced under the BSAD Methodology Statement which are inputs to the price calculation. The BSC Modification Process can alter how, and which of, these variables is included in the Imbalance Prices. However, BSAD Governance administered by National Grid is the only route to change the calculation of those variables.

The Group was not aware of any reasons why these could not be brought under a single Governance. The Transmission Company representative believed this was possible, but did note that the legal wedge between BSAD and the BSC governance that exists under its licence obligations would be likely to require considerable unpicking. There were also complex practical issues around the IT system and around how the changes to this would be paid for.

A member observed that if National Grid develops any new reserve product, then how this is incorporated into the BSC cashout variables is subject to a 28 day consultation under the BSAD governance. The member also noted that Parties cannot bring forward change proposals to BSAD governance as it can under the BSC thus the change process is not as robust. This is an inconsistent element of the different governance arrangements.

The Transmission Company representative noted that no Party had come to them expressing a desire to change the BSAD Methodology Statement. It was also noted that the Transmission Company had proposed that any issues associated with BSAD should be debated within the BSC framework in the event that any Issues or Modifications regarding cash out prices were raised there. This was indeed the case under P217.

It was noted that there were historic reasons for having the separate governance, and it was historically believed to be more efficient to allow the BSAD change process to not be subject to the same rigours as BSC changes.

The Group believed that BSAD impacts on cashout prices is a prime example of how things done outside of the BSC have the ability to impact it. Some of the Group believed that, as a minimum, it would be useful for the BSAD change process to have a requirement for a BSC impact assessment.

The Group agreed that the Ofgem led Governance Review that was initiated in November 2007 was of particular relevance and noted there was some desire to bring the BSAD and BSC under single governance. Support for this would depend on the detail of how this was achieved, thus the Group believed it would be useful to wait until the outcome of this review before pursuing BSAD governance changes further.

[7] *Include variables*

Appendix 4 – RCRC

Issue Group Summary

A presentation was provided by Ofgem to prompt discussion. This is included as Attachment 4.

There was Group consensus that, if you assume the Imbalance prices are fit for purpose, then the current RCRC mechanism is doing what it is meant to do. That is, it redistributes the surplus or deficit funds that need to be allocated to Parties after the Settlement of energy imbalances, the Balancing Mechanism (BM) and the System Operator (SO) BM charge. Furthermore, it redistributes surplus or deficit funds proportionally, according to the level of BSUoS charges paid by Parties.

Some members noted that a piece of analysis that could be completed to help verify whether the RCRC mechanism is doing what it is meant to do is to work out the correlation between RCRC and the energy component of System Operator BM Cashflow (CSOBM). If the two are equal and in the opposite direction, then this would indicate that the current RCRC mechanism works well[8]. CSOBM is the amount paid by the SO in relation to the operation of the BM. The analysis would highlight where they are different.

The majority view was that attention should be focused elsewhere within cashout as the RCRC mechanism works as it was intended to when NETA was designed. It accurately repays the cost of actions deemed to be taken by the SO for 'energy' balancing purposes to all BSUoS paying Parties, so that the cost of these actions is charged only to out-of-balance parties. BSUoS payers initially cover the cost of all the actions taken by the SO, both 'energy' and 'system'.

As the cost of 'energy' actions is also subsequently charged on imbalances, without the RCRC rebate, the cost of 'energy' would be recovered twice. The question is therefore a matter of whether 'energy' balancing actions are identified appropriately. The Group thought that it would be inefficient to try to address perceived cost-targeting problems by adjusting a mechanism that works as intended.

It was mooted that Parties could use the cashout arrangements to influence the size of RCRC and therefore their allocation. The majority of the Group did not believe it was possible to actively manage a trading strategy to take RCRC into account for a Parties benefit. There was a minority view that there could be an economic case made to give the surplus (if it was a surplus and not a deficit) to charity in order to remove any competition distortions.

The Group concluded that the idea of withholding a surplus from BSUoS paying Parties would, in economic terms, amount to a tariff; as it would be an additional charge, payable to a third party, proportional to metered volumes. The majority believed that it would be contrary to the development of an efficient market to introduce a tariff mechanism in order to foster greater competition. It was also noted that customers would ultimately pick up such an additional charge, which would also be counter to the interests of the market.

There was a minority view that the RCRC mechanism could be used to artificially correct existing distortion of Energy Imbalance Prices that exists due to the inability to remove system elements from the calculation. Parties that find it systematically more difficult to balance in a Settlement Period face an imbalance price that is considered to be 'polluted'.

However, the reallocation of those cashflows is based on metered volumes. Thus a participant that finds it more difficult to balance pays proportionally more into the pot (when it is a surplus), but this is not distributed based on the same proportions. Therefore, the suggestion of the minority is that RCRC could be

[8] This could be based on Ofgem's flow diagram on slide 6 of Attachment 4.

used to mitigate the distortion that exists elsewhere in the market. One suggested option was that this could potentially occur by distributing RCRC based on Parties imbalance levels. Considering this idea, the majority of the Group thought that it would be more appropriate to look for a better method of removing system elements from the calculation than it would be to adjust a separate mechanism to artificially account for the perceived 'pollution' problem. The Group noted that modifications P211, P212 and P217 all sought to account for system balancing actions in new ways, indicating that the perceived problem is not considered to be insolvable.

It was noted that whilst some Parties might find it systematically more difficult to balance, that those that generally balance more accurately can do so because of significant investment in forecasting, flexibility and reliability to reduce this imbalance exposure. Having incentive to invest in accurate forecasting, flexibility and reliability should be desirable.

Issue Group Further Discussions

Ofgem provided a presentation to the Group to promote discussion on RCRC. In this presentation Ofgem looked at historic RCRC, the relationship between RCRC and BSUoS, the estimated contributors to RCRC and the impacts of different cashout arrangements on RCRC generation.

The presentation highlighted that the current cashflows generated are significant and this has steadily increased in recent years. It was also noted that the level of RCRC is larger during the peaks, potentially due to larger spreads occurring during the peaks.

In looking at the relationship between RCRC and BSUoS, Ofgem noted that theoretically, RCRC should equal the energy component of BSUoS. However, they identified 3 reasons why they are not. These are:

- The system pollution in cashout prices;
- The mismatch between energy balancing costs and imbalance charges; and
- Imprecise recovery of Balancing Services Contract Cost availability fees in cash-out prices.

Ofgem highlighted that from their modelling (with no system pollution), a single cleared marginal price would result in a match between RCRC and BSUoS. However, under the current arrangements, there would be a mismatch that was due to the effect of system pollution and the effect of dual pricing.

One member suggested that the reason for the increase in RCRC could be the introduction of P205 'Increase in PAR from 100MWh to 500MWh' in November 2006. Under P205, the member expected the SO to be recovering more £/MWh from short Parties given the expected increase in SBP, but still only paying 'as bid'. However, another member noted that the incentives of P205 should have been to reduce the occasions when a Party is short[9]. The member expected there to be a correlation between NIV and RCRC. Analysis on this correlation could prove useful.

The majority of the Group believed that dual pricing is the single biggest factor in the make-up of RCRC. Additionally, RCRC should be considered a 'red herring' as the mechanism works as it is designed to. Any problems with the level of spread should be addressed through improving the calculation of the imbalance prices. One member queried whether the reverse price should be modified from being based on market price, to one in which spread (and thus RCRC) is reduced.

One member's view was that there is usually a RCRC surplus on average, and this should be rebated to ensure there are no perverse incentives. The member questioned whether there were competitive distortions

[9] Recent analysis for P217 indicates that the market is becoming less long. In 2006, the market was short (NIV>0) in 20% of Settlement Periods in 2006, but in 2007 this increased to 40% of Settlement Periods.

from how this is currently distributed back. A potential way to do this would be to net RCRC off BSUoS before it is rebated. This was recognised in the original NETA design document as a potential option. The majority of members suggested that Parties did not take expected RCRC rebates into account when making their trading decisions. It is not simple to predict and BSUoS charges effectively net off any benefit.

Appendix 5 - Gate Closure

Issue Group Summary

The Group noted that there is the potential to gain market benefits by improving the Contract Notification process and/or reducing Gate Closure.

The Transmission Company representative noted that there is no fundamental reason why Gate Closure could not be reduced from the current 1 hour. The representative did however note that the physical restrictions on plant capability ('plant dynamics') have not recently changed. Part of the reason for having a 1 hour Gate closure was that this corresponded with the 90 minute time required for many generation plants to deviate from zero. (Therefore at 1 hour, a plant could be on and generating by the end of the Settlement Period for which Gate Closure applies). Were Gate Closure to reduce below 1 hour, the SO will still have to instruct this plant based on its dynamic capabilities and would therefore have to take more pre Gate Closure actions (for example, Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs)). This might reduce the SO's flexibility to manage the system.

The Group noted that whilst there may be some extra costs to the SO to manage a reduced Gate Closure, the key question is whether this would be more economic and efficient for the market as a whole. That is, would the gains for the industry as a whole, attributable to reducing Gate Closure, exceed the extra costs on the SO to manage the reduction?

One member queried whether the time to deviate from zero might be 90 minutes because of the existing one hour Gate Closure, and not the other way around. However, it was noted that Parties do have obligations to submit accurate information about plant capabilities to the SO and therefore, if a Party should not submit a Notice to Deviate from Zero (NDZ) that corresponds to the amount of time between Gate Closure and the end of the relevant Settlement Period.

To be able to plan to balance the system in real time, it is the Physical Notifications that are critical to the SO. It was noted that Nord Pool allows for trading up until real time, but this was simpler for their market which has significant volumes of flexible plant to react in real time.

It was suggested that a shorter Gate Closure would reduce some Parties imbalance risk, because the closer they are to real time the better their forecast ability (and ability to respond to plant trips). However no analysis to support or reject this view has been established yet. This should reduce imbalance on the system. However, it was acknowledged that trading closer to real time will only occur if Parties believe they are able to achieve a better price than in the Balancing Mechanism.

Any potential proponent for reducing Gate Closure, would have to give thought as to how this would impact the Balancing Mechanism and the amount of plant available to the SO to dispatch. There could be potentially large system changes for the SO to be able to allow for more short term decision making. Additionally, if the SO has to participate more in the forward market because of its reduced ability to get the plant it needs in the BM, then the impact on forward market liquidity should be considered.

A potential 'quick win' identified by the Group is to extend the current Contract Notification process to allow for notification after Gate Closure. This is because Parties effectively have a 1.5 hour Gate Closure due to the time it takes for the Contract Notification process (particularly the time between submission and confirmation) to be completed by central systems[10]. The risk presented by not having Contract Notifications accurately submitted means that Parties were less inclined to trade up until Gate Closure. The Group could not identify any reason why the Contract Notification process for trades occurring prior to Gate Closure could

[10] The APX market for within day trades closes 1.5 hours before the start of the Settlement Period for this reason.

not be extended after Gate Closure. This is one area the Group suggested could provide benefits were a Modification to be raised. Any proponent of such a modification might wish to consider the potential that allowing Contract Notifications after Gate Closure will allow for Parties to game.

The Group noted that reducing Gate Closure could potentially help to reduce spread by increasing the trading close to real-time. This could be via making the reverse price more cost reflective (assuming product weightings in the reverse price change accordingly). Additionally, capacity could be made available and contracted in the market rather than the BM due to greater information on plant availability and demand forecasts closer to real time.

Appendix 6 - Half Hourly Balancing Energy Market

Issue Group Summary

The Group noted that, as there is no explicit definition of whether a balancing action is system or energy, the main Energy Imbalance Price calculation effectively deems each action into one of these categories. Such differentiation between system and energy can only ever be a matter of judgement.

The current live pricing Modification Proposals (P211 'Main energy Imbalance Price based on an Ex-post Unconstrained Schedule' and P217 'Revised Tagging process and Calculation of Cashout Prices') reason that the existing arrangements have inappropriate differentiation between system and energy. The underlying assumption of these Modifications is that the current arrangements include too many system actions, and therefore, too many (expensive) actions are unfairly included in the main Energy Imbalance Price Calculation.

Ofgem provided a presentation to prompt discussion on a Balancing Energy Market (BEM). This is included as Attachment 5. It was mooted that the arrangements should move much further towards providing a price that is more representative of only energy actions. The suggestion is that, by completely isolating the energy component of volumes submitted for into the Balancing Mechanism (BM), and by quantifying that energy exclusively in uniform chunks (half hour at present), we could arrive at a better definition of energy. This would be one that would be more appropriate in a free trading power market.

A member of the Group produced a more detailed straw man model of the idea of a BEM based on principles set out in Stephen Littlechild's theoretical proposal to the Ofgem-led Cash-out review. This model is set out in the presentation included as Attachment 6. The key feature in the model is that the SO would buy and sell only half hour units of isolated (non BMU specific) energy from production and consumption accounts to clear the forecast Net Imbalance Volume (NIV). The Imbalance Price would then be established against actual NIV in current prompt price timescales. Every other action would be deemed to be system and taken in the post Gate Closure BM.

The model therefore has the potential to successfully create a perfect commodity market for part of the electricity market. Looking at this new BEM on its own, the Group believed that some benefits of an efficient market might accrue. Competing buyers and sellers would trade the right quantity to settle each NIV at the equilibrium market-clearing price. It could be envisaged that the equilibrium price would lower to the point of marginal cost and the price mechanism itself would protect all traders from market power held by the bigger players and, therefore, develop competition.

The Group's conclusion was that electricity, as a whole, cannot really be considered a commodity. The BEM would be only one component function of the overall GB (or in time, European) electricity market, which also includes the forward market, spot market and BM. The overall market is imperfect (due to the nature of electricity), which is why it has to be regulated. Replicating the features of a perfect market in one of its functions (i.e. the BEM) doesn't make the whole market (i.e. including the forward market, spot market and BM) any less imperfect. Instead, problems are moved from the BEM to the other areas of the whole market.

The economic term for the additional costs of managing constraints is that these are negative externalities. These are social costs that arise, but would not be priced in the BEM. As such, their existence is an example of market failure. In the BEM straw man model presented to the Group, a trader can nominate from where they deliver the power they've sold to the SO. This choice could, conceivably, create additional constraints that the SO could not manage until the BM opened. Because such individual actions of the trader would be socialised (given that the BM costs would be socialised under this BEM model) this could be detrimental to competition. One member noted that this can currently occur right up until Gate Closure so the situation in the straw man model would be no worse than under the current arrangements.

Additionally, the Group noted that a BEM could move liquidity away from the forward markets.

The Group considered that a Half Hourly Balancing Energy Market (BEM) needs to be assessed in terms of whether the long term benefit to competition and efficient investment that might accrue under a BEM, outweigh the increased SO balancing costs. Significant analysis would be required prior to being able to take a definitive view on a BEM, potentially utilising academia.

However, in regards to the straw man, which attempted to create a clear differentiation between a price for half hour energy balancing and all other SO activities to balance the system, the majority of the Group believed that there is unlikely to produce a fairer differentiation than the current arrangements.

Future proponents of the idea would have to quantifiably prove that market positives gained in the BEM would outweigh additional negatives arising in the BM. Furthermore, they would have to show that the perceived benefit for out-of-balance Parties being cashed out using ‘purer’ cash out prices, would outweigh the downside of additional social costs picked up in the BM. Finally, they would have to explain why the BEM commodity market could ignore half hourly volumes taken in price order in the BM; essentially identical products but traded outside the proper market and under different terms.

Issue Group Further Discussions

Ofgem provided a presentation to the Group to promote discussion on Balancing Markets.

This presentation noted that recent pricing Modifications have proposed alternative methodologies for separating ‘system’ from ‘energy’ balancing costs. A Balancing Energy Market (BEM) takes a different approach by setting up entirely separate platforms. Effectively, everything in the BEM is considered ‘energy’ and everything in the Balancing Mechanism (BM) is considered ‘system’. The key questions to be considered are, is a BEM practical, and would it be efficient?

The presentation noted that a BEM may enable trading to occur closer to real time. This would be beneficial because the market should facilitate a Party self balancing. It was also noted that there were similar arrangements in the UK gas market as well as the Dutch and Texas electricity markets. Some members pointed out that the physical nature of those markets were fundamentally different from the UK electricity market, and would mean that there could be reasons that such arrangements could not be easily applied here. For example, the Dutch transmission system is less likely to be subject to transmission constraints. The presentation also suggested that implementation of a BEM could be complex, but would represent evolution from the existing open Modifications that have recently been proposed by BSC Parties.

The presentation listed some potential advantages and disadvantages and offered two variations of a Balancing Market for discussion. The first was a ‘split BM’ where there are essentially two BM phases. The first phase would be for energy balancing to clear forecast NIV prior to the Settlement Period and the second phase was for system balancing in real time. The second variation of a BEM was ‘continuous trading’ where a Power exchange is appointed to operate a BEM over a short period in the run up to each Settlement Period.

The Group noted that a ‘split BM’ loses an element of reflecting the costs of the SO in balancing the system. This is because the actions taken to balance the system in the BM would also be resolving energy imbalances. The energy imbalances might occur due to the imperfect knowledge available to parties when participating in the BEM. The ‘continuous trading’ variant retained some link to the SO actions to balance and would require the SO to effectively buy more PGBTs.

One member queried that, if there was demand for a ‘split BM’, then why has this not evolved naturally? Is the suggestion that, if it was forced on the market that there would ultimately be some benefits that accrue from this?

The Group noted that the BEM arrangements assume that the SO is the only buyer. Forecasting NIV accurately is not an easy exercise and would be critical to Imbalance Prices that result from it. There is also a more fundamental question of whether the BEM should be seeking to resolve NIV, or be a means for Parties to resolve their individual imbalances? NIV is irrelevant if resolving individual Parties long and short volumes. Additionally, would the volumes be traded have to be matched by physical delivery? If the SO is buying energy in the BEM, it would require this energy to be delivered otherwise the problem of balancing is just shifted to the BM.

The Group noted that there would need to be penalties for non-delivery as there is under the current arrangements to ensure that incentives on Parties are correct. One member queried that with physical delivery there is not much difference between such a BEM and the BM. The Group also noted that energy is not physically delivered in half hourly blocks.

A member noted that any change to the Imbalance Price calculation required careful consideration. Getting Imbalance Prices wrong, as could occur if NIV forecasting is poor, could erode the market’s ‘health’, by providing incorrect incentives which drive forward trading.

A member of the Group produced a more detailed straw man model of the idea of a BEM based on principles set out in Stephen Littlechild’s theoretical proposal to the Ofgem-led Cash-out review. It was the view of the member that the prices submitted in to the BM by participants, reflect the cost of providing the services the SO requires to balance supply and demand in real time. The members view is that it is therefore impossible to extract a pure half hour energy price from these inputs. The member suggested that a BEM would provide incentives for different prices to be submitted to the BEM (as opposed to the BM) given it would be for the simple half hour energy blocks.

The key feature in the model is that the SO would buy and sell only half hour units of isolated (non BMU specific) energy from production and consumption accounts to clear the forecast Net Imbalance Volume (NIV). The Imbalance Price would then be established against actual NIV in current prompt price timescales. Every other action would be deemed to be system and taken in the post Gate Closure BM. A Party can nominate from which BMUs they deliver the power they’ve sold to the SO.

It was noted that the ability to nominate the BMU that delivers energy has the potential for Parties to exacerbate a constraint on the system so that they could benefit by being bid down in the BM. Therefore a player with a larger portfolio would gain a natural advantage. The proposer of the straw man queried how this was any different from the current arrangements where there is potential for Parties to take advantage of constraints. Another member noted that, because the BEM would allow for trading closer to real time that there is extra time for Parties to try to take advantage of constraints.

One member noted that the straw man would require an extension of current Grid Code obligations to include a requirement on all Parties who participate in the BEM to follow their Final Physical Notifications. The member also pointed out that the SO would effectively be ‘buying blind’. This is because dynamics and location of the energy will not be known until a revised Physical Notification is received.

A member believed there could be a contradiction with the SO incentives to minimise BM costs if they had to buy energy in the BEM and could not take into account plant dynamics or location. The Group noted that there could be higher SO costs as a result, but the question is whether a BEM would result in greater market efficiency. One member believed that the Imbalance Price is key to attaining overall market efficiency.

Therefore, analysis and modelling of a BEM solution should concentrate on the outturn Imbalance Prices and their expected impact on market behaviours and the market as a whole.

Another member raised the issue of intra half hour optimisation. As the BEM was one hour prior to real time, then plant with longer reaction time is effectively excluded from participating. Additionally, if NG uses its options to bring plant on, then would this plant be able to participate?

The Group view was that if a unit is available in the BM, then it can be made available in the BEM. Some members believed that you would achieve a 'cleaner' energy Imbalance Price from a BEM, but given some plant would be excluded, there could be a premium associated with this. One member noted that there should be a principle applied to cashout arrangements where plant dynamics are honoured.

The Group believed that there was potential for not enough bids or offers in the BEM to resolve NIV. Again, it was noted that this could happen in the current BM. The Group discussed if there would be different incentives to participate in one of the BM or BEM and not the other. This might be driven by the prices attainable under each.

One member suggested that the uncertainty of the SO forecast of NIV in the BEM could drive Parties to participate in the BEM to extract the premium associated with the uncertainty. The fact that the SO is obliged to resolve the NIV would be an additional incentive to participate. The Group also noted that whether the BEM would be 'paid as bid', or at a cleared marginal price would also affect participation. A proponent of the BEM should also consider when the forecast NIV would be published, as this may also encourage participation.

A member asked who would take on the contract notification risk under the BEM. It was suggested that, given the SO is the only counterparty, the BEM accepted bids and offers should be treated in the same way as BOAs currently are.

The Group noted that reserve would essentially be considered as system balancing actions under a BEM as it would be resolved in the BM. The majority of members felt that because reserve delivers actual energy to the system when utilised that it was appropriate for these costs to be targeted on those out of balance.

The Group noted that because more costs would be socialised under a BEM that those Parties that currently find it more difficult to balance are likely to benefit. The Group queried whether this places the correct incentives on Parties.

One Group member noted that they believed that original NETA principles provide incentives on Parties to minimise their own imbalance levels. The Group agreed that the BEM models have potential issues, these were resolvable but such a change would have a very large impact, and a lot of work would be required prior to its implementation.

The Group also considered more recent environmental and Governance issues which are areas that are becoming more pertinent when considering the appropriate arrangements. In the longer term, market arrangements that take into account environmental concerns might be required due to the targets put in place by central government.

The Group believed that the BEM straw man presented would need to undergo much more detailed definition for it to be effectively evaluated.

Appendix 7 – Reverse Price

Issue Group Summary

The Group considered the underlying principle of the current Reverse Price calculation. This is calculated according to the MIDS, and its purpose is to provide an indifference price for the Half Hourly block of energy. This is an indifference price against what a Party could have traded at if it had traded in the within-day markets with perfect knowledge.

The Group considered what actions should be included in the Reverse Price calculation. It was noted that as the price was meant to be reflective of the price attainable at Gate Closure, then ideally this would include only half hourly trades that occur very close to Gate Closure.

However, the issue is one of liquidity, and this is the reason that (in addition to half hourly trades) 2 hour and 4 hour trades within 20 hours of Gate Closure are also included. 8 hour, overnight trades, or trades outside 20 hours are excluded because historic analysis has shown that these are not required for liquidity in the majority of instances. The Group noted that in the last hour of forward market trading there is usually a dip in trades that occur, partially because of the Contract Notification risk.

It was noted that there is no reason why trades closer to Gate Closure, or of shorter duration cannot be given higher weightings in the reverse price calculation. This was achievable within the current MIDS and could be considered in a future review by the ISG.

Additionally, the Group suggested that another option to deal with liquidity issues is to agree a volume of liquidity required, and a list of qualifying trades, then move backward from market closure, incorporating all qualifying trades, until the liquidity threshold is met.

Appendix 8 - Background Documentation

Ofgem NETA Documentation:
- The new electricity trading arrangements, Volume 1, July 1999;
- The new electricity trading arrangements, Ofgem/DTI conclusions, October 1999;
- The review of the first year of NETA, Volume 1, July 2002; and
- The review of the first year of NETA, Volume 2, July 2002.

BSC Modifications:
- **P012** 'Gate Closure from 3.5 hours to 1 hour' (Approved) ELEXON - Modification Proposal P012
- **P026** 'Market Driven Trading Neutrality Band' (Rejected) ELEXON - Modification Proposal P026
- **P027** 'Amendments to the Derivation of Imbalance Prices (Rejected) ELEXON - Modification Proposal P027
- **P034** 'Transfer of Imbalances caused by Balancing Services to the Transmission Company (Rejected) ELEXON - Modification Proposal P034
- **P036** 'The Generation of Bid Offer Acceptances relating to Energy delivered as a result of providing Applicable Balancing Services' (Rejected) ELEXON - Modification Proposal P036
- **P071** 'Transfer of Imbalances caused by Balancing Services to the Transmsission Company' (Accepted) ELEXON - Modification Proposal P071
- **P074** 'Single Cost-reflective Cash-out Price' (Rejected) ELEXON - Modification Proposal P074
- **P078** 'Revised Definitions of System Buy Price and System Sell Price' (Approved) Modification Documents available here: ELEXON - Modification Proposal P078
- **P090** 'Improving the Representation of Energy Balancing Actions in Cashout Prices' (Accepted) ELEXON - Modification Proposal P090
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- **P136** 'Marginal Definition of the 'main' Energy Imbalance Price' Rejected ELEXON - Modification Proposal P136
- **P137** 'Revised Definition of the System Buy Price and System Sell Price' (Rejected) ELEXON - Modification Proposal P137
- **P194** 'Revised Definition of the Main Imbalance Price' (Approved) ELEXON - Modification Proposal P194
  Ofgem Regulatory Impact Assessment available here:
  http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/12767-1706.pdf
- **P201** 'Energy Imbalance Tolerance Band' (Urgent and both rejected) ELEXON - Modification Proposal P201
- **P202** 'Energy Imbalance Incentive band' (Urgent and both rejected) ELEXON - Modification Proposal P202
- **P205** 'Market Driven Trading Neutrality Band' (Urgent and approved) ELEXON - Modification Proposal P205
- **P211** 'Main Imbalance Price based on an Ex-Post Unconstrained Schedule' (Pending) ELEXON - Modification Proposal P211
- **P212** 'Main Imbalance Price based on Market Reference Price' (Rejected) ELEXON - Modification Proposal P212

Other Documentation
- Professor Stephen Littlechild paper for the Cashout Review 'Electricity Cashout Arrangements' – 9 March 2007
  Document available here:
  http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/19091_cashoutreviewSLittlechild.pdf

- Professor Stephen Littlechild's paper references the ERCOT wholesale electricity market in Texas. A state of the market report for ERCOT at:
  http://www.puc.state.tx.us/wmo/documents/annual_reports/2006annualreport.pdf

- Slides presented to the Ofgem-led Cashout Review on 26 September 2007 available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=96&refer=Markets/WhlMkts/CompandEff/CashoutRev