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Electricity Balancing Significant Code Review - Draft Policy Decision

Consultation

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Overview:

Supply and demand on the electricity system need to be kept in balance at all times. Market participants have incentives to balance their own position (ie to match what they generate or buy with what they consume or sell) through imbalance pricing (cash-out). Parties face cash-out prices for the amount of electricity they are out of balance. Cash-out prices are therefore a key incentive on participants to trade and invest to meet consumers' electricity demand, and hence to contribute to greater security of supply.

Current balancing arrangements are not working as well as they could. Various features dampen cash-out prices, leading to insufficient signals to the market to invest in flexible generation, demand participation and other technologies that can react quickly to changes in market conditions. Weak cash-out price signals could also lead to electricity exports to other countries at times of system stress in GB. Flexibility will become crucial to ensure consumers have access to more secure supplies in a system with a high share of intermittent generation. Moreover, inefficiencies in the arrangements potentially increase balancing costs and therefore consumer bills.

The Electricity Balancing Significant Code Review (EBSCR) aims to address the issues identified. We consulted with stakeholders on potential solutions and this document sets out our draft policy decision for further consultation. Our proposals consist of a package of reforms to increase the efficiency of the cash-out price signal.

Responses to this consultation will inform our final policy decision on the EBSCR, which is planned to be published in spring 2014.

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Context

The electricity market is in transition. Capacity margins are tightening, there is a significant shift in the generation mix towards renewable generation and European reforms are aiming to create a single European electricity market.

In the face of these developments, it is critical that efficient incentives are placed on market participants to aim to ensure that GB consumers' demand is met. Balancing arrangements are important to provide these incentives and to contribute to greater security of supply.

As expressed in Project Discovery (2010), we have long-standing concerns that cash-out prices are not creating the correct signals for the market to balance, and in particular are not correctly signalling the value of flexibility and peaking generation, increasing the risks to future security of supply and undermining balancing efficiency. We launched the EBSCR in August 2012 to address these concerns.

Following consultation and extensive stakeholder engagement, this document sets out our draft policy decision for consultation. We seek stakeholders' views on our proposals and the questions we ask in the document. Responses to this consultation will be fully considered and will inform our final policy decision.

Associated documents

Electricity Balancing SCR: Draft Policy Decision Impact Assessment, July 2013, Reference 124/13
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/EBSCR%20draft%20policy%20decision%20impact%20assessment.pdf

Electricity Balancing SCR: Quantitive 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 (VoLL) 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

Update on the Electricity Balancing Significant Code Review (EBSCR) and request for comments on proposed new process to review future trading arrangements, February 2013
www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Update%20on%20EBSCR%20and%20new%20process%20to%20review%20Future%20Trading%20Arrangements.pdf

Electricity Balancing Significant Code Review (SCR) – Initial Consultation; August 2012, Reference 108/12
www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20initial%20consultation.pdf

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Executive Summary

Cash-out prices provide incentives for electricity market participants to match their contracted positions to sell or buy energy with physical generation or demand. We have significant concerns with the current balancing arrangements. Dampened and inaccurate price signals provide insufficient incentives for generators and suppliers to meet demand when the system is tight, or to invest to avoid scarcity. This could hamper security of supply. Distortions in balancing arrangements affect overall balancing efficiency and potentially inflate consumer bills.

We launched the Electricity Balancing Significant Code Review (EBSCR) in August 2012 with a wide scope including cash-out price issues and wider balancing arrangements issues. In response to stakeholders' views to our Initial Consultation, we decided to focus the EBSCR on our long standing concerns with cash-out prices. We have formed a Future Trading Arrangements (FTA) Forum to seek views on the approach to wider wholesale electricity trading arrangement issues in the context of the Electricity Market Reform, EU Target Model (TM), market and technological developments.

Rationale for reform

The System Operator (SO) balances the system in real time and its actions are the basis for the calculation of cash-out prices. A number of factors dampen current cash-out prices. They are calculated using an average of SO actions to balance the system rather than the marginal action. They do not include the costs to consumers of involuntary demand disconnections (blackouts) and voltage reductions (brownouts). Also, cash-out prices do not accurately reflect the value of reserve capacity. This means that market participants do not sufficiently react to possible tightening of reserve margins. Finally, the current dual cash-out price system[1] creates unnecessary balancing costs, in particular for smaller parties.

As a result of the shortcomings with the current arrangements, the market does not sufficiently value flexibility (the ability to ramp generation or demand up or down quickly in response to changing market conditions). This could mean market participants provide insufficient flexible generation, demand response services and storage to meet consumer demand. In a low carbon system with significant levels of intermittent generation, flexible capacity will become increasingly important for security of supply. Another consequence of dampened prices is that interconnectors may export at times of system stress. Also, current inefficiencies in the balancing arrangements could inflate consumer bills.

We note that cash-out arrangements and the Government's planned capacity market (CM)[2] have distinct but complementary roles in seeking to ensure electricity security of supply. The CM is intended to address long term security of supply risks by providing capacity holders with a secure revenue stream for their capacity investment. Efficient cash-out prices complement that by providing appropriate

[1] Under dual pricing, parties face different cash-out prices depending on whether they are out of balance in the same or in opposite direction of the system
[2] At the end of June, DECC have announced the initiation of the CM for delivery in 2018/19, subject to legislation and state aid clearance.

signals for generation flexibility, demand participation, storage and interconnectors flows. We have worked closely with DECC to ensure consistency between the CM and the EBSCR proposals. We have also been mindful of the interactions with the emerging EU TM and made sure our proposals are not in conflict with its direction.

As part of the EBSCR we have done extensive work to develop our policy proposals and engaged with industry throughout. We conducted a series of stakeholder events in the Initial Consultation phase. Following that we established an industry "Technical Working Group" to support our ongoing policy development and modelling work.

Our draft policy decision for consultation

In order to address the problems identified we propose to change the electricity balancing arrangement to ensure cash-out prices signal scarcity accurately and to remove inefficiencies in balancing arrangements. Specifically, we propose the following package of reforms:

a) **Making cash-out prices 'marginal'** by calculating them using the single most expensive action the SO takes to balance the system.

b) **Including a cost for disconnections** and voltage control into the cash-out price calculations based on the Value of Lost Load (VoLL) to consumers. We propose to introduce this cost gradually, starting with £3,000/MWh and increasing to £6,000/MWh. We plan to reach £6,000/MWh by the time the CM is introduced. We also propose to pay domestic consumers and small businesses at £5 and £10 per hour of disconnection, respectively, in recognition that they effectively provide involuntary demand side response (DSR) services to the SO.

c) **Improving the way reserve costs are priced** by reflecting the value reserve provides to consumers at times of system stress. To achieve this we propose introducing a Reserve Scarcity Pricing (RSP) function that prices reserve when it is used based on the prevailing scarcity on the system.

d) **Moving to a single cash-out price** for each settlement period to simplify the arrangements and reduce unnecessary imbalance costs.

We have carried out significant quantitative and qualitative analysis to develop and assess policy options. Our analysis suggested that the proposed reforms would make cash-out prices sharper and improve incentives for investments in flexible capacity. Whilst sharper prices in itself could increase balancing costs for participants, a move to a single price is likely to significantly counteract this effect for all parties, and in particular for smaller parties. We expect consumers to benefit through a higher level of security of supply and efficiency gains in balancing the system. We expect little impact on consumer bills.

We are consulting on this draft policy decision for 12 weeks until 22 October, and will hold a stakeholder event in that period. We aim to publish our final policy decision in spring 2014. Alongside this document we also publish our EBSCR Draft Policy Decision Impact Assessment (IA), on which we also consult, as well as London Economics' VoLL study and Baringa's modelling report.

1. Introduction

Issues and rationale for reform

1.1. In 2001, the New Electricity Trading Arrangements (NETA) introduced the current trading arrangements, which are based on bilateral trading and a residual balancer (the SO). Under these arrangements, market participant are exposed to "cash-out" prices when they generate or consume more or less electricity than they have contracted for. The cash-out price therefore is effectively a default price for uncontracted electricity and a primary incentive on participants to trade and invest to meet consumers' electricity demand.

1.2. In the past, Ofgem has raised concerns with balancing arrangements, most notably in Project Discovery (2010)[3], where we identified the electricity balancing arrangements as critical in delivering more secure electricity supplies. A particular concern expressed in Project Discovery was that the existing cash-out price signals are dampened and provide insufficient incentives to market participants to invest in adequate levels of capacity and to provide the flexibility needed in a low carbon system with significant levels of intermittent generation.

1.3. Under the current balancing arrangements, prices do not sufficiently reflect scarcity when the system is tight for the following reasons:

- Cash-out prices are calculated using an average of SO actions to balance the system rather than the marginal action;
- Costs of involuntary demand disconnections (blackouts) and voltage control actions (brownouts) are not included in cash-out prices at all. These *are* a cost to consumers that the SO and market participants do not face;
- The value of holding and using reserve is not accurately reflected in cash-out prices which means that market participants do not see and react to possible tightening reserve margins;
- Dual cash-out prices create unnecessary balancing risk, in particular for smaller and intermittent parties.

1.4. As a result of the shortcomings with the current arrangements, the market does not currently sufficiently value flexibility (the ability to ramp up or down quickly in response to changing market conditions). This means that flexible generation capacity, demand response and storage have insufficient incentives to provide (or invest in) the flexibility they could offer, and interconnectors may export at times of system stress. With tightening capacity margins and increased amount of intermittent generation flexibility will become increasingly important. In the light of

[3] Project Discovery Options for delivering secure and sustainable energy supplies, 3 February 2010 http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Documents1/Project_Discovery_FebConDoc_FINAL.pdf

these challenges it is crucial that cash-out prices efficiently signal scarcity on the system. We believe that failing to reform the existing balancing arrangements could harm future electricity security of supply and unnecessarily increase costs of balancing. For these reasons, Ofgem has started the EBSCR in August 2012 to address these pressing issues with respect to cash-out prices.

Key objectives of EBSCR

1.5. To address these issues, and to further our principal objective of protecting the interests of existing and future consumers, we launched the EBSCR in August 2012 with the following three high-level objectives:

- To incentivise an efficient level of security of supply
- To increase the efficiency of electricity balancing
- To ensure balancing arrangements are compliant with the EU Target Model (EU TM) and complement DECC's Electricity Market Reform (EMR) Capacity Market (CM)

1.6. The key to delivering these objectives is to make sure the cash-out price signals are efficient and reflect the underlying cost (to the SO and to consumers) of balancing the system. Cash-out prices that reflect scarcity on the system accurately send the appropriate signals for investments in flexible generation, DSR services, storage and other flexible technologies.

EBSCR process so far and updated scope

1.7. Issues that the EBSCR intends to address were identified in various cash-out reviews and in Project Discovery. This has since been followed by

- a **cash-out issues paper** seeking views on whether Ofgem should conduct a Significant Code Review (SCR) in November 2011
- a **scoping workshop**[4] for the SCR in April 2012
- the **launch of the EBSCR and Initial Consultation**[5] in August 2012
- **stakeholder events** including workshops during the Initial Consultation period in September–October 2013

[4] Stakeholder event on scope: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=2&refer=Markets/WhlMkts/CompandEff/electricity-balancing-scr

[5] EBSCR website: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Pages/index.aspx

- **Technical Working Group (TWG)** meetings to work up the options in light of a better understanding of stakeholder concerns in January–April 2013

1.8. Responses to the Initial Consultation showed that many stakeholders supported the EBSCR process. However several stakeholders raised two key concerns. Firstly, they stressed the importance of consistency of any proposals made under the EBSCR with developments related to EMR and the EU TM. Secondly, stakeholders expressed concerns about the timing of some of the wider considerations under the scope of the EBSCR and suggested these ideas should be assessed on a longer time frame to allow for further consideration of the issues. Stakeholders also emphasised that it is crucial that interactions between different proposed reforms and their timings are properly considered before we make any policy decisions.

1.9. In the light of this feedback, we decided to (a) reduce the scope of the EBSCR to focus on the areas where we had long standing concerns and that needed to be addressed in the short term (see our Open Letter of 18 February 2013[6]) and (b) initiate a new process to consider the potential wider impacts of EMR, EU TM and technological change on existing trading arrangements. The FTA forum was launched in May 2013.[7]

1.10. The reduced scope of the EBSCR includes the following policy considerations:

- **More marginal cash-out prices:** Current cash-out prices are calculated by averaging a number of most expensive trades made by the SO to balance the system. We considered basing the calculation on a smaller volume of trades.
- **Attributing a cost to non-costed actions:** Currently, the costs of involuntary demand disconnections (blackouts) and voltage control (brownouts) are not included in the cash-out calculation. We considered including them.
- **Improving the way reserve is costed:** Some necessary actions taken by the SO, such as the need to provide reserve, can depress or distort the cash-out price. We considered improved ways of costing reserve in cash-out prices.
- **Single or dual cash-out prices:** Dual prices may put unnecessary costs on parties who are helping to balance the system. We considered moving to a single price.
- **Gate closure time:** We considered changes to gate closure to allow parties to trade closer to real time.

[6] Open letter: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Update%20on%20EBSCR%20and%20new%20process%20to%20review%20Future%20Trading%20Arrangements.pdf
[7] FTA website: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Pages/future-trading-arrangements.aspx

- **Single or dual trading accounts:** We considered allowing parties with both generation and supply businesses to net their opposite imbalances into one account.

1.11. Another concern expressed by stakeholders was on the timing of the draft policy decision and the need for further stakeholder engagement before that. To address this concern, we have taken more time to reach our draft policy decision than originally proposed, and we have engaged with stakeholders on a finer level of detail through our TWG. We held several meetings with this group of experts between January and April this year to receive detailed stakeholder input for our ongoing policy development.

Purpose of this consultation and next steps

1.12. This document is our draft policy decision for consultation. It outlines our analysis, explains our proposals and seeks stakeholder views. With the publication of this document we enter into a 12 week consultation period which closes on 22 October 2013. We encourage stakeholders to respond to our questions and to express views on our proposals in this document so that their views can be fully considered and can inform our final policy decision.[8] We plan to conduct a stakeholder workshop during this consultation phase, most likely in September, in order to give stakeholders an additional opportunity to express their views on our proposals and to seek clarification or further information. To register your interest for this event please email EBSCR@ofgem.gov.uk.

1.13. We aim to publish a final policy decision in spring 2014. Should we direct that code changes are raised to implement the proposed reforms, industry will take forward any changes through the code modification process. Should any licence changes be necessary to implement the proposed reforms, Ofgem will consider how to take these forward.

1.14. In chapter 2 we discuss the approach we have taken to reach the draft policy decision. Chapter 3 sets out our draft policy decisions for consultation and explains their high-level impacts. In chapter 4 we provide our detailed analysis for each policy consideration. Chapter 5 describes the EBSCR's interactions with wider reforms in the electricity sector.

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[8] All responses will be published by placing them in Ofgem's library and on its website. If you want information that you provide to be treated as confidential please say so clearly in writing when you send your response to the consultation. It would be helpful if you could explain to us why you regard the information you have provided as confidential. If we receive a request for disclosure of the information we will take full account of your explanation, but we cannot give an assurance that confidentiality can be maintained in all circumstances.

2. Approach

2.1. This chapter outlines how we have engaged with stakeholders, explains the way we grouped proposed policy options into packages, describes the two pieces of consultancy analysis we have commissioned and presents the criteria used to evaluate policies.

Stakeholder engagement

2.2. We have developed the draft policy proposals presented in this document in consultation with industry and with stakeholders. We received 29 responses to the Initial Consultation.[9] During the Initial Consultation period, we engaged with stakeholders at four open workshops where we presented and discussed all policy considerations.[10] Early 2013 we set up a TWG which was composed of a small number of industry experts. We held three TWG meetings to discuss details of our quantitative analysis and our ongoing policy development. The material discussed and minutes of the meetings were published on the EBSCR section of our website. We have taken stakeholder views into account in the development of policy and outline stakeholder views and our responses where relevant throughout this document.

Policy packages

2.3. We recognised that there may be important interactions between different policy considerations in scope. Therefore, in addition to analysing each policy consideration on its own, we grouped them into packages of options, in order to take these interactions into account. This approach was also useful to focus the analysis on a particular set of the most appropriate combinations of policy options, in particular for the quantitative modelling. The policy packages should represent a spectrum of potential changes from 'Do nothing' to a set of arrangements which could deliver the most efficient price signals (Package 5). For intermediate packages we varied key policy considerations to understand how they impact on the overall results.

2.4. Taking into account discussions with stakeholders during the initial consultation and from the first TWG meetings, we decided to focus our analysis on the packages set out in Table 1:

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[9] Published on the Ofgem website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=11&refer=Markets/WhlMkts/CompandEff/electricity-balancing-scr

[10] Agenda, slides and minutes of the meetings can be found on Ofgem's EBSCR website http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Pages/index.aspx

Table 1: Our policy packages

<table>
<tr><th>Package</th><th>More marginal cash-out prices</th><th>Attributing a cost to non-costed actions</th><th>Improving the way reserve is costed</th><th>Single or dual cash-out price</th><th>Gate Closure and trading accounts</th></tr>
<tr><td>'Do nothing'</td><td>PAR500</td><td>Non-costed</td><td>STOR priced using utilisation fee and BPA for availability fee</td><td>Dual</td><td rowspan="6">1h and separate trading accounts (no changes)</td></tr>
<tr><td>1</td><td>PAR 50</td><td>No VoLL</td><td rowspan="5">STOR priced using the greater of Reserve Scarcity Pricing (RSP) function and utilisation fee</td><td>Dual</td></tr>
<tr><td>2</td><td>PAR 1</td><td>No VoLL</td><td>Single</td></tr>
<tr><td>3</td><td>PAR 1</td><td>Apply VoLL and pay interrupted parties</td><td>Dual</td></tr>
<tr><td>4</td><td>PAR 50</td><td>Apply VoLL and pay interrupted parties</td><td>Single</td></tr>
<tr><td>5</td><td>PAR 1</td><td>Apply VoLL and pay interrupted parties</td><td>Single</td></tr>
</table>

Commissioned analysis: VoLL study and cash-out model

2.5. We commissioned consultants to undertake two key contributions to the analysis: London Economics to conduct a study estimating VoLL and Baringa to help us quantify the impacts of various proposed policy packages. We have published both of their reports alongside this document.

2.6. The VoLL study, jointly commissioned with DECC and published alongside this consultation document, assesses the value that electricity users attribute to security of electricity supply. This analysis undertakes quantitative research – based on a variety of methods, the most predominant of which involved using choice experiments – to derive VoLL estimates for domestic consumers, Small and Medium sized Enterprises (SME) and Industry and Commercial (I&C) electricity users. This analysis is of particular relevance to our considerations of attributing a cost to disconnections and for costing reserve according to its value.

2.7. Baringa developed a model to estimate the combined impacts of each of the five proposed policy packages quantitatively, and compared them to the 'Do nothing' package. The Baringa modelling analysis quantifies the likely impact on cash-out prices, investment, imbalance cash-flows and consumer bills. The added-value of the Baringa analysis is that it allows us to test our qualitative analysis (based on logic, economic theory and discussions with stakeholders) and to consider the combined impact of the possible policy options accounting for interactions between them. It also complements Ofgem's internal "historical analysis", which assessed the impact of each proposed policy package on cash-out prices assuming no behavioural change.

2.8. Modelling the electricity cash-out arrangements is a very difficult and complex task. Many results derived from modelling are sensitive to the underlying simplifying assumptions that needed to be made. We discussed the key assumptions and corresponding limitations of our model with stakeholders at the first TWG meeting. We also explained that due to the limitations of any quantitative analysis, it can only be used to *support* our overall assessment. Therefore, the quantitative analysis is only one of many factors for us to consider when making policy assessments. We published Baringa's modelling report alongside this consultation document.

Impact Assessment and criteria for evaluating policies

2.9. We have undertaken an IA which we published alongside this document and on which we are also consulting and seeking stakeholder views. The IA sets out the evidence base, both qualitatively and quantitatively, that underpins our draft policy decision.

2.10. Our principal objective under the Electricity Act 1989 is to protect the interests of existing and future consumers – this is the overarching objective for these proposed reforms. The criteria we have used for evaluating policies considerations and packages are summarised in Table 2.

Table 2: Criteria for evaluating policies

Criteria	Measurement
More secure and more reliable supplies	Market provides more appropriate signal of scarcity and value of flexibility which reduces blackouts and brownouts
Balancing efficiency	Price signals are more cost-reflective and existing distortions are removed to increase efficiency of balancing and reduce overall balancing costs
Consumer bills	Higher levels of security of supply are delivered at low costs to consumers and cash-out reform delivers overall value for money for consumers
Competition	More free and fairer competition which would drive better value for money for consumers
Distributional impacts	Changes in imbalance risk are not disproportionally negative on certain stakeholders
Sustainability & transition to lower carbon economy	Distribution of effects over time and across stakeholders support achievement of de-carbonisation, fuel poverty and security of supply objectives
Risks and unintended consequences	Implementation risks of reform are manageable or can be mitigated

3. Draft Policy Decision for consultation

3.1. In this section we provide a summary of our proposals of how to address the issues with electricity balancing arrangement identified in Project Discovery and our EBSCR Initial Consultation in August 2012 (and summarised in chapter 1 of this document). We also present our assessment of the high-level impacts we expect from these proposed changes. Chapter 4 sets out our analysis that underpins the draft policy decision in detail.

Draft policy decisions for consultation

Draft policy decision 1 for consultation: Making cash-out prices marginal

3.2. We propose to make cash-out prices 'marginal' by calculating them using the most expensive action the SO takes to balance the system. This implies that the PAR level would be reduced from currently 500MWh to 1MWh. Existing tagging, flagging and re-pricing rules would continue to be applied.

Draft policy decision 2 for consultation: Including a cost for disconnection and voltage control in cash-out prices

3.3. We propose to include a cost for disconnections and voltage control into the cash-out arrangements. The cost we propose to include is based on the VoLL to consumers, for which we commissioned a study that is also published alongside this document. We propose to set the cost of both disconnections and voltage control to initially £3,000/MWh at time of implementation of our final decisions (likely in 2015) and increasing to £6,000/MWh by the time when the CM becomes effective. These figures assume that a CM will be introduced in GB.

3.4. We also propose to pay domestic consumers and non-half-hourly metered businesses at £5 and £10 per hour of disconnection, respectively, in recognition that they provide involuntary DSR to the SO. To achieve this, Demand Control[11] actions will be treated similarly to other balancing actions: they will enter the Balancing Mechanism (BM) stack with a cost and volume and will be subject to the usual tagging and flagging rules. There are a number of practical challenges with this policy, for which we propose high level solutions and are keen to receive stakeholders views how they can be refined. Challenges include estimating the volume of disconnections and adjusting supplier volumes.

[11] Demand Control actions are instructions from the SO – when it considers there to be insufficient supply to meet demand – to Network Operators to reduce demand, through either voltage reduction ('brownouts'), or firm load disconnection ('blackouts'). These Demand Control actions are balancing actions, but unlike other balancing actions they are not included in the calculation of cash-out prices, or in the determination of participants' imbalance positions

Draft policy decision 3 for consultation: Pricing reserve according to value

3.5. We propose to change the way reserve is currently priced into cash-out. Rather than being based on utilisation fee and price adjusters (using historical data) we propose to price reserve using a RSP function, reflecting the scarcity value of the reserve used in each settlement period. This policy is not designed to impact on how reserve is procured and dispatched by the SO, but only how it is priced as part of cash-out. We propose to apply the RSP function also to non-BM Short Term Operating Reserve (STOR), which is currently not included in cash-out prices.

3.6. In practice, the RSP function will be based on indicators of scarcity (margins, demand, etc) to calculate a loss of load probability (LOLP), and the VoLL to consumers. We seek views from industry on some of the practical aspects of this policy, which are set out in more detail in chapter 4 and the appendices.

Draft policy decision 4 for consultation: Moving to a single cash-out price

3.7. We propose that the cash-out price faced by parties who are out of balance in the opposite direction to the system should reflect the resulting cost savings to the SO of these imbalances. Therefore, we propose to move from a dual to a single price system, where parties with imbalances in either direction of the system face the same cash-out price. This implies that there will only be one cash-out price per settlement period, which will be equivalent to the current 'main' price. Both System Buy Price (SBP) and System Sell Price (SSP) would be equal in a given settlement period and the reverse price would no longer be used.

We are not proposing any further changes to the balancing arrangements

3.8. Our draft policy decision for consultation is not to make any changes to other areas of the arrangements, such as gate closure or single/separate trading accounts.

High-level impacts of our proposals

Proposals 1-3 (marginal prices, costing disconnections and RSP)

Proposals 1-3 make cash-out prices sharper, improve security of supply and balancing efficiency

3.9. We expect the proposed changes to impact positively on security of supply and balancing efficiency. This is mainly driven by improved cash-out price signals, which our proposals would make more cost-reflective, and thereby sharper, in particular at times of system stress. As prices will provide a better signal of scarcity, they improve incentives on parties to balance their position by trading forward and investing in and maintaining flexible generation capacity. Flexible capacity will become increasingly important for security of supply, as it will be needed to complement the growing share of inflexible, intermittent renewables on the system.

3.10. Our proposals are also likely to improve the business case of DSR and storage, which would be able to provide additional capacity to the system at times of scarcity, when prices are high. Currently large industrial users are most able to provide DSR services. As smart meters are rolled-out over time, our proposed reforms may further incentivise provision and innovation of DSR services. This could include domestic customers in the long term. Ofgem will further develop its view on how to enable this service while ensuring the fuel poor are protected.

3.11. We expect our proposals to impact on interconnector flows, increasingly so as European rules prescribe a high responsiveness of interconnector flows to price signals in the future with the introduction of market coupling. As cash-out prices and intraday prices are highly correlated, we expect sharper cash-out price signals to feed through to intraday prices, impacting on interconnector flows. The more accurately the price signals in GB reflect the underlying value of electricity to consumers, the better they enable interconnector flows to consumers that value the electricity most.

3.12. Our proposals may have a positive impact on liquidity close to gate closure. We expect our proposals will strengthen the price signals for scarcity, and parties will have stronger incentives to trade intra-day, in particular when the system is tight.

3.13. Improved price signals are also expected to improve efficiency in balancing. The more accurately prices reflect the underlying costs to the SO and the value of balancing actions to consumers, the better a signal they provide to the market. If the price signal is efficient, it provides market participants with information they can take into account to optimise their own trading and balancing behaviour, leading to a better balance between how much balancing is done through the market and how much is done through the SO. Also, with more flexible capacity on the system compared to business as usual, our reform proposals are likely to reduce overall system balancing costs.

Proposal 4 (moving to a single price)

Proposal 4 is expected to reduce overall imbalance costs, which helps smaller parties and renewables in particular, and has a positive impact on competition and sustainability

3.14. Solely making prices sharper could have negative distributional impacts, as it could adversely affect smaller parties in particular, which are often less able to balance. This could also imply negative impacts on sustainability and renewable deployment, as a large share of renewables are small independent (intermittent) generators, which find it more difficult to control their output. However, the move to a single cash-out price system significantly reduces the overall imbalance exposure, therefore in particular helping smaller parties. Our quantitative analysis indicates that introducing a single price is likely to offset the otherwise detrimental impact of sharper prices on imbalance risk. Furthermore, it simplifies the arrangements, which could reduce barriers to entry, increase competition and drive innovation in commercial aggregation and financial products that could help parties to manage imbalance risk.

3.15. Next to helping renewables by moving to a single price as part of the EBSCR, Ofgem is working closely with DECC on its Contract for Difference (CfD) policy design, which includes work on improving the route to market for independent generators and strengthening the market for Purchase Power Agreements (PPAs). PPAs help independent generators by providing a route to market and allowing generators to pass on the imbalance risk to another party that is better able to handle it. The competitiveness of the PPA market will affect the level of discount generators have to accept in return for these services.

3.16. A further potentially positive impact for sustainability could come from increased amount of DSR, to the extent DSR replaces fossil fuelled plants.

Quantitative impacts on cash-out prices and consumer bills

3.17. Our proposals are likely to make cash-out prices sharper, both increasing their average level and their volatility. The extent of the effect is uncertain, as it depends on market participants responses to the changes we propose. However, our modelling suggests that the average SBP could be around £16 (in 2020) and £22 (in 2030) higher under our proposals than under 'Do nothing'. These figures include the assumption that a CM will be introduced. If the CM is not introduced, prices could be £15 (in 2020) and £27 (in 2030) higher than under 'Do nothing'. The reason for this higher difference without a CM is that we assumed in the modelling that the CM will increase capacity margins, leading to fewer periods of system stress and hence lower cash-out prices. The estimate for the reduction in average SSP price is around £2 in both 2020 and 2030.

3.18. Despite sharper prices, we expect the effects of our proposed reform package on participants' imbalance costs to be broadly neutral compared to 'Do nothing', as the single price is likely to reduce imbalance costs significantly for all parties, and in particular for smaller and renewable parties.

3.19. Under 'Do nothing', we expect system balancing costs to go up over time, due to increased amount of intermittent generation on the system. This trend is likely to be unchanged by our proposals. We expect the impacts of our proposals on consumer bills to be broadly neutral compared to 'Do nothing', as costs in additional investments are offset by efficiency improvements. More detail on our quantitative analysis can be found in the accompanying EBSCR Draft Policy Decision IA.

4. Our assessment of policy considerations

Question for the Draft Policy Decision:

Question 1: Do you agree with our proposal to make cash-out prices more marginal?

Question 2: Do you agree with our rationale for going to PAR1 rather than PAR50? Are you concerned with potential flagging errors, and would you welcome introduction of a process to address them ex-post?

Question 3: Do you agree with our proposals for pricing of voltage reduction and disconnections, including the staggered approach?

Question 4: Do you agree with our assessment of the interactions with the CM and its impact on setting prices for Demand Control actions?

Question 5: Do you agree that payments of £5/hr of outage for the provision of involuntary DSR services to the SO should be made to non-half-hourly metered (NHH) consumers, and for £10/hr for NNH business consumers?

Question 6: Do you agree with the introduction of the Reserve Scarcity Pricing function and its high-level design? Explain your answer.

Question 7: Do you agree with our rationale for a move to a single price, and in particular that it could make the system more efficient and help reduce balancing costs? Please explain your answer.

Question 8: Do you have any other comments on this consultation, including on the considerations where we did not propose any changes?

Question related to the accompanying Impact Assessment:

Question 9: Do you have any comments regarding any of the three approaches we have taken to assess the impacts of the cash-out reform packages?

Question 10: Do you agree with the analysis of the impacts contained in this IA? Do you agree that the analysis supports our preferred package of cash-out reform? Please explain your answer.

Question 11: Do you agree with the key risks identified and the analysis of these risks? Are there any further risks not considered which could impact on the achievement of the policy objectives? Please explain your answer.

Question 12: What if any further analysis should we have undertaken or presented in this document? Do you have any additional analysis or evidence you would like to contribute to support the development of the EBSCR towards its Final Policy Decision?

4.1. In this chapter we present the analysis that underpins our draft policy decision in detail. For each policy consideration we outline the issues and rationale for reform; the options considered; our assessment of the impacts (not repeating the high-level impacts illustrated in the previous chapter); and any issues for implementation. At the end of the chapter we present some of the high-level results of the quantitative analysis.

More marginal main cash-out price

Background and rationale

4.2. When a party is out of balance in the same direction as the overall system (hence exacerbating the overall imbalance), it faces the *main* cash-out price[12]. This price is calculated as a volume weighted average cost of the most expensive 500 MWh of bids or offers accepted by the SO[13] to balance the system. The volume of actions on which the price is based is known as the Price Average Reference (PAR) volume.

4.3. We have consistently raised concerns regarding the calculation of the cash-out price based on an average of the cost of actions taken by the SO, most notably in Project Discovery. We are concerned that this averaging dampens the cash-out price as a signal of scarcity in the market, in particular at times of system stress. This could in turn be detrimental for security of supply and the overall costs of balancing[14]. Furthermore, dampened cash-out prices contribute to *missing money*[15] in the GB wholesale electricity market. The concept of missing money is used to describe a shortage of available revenue streams to allow capacity providers to cover their costs. Averaging of the cash-out price reduces the signal of scarcity passed through to forward markets, creating missing money in particular for flexible capacity providers.

4.4. Through the EBSCR, we have considered the merits of making cash-out prices *more marginal* and reducing the volume of PAR. This could improve the cash-out price as a signal of scarcity in the market, improving the incentives to balance and invest, and ultimately deliver a higher level of security of supply through the market.

Options considered and our proposal

4.5. Making cash-out prices *more marginal* would increase the extent to which the price reflects the cost to the SO of balancing the system at the margin. Reducing the PAR volume would mean the cash-out price would be based on a smaller volume of SO actions, removing relatively cheaper actions from the calculation. We have considered options from the current PAR volume of 500MWh to 1MWh (a fully marginal cash-out price) and intermediate PAR levels.

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[12] Parties out of balance in the opposite direction of the overall system imbalance face the *reverse* cash-out price. This price is a volume weighted average of near term market prices. The reverse price is considered in more detail in the single or dual cash-out price section.
[13] Under NETA, cash-out prices were calculated as an average of all actions taken by the SO to balance. This was subsequently reduced to the most expensive 500MWh of actions under BSC Modification P205 and maintained at 500MWh at the time of modification P217A.
[14] Calculating cash-out prices based on a weighted average reduces the cash-out price below the SO's marginal cost of balancing. As such, the additional unit cost of imbalance to market participants (the cash-out price) is below the additional unit cost of balancing energy to the SO. This is inefficient as it could reduce parties' incentives to balance.
[15] See Box 1 in the EBSCR Initial Consultation August 2012 for further detail

4.6. The most efficient option that would fully reflect the SO's cost of balancing the system at the margin would be to move to PAR1. In the past this reform option has not been implemented due to concerns about system pollution[16]. The current methodology for the calculation of cash-out prices includes flagging and tagging rules[17] to reduce this risk. In particular, the flagging of actions taken by the SO to resolve constraint issues was introduced in 2009 by BSC modification P217A. Follow-up analysis[18] suggests that P217A has the anticipated impact and annual SO reports on the flagging procedure indicate a high level of accuracy in implementation.[19]

4.7. **Our draft policy decision for consultation is to reduce the value of PAR to 1MWh, making the calculation of cash-out prices fully marginal**. In addition we propose reducing the Replacement Price Average Reference (RPAR) [20] to 1MWh. We do not propose any further changes to the existing flagging and tagging rules.

High-level impacts

4.8. A fully marginal cash-out price would result in parties facing the full cost to the SO of balancing at the margin, making the cash-out price sharper and more cost-reflective. This would produce a more accurate signal for parties to choose between balancing pre gate closure or facing the cash-out price.

4.9. Reform to make the cash-out price more marginal would have similar high-level impacts as our proposals to incorporate non-costed actions and to ensure the accurate pricing of reserve. These impacts have been outlined in chapter 3.

Implementation and delivery risks

4.10. Although a majority of stakeholders agreed in response to our Initial Consultation that a reduction in PAR would be appropriate, stakeholders differed in their views as to the appropriate level of PAR. In particular, stakeholders highlighted delivery risks associated with the proposed reform option of implementing a marginal price: enhanced risks of system pollution, greater susceptibility to flagging and tagging errors and susceptibility to manipulation through exercise of market power.

[16] System pollution is a distortion of the cash-out price caused by the inclusion of "system" balancing actions in the price calculation. System balancing actions are actions taken to resolve system-related imbalances, which -unlike pure "energy" balancing actions - are not related to the total balance of generation and demand between participants. It is therefore not deemed appropriate to reflect the cost of these actions in the cash-out price.
[17] See Appendix 5 on NIV tagging
[18] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/P217A%20Preliminary%20Analysis.pdf
[19] http://www.nationalgrid.com/uk/Electricity/Balancing/transmissionlicencestatements/SMAF/
[20] RPAR refers to the volume of actions on which the replacement price is calculated. This price is assigned to actions as part of the flagging process. We propose reducing RPAR to the same as PAR to ensure consistency in the pricing methodology. Without this, in periods where the marginal action is re-priced, the marginal price would in fact be based on a weighted average price of a larger volume of PAR. This would lead to prices which are averaged over a large number of actions and would therefore dampen the impact of the reform of PAR.

4.11. On the issue of system pollution, we note the SO takes actions over the course of the day to balance both system and energy simultaneously, whereas the cash-out price attempts to derive a half-hourly energy price in a given settlement period. To try to remove the influence of these system balancing actions, P217A introduced a set of flagging and tagging rules to be applied to Bids and Offer Acceptances (BOAs) in the price calculation. In addition to these rules, prices are calculated as a weighted average with a PAR of 500MWh to further reduce risk of pollution. When P217A was implemented, we noted we would keep the PAR level under review. Some stakeholders argue that a lower value of PAR may increase the risk of system pollution, as the price calculation is based on a smaller subset of balancing actions.

4.12. Given the nature of the balancing arrangements and the way in which the SO balances the system, it is impossible to fully separate system from energy balancing actions. Hence system pollution is an inherent risk in the calculation of prices. The choice of PAR entails the trade-off between the benefits of more efficient price signals and the risk of system pollution.

4.13. In our view, flagging and tagging rules introduced by P217A are sufficient effective at removing system pollution, and indeed may over-correct for pollution, as:

- NIV tagging does not reflect plant dynamics
- NIV tagging removes the most expensive actions taken by the SO to balance
- the replacement price applied to un-priced actions is a lower bound of possible prices that could be applied
- actions that are taken for *both* system and energy reasons are tagged and re-priced (in theory only part of them should retain their price).

4.14. Therefore we view the flagging process as very conservative and likely to mitigate increased risk of system pollution resulting from a more marginal price. This assessment is strengthened by our ex-post analysis of the past three years which found that even under a PAR 1MWh cash-out price, there would still have been, on average, several actions which fed into the calculation of the cash-out price. This suggested a low likelihood that the marginal price will be set by one unrepresentative action.

4.15. Another concern expressed by stakeholders was that implementing a marginal cash-out price would increase the likelihood of the price being distorted by errors in the flagging process. In the three annual SO reports[21] to date on the application of SO flags and the accuracy of this flagging process the SO has reported that flagging

[21] See National Grids' report 'Accuracy of the System Management Action Flagging Methodology' covering May 2011 to April 2012 inclusive http://www.nationalgrid.com/NR/rdonlyres/A1F86291-4DF3-48DB-8DCA-E0350B42D71D/58364/P217FlaggingAccuracy_report201112Final4.pdf

is likely to be highly accurate and the impact of any mis-flags is likely to be small. Further, National Grid is currently undertaking an internal review of a recent instance of mis-flagging and may seek to bring forward change to address current limitations around the correction of mis-flagging after the settlement period.[22] We believe that this could be a positive change consistent with our proposals under the EBSCR that could improve the accuracy and efficiency of the price calculation. We will continue to engage with National Grid regarding this process and its interactions with the EBSCR. Should a proposal not be brought forward or implemented, we may choose to explore options to allow ex-post correction of SO flags further under the EBSCR. We would welcome stakeholder views on this issue as part of this consultation.

4.16. Some stakeholders noted that a marginal price could be more susceptible to abuse of market power – on the grounds that a smaller sample of actions may be easier to manipulate[23]. Our analysis[24] however, conducted as part of the IA, suggests there is no evidence that points to a higher risk of abuse of market power. There are a range of mechanisms in place that mitigate this risk, in particular the flagging and tagging rules, which in most periods eliminate the most expensive actions and create uncertainty around which bids or offers could feed into the cash-out price. Furthermore, we agree with the view of other stakeholders that policy interventions such as the Transmission Constraint Licence Condition (TCLC)[25] and the Regulation on wholesale energy market integrity and transparency (REMIT) are effective in mitigating market power concerns that have been raised since the introduction of NETA, and therefore consider the current environment better suited to this reform.

4.17. Finally, potential implementation of marginal cash-out prices is likely to incur only small administrative costs. As PAR is a parameter that already exists in the cash-out arrangements, reducing PAR to 1 MWh would only require minor changes to Elexon’s systems. Also required could be a change to the SO and Elexon’s system to allow flags to be corrected where errors have occurred and potentially some amendments to the systems of market participants and their hedging strategies.

4.18. In sum, there is a strong argument to introduce a marginal price in the cash-out arrangements that adequately incentivises parties to balance and deliver secure supplies. We consider the benefits of appropriately reflecting scarcity to outweigh the potential additional risks, all of which our analysis suggests are manageable.

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[22] See paragraph 12.2 of BSC Panel minutes from May 2013 meeting; www.elexon.co.uk/wp-content/uploads/2012/09/212a-Approved-Panel-Minutes-Public.pdf

[23] Other stakeholders expressed concern about market power concerns in conjunction with possible introduction of Pay As Clear (PAC). Note, however, that the PAC consideration has been removed from the scope of the EBSCR

[24] See ‘Risks and unintended consequences’ chapter of accompanying Impact Assessment

[25] The TCLC was introduced to prevent generators exploiting transmission constraint periods. http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/TCLC%20Guidance.pdf

Attributing a cost to non-costed actions ("VoLL pricing")

Background and rationale

4.19. When the SO considers there to be insufficient supply to meet demand, it may instruct the Network Operators to reduce demand, which the Network Operators can do through either voltage reduction ('brownouts'), or firm load disconnection ('blackouts')[26]. These 'Demand Control' actions are balancing actions, but unlike other balancing actions they are not included in the calculation of cash-out prices, or in the determination of participants' imbalance positions. Further, when consumers are disconnected as a result of Demand Control, they receive no payment for providing these involuntary DSR services.

4.20. Having a price which accurately reflects the SO's full balancing costs is central to ensuring that the cash-out price reflects scarcity at times of system stress, and that participants face the correct incentives to balance their positions. Incorporating volumes and appropriate prices for Demand Control actions into the arrangements should improve the incentives for generators and suppliers to avoid disconnection of consumers. The benefits of including a cost for Demand Control actions within the cash out price should be felt regardless of whether Demand Control actions actually happen. In fact, by pricing in the cost of Demand Control actions it reduces the likelihood of their occurrence.

Options considered and our proposals

4.21. We have considered options and put forward proposals in relation to a number of key considerations:

VoLL pricing: Setting the cost of voltage control and disconnections

4.22. In order to incorporate non-costed actions into cash-out prices at the appropriate level, we have commissioned a VoLL study jointly with DECC that estimated the likely value consumers put on security of supply. In setting the costs for disconnections and voltage reductions, we have taken into account the study's results as well as further considerations, as set out in Box 1 below. **Our draft policy decision for consultation is to set the cost for both disconnections and voltage control actions to initially £3,000/MWh at time of EBSCR implementation (likely 2015) and increasing to £6,000/MWh by the time the CM is introduced.** These figures assume a CM will be introduced in GB.[27] We propose to introduce VoLL pricing in two steps in order to allow parties to adapt to the new arrangements.

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[26] Operating Code (OC) 6 sets out Demand Control provisions to be made by Network Operators, and in relation to Non-Embedded Customers by National Grid Electricity Transmission Plc (NGET), to permit the reduction of demand.

[27] A CM also provides a signal for investment, which is why we propose a figure below the 'true' VoLL estimated in the VoLL study. We discuss a scenario without a CM in Appendix 6.

Box 1: Estimating the value of lost load (VoLL) to set the cost for disconnections and voltage reduction in cash-out[28]

As no robust market exists for supply interruptions VoLL cannot be observed directly from market behaviour. As a consequence VoLL must be determined indirectly. To inform the EBSCR analysis we commissioned external research, jointly with DECC, to estimate the VoLL for electricity consumers in GB. Establishing an accurate estimation of VoLL for GB consumers is difficult and there is no single VoLL for all GB electricity consumers. It differs between different consumers and consumer types and depends on the specific context (peak/off-peak, winter/summer, etc) even for the same consumer. When setting an administrative VoLL there are several considerations regarding how to best reflect consumers' diverse preferences.

The VoLL study provided a large range of estimates that consumers place on secure electricity supplies. The study suggested that £17,000/MWh may be a fair reflection of the *average* VoLL for domestic consumers and SMEs on a winter peak day. Averaging only across SMEs and domestic consumers recognises that I&C consumers are more likely to enter into interruptible contracts (and should be incentivised to do so).

This evidence must also be combined with considerations, such as the appropriate balance between performance incentives and risk for market participants, international comparisons with other electricity markets and interactions with other energy market developments, for example a CM. Importantly, with the introduction of a CM in GB, part of the 'missing money' problem could be solved by the CM, which aims to ensure overall capacity adequacy.

Taking these considerations into account, we propose to set VoLL for the purpose of costing disconnections and voltage control at £6,000/MWh, assuming GB introduces a CM. There are a number of reasons why we propose this figure. Firstly, it represents the upper end of I&C VoLLs and hence provides incentives for most I&Cs to enter into interruptible contracts and provide DSR services, which increases overall capacity availability. A VoLL below this level would remove this incentive for a proportion of I&C consumers to enter into these contracts. Secondly, it is important that prices send signals for the efficient use of interconnectors, so that electricity flows to consumers who value it most. Given consumers' average 'true' VoLL of £17,000/MWh, setting the value to £6,000/MWh would go some way to improving the efficiency of interconnector flows, in particular at times of system stress. Thirdly, a VoLL of £6,000/MWh should provide sufficient financial incentives for existing market participants to increase generation or reduce demand when the system is tight, whilst limiting the overall financial risk to them if they are still out of balance. Finally we are mindful that it may take industry some time to respond to these price signals, which is why we propose a stepped approach of introducing VoLL into the arrangements, further limiting the risk on participants.

We also considered whether different costs should be applied to volumes associated with firm load disconnections (blackouts), as opposed to reductions in voltage on the distribution networks (brownouts). However, the VoLL study indicated a significant amount of uncertainty around the cost estimates for voltage reductions. Further, when Demand Control is necessary, there is currently a level of uncertainty as to whether Distribution Network Operators (DNOs) will implement this using voltage reduction, or firm disconnections[29]. Also, voltage reduction is classified as an emergency action, suggesting a significant cost to the system of using it. We therefore, and for simplicity, propose to use the same value for voltage control and for disconnections in the cash-out price calculation.

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[28] Full details of our proposed figure for VoLL can be found in Appendix 6.
[29] This was highlighted at the ongoing Demand Control and O6 working group: http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/Demand+Control+OC6/

Including Demand Control actions in the cash-out price

4.23. We considered whether Demand Control actions would be included in the stack of balancing actions, with a volume and price attached and subject to flagging and tagging procedures. Alternatively, the cash-out price could automatically be set at VoLL when Demand Control is used to balance the system. While the latter approach would create the strongest balancing incentives, it would be inconsistent with how other balancing actions are treated, and could result in the pollution of cash-out prices when Demand Control is used to resolve a non-energy imbalance. Therefore, **our draft policy decision for consultation is to treat Demand Control actions similarly to other balancing actions for the purposes of calculating the cash-out price.**

Estimating Demand Control volumes to incorporate into cash-out price calculation

4.24. We considered whether it would be possible to use a 'top down' estimation of the Demand Control volume, or whether a more complex, 'bottom-up' approach would be needed. A top-down approach would use the SO's best estimate of the Demand Control volume, using information supplied by the relevant Licensed Distribution System Operators (LDSOs). A bottom-up approach involves the identification of individual consumers who have been disconnected, and a process for estimating what each consumer type would have consumed. Given the complexity involved with the latter approach, and given these arrangements would ideally be used extremely rarely, we are keen to strike an appropriate balance between accuracy and simplicity. Therefore, **our draft policy decision for consultation is to use a top down approach based on the SO's best estimate to reflect volume of Demand Control actions in the cash-out price.**

Adjusting supplier imbalance volumes

4.25. Demand Control actions affect the physical and therefore contract positions of the suppliers of the affected consumers. Furthermore, because of how demand for NHH consumers is determined[30], a Demand Control action will also impact on the positions of all NHH customers within the affected Grid Supply Point (GSP), not just those who have been disconnected.

4.26. A 'bottom up' approach, using data from DNOs, would allow estimation of what each supplier's customer would have consumed had there not been a Demand Control action. It would also allow an adjustment to the profiling for NHH customers in the relevant GSP. We consider adjusting supplier imbalances with reasonable accuracy important, as signals to market participants subject to Demand Control actions could otherwise be distorted. We do, however, recognise the potential for complexity in this area, and aim to limit any changes to industry systems. Further

[30] Load profiles are used to determine the half-hourly pattern or 'shape' of NHH metered consumers' usage across a day for the average customer of each of eight profile classes. If the overall demand for a Grid Supply Point (GSP) is affected by Demand Control, this will be smeared across all NHH customers within that GSP.

detail on this is set out in Appendix 2. **Our draft policy decision for consultation is that suppliers' positions should be restored to their pre-Demand Control positions, using a bottom-up approach based on DNO data.**

Payments to suppliers for adjustments to their positions

4.27. A physical disconnection on the network represents a loss of revenue to suppliers, as they would have procured energy for which they cannot bill their customers. We consider it appropriate for suppliers to be paid for the loss of revenue at a price which represents a proxy for the revenue they would have earned had they been able to sell that electricity to the disconnected consumers. These payments would be independent of payments to consumers for involuntary DSR services. It is important that suppliers do not benefit from receiving this price, and that it does not undermine signals on parties to balance. **Our draft policy decision for consultation is that suppliers should be paid for electricity procured for which they cannot bill their customers due to disconnections.**

Payments to consumers for involuntary DSR service provision

4.28. Disconnections impose real costs on consumers and under the current arrangements they do not receive any payments when they are disconnected. Because consumers are involuntarily taken off supply in these instances, they are providing balancing services in the form of involuntary DSR to the SO and should be remunerated for this service provision. We have used the VoLL study to determine an appropriate level of payments, acknowledging that it is not possible to pay each consumer at their individual VoLL and some simplification is necessary. **Our draft policy decision for consultation is that domestic consumers and NHH businesses should be paid for £5 and £10 per hour of disconnection, respectively, in recognition that they provide a DSR service to the SO**. See Appendix 3 for the analysis underpinning our proposed level of payment to consumers for this service.

System warning requirement before VOLL pricing

4.29. We considered whether the market should receive a pre-gate closure 'warning' that VoLL pricing will apply. Stakeholders had suggested that without sufficient warning, the market will not be able to respond to cash-out prices. However, we consider a warning to be inconsistent with the current cash-out price calculation, which bases the cash-out price on actions taken in real-time. There is no warning given for any other level the cash-out price could reach. A warning would also reduce the value of providing capacity that can react in very short timescales. Therefore, **our draft policy decision for consultation is that no ex-ante warning is required before for VoLL pricing is applied**.

High level impacts

4.30. Attributing a cost to non-costed actions has a similar high-level impact as making prices more marginal and improving the way reserve is costed – as presented in chapter 3. It should make prices more efficient by signalling the costs of disconnections and voltage reductions to market participants.

4.31. Some responses to our initial consultation stated that incorporating a price for Demand Control actions into the arrangements would not improve incentives on participants to balance their positions in the market, either in real-time, or by incentivising additional investment in flexible generation or DSR. They suggested that efforts would be better focused on encouraging commercial DSR services. We believe that ensuring adequate cash-out price signals are key to encouraging commercial DSR and other market-driven balancing solutions.

Implementation and delivery risks

4.32. A number of stakeholders felt that pricing Demand Control actions would create unnecessary and unmanageable risk for participants, particularly smaller and intermittent players. We agree that participants should not be exposed to inappropriate levels of risk. However we believe this proposal represents an adjustment to cash-out prices to ensure they more accurately reflect existing costs. Costs and risks of disconnection are currently mainly borne by consumers who are generally unable to manage such risks. Reflecting these costs in the cash-out price is expected to bring about appropriate market-driven solutions to manage them. Further, flagging and tagging mechanisms exist to prevent inappropriate costs from being reflected in the cash-out price, as explained in more detail in Appendix 5.

4.33. Some stakeholders raised concerns that incorporating a price for Demand Control into the cash-out price could cause offers submitted in the BM to congregate around this price – ie it would become a 'target price'. Incentives to do so could come from increased revenues received in the BM as a result of individual Balancing Mechanism Units (BMUs) bidding higher. However, we do not believe that this is a risk in practice as experience suggests that there is sufficient competition in the BM that has prevented the existing cap on offer prices acting as a target price. Parties submitting offers at VoLL are likely to forego more certain revenues in the forward market. We will monitor party behaviour as part of our work under REMIT.

4.34. Some stakeholders expressed concern in their Initial Consultation responses that incorporating non-costed actions would prove too complex to be workable. When considering options for the potential detailed implementation of these proposals, we recognise that there will be a trade-off between accuracy and simplicity. We believe that our high-level proposals – which we look to develop further with the support of stakeholders – strike the right balance in this regard. We recognise that some aspects of potential implementation may be easier or may allow for greater accuracy in a world where smart meters are common-place, and that these proposed arrangements could serve as an interim solution until that point.

Improving the way reserve is costed

Background and rationale

4.35. The SO is responsible for balancing the electricity system second by second and it has incentives to minimise the costs associated with balancing. In order to ensure that it can balance the system securely and efficiently, the SO can strike up contracts with providers of reserve services who would agree to be available at specified time for a specified price, in exchange for an availability payment. The main source of reserve is STOR. STOR is used in combination with bids and offers from the BM to balance the system in real time. However, the way that the cost of these STOR contracts is currently reflected in the cash out price can have a distortive and dampening impact on the cash-out price, undermining balancing efficiency[31].

- Reserve products have a more complex payment structure than BM bids/offers. In particular, reserve providers often receive a regular availability payment, simply for being available to generate when asked. Ideally, these availability payments would be reflected in cash-out prices and targeted to the periods where reserve is used to balance the system. The current approach is inaccurate as it uses historical data to allocate availability payments into settlement periods, which is often not an appropriate proxy of when reserve was used and valued most.

- Balancing Services procured via contracts can be seen as a hedge around potentially high prices in the BM. When a balancing service provider has a forward contract with the SO, it must offer this service at a fixed price. Providers are not able to adjust the price of pre-contracted service closer to real-time, and therefore not able to respond to scarcity, unlike resource that does not have forward contracts. This dampens the cash-out price as the reserve is not costed at the value it provides to the system.

- Non-BM STOR is not reflected in the cash-out price. The costs of utilisation of STOR that is not exercised in the BM (such as embedded generation or DSR are not reflected in the cash-out price.

4.36. Some stakeholders suggested that reserve should be seen as an 'insurance policy'. While we agree that reserve can be viewed as such, and that it may not be appropriate to reflect all reserve costs procured by the SO (eg which weren't use to resolve energy imbalances), we believe that it is appropriate to adjust cash-out prices where they are dampened by the SO's forward provision of balancing services.

[31] More detail on current reserve arrangement is outlined in Appendix 4.

Options considered and our proposals

4.37. We have considered a number of options for pricing STOR actions since the publication of the Initial Consultation document. We sought views on whether improvements could be made to the current mechanism for targeting STOR and other balancing costs – the Buy Price Adjuster (BPA). We do not think there is a way to significantly improve the BPA, and we did not receive any proposals from stakeholders detailing how this could be done.

4.38. An alternative methodology, proposed by some stakeholders, suggested that an uplift based on availability fees could be added to STOR actions when they are used to balance the system. This uplift would be calculated ex-ante and would aim to ensure availability fees are fed into the cash-out price at times when STOR is actually used to resolve an energy imbalance. Adding an uplift would make STOR look like a standard BOA, and could be derived from STOR option fees. However, there would be significant difficulties with establishing what the uplift should be. The SO would be required to take an advance view of how regularly STOR plant would likely be used, which we understand is very difficult. Further, it was suggested that any inaccuracies in the SO's forecast would require a retrospective adjustment, which would undermine the timeliness of the cash-out signal. A further issue with this approach is that fixing the uplift means that prices will not necessarily correspond to system conditions – price spikes could occur in non-scarce periods when STOR is also used, or prices could be prevented from rising sufficiently when there is scarcity.

4.39. A further option considered applying a replacement price based on the next most expensive unflagged action in the price stack, or on the next unaccepted offer. This proposal received no support from stakeholders and was described as 'arbitrary'. We agreed that a more sophisticated approach to pricing could be devised.

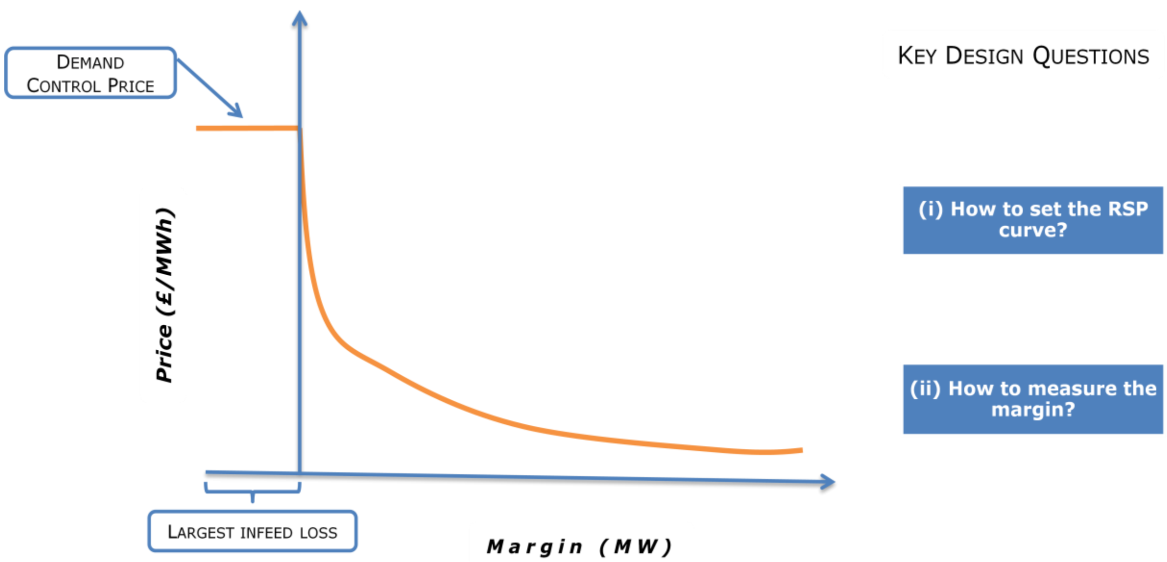
4.40. Recognising the practical difficulties of allocating supply side costs, we explored the merits of the option of applying a RSP function. This approach builds on the experience of US markets such as PJM[32] which prices reserve using a function of VoLL and Loss of Load Probability (LOLP)[33]. Rather than pricing based on the underlying costs incurred to procure the reserve plant (ie the supply side costs), pricing for operating reserve is derived from the demand side. Decoupling the pricing from the supply side costs overcomes the inherent difficulties with the targeting of these costs and instead reflects the value that operating reserve delivers. In theory the two approaches should deliver the same outcome.

4.41. The price derived from the RSP function would depend on the prevailing margin on the system, and a pre-defined RSP curve that further depends on the

[32] The Pennsylvania, Jersey, Maryland Power Pool.
[33] Following order number 719 from the Federal Energy Regulatory Commission (FERC) a number of jurisdictions in the US have or are planning to introduce a demand curve pricing approach for operating reserve. Further detail can be found at: http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf

price for demand control actions and the LOLP. With decreasing margins the price that would be derived from this approach would increase up to the level of the price for Demand Control actions when margins (excluding the capacity of the largest infeed loss[34]) fall to zero, as illustrated in Figure 1. This takes into account that the SO normally keeps a minimum level of reserve, and starts using Demand Control actions before using up this minimum amount. The level at which reserve is priced when used in the BM would then be the greater of the RSP function value or the utilisation fee. It is important to note that this approach is not designed to change the way the SO procures and dispatches reserve, but only change the way reserve is priced in the cash-out calculation when used to balance the system.

Figure 1: Design of the Reserve Scarcity Pricing function



4.42. Current arrangements for reflecting STOR costs fail to create the correct balancing signals. Non-BM STOR is not reflected in the cash-out prices, and the BPA smears availability fees across settlement periods and historically has not created signals in the cash-out price as it has not corresponded to scarcity or STOR usage. Stakeholders agreed that it was not accurate, and it has been described as 'random and largely irrelevant'. The RSP function approach ensures cash-out prices reflect scarcity more accurately and provide appropriate signals to market participants to balance and invest in flexible capacity. For these reasons **our draft policy decision is to improve the way reserve is costed by applying a RSP function methodology for costing BM and non-BM STOR actions into cash-out prices** when they are used to resolve an energy imbalance on the system. We propose to use the same prices established for Demand Control in the previous section ("VoLL pricing"), ie £3,000/MWh rising to £6,000/MWh when the CM is introduced. The RSP function approach would replace the current BPA approach of pricing reserve.

[34] The SO always keeps reserve to cover the potential loss of the largest generator.

High-level impacts

4.43. The RSP function is designed to reflect the value of reserve balancing resource in the cash-out price when it has been used to resolve an energy imbalance. This will strengthen signals to balance, particularly during times of system stress. High-level impacts of this reform are therefore expected to be similar to other proposals that make cash-out prices sharper (making prices marginal and incorporating non-costed actions). These high-level impacts are presented in chapter 3.

4.44. The removal of the BPA and implementation of the RSP function could have the effect of reducing the *average* cost of reserve that is targeted into any given settlement period and hence into cash-out prices. However, the RSP function would better target reserve costs, making them higher when the system is tight and lower during other times. This helps cash-out prices better reflecting scarcity.

4.45. The RSP function would have the additional benefit of in causing cash-out prices to rise gradually as margins tighten and system stress increases. This would provide a good complement to VoLL pricing, reducing the frequency of sharp, sudden rises in the cash-out price. Making the RSP metric visible to the market ahead of gate closure could increase transparency and provide a scarcity signal to the market, improving the ability for parties to respond before emergency balancing actions are needed.

Implementation and delivery risks

4.46. An RSP function is intended to ensure that the pricing of reserve actions in cash-out is linked to market conditions. STOR and non-BM STOR actions would be re-priced using the RSP function**.** These actions would then be subject to the same flagging and tagging mechanisms as 'normal' balancing actions. We note that this treatment of re-priced actions could mean that often reserve actions could be NIV tagged, and would then not be reflected in the cash-out price (see Appendix 5 for a discussion of NIV tagging).

4.47. There was general support for the Reserve Scarcity Function when we raised the proposal with our TWG. Stakeholders noted that the methodology for calculating prices would ideally be dynamic, and may need to be updated regularly depending on the day and time of year. They also proposed that the pricing function should be visible to parties ahead of real-time, and updated as close to real-time as possible. It was suggested by stakeholders that the prices for reserve could be set up to four hours ahead.

4.48. There are a number of questions to be resolved regarding the detail of the implementation. The key design questions for the RSP function are on how to define the RSP curve (including a measure of LOLP) and how to measure the margin close to real time for a given half-hour. We propose to develop the exact details of the RSP function in consultation with industry and the SO. Further implementation questions are set out in Appendix 4.

Single or dual cash-out prices

Background and rationale

4.49. The balancing arrangements currently operate under a dual price system where there are two cash-out prices in every settlement period. The cash-out price faced by a party that is out-of-balance is determined both by the direction of its imbalance, and that of the overall system. Parties out of balance in the same direction as the overall system face the main cash-out price, based on the costs of the SO's balancing actions. Those out of balance in the opposite direction to the overall system face the reverse cash-out price, which is calculated as a weighted average of near term market prices (see Table 3 below).

Table 3: Pricing structure under existing dual[35] price arrangements

		System Position	
		Long	Short
Party Position	Long	Receive SSP (Main price)	Receive SSP (Reverse price)
	Short	Pay SBP (Reverse price)	Pay SBP (Main price)

4.50. The dual price creates a spread between cash-out prices for parties that are long or short in a given settlement period. We are concerned that this spread does not reflect the true costs or cost savings which out of balance parties place on the system. This creates a distortion in the balancing arrangements, unnecessarily increasing overall balancing costs for parties, and harming in particular those less able to balance, for example smaller and renewables parties.

Options considered and our proposals

4.51. The key options under consideration are either to maintain the existing dual price system or to move to a single cash-out price.

4.52. Under a single cash-out price, all out-of-balance parties in a given settlement period would face the same imbalance price, irrespective of whether the party is long or short. The cash-out price faced would be based on the cost of actions taken by the SO to balance the net imbalance on the system. This means that the current main imbalance price calculation would apply to all imbalances (both short and long) in a given settlement period and the reverse price would no longer be used. For example, when the system is long, the cash-out price faced by all parties whether long or short would be based on the net volume of bids accepted by the SO (see Table 4 below). The existing flagging and tagging rules in the calculation of the main price would remain in place.

[35] Note that 'dual' refers to the use of main and reverse prices, rather than the use of a SBP and SSP.

Table 4: Pricing structure under single price

		System Position	
		Long	Short
Party Position	Long	Receive cash-out price	Receive cash-out price
	Short	Pay cash-out price	Pay cash-out price

4.53. We also consider (outlined below) whether additional measures would be required under a single price to ensure parties continue to submit accurate Final Physical Notifications (FPNs).

4.54. Under a dual price system, parties face a different price according to whether they are long or short in a given settlement period. This design undermines the cost-reflectivity of prices as the different imbalances do not place different costs on the SO to resolve. When considering only energy imbalances: imbalances in the opposite direction to the overall imbalance reduce the balancing actions required by the SO. In view of this, the true value of these 'opposite' imbalances is the cost of avoided actions that the SO would otherwise have taken. Thus, the spread between cash-out prices that the dual price system drives inefficient balancing outcomes – and may for instance under current arrangements over-incentivise balancing particularly at times when the system is not tight. This spread is likely to widen in future in light of the increasing (wind-driven) variability of imbalance, and as a result of other EBSCR policy options which sharpen prices.

4.55. To remove this distortion, and to remove unnecessary balancing costs from parties, **our draft policy proposal for consultation is to move to a single cash-out price**. Further, at this stage we are of the view that no additional arrangements are required to avert the risk of parties deviating voluntarily from FPNs following Gate Closure, given the existing provisions in the Grid Code.

High-level impacts

4.56. Under a single (marginal) price, imbalances in the opposite direction to the overall system length would receive a price based on the most expensive action taken to resolve the net imbalance. This would remove the inefficient spread between cash-out prices, which would now reflect the value of the balancing action that the SO was spared from taking owing to the 'opposite' imbalance. A single cash-out price would therefore improve the cost-reflectivity of the balancing arrangements and it would enhance incentives to balance efficiently. As noted by stakeholders in their responses to the Initial Consultation, it would reduce the risk of imbalance across all market participants as well as total gross imbalance charges in the market and ultimately improve the overall efficiency of the balancing arrangements.

4.57. A single cash-out price would have a net zero effect on market participants as a whole, as imbalance charges are reimbursed to parties through the RCRC[36]. However it could have positive competition and distributional impacts for smaller and newer parties and intermittent generators. These parties are more likely to be out of balance, either owing to relatively less experience with balancing, lower portfolio balancing opportunities or greater inherent uncertainty in generation. Hence they are also more likely to be penalised by the artificial spread between cash-out prices under a dual price. This effect is further amplified by the dual system as it inflates total imbalance charges, which are then redistributed to parties according to size. The result of which is that wind generators receive a relatively low share of the RCRC pot, compared with vertically integrated utilities (VIUs). Thus removing this spread may benefit renewables and small parties in particular. Our quantitative analysis supports this, and further suggests a single price could mitigate or entirely outweigh the potentially negative distributional impacts of our other EBSCR proposals (which are likely to make prices sharper).[37]

4.58. A single cash-out price could also reduce credit and collateral requirements under the Balancing and Settlement Code (BSC), which are relatively burdensome for smaller or newer parties. In addition, and as noted by many stakeholders in their responses to the Initial Consultation, it could imply an improvement in the simplicity and transparency of the balancing arrangements and may improve liquidity by incentivising the development of new balancing products. These impacts could also reduce the risk of market entry and improve market competitiveness.

Implementation and delivery risks

4.59. In responses to the Initial Consultation, stakeholders raised several potential delivery risks associated with the implementation of a single cash-out price. The first relates to the possibility following introduction of a single price that market participants would be able to gain from being out-of-balance in the opposite direction to the overall system. Parties may receive a favourable price relative to what they could have earned through trading in forward markets. This creates an incentive for parties to try to anticipate the overall system length and take an opposing spilling position into the settlement period. In theory, this could drive significant uncertainty for the SO if market participants chase the system length as parties' positions continually adjust and the anticipated system length continually flips.

4.60. Some stakeholders expressed concerns that a single cash-out price could remove the incentive on market participants to trade forward opposite imbalances and thereby reduce liquidity and competition and ultimately augment balancing costs. However, our analysis suggests – owing largely to enduring uncertainty in forecasting net imbalance volumes – that such effects are unlikely to materialise. However, we believe that chasing the system length is unlikely to be a sustainable strategy for market participants. Before the settlement period, Net Imbalance

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[36] Residual Cashflow Reallocation Cashflow: the surplus/deficit from cash-out that is redistributed to market participants according to their size.
[37] Find an illustration of the effects of a single price on cash-out in the annex of the IA

Volume (NIV) is highly unpredictable and difficult to forecast accurately[38]. In view of this, any strategy attempting to gain from an imbalance position would be significantly risky. As such, trading forward is likely to remain a dominant strategy under a single price.[39]

4.61. Even if parties face significant uncertainty around chasing the net imbalance, parties would have an incentive to deviate from FPNs after Gate Closure to balance energy across their portfolio under a single price. Where a party is out of balance on one account, deviations from FPNs on another account may allow them to net off the primary imbalance. Any such actions by parties could create uncertainty for the SO when fulfilling its balancing role. However, it is important to note that a similar incentive for participants to act in this way already exists under dual pricing with regards to balancing across multiple accounts of the same type under a party's portfolio. This has not been considered a significant issue so far, because under the existing Grid Code, participants are required to submit accurate FPNs and adhere to them. Thus although a single price may increase the incentive to deviate, parties are unlikely to act on this as doing so risks the launch of an investigation into the breach of the party's code and licence obligations.

4.62. As part of the development of the single price policy, we considered whether additional measures could be required to mitigate this incentive. These included use of information imbalance charges, enhanced monitoring, a performance standard (similar to that used in the Netherlands) or hybrid pricing structures considered in the Initial Consultation. At this stage we are minded that no further measures are required given the existing arrangements. We welcome stakeholder's feedback on this issue and will continue to work with the SO to ensure that appropriate arrangements are in place to ensure parties do not deviate from their FPNs post gate closure.

4.63. A final concern is that under a single price parties can potentially gain more through spilling pre Gate Closure than offering balancing energy voluntarily into the BM. This is an issue because we consider it to be preferable that parties place any additional balancing energy into the BM for the SO despatch as required. However, given the uncertainty around the direction of net imbalance, we believe that parties will continue to offer surplus energy through the BM rather than spilling to take advantage of a single price. Nevertheless, we are aware of this issue and, in particular, its interaction with a pay-as-clear structure for accepted bids and offers. We welcome stakeholder views on its likely severity and potential impact and note that pay-as-clear pricing may be considered further under Ofgem's ongoing Future Trading Arrangements project.

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[38] The SO's forecast of imbalance was incorrect in 34% of settlement periods. This suggests that individual parties – with limited sight of party imbalance compared with the SO – may find it hard to forecast system imbalance correctly much better than 50%. See the Impact Assessment 'Risks and unintended consequences' chapter for more detail
[39] See Impact Assessment 'Risks and unintended consequences' chapter

Single or separate trading accounts

Background and rationale

4.64. Under current balancing arrangements, parties are required to keep licensed generation separate from licensed consumption. Each BSC Party is assigned a production account and a consumption account to which licensed energy is credited. We considered whether allowing parties to trade both production and consumption through a single account (or to combine imbalances across their portfolio) could improve the efficiency of the balancing arrangements.

Options considered and our proposals

4.65. The two key options under this consideration are either to maintain separation of trading accounts or allow parties to trade energy through a single account. Note there are strong interactions between this consideration and a single cash-out price. As such, we have developed the two policy options together.

4.66. The primary benefit of allowing parties to combine credited energy is that vertically integrated parties could net imbalances across accounts and therefore reduce the risk of facing the spread between cash-out prices. This would be more cost reflective, as the SO only needs to resolve the net imbalance considering only energy imbalances. Some respondents to the Initial Consultation noted other benefits of single accounts including improved simplicity of the balancing arrangements, reduced transaction costs for market participants and reduced contract notification risk.

4.67. Introduction of a single cash-out price would also allow market participants to avoid the risk of the spread between cash-out prices – but to a greater extent than single trading accounts. A single price would allow *all* market participants to avoid this risk, whereas single trading accounts only allow vertically integrated parties that have both production and consumption accounts with opposing imbalances to avoid this risk. Some stakeholders therefore expressed concern that a single account could have a negative impact on competition.

4.68. A single cash-out price would capture all of the efficiency benefits and more of single trading accounts. An additional move to a single trading account is unlikely to realise significant further benefits. Also, keeping separate trading accounts would help maintain the current level of transparency with regards to trading activities in the market, and would also reduce the need for changes to industry systems. **Our draft policy proposal for consultation therefore is to maintain separate accounts**.

Gate closure

Background and rationale

4.69. Gate closure is the point at which participants cease trading and the BM begins. At this point participants submit FPNs (signalling their expected physical position) and contract notifications (signalling the volumes that they have traded). Gate closure is currently set one hour ahead of real time.

4.70. As parties are exposed to imbalance risk for inaccurate demand forecasts or plant failures between gate closure and real time, the nearer gate closure is to the commencement of the BM the better parties may be able to manage this risk.

Options considered and our proposals

4.71. As part of the secondary considerations set out in our Initial Consultation, we considered the merits of moving gate closure closer to real time. We also consulted on the possibility of submitting contract notifications after gate closure, and allowing parties to trade out imbalances after gate closure where it was mutually beneficial. Taking into account the potential benefits and risks identified together with stakeholders, the TWG considered our two proposals:

- Reduce gate closure to 30 minutes for physical and contract notifications

- Keep current gate closure but allow contract notifications after gate closure, reducing the current *de facto* gate closure of 1.5 hours

4.72. Several stakeholders acknowledged the potential benefits of changes to gate closure in terms of lower imbalance risk. Respondents to our Initial Consultation recognised that this proposal could be particularly beneficial for renewable generators, potentially allowing their forecasts to improve. However, stakeholders have also expressed the view that the benefits are likely to be relatively small. Most stakeholders also thought that allowing contract notifications after gate closure is unlikely to yield significant benefits that would justify a change.

4.73. Stakeholders also identified risks, in particular with moving gate closure to 30 minutes. A shorter period between gate closure and real time may significantly affect the SO's ability to balance the system in an optimal manner, as it would reduce – potentially quite significantly – the pool of plants available to the SO that could ramp up or down quickly enough to help balance the system.

4.74. On balance, whilst we can see the potential for some improvements in forecasting, we consider them to be small, and the risks and potential costs for the SO of balancing the system over a shorter timeframe to be more material. **Our draft policy proposal for consultation is to maintain the existing rules for gate closure.**

Quantitative assessment of policy packages

4.75. We have conducted a detailed quantitative analysis of a range of policy options as part of the EBSCR and commissioned Baringa to support us with the modelling of impacts. This section provides a set of key results we obtained from this work. The more detailed results of Baringa's work are set out in our IA as well as in Baringa's report, both of which are published alongside this document.

4.76. As set out in chapter 2 we have grouped policy options into packages to take into account potential interactions between them. The packages range from a scenario where only PAR levels are changed and a scarcity function is implemented (Package 1) to a package that ensures most efficient price signals (Package 5 – this corresponds with our draft policy decision).[40]

4.77. We have assessed how each of these potential packages compares with a 'Do nothing' scenario, based on our objectives and considering the effects of each of these packages on consumer bills, security of supply, efficiency, competition, distributional effects, sustainability and risks for market participants. It is important to note that our baseline scenario for the quantitative modelling excludes a CM.[41] However we have modelled a sensitivity where a CM would be implemented in GB (by changing the assumed underlying capacity margins).

Impact on cash-out prices and volatility

4.78. Our results show that all potential packages are likely to make cash-out prices sharper (ie the price paid for short imbalances increases and the price parties are paid for long imbalances decreases) relative to the status quo. The modelling suggests that the volatility of cash-out prices is likely to increase. Both average cash-out price increases and volatility depend crucially on the assumed capacity margin, and therefore also on the question of whether there will be a CM in place. The increases in both average price and volatility are significantly lower in our "with CM" sensitivity, which assumes higher margins and therefore also fewer expected periods of scarcity and greater balancing resources available to the SO.

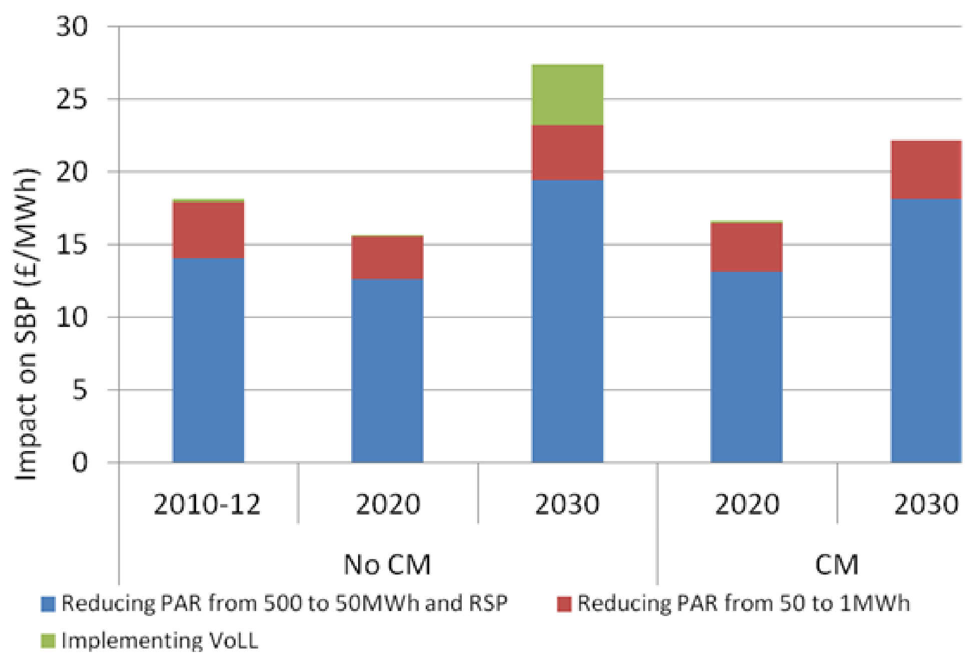
4.79. As show in Figure 2 below, our modelling suggests that our proposals (package 5) are likely to increase average SBPs compared to 'Do Nothing'. With a CM, prices could be about £16 higher than 'Do nothing' in 2020, and £22 in 2030. If no CM is introduced, prices could be £15 (in 2020) and £27 (in 2030) higher than under 'Do Nothing'. Figure 2 also illustrates the contribution of different policy considerations to the price increases. of the package[42]. It suggests:

- the effects of marginal pricing (from PAR500 to PAR50, and subsequently to PAR1) combined with the introduction of the RSP Function may have most substantial impacts on prices.

[40] Find the full list of packages in chapter 2
[41] At the time when we conducted the quantitative analysis the CM was not yet initiated.
[42] Noting the caveat that this illustration not fully captures the interaction effects

- in 2030 – characterised by much tighter margins – reforms will have a greater impact than in 2020, including in the no CM scenario an additional £4/MWh resulting from VoLL pricing.

Figure 2: Modelled increase of average SBP relative to 'Do Nothing'



4.80. The modelled impact on average SSPs is more modest – around a £2/MWh reduction in 2020 and 2030 as a result of EBSCR packages. Due to the fact that the move from PAR500 to at least PAR50 and the RSP function are common to all packages, impacts of other policy packages (Packages 1-4) are very similar to the impacts presented in Figure 2. The price range between all packages is lower than £10 in any year/scenario.

4.81. The modelling also suggests that cash-out price volatility is likely to increase significantly under our proposals, as shown in Table 5 below. If a CM is introduced, this effect is significantly smaller than without a CM. More volatile cash-out prices are likely to increase balancing costs for participants that are less able to balance.

Table 5: Modelled volatility of cash-out prices in 2030 (compared to historic)

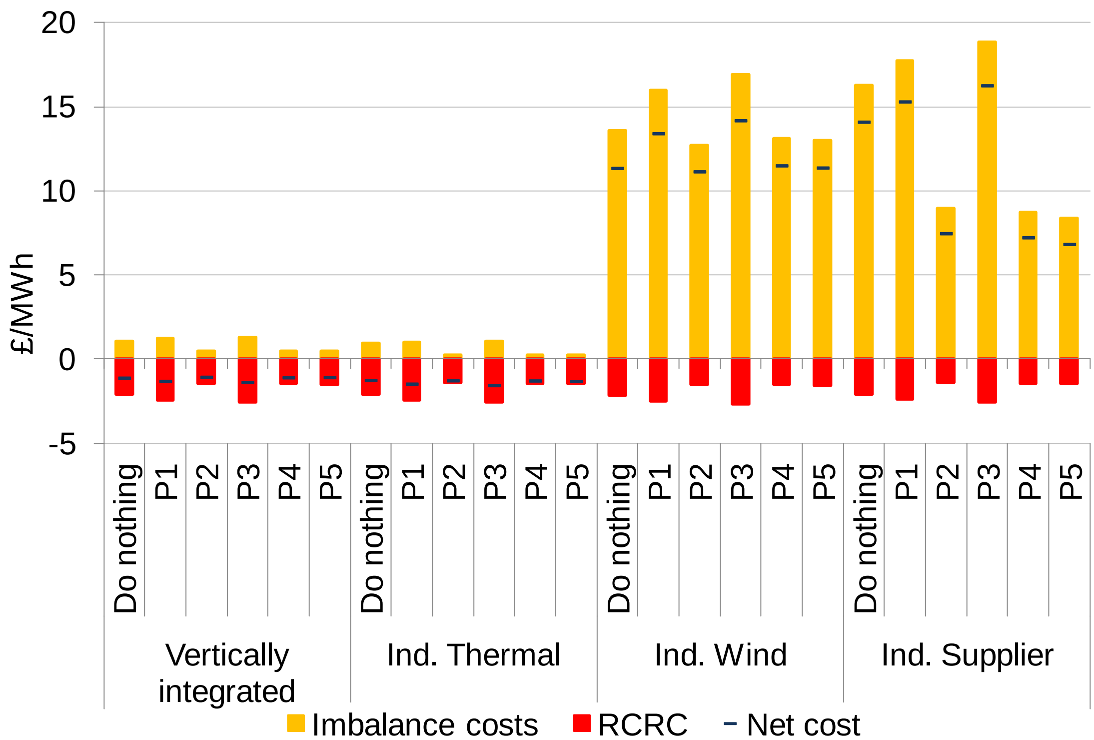
Standard deviation of SBP (£/MWh)	Year	Do Nothing	Package 1	Package 2	Package 3	Package 4	Package 5
No CM	2010-12	26	175	186	191	180	191
	2030	92	175	177	223	223	222
With CM	2030	30	63	86	74	69	74

Distributional impacts

4.82. Our quantitative analysis shows that packages with a single price (packages 2, 4 and 5) significantly soften and in some cases outweigh the increase in net imbalance costs caused by the other proposals. This is because parties, under a single price are able to benefit when helping the system by being out of balance in the opposite direction to the overall system length. Smaller parties, owing to the fact that they are generally weaker balancers, benefit most from a move to a single price. According to our modelling results, renewables are net beneficiaries of a move to a single price (although less so than other smaller parties) even though they are often out of balance in the same direction as the system. Although a single price also reduces larger parties' net imbalance costs, owing to the reduced RCRC smear back in a single price system, they slightly lose out overall.

4.83. This is illustrated in Figure 3 which shows the net cost (balance of RCRC payments and imbalance costs) by different party type of the 'Do Nothing' and all five policy packages in 2030. Compared to 'Do Nothing', the net cost for independent suppliers falls under packages 2, 4 and 5 (the single price packages), and the increase in net cost for independent wind is much less under packages 2, 4 and 5.

Figure 3: RCRC and 'opportunity cost' as a proportion of total credited energy in 2030 – positive values represent costs



4.84. The quantitative analysis of packages supports the qualitative assessment of policy options: Package 5 sends the most efficient price signals to the market and mitigates the otherwise negative distributional effects from sharper prices by moving to a single price.

Cost-benefit-analysis

4.85. We have commissioned Baringa to conduct a cost-benefit-analysis (CBA) based on their quantitative model. We note in the IA that the quantitative analysis has limitations. These apply in particular to the CBA, as not all costs and benefits could be quantified. For example, the analysis excludes benefits such as efficiency gains from more responsive interconnector flows, more competition and innovation under a single price, and generally better price signals. On the other hand, it excludes potential costs, such as potentially increased costs of capital resulting from higher cash-out price volatility.

4.86. As illustrated in Table 1Table 6 below, the CBA estimates an overall net benefit of our proposed package 5 of £13m in 2020 and £152m in 2030. Impacts on consumer bills compared to the business as usual case are expected to be broadly neutral, as costs of additional investment are likely to be offset by efficiency improvements. The key difference between packages with and without a single price stems from the assumed savings for parties due to slightly reduced incentive to balance when the system is not tight (which is most periods), which in the model outweigh the costs of increased incentive to balance in periods when the system is tight.

Table 6: Summary of Cost Benefit Analysis

Packages			1	2	3	4	5
'No CM'	**2020**	Total net benefit in £m	-7	14	-7	13	13
		Impact on average domestic bill in £/year	0.07	-0.15	0.07	-0.14	-0.14
	2030	Total net benefit in £m	59	148	59	148	152
		Impact on average domestic bill in £/year	0.24	-0.61	0.25	-0.61	-0.64
'With CM'	**2020**	Total net benefit in £m	-7	12	-7	12	13
		Impact on average domestic bill in £/year	0.08	-0.13	0.08	-0.13	-0.14
	2030	Total net benefit in £m	-24	55	-31	57	53
		Impact on average domestic bill in £/year	0.24	-0.52	0.31	-0.53	-0.50

5. Interactions

5.1. In this chapter we explore the links between the EBSCR and other ongoing energy market developments, notably Government's EMR, the implementation of the EU TM, and several of Ofgem's other projects.

EMR Capacity Market

5.2. The Government's CM aims to ensure there is enough overall capacity to meet demand. It does this by procuring a specified amount of capacity centrally and providing capacity providers regular payments outside of the energy market. In return for these capacity payments, capacity providers must be available to produce energy or reduce demand when the system is tight, or face penalties.

5.3. Balancing arrangements and the CM have distinct but complementary roles in increasing electricity security of supply. With the CM ensuring overall capacity adequacy, cash-out remains crucial in providing efficient short-term price signals to the market. These price signals are important for efficient dispatch, investment in flexible capacity as well as in order to support more efficient interconnector flows. The CM aims to reduce the risk for investors from collecting all of their revenues in the energy market, and instead offers a separate, more certain revenue stream. Cash-out reform on the other hand focuses on improving the incentives in the energy market itself, including the incentives for flexible capacity. Both cash-out reform and the CM are likely to affect investment decisions. Cash-out reform is unlikely to have a large impact on investment decisions in the short term, but is more likely to affect investment decisions in the medium to longer term as the price signals work through the system.

5.4. On 27 June 2013 DECC published its Detailed Design Proposals for the CM[43]. These proposals set out that penalties on capacity providers for failing to be available when needed would be linked to the VoLL minus the prevailing cash-out price (the SBP for each half hourly settlement period in which there was system stress).[44] This formula for penalties ensures that the overall incentives for parties remain constant following any reform to cash-out arrangements. We will continue to work closely with DECC to ensure these policies are compatible.

EMR CfDs and route to market

5.5. As part of EMR, DECC plans to introduce CfDs to provide more revenue certainty to low carbon generators in order to reduce their investment risk. Related to this work, DECC is considering further ways to improve the route to market for renewables, in particular for independent renewables generators, which play an

[43] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/209280/15398_TSO_Cm_8637_DECC_Electricity_Market_Reform_web_optimised.pdf
[44] We have commissioned a study to estimate VoLL study jointly with DECC

important role in transitioning to a low carbon electricity system. Independent generators usually sell their power through PPAs to aggregators or large suppliers who then take on the imbalance risk and provide a route to market. The competitiveness of the PPA market will affect the level of discount generators have to accept in return for these services. DECC is working on improving the competitiveness of the PPA market to ensure renewables have a viable route to market that should enable them to secure investment. As the EBSCR may have an impact on imbalance costs we will continue to work closely with DECC colleagues to ensure potential changes to balancing arrangements are considered as part of DECC's work on CfDs and route to market for independent generators.

EU TM implementation

5.6. One of Ofgem's objectives as the national regulatory authority for GB, stemming from its obligations under EU legislation and which has been reflected in Ofgem's principal objective, is to promote a competitive, secure and environmentally sustainable internal market in electricity within the European Union. EU legislation is triggering far-reaching reforms to create a single European energy market through the implementation (amongst other measures) of what is commonly referred to as the EU TM.[45] The EU TM establishes common rules to facilitate efficient use of cross-border capacity and to encourage harmonisation of European wholesale market arrangements.

5.7. Balancing market arrangements are a key focus of this European harmonisation. The EU TM aims to foster effective cross-border trading and sharing of balancing resources between member states in order to enhance security of supply and reduce the costs of system balancing. Exact details of the EU TM are not expected to be finalised until 2014; however, ACER's Framework Guidelines on Electricity Balancing[46] and ENTSO-E's early Draft Network Code on Electricity Balancing[47] provide insights into the intended design of the harmonised EU TM.

5.8. In undertaking the EBSCR we have been mindful of the interactions between the emerging EU TM and the EBSCR policy considerations. These interactions were one of the drivers for our decision to reduce the scope of the EBSCR and to launch the FTA forum. Throughout the EBSCR process the team has worked closely with colleagues actively involved in European policy development to ensure that any policy reforms proposed by the EBSCR are not in conflict with the direction of the EU TM.

[45] Also known as the "Third Package", EU legislation on European electricity and gas markets entered into force in September 2009. For more information: http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm
[46] For more information: http://www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/Balancing.aspx
[47] For more information: https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/

Future Trading Arrangements Forum

5.9. In May 2013 Ofgem formally launched the FTA Forum. Taking a holistic view of the challenges facing the GB wholesale electricity market, the objective of the FTA Forum is to seek views on a coherent and consistent approach to wholesale electricity trading arrangements in the context of EMR, EU TM, market and technological developments.

5.10. A contributory factor to the development of the FTA Forum was our decision to reduce the scope of the EBSCR. This decision placed the longer-term original EBSCR policy considerations, such as the policy proposals relating to the possible introduction of a Balancing Energy Market or a day-ahead reserve market, within the wider scope of the FTA Forum. The FTA Forum's holistic approach is designed to consider the interactions between the multiple drivers for change in the GB electricity market. A holistic approach should avoid the development of an incoherent set of mechanisms or a series of overlapping reforms proposals which may involve undoing previous decisions within the space of just a few years. Moreover, such an approach could lead to improved investor certainty, with benefits for consumers in terms of lower cost of capital and less redundancy in systems redesign.

Gas SCR

5.11. Gas plays an important role in electricity generation. Gas-fired plants generate around 30-50% of GB electricity and provide an important source of flexible electricity. Ofgem's Gas SCR[48] proposed reforms of the gas cash-out mechanism with the aim of sharpening the incentive on gas shippers to enhance gas security of supply. These reforms include the introduction of VoLL pricing for the provision of involuntary DSR services (if firm customers are interrupted) in the gas cash-out arrangements.

5.12. Gas-fired generators are uniquely placed to operate in both the gas and electricity markets. If a gas emergency event led to the interruption of gas supplies to gas-fired generators then these generators may simultaneously receive a payment in one market (gas) and face imbalance charges in the other (electricity). This interaction means that the gas SCR and the EBSCR should try to ensure coherent signals are provided by cash-out policies in each market. Throughout our VoLL policy development Ofgem's EBSCR and Gas SCR teams have worked closely to ensure that Ofgem's cash-out policy proposals provide appropriate incentives and price signals to market participants. Central to this policy development is the role for market participants to determine their own response to these arrangements, including the actions they may take to manage and mitigate risks. In light of this, the Gas SCR consultation is requesting stakeholder views on the appropriate treatment of gas-fired generation within the proposed reforms of the gas cash-out arrangements.

[48] Gas SCR website:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx

Liquidity Project

5.13. Ofgem's liquidity project aims to identify and remove barriers to competition in the wholesale energy markets. On 12 June Ofgem published final proposals for a 'Secure and Promote' licence condition[49]. These proposals aim to improve the access of independent suppliers to the wholesale market and ensure that the wholesale market provides the products and price signals that all market participants need to compete effectively.

5.14. We believe that there is likely to be limited direct interaction between the EBSCR and liquidity project proposals because our liquidity proposals focus on longer term forward markets. However, some of the proposals being considered as part of EBSCR could have a positive impact on wholesale market liquidity in the near-term. The considerations under the scope of the EBSCR which improve the cash-out price as a signal of scarcity – 'more marginal' cash-out prices, costing of disconnections, and improving the costing of reserve – could improve liquidity as incentives to trade ahead of gate closure become greater, in particular at times of system stress. Further, some stakeholders have suggested that a single cash-out price could encourage the development of a more robust market reference price and related products that could be more widely traded, which could improve liquidity.

Mid-decade additional balancing services

5.15. Ofgem's Electricity Capacity Assessment 2013[50] suggests electricity margins could tighten in 2015-2016 to between around 2 and 5 per cent depending on demand. While we consider supply disruptions are not imminent or likely, in light of the uncertain outlook Ofgem, DECC and National Grid agree it is prudent to consider the need for National Grid to design, procure and dispatch two potential new balancing services – Demand Side Balancing Reserve and Supplementary Balancing Reserve. Ofgem published an open letter[51] asking for stakeholder views on the case for these new services. National Grid published an informal consultation document on these proposals[52]. We would have to consider how these services would be priced in cash-out when they are activated. These prospective services would help safeguard against the risks of potential supply disruptions. These mid-decade proposals are not aimed at tackling the underlying issues with the market and are therefore not substitutes for the proposed EBSCR reforms.

[49] Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition June 2013: http://www.ofgem.gov.uk/Markets/RetMkts/rmr/Documents1/Liquidity%20final%20proposals%20120613.pdf

[50] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%20Report%202013.pdf

[51] Ofgem open letter 27 June 2013 http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/Documents1/Consultation%20on%20the%20potential%20requirement%20for%20new%20balancing%20services%20to%20support%20an%20uncertain%20mid.pdf

[52] National Grid Consultation on Demand Side Balancing Reserve and Supplemental Balancing Reserve 27 June 2013 http://www.nationalgrid.com/NR/rdonlyres/432E936B-ABDF-48A0-9021-9B34455918C2/61220/130627BalancingServicesConsultationfinal.pdf

Appendices

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. We are also consulting on the accompanying EBSCR Draft Policy Decision Impact Assessment (IA). The relevant questions for the IA are added to the list of questions on the draft policy decision document below. We advise parties to amalgamate responses to both documents into one submitted response.

1.4. Responses should be received by Tuesday 22 October 2013 and should be sent to:

Andreas Flamm
Wholesale Markets
Ofgem
9 Millbank
London
SW1P 3GE
Email: EBSCR@ofgem.gov.uk

1.5. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.6. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.7. Next steps: Having considered the responses to this consultation, Ofgem intends to publish a final policy decision in spring 2014. Any questions on this document should, in the first instance, be directed to Andreas Flamm or Dominic Scott at the contact details above.

Questions for this consultation and our consultation on the accompanying Impact Assessment

Question for the Draft Policy Decision:

Question 1: Do you agree with our proposal to make cash-out prices more marginal?

Question 2: Do you agree with our rationale for going to PAR1 rather than PAR50? Are you concerned with potential flagging errors, and would you welcome introduction of a process to address them ex-post?

Question 3: Do you agree with our proposals for pricing of voltage reduction and disconnections, including the staggered approach?

Question 4: Do you agree with our assessment of the interactions with the CM and its impact on setting prices for Demand Control actions?

Question 5: Do you agree that payments of £5/hr of outage for the provision of involuntary DSR services to the SO should be made to non-half-hourly metered (NHH) consumers, and for £10/hr for NNH business consumers?

Question 6: Do you agree with the introduction of the Reserve Scarcity Pricing function and its high-level design? Explain your answer.

Question 7: Do you agree with our rationale for a move to a single price, and in particular that it could make the system more efficient and help reduce balancing costs? Please explain your answer.

Question 8: Do you have any other comments on this consultation, including on the considerations where we did not propose any changes?

Question related to the accompanying Impact Assessment:

Question 9: Do you have any comments regarding any of the three approaches we have taken to assess the impacts of the cash-out reform packages?

Question 10: Do you agree with the analysis of the impacts contained in this IA? Do you agree that the analysis supports our preferred package of cash-out reform? Please explain your answer.

Question 11: Do you agree with the key risks identified and the analysis of these risks? Are there any further risks not considered which could impact on the achievement of the policy objectives? Please explain your answer.

Question 12: What if any further analysis should we have undertaken or presented in this document? Do you have any additional analysis or evidence you would like to contribute to support the development of the EBSCR towards its Final Policy Decision?

Appendix 2 – Adjusting supplier imbalances

1.1. If a part of the network is physically disconnected, or if voltage on the network is reduced, this will have an impact on the physical (and therefore imbalance) positions of the suppliers who were supplying the affected customers. Further, as demand for non half-hourly (NHH) metered consumers is determined using profiles, any reduction in demand resulting from a Demand Control action will be smeared across all NHH customers in the Grid Supply Point (GSP) Group according to these profiles, rather than targeted to the correct periods and to the correct customers. This implies that two adjustments should be made following a Demand Control action:

(i) The physical and contract positions of the supplier of the customers who had their demand reduced through voltage reduction or firm disconnection should be adjusted.

(ii) The position for all NHH profiles within the affected GSP Group should be adjusted.

Adjusting the position of supplier of consumers who have had their demand reduced

1.2. When a DNO reduces voltage across a GSP Group, or disconnects firm load of a proportion of a GSP Group, these actions impact on the physical, and therefore imbalance, positions of the suppliers who were supplying the affected consumers. Suppliers' positions will be longer than they would have been. A balanced supplier would be driven long, and would be cashed out for the difference. A short supplier would be made less short, or could even flip from being short to long, following a Demand Control action. There is currently no mechanism in the BSC to adjust for this defect.

1.3. If we do not adjust suppliers' imbalances following Demand Control, their imbalance positions could be affected by actions over which they (or their consumers) had no control. This could result in the perverse outcome whereby suppliers benefit from their consumers' curtailment.

1.4. In order to address this issue, we propose to adjust suppliers' imbalance positions by the volume of demand which was disconnected or reduced following a Demand Control action. It would be appropriate to adjust suppliers' imbalances whenever there is Demand Control, even if the cash-out price has not reached VoLL (due to tagging and flagging). It is envisaged that adjustments to both physical and contract positions will be required to return a supplier's imbalance to the position prior to disconnection.

1.5. If we adjust suppliers' physical and contract positions, it would be appropriate to pay suppliers for this volume. A physical disconnection on the network represents a loss of revenue to suppliers, as they have procured energy for which they cannot bill their customers. We propose that suppliers should be paid a price which represents a proxy for the price the supplier would have paid for that energy. It is important that suppliers do not benefit from receiving this price, and that it does not undermine incentives on parties to balance.

Estimating the demand reduction

1.6. While it may be possible to incorporate the SO's 'best estimate' of demand reduction in the cash-out price, a more complex, 'bottom-up' estimation of demand reduction would be desirable in order to restore suppliers' positions to their pre-Demand Control position. This approach is necessary because demand is usually measured at the GSP level, while disconnections would occur at the sub-GSP group-level.

1.7. Each meter point on the network has a Meter Point Administration Number (MPAN). Most domestic consumers have a single MPAN. Information about each MPAN is stored on the Meter Point Registration System (MPRS). MPANs can be used by the Distribution Network Operators (DNOs) to determine which customers and which customer types have been disconnected.

1.8. Different approaches are necessary for different consumer types. Some consumer sites are half-hourly (HH) metered. For these consumers, consumption data for each half-hour is recorded and used in settlement. Under the gas arrangements, the Emergency Curtailment Quantity (ECQ) methodology is used to estimate how much gas daily metered (DM) consumers would have consumed during a day had an Emergency Curtailment not occurred[53]. We envision that a similar methodology would be developed for the estimation of demand of HH electricity customers, according to similar principles where appropriate.

1.9. Non half-hourly metered (NHH) consumers' meters are read less frequently, but for the purposes of Settlement a half-hour value must be calculated. This half-hourly estimate is derived from an estimate of annual consumption. Where actual meter data is available, this is called an Annualised Advance (AA), and where no metered data is available an Estimated Actual Consumption (EAC) is calculated.

1.10. Profiling is then used to determine NHH consumers' demand. All NHH meters are classified into one of eight Profile Classes. Profile Classes 1 and 2 are for domestic premises and classes 3 to 8 are for non-domestic premises. Sites are categorised into Profile class according to its pattern of electricity usage and the type of meter installed. These profiles would allow us to estimate what a suppliers'

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53 http://www.gasgovernance.co.uk/sites/default/files/Emergency%20Curtailment%20Quantity%20v2.0_1.pdf

disconnected consumers would have consumed during a given period, once the disconnected consumers have been identified.

Adjust all NHH customers within the GSP group

1.11. GSP Group Correction Factors are used to ensure that the total energy allocated to suppliers in each Settlement Period in each GSP group matches the energy entering the GSP Groups from the transmission system. There are a number of reasons why this correction factor is needed, including inaccuracies which arise from the use of profiles to allocate NHH metered volumes to a particular settlement period. The correction factors will scale NHH take up or down, such that total of NHH and HH takes in that GSP Group for that half hour equals the GSP Group Take. The GSP correction factor will also apply to HH customers to account for line losses.

1.12. The use of the GSP Group correction factor means that any reduction in NHH demand which occurs because of a Demand Control action will be smeared across all NHH consumers within the Grid Supply Point (GSP) group. This will result in a distortion to all suppliers of NHH customers within the GSP group. For this reason it would be appropriate to adjust the GSP group correction factor for these periods so that it more resembles what the correction factor that would have fed in had the Demand Control action not taken place. We therefore proposed to adjust the GSP Group Take used in settlement by the estimated volume of Demand Control provided by NHH customers. This adjustment could be based upon the SO's best estimate of the overall Demand Control volume (as informed by DNO data and the forecasted demand for the affected GSP prior to the disconnection action), as well as the estimated load reduction by HH customers. Adjusting the allocated load in this way would ensure that positions of NHH customers who were unaffected by the Demand Control action would not be underestimated. The positions of consumers who were disconnected would not be adjusted in this way.

Appendix 3 – Paying consumers for involuntary demand side response

1.1. We propose that payments should be introduced for non half-hourly (NHH) metered consumers for involuntary DSR services they provide to the SO. These payments are proposed for firm load disconnections only as our analysis suggests that it is very difficult to estimate the direct cost associated with voltage control. We do not propose that payments should be introduced for half-hourly (HH) metered consumers: these consumers are large energy users who are therefore more capable of managing their demand, and may have arrangements with suppliers which reflect their VoLLs.

1.2. There are a number of options for determining how and what consumers are paid for the involuntary DSR services they provide to the SO, which vary in terms of complexity and likely cost. Our draft policy decision is to link payments to consumers to the average domestic VoLL as estimated by the London Economics study. We would seek to work up a proposal for paying consumers for these services. Payments would be funded by Balancing Services Use of System (BSUoS) charges. Ideally payments would be allocated automatically to consumers (or automatically deducted from bills).

Domestic consumers

1.3. Our draft policy decision is that domestic consumers would receive £5 per hour for the provision of involuntary DSR services. This payment ensures that the involuntary DSR service that domestic consumers provide is remunerated. The £5 figure is based on the VoLL study and represents an average domestic VoLL. This means that some consumers will receive a payment lower than their VoLL, while other consumers will receive a service payment above their individual VoLL. We do not believe that it is practical to ensure that each consumer receives a payment that reflects their individual VoLL until the smart meter roll-out is complete, and suppliers offer tariffs that allow consumers to indicate their own VoLLs.

Non half-hourly metered non-domestic consumers

1.4. Estimating appropriate payments for non-domestic NHH consumers is more complex. Demand for all NHH consumers is estimated using profile classes, with profile classes 3-8 used for non-domestic consumers. These profiles reflect the variability of consumption patterns and levels amongst non-domestic consumers, and as such determining appropriate payments is significantly more complicated for this consumer group.

1.5. For simplicity, following the precedent set by Guaranteed Standards for Network Operators, we propose to pay NHH metered non-domestic consumers twice (£10) the domestic payment for an hour of involuntary DSR. We welcome views on whether a different approach should be taken. An alternative would be to base payments on bandings according to load profile classes.

Half-hourly metered consumers

1.6. We do not propose that payments be made to half-hourly metered (HH) consumers for the provision of involuntary DSR services to the SO; as they are larger energy consumers, they capable of entering into bilateral arrangements with their suppliers, the DNOs or the SO. We further note that the System Operator's informal consultation on new balancing services, could offer further opportunity for HH metered consumers to offer DSR. We would like to maintain strong incentives on these parties to offer DSR services.

Appendix 4 – Pricing reserve: current arrangements, and proposals for setting the Reserve Scarcity Pricing function

Current arrangements for pricing reserve

1.1. In order to ensure that it can balance the system securely and efficiently, the SO can also strike up contracts for balancing services with market participants (including both generators and DSR providers). These participants provide reserve services and agree to be available at specified time for a specified price, in exchange for an availability payment. The main source of reserve is Short Term Operating Reserve (STOR). The way that the cost of these contracts is reflected in the cash-out price can have a distortive and dampening impact on the cash-out price, undermining balancing efficiency.

1.2. Utilisation of reserve actions taken within the Balancing Mechanism (BM) feed into the main cash-out price through the BM accepted stack. The normal tagging and flagging rules then apply. Utilisation payments paid to parties not participating in the BM (Non-BM Reserve) do not feed into imbalance charges.

1.3. Other reserve contracting costs are reflected into the cash-out price using the Buy Price Adjuster (BPA) and the Sell Price Adjuster (SPA). The BPA and SPA are added to the System Buy Price (SBP) and subtracted from the (SSP), respectively. The BPA and SPAs are determined by building a daily half-hourly profile based on historic STOR utilisation. This profile takes into account historic seasonal and business day/non-business day variations. This determines a weighting factor for the allocation of actual option fees to cash-out prices.

1.4. The BPA approach to reflecting STOR contracting has the effect of adding a small uplift to cash-out prices over peak periods across the day. Because it is based on historic data, it does not necessarily correspond with actual system stress, or STOR usage. We do not believe that it is creating the right signals to balance when the system is under stress.

The Reserve Scarcity Pricing function (RSP)

1.5. The aim of the Reserve Scarcity Pricing function (RSP) is to ensure that the pricing of reserve actions in the cash-out price reflects the value that those actions deliver to the system. This value is higher the lower the capacity margin, and could rise gradually to VoLL as the margin approaches zero.

International Experience

1.6. In the US, scarcity pricing of operating reserve has been advocated by academics (eg Hogan, Stoft) and has been implemented in some US regional markets, New York (NYISO), New England (ISONE) and the Mid West (MISO). In MISO pricing for operating reserve is equal to the product of the Value of Lost Load (VOLL) and the estimated conditional probability of a loss of load.

1.7. In the Single Electricity Market (SEM) in Ireland, a measure of Loss Of Load Probability (LOLP) is used in the determination of capacity payments which generating capacity receives for availability in the electricity market. A 'margin versus LOLP look-up table' was derived. This assumes that probability of a loss of load at a certain margin is constant regardless of the level of system demand or plant mix. This is revised when there is a change to installed capacity.

Defining the RSP function

1.8. In jurisdictions such as MISO, pricing of operating reserve is determined with reference to LOLP and VoLL (or the market price cap). This allows the price that operating reserve receives (and the price which is reflected in the imbalance price) to reflect scarcity on the system. Ideally, the RSP function would follow the same principles and ensure that the pricing of reserve actions in the cash-out price reflects the value that those actions deliver to the system. This value should be higher when the system is tight than when it is not, and prices should be allowed to rise gradually to VOLL.

1.9. The RSP would be a function of a number of input parameters, such as

- The LOLP (which itself would be a function of the capacity margin)
- The Demand Control price ("VoLL")
- The largest infeed loss[54].

When to set the RSP curve

1.10. One important design question is when to set which parameter. Our view is that VoLL and the largest infeed loss are figures that can be set in advance.

1.11. There is a question about how to define the *RSP curve* (as shown in Figure 4 below) to reflect the likelihood of a Demand Control action associated with a given margin. One option would be to define the curve annually. The only variable that would be calculated dynamically for each settlement period would then be the margin

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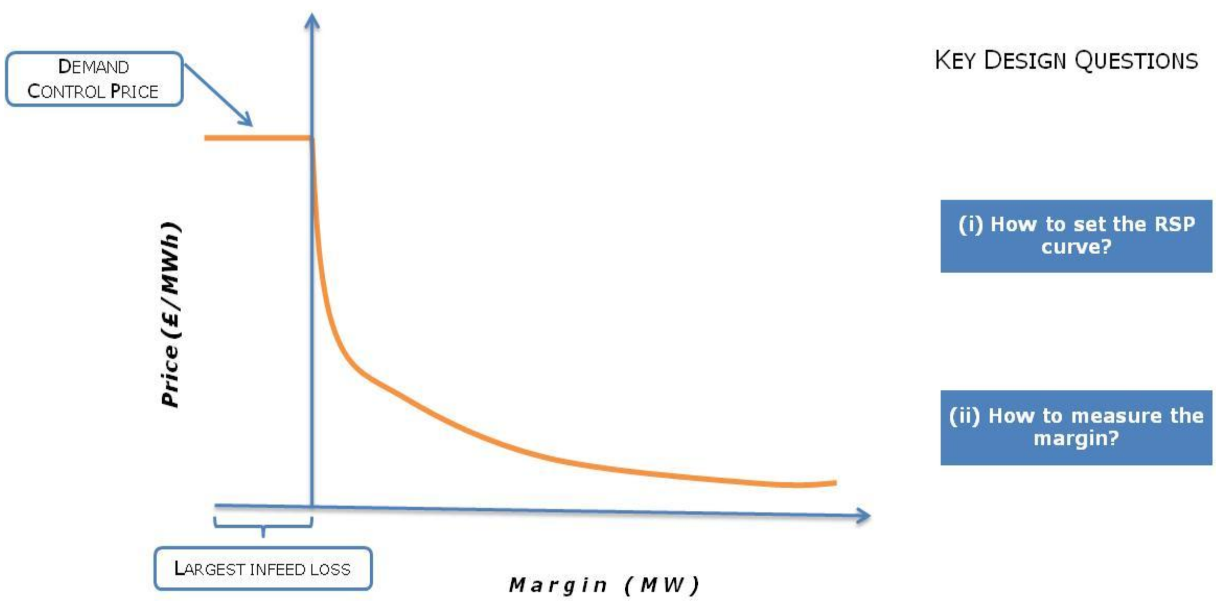
[54] National Grid reserves power to maintain the integrity of the network in the event of the loss of the largest generator (the largest infeed loss). Its importance is such that National Grid would curtail demand before using this reserve. Currently the National Electricity Transmission System Security Quality of Supply Standards, which is approved by Ofgem, limits the largest infeed loss reserve to approximately 1.3GW. The limit is scheduled to increase to 1.8GW in April 2014. For further information refer to: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/.

(excluding the largest infeed loss). The margin for each period, combined with the fixed RSP curve, would then determine the price for reserve in each settlement period.

1.12. Alternatively, different curves could be defined for different seasons. While the overall installed capacity will stay largely the same over time, other attributes such as the season may have an impact on the available generation mix (eg there is likely to be more planned outage in summer), and these could be accounted for by deriving a set of different curves.

1.13. A further approach would be to dynamically measure the available generation for at a given point in time ahead of real-time. This approach would be the most accurate approach, as it would take account of which plant were available to operate for the period in question. This would mean both the shape of the curve and the margin are dynamic for every settlement period. However, it may be the case that this approach would imply the highest level of complexity and cost.

Figure 4 - Reserve Scarcity Pricing function - key design questions



When to measure the margin

1.14. The margin would include forecasts for (i) demand, (ii) wind output and (iii) plant availability for each settlement period. The timing chosen for setting the margin will impact on these forecasts and hence for the resulting price of reserve.

1.15. We suggest there are three high-level options for when to set the margin:

1. *Measure the margin four hours ahead of real-time.* In initial discussions at our Technical Working Group (TWG) stakeholders felt that it is at this point that accurate wind forecasts can be determined. The TWG also suggested that this would allow the market sufficient time to respond to the signal created by the RSP. However, there is a question as to whether this would be too far ahead of real-time to capture real time system scarcity.

2. *Measure the RSP at gate closure*. This would allow Final Physical Notifications (FPNs) and other physical information to feed into the measure of the margin. It would also mean that the RSP price calculation would be aligned with the point at which bids and offers are submitted into the Balancing Mechanism (BM). As it is closer to real time it would also better reflect actual system scarcity.

3. *Measure the RSP at the start of the settlement period.* Stakeholders have suggested that setting the RSP so close to real-time could create too much volatility. Further it could be that setting the RSP at this point would be inconsistent with when prices for bids and offers in the BM are set. It would however provide the most up-to-date signal of scarcity.

1.16. Once the margin is defined, it would be applied to the RSP curve to determine what the corresponding price for reserve should be. This price would be used as a replacement price for STOR actions, where the RSP price is higher than the original utilisation price. The Buy Price Adjuster (BPA) would no longer apply. Re-priced STOR actions would be subject to the normal flagging and tagging processes.

1.17. We acknowledge the likely trade-off between accuracy and simplicity when designing the exact form of the RSP function. It is important to keep costs for the calculation of the RSP low whilst making sure reserve is priced more accurately into each settlement period. We seek to develop the details of the RSP function and its parameters in further consultation with industry and the SO.

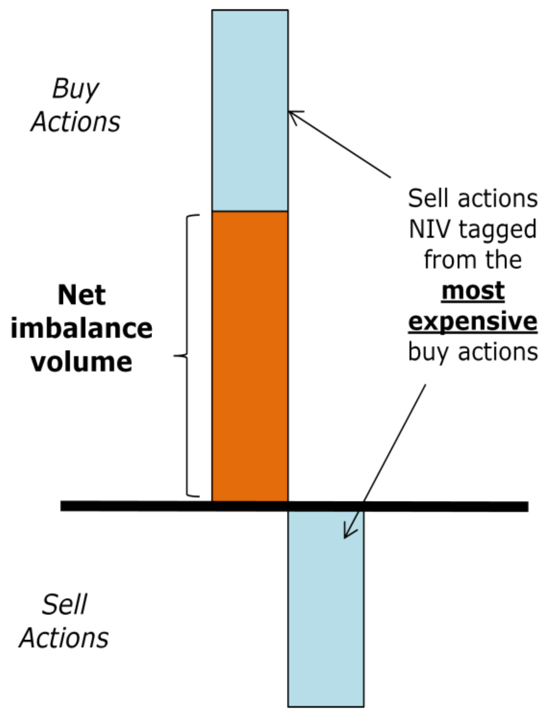
Appendix 5 – NIV tagging

NIV tagging

1.1. The role of the SO has two components: 1) residual energy balancer ("energy balancing") of the overall imbalance across the half-hour settlement period; and 2) provision of system balancing services ("system balancing"), such as frequency response, constraint management and fast reserve that are currently most cost effectively managed by a single licensee on behalf of the whole market.

1.2. The cash-out price is designed to reflect only the SO's energy balancing actions. Flagging and tagging mechanisms classify which actions are 'energy' and therefore should be reflected in the cash-out price.

1.3. One of these mechanisms, NIV tagging, is likely to have a large impact on whether high priced actions feed through to the cash-out price. This determines the NIV, the overall length (volume) and direction of 'energy' imbalance for a given half-hour by netting off bids and offers. The shorter stack of either bids or offers is netted off the most expensive actions in the longer stack. Further mechanisms are then applied to remaining stack of actions to determine which are appropriate to reflect in the cash-out price.



1.4. Because NIV tagging removes the most expensive actions, higher priced actions (such as demand disconnection priced at VoLL) will tend to be removed if there are actions in the opposite direction. Actions can happen in the opposite direction due to constraints, the need to ensure there is sufficient reserve on the system, a flip in the NIV during the settlement period or due to the imperfect foresight of the SO.

1.5. In most periods the SO takes actions in both directions. Even when there is scarcity, the SO may need to take actions to turn generators down. For example, on 11th February 2012 the System Operator needed to use voltage reduction to balance the system. Our analysis shows that if this was a priced action, it would have entered the cash-out price calculation in only 2 out of 4 settlement periods, due to NIV-tagging, which would have taken into account the SO's actions in the other direction.

1.6. More detail on the current arrangements is set out in our EBSCR Initial Consultation document, which is available on the EBSCR website.

Appendix 6 – Value of lost load calculation

Rationale

1.1. Ideally every consumer would be able to specify how much money they would want to receive in order to accept a lower reliability of supply, or alternatively how much money they are willing to pay to ensure a greater reliability of supply. This would allow the efficient level of security of supply to be reached as no consumer would be disconnected at a price below what they would be willing to accept a disconnection and no consumer would receive more than the price at which they would be willing to accept a disconnection. This theoretical 'optimal' level of security of supply could only be revealed in a world with ubiquitous smart meters and time-of-use tariffs — in which all consumers had both the means and the ability to express their preferences quickly. Before such a world is realised, it is appropriate to select an 'administrative' VoLL for GB consumers.

Methodology and considerations

1.2. As no robust market exists for supply interruptions VoLL cannot be determined or observed directly from market behaviour. As a consequence VoLL must be determined indirectly. To inform the EBSCR analysis we commissioned external research (jointly with DECC) to estimate the VoLL for electricity consumers in GB[55]. This study used a combination of consumer surveys and econometric analysis to elicit domestic and small business consumers' VoLLs, plus a variety of statistical analyses of secondary data sources were undertaken to estimate large industrial and commercial (I&C) consumers' VoLLs. In addition the study also investigated the evidence surrounding the impacts and costs of voltage control. The research report has been published in full as part of the EBSCR Draft Policy Decision evidence base.

1.3. Establishing an accurate estimation of VoLL for GB consumers is a difficult task. There is no single VoLL for all GB electricity consumers – it will differ between different consumers and consumer types and depend on the specific context even for the same individual consumer. Season, time of day, day of week and duration of interruption are all likely to impact on any individuals' VoLL at any particular time. Our VoLL study provided a wide range of VoLL estimates which reflect these differences.

1.4. When setting an administrative VoLL there are several questions regarding how to best reflect consumers' diverse preferences. These considerations and our response are provided in Table 7 below.

[55] London Economics (2013), *'Estimating the Value of Lost Load (VoLL) for Electricity'*

Table 7: Considerations for setting an administrative VoLL

VoLL consideration	Response
1. Given the variation in VoLL estimates, how many different administrative VoLLs should be applied? For example, VoLL could be differentiated by consumer type, season, or time of day.	With current technology it is not possible to know exactly which type of consumer has been disconnected and therefore differentiating VoLL by consumer type is not feasible. Although it would be possible to apply different VoLLs depending on the season/time of day, the feedback from our Technical Working Group strongly suggested that the benefits of improved accuracy do not outweigh the added complexity in using several VoLL figures. It was also suggested that varying VoLLs may increase the risk for participants as the costs associated with disconnections would no longer be fixed, therefore increasing the complexity of hedging against these costs.
2. Our VoLL research includes estimates of consumers' willingness to pay (WTP) to avoid an outage and willingness to accept (WTA) compensation to experience an outage. Although in theory these two methods could produce identical results, in practice this is often not the case.	Our VoLL research suggested that the WTA results are significantly more robust than the WTP results. The research found that consumers typically engaged more quickly and easily with the concept of WTA and therefore provided more robust responses. For this reason we have chosen to use the VoLL estimates that produced using WTA methods. This approach is also consistent with the approach of Ofgem's Gas SCR.
3. Which 'types' of VoLL estimates should we use to determine the administrative VoLL? (ie marginal, average, what type of average?)	In theory, to maximise the balancing incentive for market participants the marginal VoLL would be applied. However, given the wide range of VoLL estimates provided by London Economics' VoLL study, a marginal VoLL would likely place too great of a risk on market participants (and also appears particularly high compared to VoLL in other countries). We have therefore decided to select an administrative VoLL based on an average of the study's VoLL estimates. Although the research provided VoLL estimates for domestic, small business and large I&C consumers we have only used an average of the domestic and small business results in our administrative VoLL. I&C consumers are most likely to have the capability to reveal their 'true' VoLL through demand side response/ interruptible contracts. VoLL figures per MWh for I&C consumers are generally significantly lower than for domestic and small business consumers, as I&Cs use more electricity which impacts on the value they put on each MWh. Also, they have the potential to use back-up equipment when production is load-critical, which limits their VoLL. An administrative VoLL based on an average of domestic and small business VoLL and hence above the

	'true' VoLL of I&C consumers should therefore provide appropriate incentive for I&C consumers to voluntarily enter into arrangements to reduce load at times of system stress.
4. Which 'type' of outages should be considered when determining the administrative VoLL? (winter /summer/peak/off-peak/ etc)	In considering VoLL for cash-out arrangements we are most concerned with ensuring that the cash-out price reflects scarcity at times of system stress and provides the strongest incentive for market participants. Therefore we have based our administrative VoLL figure on the estimates of VoLL at typical winter peak periods. By selecting these higher-end, more marginal estimates we also ensure that the greatest incentives are in place to encourage participants to reveal their 'true' value of VoLL through demand side response/ interruptible contracts.

1.5. In light of the considerations noted above, and the attributes deemed to be most appropriate, London Economics' study suggested a theoretical average value for VoLL of £17,000/MWh. This corresponds to the load weighted-average VoLL estimation for domestic and small business consumers and for winter, peak, weekday disconnections. There are a range of considerations that follow on from this estimation that affect how we set VoLL in practice. These include the existence of a Capacity Market and the appropriate balance between performance incentives and risk for market participants.

Lower VoLL with introduction of a Capacity Market

1.6. In energy-only markets, such as the current GB market, the implementation of VoLL pricing in cash-out arrangements has two important purposes: firstly, the impact of VoLL on energy prices at times of system stress may help capacity providers to collect sufficient revenue above their short-run marginal costs to cover their fixed costs (and hence solve part of the 'missing money' problem). Secondly, VoLL provides an explicit performance incentive to ensure that market participants act appropriately at times of system stress and flexibility (in terms of generation and demand) is appropriately rewarded.

1.7. The introduction of a GB capacity market, with associated capacity payments presents an alternative route for capacity providers to collect sufficient revenues above their short-run marginal costs to cover their fixed costs. With a well functioning Capacity Market, the main benefit of including VoLL in cash-out arrangements would be to provide a performance incentive for market participants and rewards for flexible plant. Therefore, if the real-time price signal is mainly used as a performance/ flexibility incentive (rather than as an investment incentive), there is a strong argument to suggest that prices do not need to rise to the full VoLL level. This reduces performance risk considerably whilst achieving results similar to the higher VoLL figure.

1.8. In determining an appropriate lower value for VoLL we must consider the trade-off between reducing performance risk and maintaining a sufficient performance incentive. Two aspects are important when assessing this value: prices in interconnected markets; and estimates of I&C consumers' VoLL. These aspects are discussed further below.

1.9. At times of system stress it is important that GB has the potential to import electricity from neighbouring markets through its interconnectors, as far as this is efficient. To support most efficient interconnector flows, market prices signals must reflect the underlying value of electricity to consumers. The development of market coupling arrangements[56] further emphasises the importance of robust price signals. London Economics' study suggested that the value of lost load to GB consumers was above the upper limit of prices in neighbouring markets[57]. This suggests that, at times of system stress in GB, it is efficient for GB to be importing electricity through its interconnectors. This is most likely to be achieved if the GB price during these periods reflects this scarcity appropriately. If GB prices do not reflect GB consumers' preferences this may create inefficiencies during times of system stress if cross-border energy flows do not go to those areas where energy is most valued.

1.10. In setting the lower value for VoLL we must also take into account the estimates of I&C consumers' VoLL. It is important that these larger consumers are provided with sufficient incentive to reveal their individual VoLL through entering into demand side response/ interruptible contracts. Only a VoLL above I&C consumers' individual VoLL will provide this incentive. The range of VoLL estimates from our study is illustrated in Figure 5 below. It shows LE's estimates of VoLL, and suggests that a lower value for VoLL of approximately £6,000/MWh would be sufficiently high to allow the majority of I&C consumers to reveal their individual VoLL.

1.11. Based on this assessment and in light of the introduction of the Capacity Market in GB, our draft policy decision is to set a lower value for disconnection at £6,000/MWh. Should a GB Capacity Market not be introduced, then we would utilise the evidence provided by the London Economics study to set VoLL for disconnections at £17,000/MWh.

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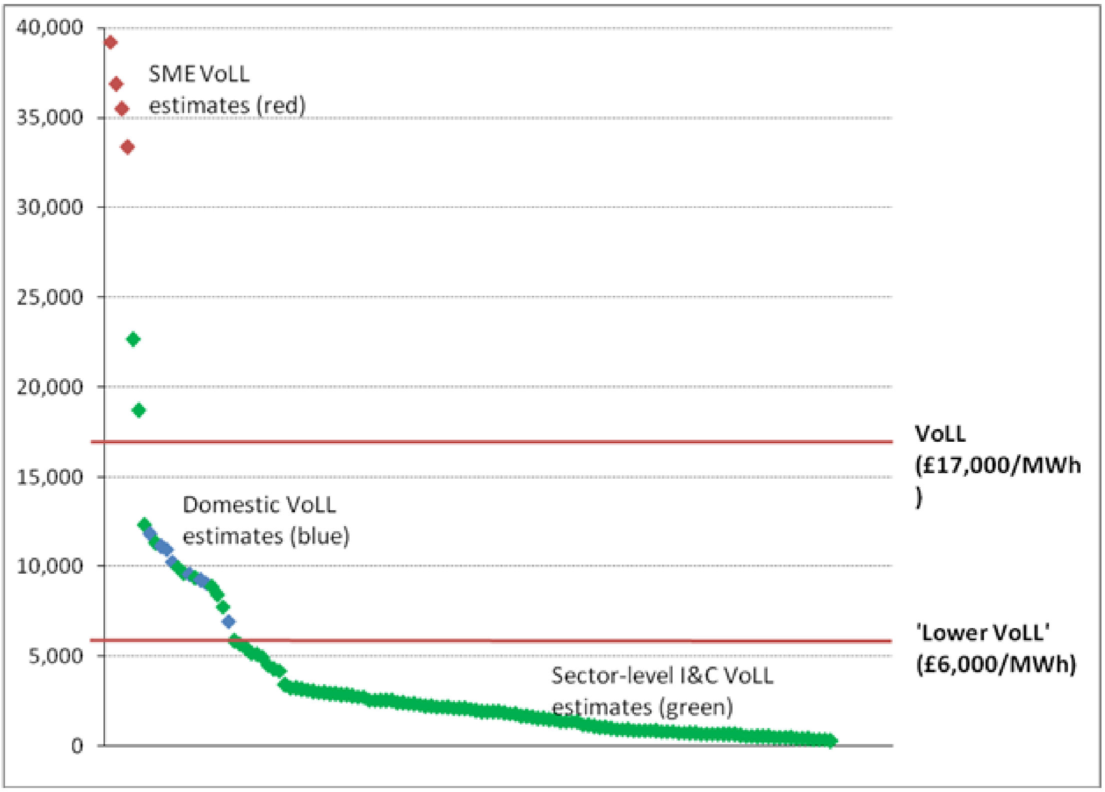
[56] The efficiency of interconnector flows is boosted by the development of market coupling arrangements. Without market coupling, transmission capacity on an interconnector is auctioned to the market separately and independently (known as an explicit auction) from the market where electricity is auctioned. With market coupling the auctioning of transmission capacity is included (implicitly) in the auctions of electricity. The one-step process of implicit auctions means that traders have a better understanding of the price of each commodity at the time of the trade. This better information should foster more efficient utilisation of interconnectors, encouraging electricity to flow from the low price market towards the high price market.

[57] An assessment of recent Dutch and French wholesale prices shows €3,000/MWh (approximately £2,500/MWh) to be the maximum price in France (Dutch prices are typically below this). The French price spike occurred in October 2009 when the sales offers on the Spot market were unable to meet the purchase offers over a period of four hours. During this period the French Spot price reached €3,000/MWh, which is the 'technical ceiling' of the EPEX Spot market.

Figure 5: VoLL estimates[58]



Setting a price for voltage reduction

1.12. Part of the London Economics study examined the cost in £/MWh of SO-directed voltage reduction. During a power supply shortage the first step in balancing supply and demand would likely be for the system operator (SO) to request DNOs to reduce voltages by 3-6%. London Economics' analysis suggested that given the statutory range of voltages, and the maximum 6% reduction, these actions are unlikely to cause significant costs to household and SME consumers

1.13. If direct costs to consumers were the only concern voltage reduction would be a widely used tool to target both energy balancing and energy saving. However, voltage reduction is an out-of-market, emergency action required in order to preserve the integrity of the Electricity Transmission System. Ideally emergency actions should only be used after all market balancing resource has been exhausted, and therefore these actions should be priced at a level that reflects this.

[58] The I&C VoLL estimates shown in the figure are disaggregated at 2-digit Standard Industrial Classification (SIC) code level. These estimates are those using the 'translog' production function model. The SME and domestic estimates are not disaggregated and reflect the statistically significant willingness to accept VoLL estimates. Further details can be found in London Economics (2013), *'Estimating the Value of Lost Load (VoLL) for Electricity'*

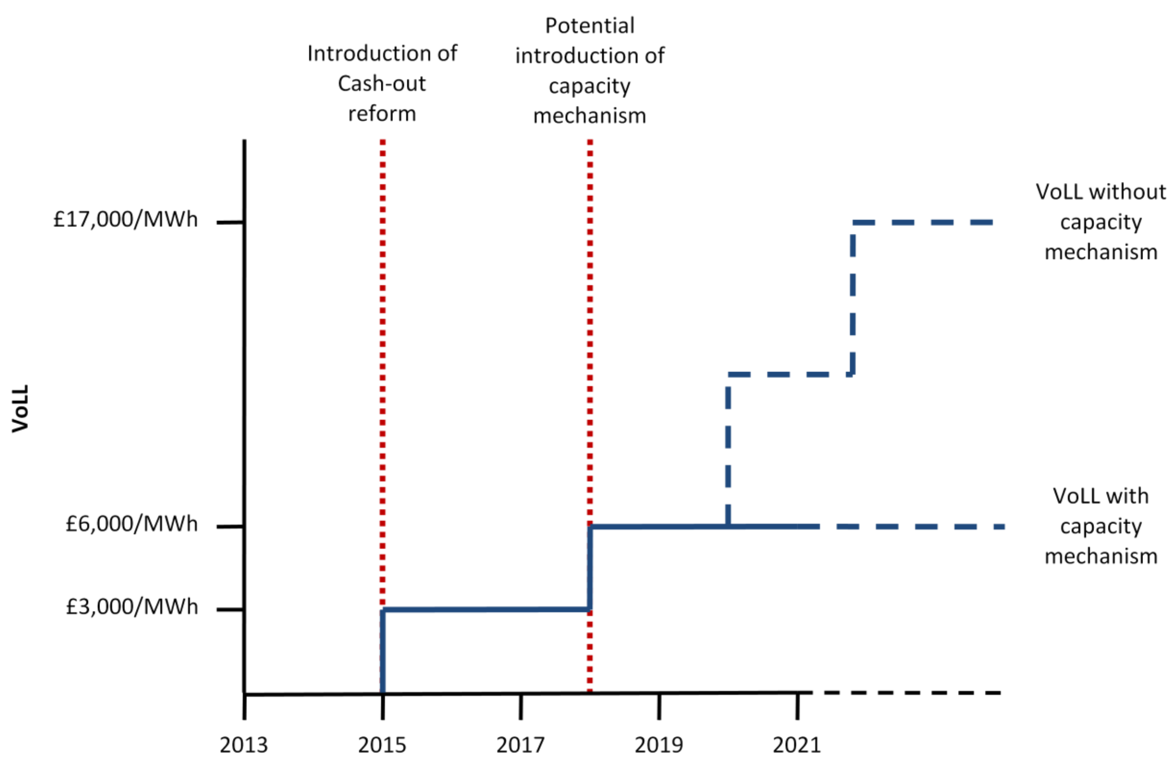
1.14. It is important that the pricing of voltage reduction does not create distortions in the energy market, and that the price is at a level above the short run marginal cost of all generators on the system, and at a level that should encourage DSR and efficient interconnector flows. On the basis of the previous analysis above, and for simplicity of implementation, **our draft policy decision is to set a value for voltage reduction at £6,000/MWh**.

Graduated VoLL implementation

1.15. Our proposal is to introduce VoLL into the cash-out arrangements in graduated steps. This would ensure that the implementation of VoLL is undertaken in such a way that allows market participants to adapt their behaviour and investment decisions over a number of years.

1.16. As illustrated in Figure 6 below, with introduction of VoLL in 2015, the initial value would be £3,000/MWh. This would be raised to £6,000/MWh by the time the CM is introduced. VoLL will remain at £6,000/MWh as long as the Capacity Market remains in place. Should a GB Capacity Market not be implemented, we propose VoLL for disconnections to gradually rise over a number of years to £17,000/MWh.

Figure 6: Graduated VoLL implementation



Appendix 7 – Glossary

B

Balancing and Settlement Code (BSC)

The Balancing and Settlement Code (BSC) contains the governance arrangements for electricity balancing and settlement in Great Britain. The energy balancing aspect relates to parties' submissions to the System Operator (SO) to either buy or sell electricity from/to the market at close to real time in order to keep the system from moving too far out of balance. The settlement aspect relates to monitoring and metering the actual positions of generators and suppliers (and interconnectors) against their contracted positions and settling imbalances when actual delivery or offtake does not match contractual positions.

Balancing Mechanism (BM)

The Balancing Mechanism is the principal tool used by the System Operator to balance the electricity system on a second-by-second basis. Generators and consumers with spare flexibility in their portfolios submit offers (to increase generation or decrease demand) and bids (to decrease generation or increase demand) to the SO via the Balancing Mechanism. The SO uses the Balancing Mechanism for energy balancing and for system balancing actions.

Balancing Mechanism Unit (BMU)

The basic unit of participation in the Balancing Mechanism, describing one or more generation or demand units which import or export electricity from or to the electricity system.

Balancing Services

The SO supplements the Balancing Mechanism with forward contracts for a range of Balancing Services. The SO will enter into these agreements where it believes that it cannot source the service through the Balancing Mechanism, or it wishes to reduce the costs of Balancing Mechanism actions by guaranteeing the availability of certain units.

Balancing Services Use of System charges (BSUoS)

Balancing Services Use of System charges (BSUoS) recover the costs that the SO incurs in the Balancing Mechanism and in procuring Balancing Services from parties using the system. They are charged on a half-hourly basis based on energy volumes.

Bid/Offer Acceptances (BOAs)

Acceptances by the SO of Balancing Mechanism offers to increase electricity on the system, or bids to reduce electricity on the system. The prices of BOAs form the basis for the calculation of the Energy Imbalance or cash-out prices.

C

Capacity Market

Detailed designs proposals for the capacity market were published in June 2013 as part of the Government's Electricity Market Reform (EMR). In this publication, Government announced that it will run the first Capacity Market auction in 2014 for delivery of capacity from the winter of 2018/19. The Capacity Market is designed to cost effectively bring forward the amount of capacity needed to ensure security of electricity supply.

Contracted position

Parties must notify their contracted position to the SO for each settlement period through the process of Contract Notification. A long contracted position indicates that a party has contracted more supply than demand and a short contracted position vice versa. Any difference between a participants contracted position and its metered position will result in that party being out of balance.

Contract Notification

A contract notification details the volume of any energy bought and sold between participants. A single agent acts on behalf of both trading parties, and submits a single contract notification prior to gate closure.

Constraints

There are various parts of the transmission network where import or export capacity is limited. Constraints can become active when this capacity limit is reached. This may require the SO to take balancing actions to reduce generation behind the constraint, and increase generation or reduce demand elsewhere on the network to maintain the energy balance. These actions may be more expensive than energy balancing actions the SO would otherwise have taken.

D

De Minimis tagging

Individual BOAs with volumes below 1 MWh are excluded from the price calculation. This is intended to remove any 'false' actions which are created because of the finite accuracy of the systems used to calculate bid and offer volumes.

Demand Control

Demand Control actions are instructions from the SO – when it considers there to be insufficient supply to meet demand – to Network Operators to reduce demand, through either voltage reduction ('brownouts'), or firm load disconnection ('blackouts'). These' Demand Control' actions are balancing actions, but unlike other balancing actions they are not included in the calculation of cash-out prices, or in the determination of participants' imbalance positions

Demand side response (DSR)

Demand side response involves electricity users varying demand due to changes in the balance between supply and demand, usually in response to price.

The Department of Energy and Climate Change (DECC)

The British Government department responsible for energy and climate change policy.

E

Electricity Market Reform (EMR)

The Government-led Electricity Market Reform Project aims to develop and deliver a new market framework that will ensure secure, low carbon and affordable electricity supplies.

Elexon

Elexon is the Balancing and Settlement Code company which manages the BSC on NGET’s behalf.

Energy Imbalance Prices (or cash-out prices)

Energy Imbalance Prices are applied to parties for their imbalances in each half-hour period. System Buy Price (SBP) is charged for short contracted positions. System Sell Price (SSP) is paid for long contracted positions.

Energy Imbalance

Energy imbalances are differences between the total level of demand and the total level of generation on the system within the half hour balancing period. The cash-out price aims to reflect the price of actions taken to solve energy imbalances, rather than those taken to solve system imbalances.

Energy stack

The energy stack comprises of Bid Offer Acceptances in price order and is used to calculate the main energy imbalance price, once relevant tagging has been applied.

F

Feed-in Tariffs with a Contract for Difference (FiT CfDs)

Long term contracts to be introduced by Government as part of EMR to encourage investment in low-carbon generation. FiT CfDs are intended to provide greater long-term revenue certainty to low carbon investors.

Final Physical Notification (FPN)

The Final Physical Notification (FPN) is the level of generation or demand that the BMU expects to produce or consume.

Flagging

SO identification of balancing actions deemed as potentially being impacted by a transmission constraint.

G

Gate closure

The point in time by which all Contract Notifications and Final Physical Notifications must be submitted for each settlement period. Parties should not change their positions other than through instruction by the SO after gate closure. It is currently set at one hour before the start of the relevant settlement period.

I

Imbalance

The difference between a party's contracted position and metered position measured on a half-hourly basis.

Information Imbalance Change

This is a provision in the market rules to levy a charge on participants who deviate from their Final Physical Notification. It is currently set to zero.

Involuntary Demand Side Actions

Actions such as voltage reduction and involuntary demand reduction. These are currently unpriced and are therefore not reflected in the cash-out price.

M

Main Price

There are two Energy Imbalance Prices, 'Main' and 'Reverse'. The Main Price is charged to parties out of balance in the same direction as the system. When the system is long, long parties receive the Main Price (SSP), whilst when it is short, short parties pay the Main Price (SBP).

Market Index Price (MIP)

The Market Index Price (MIP) is used to set the reverse Energy Imbalance Price. It is calculated based on short term trading activity on exchanges. Currently the MIP is set based on selected trades undertaken on the APX and N2EX exchanges over a period of 20 hours before gate closure.

Metered Position

The actual volume of electricity generated or consumed by a participant. It is the sum of the actual volume of electricity imported or exported at each BMU.

Modification Proposal

In this context, a proposal to modify the Balancing and Settlement Code (BSC). Modifications can be raised by any Party to the BSC. Modifications are then defined and assessed by a Modification Group formed of BSC Parties in conjunction with Elexon. The BSC Panel will recommend whether a modification should be approved or rejected. The final decision is made by the Gas and Electricity Markets Authority.

N

Net Imbalance Volume (NIV)

The overall energy imbalance on the system as determined by the net volume of actions taken by the SO in the Balancing Mechanism and under Balancing Services contracts.

New Electricity Trading Arrangements (NETA)

The electricity market arrangements introduced in 2001.

NGET

National Grid Electricity Transmission plc (NGET) is the system operator (SO) for the electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits.

P

Price Average Reference (PAR)

The volume of electricity from the energy stack (taken in descending price order) included in the calculation of the Main Price. PAR is currently set to 500 MWh. The PAR volume is always the most expensive 500 MWh of available electricity in the main stack.

Project Discovery

Project Discovery was Ofgem's year-long study of whether the current arrangements in GB are adequate for delivering secure and sustainable electricity and gas supplies over the next 10-15 years. Its findings were published in February 2010.

R

Reserve

Additional capacity available to the SO in order to manage uncertainty in the supply/demand balance.

Reserve creation

The use of BOAs in order to create sufficient flexibility and responsiveness to meet variations in the supply/demand balance.

Reserve Scarcity Function

The Reserve Scarcity Function (RSP) derives pricing for reserve actions with reference to a measure of loss of load probability (LOLP) and the margin on the system for a given settlement period. The aim is to ensure that the reserve actions are reflected in the cash-out price according to the value that those actions deliver to the system. The RSP would be used to in place of the Buy Price Adjuster (BPA).

Residual Cashflow Reallocation Cashflow (RCRC)

The net cashflow received by Elexon through energy imbalance charges and which is reallocated amongst participants based on their credited energy volumes on a half-hourly basis.

Reverse price

There are two Energy Imbalance Prices, 'Main' and 'Reverse'. The Reverse Price is charged to parties out of balance in the opposite direction to the system. When the system is long, short parties pay the Reverse Price and vice versa. The Reverse Price is currently set to the Market Index Price.

S

Short Term Operating Reserve (STOR)

A contracted Balancing Service, whereby the service provider delivers a contracted level of power when instructed by the SO, within pre-agreed parameters. The SO makes two kinds of payments for use of STOR, availability payments and utilisation payments.

Spread

The difference between the Main Price and the Reverse Price. This is a consequence of a dual cash-out price.

System Operator (SO)

The entity charged with operating the GB high voltage electricity transmission system, currently NGET.

System Buy Price (SBP)

The price that parties face for a negative energy imbalance.

System pollution

A number of mechanisms are in place to exclude the cost of solving system imbalances when calculating the cash-out price as participants cannot be expected to avoid these costs. However, separating system imbalances from energy imbalances is complex, and sometimes system balancing costs remain in the calculation. This is called system pollution. System pollution can distort cash-out prices.

System Sell Price (SSP)

The price that parties face for a positive energy imbalance.

T

Tagging

The process by which bids and offers are removed from the energy stack, either completely or leaving only volume, so that remaining actions determine energy imbalance prices.

Transmission system

The national high voltage electricity network, operated by the SO.

Uncosted SO actions

There are a number of actions affecting consumers that the SO can take that currently do not have a price associated with them (eg voltage reductions and disconnections). In Project Discovery we argued that a cost should be attributed to these actions and this should be reflected in the Balancing Mechanism.

V

Value of Lost Load (VoLL)

The price at which a consumer is theoretically indifferent between paying for their energy, and being disconnected.

Appendix 8 - Feedback Questionnaire

Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

Please send your comments to:

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