

Electricity Balancing Significant Code Review - Final Policy Decision

Final decision

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Contact: Andreas Flamm / Dominic Scott

Team: Wholesale Markets, Electricity Policy

Tel: 020 7901 7000

Email: EBSCR@ofgem.gov.uk

Overview:

Cash-out prices, which parties face on their imbalances (the difference between what they generate or buy and what they sell or consume), are a key incentive on market participants to balance. Current balancing arrangements are not working as well as they could, undermining efficiency in balancing and security of supply.

This document is the culmination of the Electricity Balancing Significant Code Review (EBSCR), launched to develop solutions to the issues. It presents our reforms for improving efficiency in balancing and security of supply.

This publication concludes this SCR. We have published accompanying documents, including the SCR Directions, through which we direct National Grid Electricity Transmission to raise the required Balancing and Settlement Code (BSC) modification proposals to give effect to these reforms. This initiates the normal BSC governance process, which will involve a further stage of industry led work and consultation before a final BSC modification report is sent to us for decision. BSC parties will be able to suggest improvements to the current proposals in a manner consistent with the EBSCR policy intent. Ofgem strongly urges industry and the BSC Panel to expedite the modification process in order to allow for timely implementation.

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 meet GB consumers' demand. Balancing arrangements are important to provide these incentives and to support 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. This increases the risks to future security of supply and undermines balancing efficiency.

We launched the EBSCR in August 2012 to address these concerns. We have consulted extensively with stakeholders through an initial consultation, through a further consultation on our Draft Policy Decision in autumn 2013 and through ongoing expert workshops. We have developed a robust and comprehensive evidence base through internal and commissioned analysis. This document sets out our Final Policy Decision and is the basis for our directions to National Grid, published alongside this document.

Associated documents

EBSCR – Final Policy Decision Impact Assessment, May 2014

EBSCR – Business Rules, May 2014

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

These three documents can be accessed at:

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

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

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

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

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

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

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

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Executive Summary

Background and process

Electricity Balancing arrangements, in particular imbalance prices, provide incentives for generators and suppliers to balance positions¹ and meet demand when the system is tight. They are therefore critical for efficient delivery of secure electricity supplies. In Project Discovery (2010) we expressed concerns that dampened and inaccurate cash-out prices undermine efficiency in balancing and security of supply.

We launched the Electricity Balancing Significant Code Review (EBSCR) in August 2012 to address these issues. Following our Initial Consultation we published our Draft Policy Decision consultation in July 2013. We have now completed our review of electricity balancing arrangements. This 'Final Policy Decision' sets out our reform conclusions, and builds on more than two years of extensive analysis and stakeholder engagement – the latter including a series of stakeholder events and the establishment of an industry "Technical Working Group" to support ongoing policy development. We thank all those involved for engaging with us in this process.

Alongside this document, we have published our Final Impact Assessment, the Baringa modelling report, Business Rules for implementation as well as the SCR Directions, through which we direct National Grid Electricity Transmission (NGET) to raise the Balancing and Settlement Code (BSC) modification proposals giving effect to these reforms. We envisage the first small step to be implemented by winter 2014/15, the bulk of the reforms by winter 2015/16, and the final step by winter 2018/19.

Rationale for reform

The System Operator (SO) balances the energy in the system in real time and its actions are the basis for the calculation of cash-out prices. A number of factors currently dampen cash-out prices. First, prices are calculated using an average of the top 500MWh (PAR500²) of SO actions taken to balance the system, rather than the marginal action. Second, prices do not include the costs to consumers of involuntary demand disconnections (blackouts) and voltage reductions (brownouts). Third, the way reserve capacity is costed does not allow cash-out prices to rise to reflect tight margins. Finally, the current dual cash-out price system³ creates unnecessary balancing costs, disadvantaging in particular 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). As a consequence, market participants have insufficient incentives to provide flexible capacity (such as flexible generation, demand response services and storage) to meet demand. Shortcomings may also make it more likely that interconnectors export at times of system stress (or import less than under more efficient arrangements). As the share of intermittent generation grows, flexibility will only become more important for security supply.

¹ To produce or buy as much as they sell or consume.

² PAR stands for "Price Average Reference" and represents the volume being averaged.

³ Under which parties face different prices depending on their direction relative to the system.

We note that cash-out arrangements and the government’s planned Capacity Market (CM) have distinct but complementary roles in seeking to ensure electricity security of supply. The CM is intended to address longer term capacity adequacy by providing capacity providers with a secure revenue stream for their investment. Cash-out reform complements this by providing efficient signals of the value of flexibility, influencing the type of capacity coming forward. In addition, sharper cash-out prices have the potential to reduce the cost of procuring capacity in the CM auction.

Our Final Policy Decision

Our Decision addresses the problems identified and removes existing inefficiencies in balancing arrangements. It ensures cash-out prices signal scarcity accurately and increase incentives to innovate and invest in flexible technologies. Specifically, we direct NGET to raise two⁴ modification proposals to the Balancing and Settlement Code (BSC) to implement the following package of reforms.

- a) **Make cash-out prices ‘marginal’** by calculating them using the most expensive action the SO takes to balance the system (PAR1). Our final decision is to introduce this change in steps, starting with a reduction to PAR250 by early winter 2014/15 (through a distinct, stand-alone mod), followed by a reduction to PAR50 by early winter 2015/16 and finally to PAR1 by early winter 2018/19.
- b) **Include a cost for disconnections** and voltage reduction into the cash-out price calculations based on the Value of Lost Load (VoLL) to consumers, and correct supplier imbalance volumes for disconnections. Our final decision is to introduce this cost in two steps, starting with £3,000/MWh by early winter 2015/16 and increasing to £6,000/MWh by early winter 2018/19.
- c) **Improve the way reserve costs are priced** by reflecting the value reserve provides to consumers at times of system stress. To achieve this our final decision is to introduce a Reserve Scarcity Pricing (RSP) function that prices reserve when it is used based on the prevailing scarcity on the system.⁵ In order to help market participants to anticipate system tightness NGET will publish indicators of the scarcity on the system ahead of each settlement period.
- d) **Move to a single cash-out price** for each settlement period to simplify the arrangements and reduce imbalance costs, in particular for smaller parties.

These decisions are substantially similar to our proposals at draft decision stage. Following stakeholder feedback and further analysis we have changed the following two areas: (i) We decided to introduce a fully marginal price in steps to help industry adjust to the changes over time; (ii) We no longer propose payments to non-half-hourly (NHH) metered consumers mainly because the up-front costs involved in administering these payments likely significantly exceed the benefits to consumers.

Our analysis has shown that sharpening cash-out prices will improve incentives for investments in flexible balancing solutions. It shows that consumers will benefit from the reforms as they drive efficiency gains in balancing the system, support security of supply, and realise (small) bills savings. We find that impacts of sharper prices on balancing costs and risk for market participants are significantly counteracted by those of moving to a single price. This helps smaller parties in particular.

⁴ (i) PAR250 by early winter 2014/15, and (ii) the main package by early winter 2015/16.

⁵ Using the Loss of Load Probability (LOLP) and the Value of Lost Load (VoLL).

1. Introduction

In this chapter we outline first the existing issues with cash-out arrangements and the rationale for intervention. Then we set out the EBSCR objectives, process to date and next steps. Finally, we outline the structure of the remainder of this document.

Issues and rationale

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 participants 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 the default price for uncontracted electricity and a primary incentive on participants to trade and invest in flexible solutions to help balance their positions.

1.2. Ofgem has raised concerns with balancing arrangements, most notably in Project Discovery (2010)⁶, where we identified the electricity balancing arrangements as critical in delivering more secure electricity supplies. A notable concern was that existing arrangements serve to dampen cash-out price signals and thereby provide insufficient incentives – in particular during periods of system tightness. This results in insufficient incentives on market participants 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 properly reflect scarcity – particularly 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 reduction 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.

1.4. In addition, the dual cash-out price system creates unnecessary balancing risk, in particular for smaller and intermittent parties.

1.5. As a result of the shortcomings with the current arrangements, the market does not place sufficient value on flexibility (the ability to ramp up or down quickly in response to changing market conditions). This dampens incentives to provide (or

⁶ 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.

invest in) flexibility – such as flexible generation capacity, demand response and storage – and means interconnectors may export at times of system stress.

1.6. With tightening capacity margins and increased amount of intermittent generation, flexibility will become increasingly important. In the light of these challenges it is crucial that cash-out prices efficiently signal scarcity on the system. Failure to reform the existing balancing arrangements could affect electricity security of supply and unnecessarily increase the costs of balancing.

Objectives

1.7. 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 the Department for Energy and Climate Change's (DECC) Electricity Market Reform (EMR) Capacity Market (CM).

1.8. 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.

Process

Process up to Draft policy Decision

1.9. 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**⁷ for the SCR in April 2012
- the **launch of the EBSCR and Initial Consultation**⁸ in August 2012. In responses to the consultation, stakeholders suggested certain issues should

⁷ Stakeholder event on scope: <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=2&refer=Markets/WhIMkts/CompandEff/electricity-balancing-scr>.

be considered over a longer time frame together with wider market changes (such as EMR and EU Target Model) and to focus the EBSCR on addressing the more immediate concerns with cash-out prices. So, in February 2013, we decided to (a) reduce the scope of the EBSCR to focus on the areas where we had long standing concerns that needed to be addressed in the short term⁹ and (b) initiate a new process to consider the potential wider impacts of EMR, EU TM and technological change on existing trading arrangements through the launch of the Future Trading Arrangements (FTA) project¹⁰

- **stakeholder events** including workshops during the Initial Consultation period in September–October 2012 and Draft Policy Decision consultation period in October 2013 and **Technical Working Group (TWG)** meetings to work up options and test proposals with a group of industry experts in light of a better understanding of stakeholder concerns, (January–April 2013 and January 2014)
- publication of our **Draft Policy Decision**¹¹ for consultation in July 2013 with accompanying draft Impact Assessment and externally commissioned analysis¹², as well as open stakeholder workshops during consultation stage.

Responses to the Draft Policy Decision and further analysis

1.10. We received over 30 responses¹³ to our consultation including responses from the SO, the six largest suppliers (plus Energy UK), independent generators and suppliers, renewables, and other parties such as storage, aggregation, and DSR.

1.11. Our further analysis has been guided by responses to our Draft Policy Decision. We have sought to provide further detail where stakeholders asked for it – and we have tested and strengthened this in meetings with the TWG. We have sought further to develop the evidence base where stakeholders expressed concern – to provide confidence in our decision, and where appropriate to amend it.¹⁴

⁸ See papers here: <https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-scr-launch-statement>.

⁹ 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>.

¹⁰ FTA website: <http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Pages/future-trading-arrangements.aspx>.

¹¹ Draft Policy Decision: <https://www.ofgem.gov.uk/ofgem-publications/82294/ebscr-draft-decision.pdf>.

¹² See Baringa "EBSCR Quantitative Analysis" <https://www.ofgem.gov.uk/ofgem-publications/82296/baringa-ebscr-quantitative-analysis.pdf> and London Economics "The Value of Lost Load (VoLL) for Electricity in Great Britain" <https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gb.pdf>.

¹³ See responses here: <https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-draft-policy-decision>.

¹⁴ See chapter 2 for further detail on the substance of responses and our further analysis.

Final Policy Decision and next steps

1.12. This document is the culmination of our work, drawing from our wide-reaching and thorough assessment of the evidence for reform and appraisal of impacts, as well as from views provided by stakeholders.

1.13. Alongside the Final Policy Decision we publish our Final Impact Assessment (setting out the evidence base for our decision), the Baringa modelling report (supporting our impact assessment), Business Rules (providing further detail on implementation of our decision) and our SCR Directions.

1.14. Through the SCR Direction, the Authority¹⁵ directs National Grid, as the relevant licence holder, to raise two modification proposals ('mods') to the BSC to effect our conclusions. Following completion of the mods process, the BSC panel will make its recommendation, and informed by this the Authority will make a final decision. Ofgem strongly urges industry and the Panel to complete the mods process in time to allow for implementation in the following timescales:

- early winter 2014/15¹⁶ release date for the first (distinct, stand-alone) mod to reduce the PAR level to 250
- early winter 2015/16 release date for the second mod encompassing the remainder of the package (with the final reform step being triggered automatically by winter 2018/19).

1.15. This is in order to:

- give industry certainty as soon as possible for other complementary market reforms¹⁷, such as the annual capacity auctions for the delivery of the Electricity Market Reform (EMR) Capacity Market (CM)
- help alleviate possible tight margins in advance of the introduction of the CM
- help industry to adapt to new arrangements through a phased approach, and so that new arrangements are in place ahead of the first CM delivery year.

1.16. We draw industry's attention to Ofgem's robust and comprehensive evidence base as well as the public consultations and stakeholder engagement we have conducted (such as through the TWG) over the past two years. We encourage parties to leverage this evidence base¹⁸, knowledge and expertise to assist timely delivery.

¹⁵ The terms Authority and Ofgem are used interchangeably in this document. The Authority is the Gas and Electricity Market Authority. Ofgem is the Office of Gas and Electricity Markets.

¹⁶ Reference to 'by early winter' indicates our intention for changes to be reflected in Elexon's last release before winter, usually in November.

¹⁷ Plus introduction of National Grid's New Balancing Services for ensuring secure supplies

¹⁸ Including the informal Business Rules that accompany the EBSCR conclusions which, in

1.17. This publication concludes this SCR, however it does not signal the end of the process or our involvement. The SCR Directions will initiate the normal BSC governance process, which will involve a further stage of industry led work and consultation before a final BSC modification report is sent to us for decision. As part of the BSC process parties will be able to suggest improvements to the current proposals in a manner consistent with the EBSCR policy intent.

1.18. In parallel to the mods process Ofgem will continue to assess whether licence changes are required in order to bring the reforms into effect.

Structure of this document

1.19. The remainder of the Final Policy Decision is structured as follows.

1.20. Chapter two presents our Final Policy Decision, the culmination of our work, which draws from our wide-reaching and thorough assessment of the evidence for reform and appraisal of impacts, as well as from views provided by stakeholders. The chapter concludes with an account of how our Draft Decision evolved into our Final Decision.

1.21. The next two chapters present our evidence base: chapter three presents our assessment of each policy consideration and chapter four presents the qualitative and quantitative assessment of expected impacts of our policy package as a whole.

1.22. Chapter five presents an overview of the links between the EBSCR and other key on-going energy market developments and reflects the joined-up and open approach we have adopted to ensure our Final Policy Decision is aligned with the wider policy context.

particular, contains a detailed proposal to implement the Value of Lost Load policy.

2. Our Final Policy Decision

In this chapter we summarise Ofgem’s decision to direct National Grid to raise a mod to the BSC to effect our reform package¹⁹ to make prices more marginal, to include a cost for disconnection and voltage reduction in cash-out prices, to improve the way reserve is incorporated in cash-out prices and to move to a single cash-out price.

The Decision

2.1. Our Final Policy Decision is composed of the following four key elements of reform.

More marginal main cash-out price

- An early reduction to PAR250 will be implemented by early winter 2014/15, progressed through a distinct, stand-alone mod (all reforms other than PAR250 sit together in the second mod).
- This is followed by a reduction to PAR50 for implementation by early winter 2015/16.
- The final reduction to PAR1 will be implemented by early winter 2018/19.

Including a cost for Demand Control actions in cash-out prices

- An administrative cost will be included in the cash-out price for volumes of SO-instructed disconnection and voltage reduction (or ‘SO-instructed Demand Control actions’).
 - This will be £3,000/MWh upon introduction with the core EBSCR reform package, by early winter 2015/16, and will rise to £6,000/MWh by early winter 2018/19.
 - For the initial indicative cash-out price run²⁰, volumes will be estimated by the SO (a ‘top-down’ approach). These actions will enter the Balancing Mechanism stack with a cost and volume and will be subject to the usual tagging and flagging rules (including CADL tagging).
- Suppliers’ imbalance volumes will be corrected following SO-instructed disconnections.

¹⁹ From here on we reduce this to ‘Ofgem’s decision’ to assist the readability of the document.

²⁰ The indicative cash-out price run is published roughly fifteen minutes after the end of the settlement period. Later estimates of the cash-out price use more accurate data to provide a more accurate calculation of the cash-out price to be applied to imbalance volumes.

- A 'bottom-up' methodology will be used to correct imbalance volumes. This entails identifying individual consumers who have been disconnected, and a process for estimating what each consumer type would have consumed had the disconnection not taken place. This will support accuracy in estimation of imbalance volumes and calculation of cash-out prices ultimately paid on these.
- Positions will be corrected regardless of whether the SO-instructed disconnection is flagged and tagged or not.
- SO-instructed voltage reduction should be accounted for – through correction of supplier imbalance volumes and calculation of cash-out price in later runs – if the mod group can identify a way to deliver sufficient accuracy.
- We direct National Grid to propose that the BSC mod group considers whether Demand Control achieved through automatic Low Frequency Demand Disconnection ('LFDD', not instructed by the SO) can and should also be priced into cash-out.
- Payments to consumers will not be made for provision of involuntary DSR balancing services in event of disconnection²¹.
 - In our Draft Policy Decision, we considered introducing direct payments to consumers when disconnected, on the grounds that they provide a balancing service (in the form of involuntary DSR), with the effect of helping to reduce system stress. However we have decided not to take this forward as with further development of the evidence base – in particular up-front costs of implementation – it became clear that costs of administering such a payment would outweigh benefits to consumers at this time²².
- Payments to suppliers for adjustments to their positions (for energy procured for which customers cannot be billed) will not be made, in order to be consistent with our decision not to pay consumers for disconnections. We tested this further with our TWG, who supported the view that payments to suppliers were not necessary.

Improving the way reserve is incorporated in cash-out prices

- BM and non-BM Short Term Operating Reserve (STOR) actions will be costed into cash-out prices using a Reserve Scarcity Pricing (RSP) function methodology.

²¹ To assist readability we refer to 'provision of involuntary DSR balancing services in event of disconnection' as 'involuntary DSR' from here on.

²² As well as significant up front costs (as estimated by suppliers), important factors in our decision are increasing scope for engagement by consumers in DSR over the short to medium term as well as an assessment that DNOs do not currently have the capability to implement automatic payments. For further detail see 'Attributing a cost to non-costed actions ("VoLL pricing")' section in following chapter.

- The price at which a STOR action enters the cash-out calculation will be equal to the Loss of Load Probability (LOLP) multiplied by VoLL (where this is greater than the utilisation price for that STOR action).
 - The VoLL value used for the RSP function will be consistent with the administrative VoLL value used for pricing Demand Control actions.
 - The LOLP will be calculated by National Grid at Gate Closure for each Settlement Period according to a new industry-owned methodology.
 - Indicative LOLPs for each Settlement Period will be calculated and released to the market ahead of Gate Closure to provide parties with an indication of how much STOR might be valued in cash-out.
- STOR availability costs will no longer be allocated to settlement periods via the Buy Price Adjuster (BPA).

Single cash-out price

- The reverse price will be set equal to the main price rather than the Market Index Price.
 - Parties with reducing imbalances²³ and parties with aggravating imbalances²⁴ will face the same cash-out price. Thus, under a short system, those with reducing imbalances will *be paid* the main price (rather than the Market Index Price), and under a long system, those with reducing imbalances will *pay* the main price (rather than the Market Index Price).

Other changes – Gate Closure and single/separate accounts

- We are not directing National Grid to raise any further proposals for changes to the balancing arrangements such as to Gate Closure or single/separate trading accounts.

Two modifications

- Our rationale to direct National Grid to raise two BSC mod proposals to bring effect to our decision is based on the following points.
 - The reforms draw from Ofgem’s *holistic* review of issues with cash-out arrangements. Ofgem’s identified solutions have therefore been assessed and designed as a package which takes account of

²³ ‘Reducing imbalances’ are in the opposite direction to the overall system imbalance and thereby reduce it.

²⁴ ‘Aggravating imbalances’ are in the same direction to the overall system imbalance and thereby contribute to it.

sophisticated interactions, such as timing and party effects, as well as varied complementary and opposing effects. Furthermore, the evidence base that we have developed reflects the holistic approach we have taken, and so is suited to supporting the case for introducing measures as a unified package rather than as a series of separate reforms. Our preference therefore is for the reforms to be considered in the BSC mod process as a single package.

- Nevertheless, we recognise that allowing the possibility of PAR250 reform by early winter 2014/15 requires separating this aspect of reform from the rest of the EBSCR package owing to tight implementation timescales.

How our Draft Decision evolved into our Final Decision

2.2. Our Final Policy Decision draws from the qualitative and quantitative evidence base used for the Draft Policy Decision. It adds to this updated modelling that looks at a wider range of impacts, further stakeholder engagement including consultation responses, more detailed implementation options worked up with experts, as well as implementation cost estimates from stakeholders. We provide greater detail on these in chapter 3.

Stakeholder views and evidence

2.3. Responses to our Draft Policy Decision were broadly positive. Most stakeholders agreed with the principles that underpin our proposals. Some elements of reform received almost unanimous support – in particular single pricing.

2.4. Nevertheless, stakeholders raised a number of considerations.

- Stakeholders expressed concern with specifics of some proposals – in particular there was strong push-back on payments to consumers on a number of grounds including likely up-front implementation costs.
- Stakeholders requested further detail on proposals – in particular how the reserve policy (the RSP function) and the VoLL policy would work – to reassure the industry that the proposals can be implemented.
- A large number of respondents asked us to consider a phased implementation of our proposals – in particular in relation to PAR, with a number of stakeholders volunteering that a first-step PAR reduction also be implemented more quickly and by early winter 2014/15.
- A number of stakeholders expressed concern about potential risks and unintended consequences of reform including of marginal PAR (PAR1).

How our Final Policy Decision draws on stakeholder views

2.5. We drew on these stakeholder responses in further development of our proposals in the following ways (covered in more detail in chapter 3).

- We engaged with industry to estimate the cost of implementing the consumer payments policy. We concluded that up-front implementation costs are likely to significantly exceed the funds that would be redistributed to customers. As a result of this our Final Policy Decision is that consumers will not be paid for involuntary DSR they provide in the event of a disconnection.
- We developed further detail of our proposals for the RSP function as well as a model demonstrating the feasibility of VoLL policy implementation. We tested and strengthened the proposals further in presentations with industry experts in our Technical Working Group.
- We assessed the case for a phased introduction of marginal pricing reform and decided to phase the introduction of a fully marginal price in three steps over four years.
- We ensured the updated modelling shed light on potential risks by assessing party-specific impacts such as credit cover requirements.

3. Our assessment of policy considerations

In this chapter we present in greater detail the analysis that underpins our Final Policy Decision. For each policy consideration, we outline the issues and rationale for reform. We then outline stakeholder responses, how our analysis responds to stakeholder concerns and our Final Policy Decision. Finally, we present our high-level qualitative assessment of impacts, noting our reforms are motivated by our strong qualitative arguments. The quantitative analysis – which we use further to test our proposals – is outlined in the following chapter, while interactions are explored in more detail in the final chapter.

More marginal main cash-out price

Background and rationale for reform

3.1. When a party is out of balance in the same direction as the overall system (so exacerbating the overall imbalance), it faces the *main* cash-out price²⁵. This price is calculated as a volume weighted average cost of the most expensive 500 MWh of bids or offers accepted by the SO²⁶ to balance the system. The volume of actions on which the price is based is known as the Price Average Reference (PAR) volume.

3.2. 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 – and contributes to *missing money*²⁷ in forward markets especially for providers of flexibility. This in turn has detrimental impacts for security of supply and the overall costs of balancing²⁸.

Stakeholder responses, our analysis and Final Policy Decision

3.3. Consultation responses to our Draft Policy Decision highlighted the following.

²⁵ 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.

²⁶ 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.

²⁷ 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. See Box 1 in the EBSCR Initial Consultation August 2012 for further detail.

²⁸ 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.

- Most parties supported the principal of more marginal pricing.
- Many parties felt the step to significantly more marginal prices should only be taken with introduction of a single price.
- Many parties had concerns about a move to a fully marginal cash-out price, in particular in relation to potential for negative distributional impacts – such as net exit, disproportionate effects on certain party types, and impacts on risk premia – as well as other concerns²⁹ such as gaming, and system pollution³⁰.

3.4. We have undertaken significant analysis and modelling to investigate further the risk faced by parties from sharper cash-out prices. This analysis demonstrates that making prices fully marginal does not lead to negative distributional effects when accompanied by the introduction of the single price. See chapter 4 of this report and the accompanying Impact Assessment for further detail.

3.5. We consider the risks of gaming to be low, for the reasons outlined in the Draft Policy Decision³¹. In terms of system pollution, we note the high accuracy of the current tagging/flagging processes and the fact that it is designed in a conservative way and likely to over-correct for system pollution as outlined in the Draft Policy Decision³². In addition we note National Grid is effecting a change³³ that allows ex-post correction of mis-flagged or tagged actions. This comes into effect in June 2014 and further mitigates concerns that parties raised over possible system pollution. We thus consider potential for additional risks of system pollution arising from a fully marginal price to be manageable.

3.6. Using the marginal (most expensive) action to set the cash-out price sends the most efficient signal to the market. It most accurately reflects the SO's cost of balancing the system at the margin and provides the signal to market participants to exhaust all opportunities to achieve an extra unit of balance where the cost of doing so is less than that of the SO.

3.7. In reforming arrangements to a fully marginal price we nevertheless acknowledge concerns raised by stakeholders regarding the time that it would take parties to adjust their trading and hedging strategies in order to respond to the new arrangements and requests from stakeholders asking us to consider reducing the PAR level in steps over a number of years.

²⁹ We note mixed responses on possible liquidity impacts, aligning with our broadly neutral assessment (see the accompanying Final Policy Decision Impact Assessment).

³⁰ 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.

³¹ Paragraph 4.16.

³² Paragraphs 4.13 – 4.15.

³³ See Final Report CP1400 December 2013 http://www.elxon.co.uk/wp-content/uploads/2013/09/CP1400_Final-Report_v1.0.pdf.

3.8. Our Final Policy Decision is therefore to adopt a phased approach when administering our reforms. This will take the form of three separate stages:

- by early winter 2014/15 the PAR will be set at 250 (through a distinct, stand-alone mod)
- by early winter 2015/16 the PAR will be set at 50, and
- by early winter 2018/19 the PAR will be set at 1³⁴.

3.9. These phasing stages were chosen to link in with the other parts of our reform package. The initial reduction to PAR250 will be implemented on its own in order to accommodate requests by parties for a phased approach and for an early PAR reduction in advance of Winter 2014/15, on grounds that this may help counter-act potential tightening of margins. The second stage, the reduction to PAR50, is timed to fit in with the introduction of VoLL pricing, Reserve Scarcity Pricing and Single pricing. The final stage, the reduction to PAR1 is timed to fit in with the increase in VoLL to £6,000 by early winter 2018/19.

High-level impacts

3.10. More marginal cash-out prices (along with VoLL pricing and improved reserve pricing) sharpen cash-out prices and make them more reflective of the underlying scarcity on the system, therefore improving price signals in particular at times of system stress.

3.11. A fully cost-reflective, marginal cash-out price will help ensure parties face the full cost to the SO of balancing at the margin. This aligns incentives with those of the consumer, thereby incentivising participants to exhaust all opportunities in advance of Gate Closure to achieve balance where it is in the interests of the consumer to do so (ie, where it can be done more cheaply than the SO).

3.12. Our modelling suggests marginal pricing reform improves the incentives to balance and invest in flexibility, and ultimately supports security of supply. See chapter 4 for greater detail on the impacts of the marginal pricing reform in conjunction with the other elements of the EBSCR.

³⁴ Note in our SCR directions we also require consideration to be given to provision of indicative prices to industry ahead of the reduction in PAR levels. This is intended to assist understanding of the impact of our reforms in advance of introduction.

Including a cost for Demand Control actions in cash-out prices

Rationale for reform

3.15. When the SO considers supply to be insufficient to meet demand, it may use Demand Control³⁵ actions. These are emergency actions that are used as a last resort. This may involve the SO instructing Network Operators to reduce demand, which the Network Operators can do through either voltage reduction ('brownouts'), or firm load disconnection³⁶ ('blackouts'). Furthermore, there are situations where automatic Low Frequency Demand Disconnection (LFDD, which is not instructed by the SO) may occur to resolve an imbalance of supply and demand.

3.16. These Demand Control actions are balancing actions, but unlike other balancing actions they are currently not included in the calculation of cash-out prices, or in the determination of participant's imbalance positions.

3.17. The effect of the current non-costing of Demand Control actions to balance the system is to shield industry from facing the full cost Demand Control imposes on consumers. This dampens cash-out prices as a signal of scarcity at times of system stress, and leads to reduced incentives on participants to balance their positions and efficiently procure electricity to avoid the disconnection of consumers.

Stakeholder responses, our analysis and Final Policy Decision

3.18. As set out in the Draft Policy Decision, cost-reflectivity and formation of incentives that align with the consumer interest require Demand Control actions to be included in the stack of balancing actions with a volume and price attached, and to be subject to flagging and tagging procedures, as for any other balancing action. A detailed proposed approach to implementing this policy decision can be found in the accompanying Business Rules, which we encourage industry to consider.

3.19. Attributing a cost to non-costed actions requires consideration of a number of aspects. We discuss each and present our decision below:

VoLL Pricing: Setting the cost of voltage reduction and disconnections and including Demand Control actions in the cash-out price

3.20. We note general acceptance in stakeholder responses to our Draft Policy Decision on the principle of pricing Demand Control and pricing this at the level of administrative VoLL proposed. The rationale for this – which remains unchanged for Final Policy Decision – is outlined in the Draft Policy Decision.

³⁵ Demand Control actions are described in the Grid Code. For further information see <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/>.

³⁶ Referred to as 'disconnection' or 'SO-instructed disconnection' in this chapter for readability.

3.21. Our Final Policy Decision is to set the cost for both disconnections and voltage reduction actions instructed by the SO at the administrative VoLL level (a 'VoLL Price'). This is £3,000/MWh at the time of EBSCR implementation (by early winter 2015/16), increasing to £6,000/MWh by early winter 2018/19 and ahead of the first delivery year of the CM.³⁷ The Authority maintains discretion to direct changes to this figure in the future³⁸. SO-instructed Demand Control actions should be treated similarly to other balancing actions for the purposes of calculating the cash-out price.

3.22. Industry may wish to consider whether Demand Control achieved through LFDD can and should also be incorporated in to cash-out and can be appropriately reflected in Settlement³⁹.

3.23. The pricing of NGET's 'New Balancing Services'⁴⁰ in cash-out is out of EBSCR scope and their treatment will be considered through a separate mod proposal. We note nevertheless a case for treating these measures in the same way that our reforms treat Demand Control actions, as the new services are intended and designed to be 'last resort' substitutes for Demand Control actions. See chapter 5 for more detail.

Estimating Demand Control volumes to incorporate into the (15-minute run) cash-out price calculation

3.24. In our Draft Policy Decision we consulted on incorporation of a 'top down' SO estimate of Demand Control volume in the 15-minute cash-out price⁴¹. We think this strikes the best balance between accuracy and simplicity in sending an appropriate price signal to market participants, noting these arrangements will be used extremely rarely.

3.25. Stakeholders agreed with the principles of this policy, however they noted the potential complexities and requested further information about possible implementation. In response, we conducted further work with stakeholders including with the TWG, Elexon and the SO to develop this top-down approach. We have set this out in greater detail in the Business Rules that accompany this Decision document. This work has demonstrated that there is at least one feasible route (and possibly a number of feasible options) to implementing this decision. This offers reassurance in response to stakeholder feedback which questioned whether the proposals can be implemented. For the modification process we strongly encourage industry to consider and draw on this work and the Business Rules.

³⁷ These figures assume a CM will be introduced in GB. Should a CM not emerge or be delayed, Ofgem may consider directing changes to the level of VoLL.

³⁸ While we consider it appropriate for the value of VoLL to be governed by industry, we highlight that the level of VoLL has been based on a study performed for DECC and Ofgem and further policy considerations. Should we feel that changes to this figure are needed in the future, such as due to a new study of VoLL being performed, we believe it is appropriate to maintain the ability to direct a change to this value.

³⁹ See Appendix 3.

⁴⁰ These are Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR). See <http://www.nationalgrid.com/uk/electricity/additionalmeasures>.

⁴¹ This is an indicative cash-out price published approximately 15 minutes after the end of a Settlement Period.

3.26. Our Final Policy Decision therefore is to use a top down approach based on the SO instructed volume of disconnection and voltage reduction actions in the cash-out price for the 15 minute run.

Correcting supplier imbalance volumes for accurate calculation of imbalance volumes and further improving accuracy of later cash-out price calculations (notably the Initial Settlements (SF) run)⁴²

3.27. Demand Control actions impact the positions of suppliers of affected consumers. Furthermore, because demand for NHH consumers is determined through profiles⁴³, a Demand Control action will also impact on the positions of all customers within the affected Grid Supply Point (GSP), not just those disconnected.

3.28. We considered whether supplier imbalance volumes should be corrected using a 'bottom-up' or 'top-down' methodology. As outlined in the Draft Policy Decision, a 'bottom up' approach, using data from Licensed Distribution System Operators (LDSOs), would allow estimation of the customer consumption of each supplier 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 it important to adjust supplier imbalances with a high degree of accuracy, as signals to market participants subject to Demand Control actions could otherwise be distorted.

3.29. In response to stakeholder comments at consultation and in order to assess the feasibility of our proposals, we worked with a number of stakeholders – particularly with Elexon – to understand how this policy can be implemented⁴⁴ and whether deficiencies of previous industry modifications could be overcome⁴⁵.

3.30. Through this work we identified a feasible route to implementing this policy in relation to demand disconnection as outlined in the Business Rules published alongside this Decision. This route overcomes deficiencies of previous industry modifications, particularly through the use of LDSO data for the event. We shared this 'strawman' with our TWG and received positive feedback. We consider this to be sufficiently detailed for industry to take forward and work out the remaining details as part of the mod process.

⁴² The Settlement calculations are performed several times for the same date between 5 working days after the date to approximately 14 months after. This is to allow more 'actual' data (ie, data based on actual meter readings) for Non-Half Hourly metering systems to be used in the calculations. The first calculation run is called the 'Interim Information' (II) run. This run is used to provide data for information. The 'Initial Settlements' (SF) Run is approximately 16 working days after the date of the Settlement Period in question and is the first run that monies are exchanged on. Further information can be found in BSCP01 on the ELEXON website www.elexon.co.uk.

⁴³ See Draft Policy Decision for further information.

⁴⁴ We also explored with a number of parties whether the proposals can be delivered primarily through existing processes or capabilities parties have. We understand the majority of any process required will be through existing processes or capabilities.

⁴⁵ Industry has previously proposed a modification (BSC modification P199) in this area that was not taken forward.

3.31. We also note further work⁴⁶ by industry seeking to achieve clarity on whether instructed disconnection or voltage reduction is used and on implementation times for voltage reduction on instruction by the SO. In light of this on-going proposal, we ask National Grid to consider how suppliers' imbalance volumes can be accurately and transparently corrected not only for demand disconnection but also for voltage reduction.

3.32. Our Final Policy Decision is that suppliers' imbalance volumes should be restored to their pre-Demand Control positions using a bottom-up approach based on LDSO MPAN data for SO-instructed disconnection. This will also be used to provide a more accurate calculation of cash-out prices for later runs (notably SF run). Suppliers' imbalance volumes should be corrected even if the Demand Control action is subject to flagging and tagging. We also ask industry to consider solutions for restoring supplier imbalance volumes to pre-voltage reduction positions.

Payments to consumers for involuntary DSR service provision; payments to suppliers for electricity procured which they cannot bill their customers due to disconnections

3.33. Our Draft Policy Decision for consultation was that NHH⁴⁷ domestic and businesses should be paid for £5 and £10 per hour of disconnection⁴⁸, respectively.

3.34. In response to stakeholder views to our Draft Policy Decision, we have appraised this policy further, in particular to assess:

- the extent to which the reform proposal may be expected to have enduring effects
- proportionality in light of expected (up-front) implementation costs.

3.35. In relation to the former (enduring effects), at this point we consider this policy would be a transitory measure. This is because payments to NHH consumers for involuntary DSR balancing services may not be as necessary once they have stronger incentives and more scope to engage in (voluntary) DSR. In this respect we note the roll-out of smart meters – expected to be completed by 2020⁴⁹ – will create new opportunities for suppliers to engage current NHH consumers in DSR (in addition to HH customers)⁵⁰. We expect that smart meters and settlement reform⁵¹ can create

⁴⁶ Grid Code modification GC0050, related to Grid Code OC6. This proposal has put forward that the SO may call on disconnection and voltage reduction separately.

⁴⁷ To note, payment was not proposed for HH metered consumers for involuntary DSR services to the SO, as they are generally larger energy consumers more capable of entering into DSR arrangements and we wish to maintain strong incentives on these parties to offer DSR services.

⁴⁸ This was derived from the average domestic VoLL as estimated by the London Economics Study. See Draft Policy Decision.

⁴⁹ See the following webpage for further information on the smart meter roll-out <https://www.gov.uk/government/policies/helping-households-to-cut-their-energy-bills/supporting-pages/smart-meters> (accessed 28/04/2014).

⁵⁰ For further information regarding our Smarter Markets programme, please see <https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter->

more possibility for consumers to react to price signals, further limiting the risk of involuntary disconnection of consumers and therefore the likelihood of needing administrative payments.

3.36. In relation to the latter (cost), we have further explored up-front costs of implementation through suppliers. The evidence we received from a number of supplier in confidence suggested that the costs⁵² of IT changes and process changes (ultimately borne by consumers) will likely significantly outweigh the funds that may be redistributed to affected NHH consumers⁵³. Given this, and given any payments to consumers would ultimately be paid for by all consumers as well, we do not consider this proposal to be in the interest of consumers at this time.

3.37. We also explored implementing this proposal through LDSOs, who currently administer payments under the Guaranteed Standards of Performance (GSOP)⁵⁴. Implementation challenges were identified (eg the availability of necessary data such as bank details, name, address) that suggests that this was not a viable alternative for making payments to suppliers at this time. Whilst our GSOP work stream will bring in changes that are expected to overcome these challenges, these are not expected to be in place at the time of the EBSCR directions⁵⁵.

3.38. **Our Final Policy Decision is that NHH consumers should not be paid for the involuntary DSR balancing service they provide to the SO.** We intend nevertheless to keep this policy under review, to take into account pending decisions on the smart meter roll-out and the Guaranteed Standards of Performance for LDSOs.

3.39. At our Draft Policy Decision we consulted on our proposal to pay suppliers for electricity they procured for which they cannot bill consumers due to disconnections. At follow-up engagement with our TWG supplier representatives, they said it was more important to improve the cash-out price signal, and that payments to suppliers were a low priority. Given this, and in light of our decision not to pay consumers, **our Final Policy Decision is to drop the proposal to pay suppliers.** As with payments to consumers we retain discretion to reconsider whether this policy should be taken forward in the future in light of smart meter roll-out and settlement reform.

[markets-programme](#).

⁵¹ Our recent launch statement set out that we believe it is in consumers' interests to be settled against HH data from smart and advance meters. The next stage of the settlement project will develop and assess options which achieve this. For further information:

<https://www.ofgem.gov.uk/ofgem-publications/87053/electricitysettlementlaunchstatement.pdf>.

⁵² Information received suggests up-front costs faced by suppliers may have been in the region of over £6million, and that an ad-hoc process would unlikely have been feasible.

⁵³ To note, in our Draft Policy Decision we proposed for funds for this Involuntary DSR service to be recovered through BSUoS charges, which are ultimately paid for by all consumers.

⁵⁴ We note that the duration of these interruptions (for energy reasons) is unlikely to last long enough to trigger Guaranteed Standards of Performance payments. We also note the role of rota disconnections of electricity consumers in the case of prolonged energy shortages which assists distributional fairness.

⁵⁵ A transparent, consultative approach is important for such changes, and the results of this consultation could not be pre-empted for the purpose of EBSCR.

System warning requirement before VoLL pricing

3.40. As in our Draft Policy Decision we consider that VoLL pricing should not be made conditional on the market having received a pre-Gate Closure 'warning'. However, we consider any information that helps the market function more efficiently and that can practically be provided to be beneficial. Note in this context we propose indicative LOLPs be published ahead of Gate Closure as part of our reserve policy. We expect this will help the market anticipate scarcity and manage risks. **Our Final Policy decision is that no formal warning is required before VoLL pricing is applied for Demand Control actions.**

High-level impacts

3.41. Attributing a cost to non-costed actions has a similar high-level impact – producing sharper price signals – as making prices more marginal and improving the way reserve is costed. By placing a price on Demand Control, generators and suppliers are incentivised to exhaust all opportunities to avoid disconnection of consumers where these entail lower cost than the cost imposed on consumers of disconnection. This supports market signals for commercial DSR, efficient interconnector in-flows, and other market-driven balancing solutions during system stress, and thus assists with security of supply.

3.42. The VoLL proposals should result in benefits from costing Demand Control actions regardless of whether Demand Control actions actually happen. In fact, by stimulating behaviour change, pricing in the cost of Demand Control actions makes them less likely.

Improving the way reserve is incorporated in cash-out prices

Background and rationale for reform

3.43. The SO is responsible for balancing the electricity system second by second and faces 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 to provide availability of additional capacity at specified times for a specified price, in exchange for availability payments.

3.44. The main source of reserve is Short Term Operating Reserve (STOR). STOR is used in combination with bids and offers from the BM to balance the system in real time. However, the payment structure for STOR means it is difficult to price these costs into cash-out in a way that efficiently reflects costs and accurately signals scarcity. Whereas non-STOR parties are able to adjust their bids and offers in the BM to reflect system conditions, the price the SO pays for *using* STOR (the 'utilisation payment') is agreed in advance⁵⁶. The addition of payments to STOR providers *simply for being available* ('availability payments') impedes the accurate reflection of costs in cash-out as it is not obvious which settlement periods these costs should be allocated to.

3.45. Ideally, availability payments should be fed into the periods where STOR is used and valued the most, as the reason the SO incurs these costs is to provide cover for these periods. A key problem is that it is very difficult to anticipate when these periods will be and therefore appropriately to target costs in advance⁵⁷. Under existing arrangements, a half-hourly profile based on historic STOR usage is built to determine a weighting factor for each settlement period. The costs incurred by the SO for STOR availability payments (which are known in advance) are then allocated to each settlement period according to this weighting. This is fed into cash-out via the Buy Price Adjuster (BPA), which is a £/MWh addition to the System Buy Price (SBP in each period).

3.46. The BPA approach has the effect of adding a small uplift to cash-out prices over peak periods across the day. This does not necessarily correspond with tight margins or STOR usage. As a result, the cash-out price is dampened during times of system stress and arbitrarily increased when STOR is not required. We do not consider this is creating the right signals to balance.

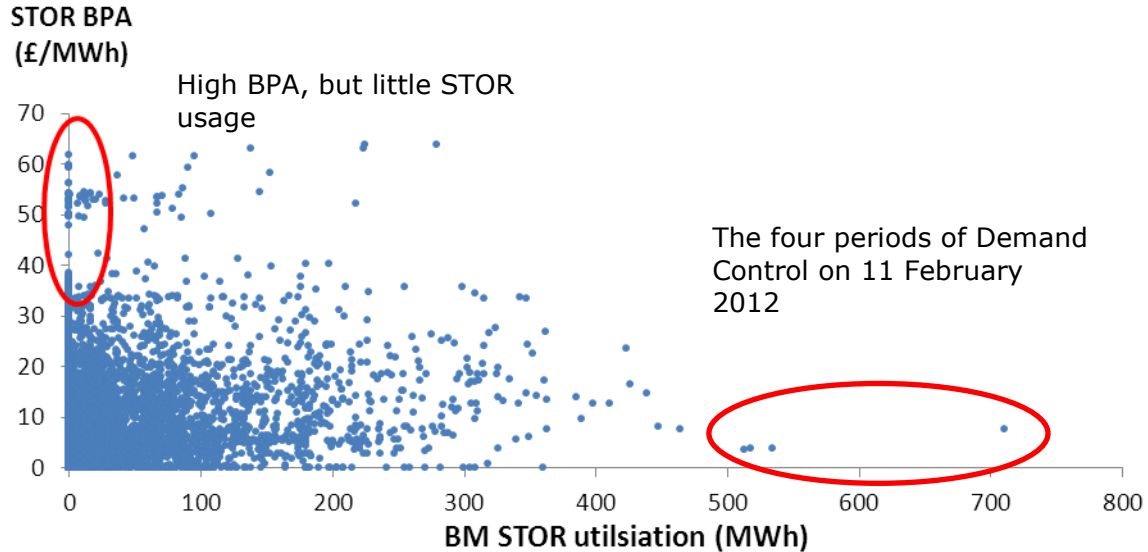
3.47. Figure 1 shows the very little correlation between STOR utilisation and the costing of STOR through the BPA. We also note that in the four periods of Demand

⁵⁶ As a result, providers are unable to adjust prices to reflect the value of their reserve service at the time of use. Therefore, even though utilisation payments are accurately reflected in cash-out, they send imperfect signals to the market for scarcity.

⁵⁷ As an illustration consider – for a 'current' settlement period where STOR is used, and an SO's total availability costs of say £x million per year – the impossibility of accurately apportioning this £x million to the 'current' settlement period, given it cannot be known until year end how many times the product will be used in the remaining periods in the year and therefore what portion the current settlement period accounts for of the total.

Control on 11 February 2012, arguably the periods in which STOR was most valued in the whole assessment period, the BPA for STOR availability costs was very small.

Figure 1 – BPA versus STOR utilisation November 2009 to November 2013

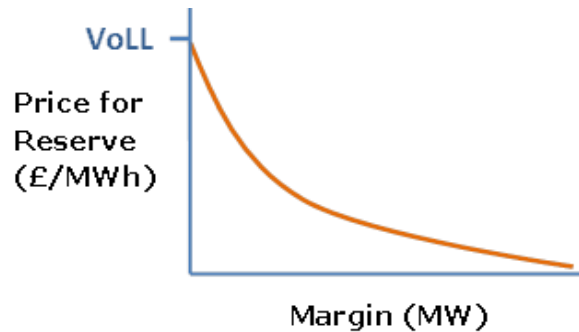


3.48. An additional distortion is driven by omission of certain STOR costs from cash-out altogether – those incurred by the SO for use of STOR not exercised in the BM ('non-BM STOR'). This further dampens the cash-out price.

Stakeholder responses, our analysis and Final Policy Decision

3.49. Given the difficulties with appropriately targeting STOR costs, we explored the possibility of pricing STOR into cash-out according to its *value* to the system.⁵⁸ Under this approach, rather than pricing STOR into cash-out based on the underlying costs (ie, the supply side), pricing for reserve is instead derived from the demand side. The value of reserve to the system can be defined as the extent to which its use lowers the expected cost of interrupted supplies by reducing the probability of Demand Control, calculated as the VoLL multiplied by the Loss of Load Probability (LOLP). It follows that as margins tighten (and the LOLP increases), the maximum the demand side would be willing to pay to avoid interruption of supplies increases until VoLL, at which point lost load and associated costs would otherwise be a certainty. An example of a demand curve for reserve is shown in Figure 2.

⁵⁸ This approach builds on the experience of US markets such as the Pennsylvania, Jersey, Maryland Power Pool system. See our Draft Policy Decision for further discussion.

Figure 2 – example demand curve for reserve based on system scarcity

3.50. This approach overcomes the inherent difficulty in targeting STOR availability payments as well as pricing inflexibility issues with utilisation payments. A value approach provides the closest proxy of (long-run) cost reflectivity and should allow for the most accurate signal of scarcity to the market in the short run (settlement period timeframe). It was received favourably when presented at our TWG and the concept had broad support from respondents to our Draft Decision consultation.

3.51. Our Final Policy Decision therefore 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 intend for the RSP to come into effect by early winter 2015/16.

3.52. There has been no change to the substance of our Draft Policy Decision. However, we have responded to stakeholder requests to develop the detail of the RSP further and to understand its impact better. In particular, we have carried out further qualitative and quantitative analysis and held detailed discussions with National Grid. We presented the results of our analysis to our TWG where we reached broad agreement on a number of RSP function design aspects.

3.53. The RSP function will produce a price in each settlement period that reflects the value of reserve to the system (the 'RSP price'). Under existing arrangements, STOR actions enter the cash-out calculation at their utilisation price. Under our Final Policy Decision, the RSP price will replace the utilisation price for each STOR action if it is greater than the utilisation price. The normal cash-out calculation will then apply and re-priced STOR actions will still be subjected to normal flagging and tagging procedures.

3.54. STOR availability costs will no longer be allocated via the BPA, as the RSP price is intended to capture these costs. However, the BPA will remain in place for the allocation of BM Start-up costs⁵⁹.

⁵⁹ BM Start-up gives the SO on-the-day access to additional balancing units that would not otherwise have run, and which could not be made available in BM timescales due to associated lead-times. BM start-up costs are currently well targeted into the periods for which they are incurred via the BPA and do not suffer from the same issues as STOR availability costs.

3.55. The RSP price will be equal to VoLL multiplied by the LOLP for each settlement period. We intend to use the same VoLL values established for Demand Control, ie, £3,000/MWh rising to £6,000/MWh by early winter 2018/19.

3.56. The LOLP used to determine the RSP price in each settlement period will be calculated by National Grid according to a new 'LOLP calculation methodology'. This will be made available to industry in advance and reviewed regularly. In order to ensure the RSP function reflects our policy intent, and in response to requests from stakeholders to provide as much detail as possible before the modification process, we have made decisions on several key aspects of the LOLP calculation. These are outlined below.

- It should be calculated **dynamically** each settlement period, reflecting information about the type of plant available. This helps to ensure that the LOLP calculation is accurate so that STOR is valued correctly. This is unlikely to involve significantly more costs than a static LOLP curve approach.
- It should be calculated using information available at **Gate Closure**, and published to the market shortly after Gate Closure. This is close enough to real time to achieve an appropriate level of accuracy but at the same time minimises the risk of parties facing high cash-out prices they are unable to reasonably anticipate or react to⁶⁰.
- **Reserve for Response**⁶¹ should be calculated dynamically each settlement period and subtracted from available capacity, in order to ensure a more accurate reflection of the likelihood of Demand Control.
- BM and Non-BM **STOR** availability should be included in the available capacity measure, as, in theory, all available STOR should be used (except Reserve for Response) before Demand Control is initiated.
- **National Grid's new balancing services**⁶² and **emergency services** should not be counted as available capacity⁶³. This is because these actions are intended and designed to be 'last resort' substitutes for Demand Control actions (priced at VoLL). Including them in the RSP margin would undermine this intent by signalling that these new services

⁶⁰ This essentially means the RSP price is fixed at Gate Closure. Any unexpected system developments that occur after Gate Closure will not affect the RSP price. This should help reduce imbalance risk for market participants.

⁶¹ The SO holds frequency response in order to prevent a single large unit failure from causing widespread disconnections. This response holding is made up (in part) by de-loaded generation in frequency response mode. The total amount of de-loaded capacity is referred to as "reserve for response". Practically, this means that when the generation capacity available is less than demand plus the reserve for response, the SO will instruct Demand Control to ensure the electricity system remains secure.

⁶² These are Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR). See <http://www.nationalgrid.com/uk/electricity/additionalmeasures>.

⁶³ Unless the Mod process for pricing NBS requires inclusion in the margin for the RSP for consistency reasons.

are rather 'normal' market services with potential to displace the market's existing offerings.

- **Indicative LOLPs** should be calculated by National Grid and published ahead of Gate Closure (for example at 4 hours, 3 hours and 2 hours head). This provides parties with a signal they can respond to, helping to limit cash-out risk and encourage efficient balancing behaviour.

3.57. The RSP price is only relevant for the cash-out calculation. It is not intended to affect payments to STOR providers or the way the SO balances the system.

High-level impacts

3.58. Under the RSP function the price of STOR in cash-out is much more aligned with system conditions. Our historical analysis suggests that its introduction will have no impact on the cash-out price in the majority of periods. This is because the LOLP is generally very low. However, during periods with tight margins the cash-out price will be able to rise significantly, and approaching VoLL where Demand Control is very likely. This solution provides a more accurate signal of scarcity because availability payments are shifted from the periods where STOR has little or no value⁶⁴ to the periods where it is valued the most.

3.59. The provision of indicative LOLPs before Gate Closure provides parties with an early signal of the likely RSP price and therefore greater visibility of their potential cash-out exposure. This is of particular value as margins tighten. This supports both a clearer signals for scarcity created by the RSP function and a more efficient market response at times of system stress⁶⁵. The inclusion of Non-BM STOR costs in cash-out further supports long-run cost-reflectivity in cash-out prices and provision of a more efficient signal to the market to balance.

3.60. Some stakeholders have raised concerns about de-linking the price of STOR in cash-out from actual STOR costs. We note that without perfect foresight, perfect short-run cost-reflectivity is impossible to achieve under any approach. This owes to the impossibility of determining the proportion of total availability payments to be fed into each settlement period. This is a key motivation for our development of a demand-side approach for allocating STOR costs. However, we recognise that while in theory a demand-side approach should achieve the same outcome as a supply-side approach, the extent to which costs are reflected is highly dependent on the LOLP calculation and VoLL level. As such, we have carried out quantitative analysis of historic data to test the potential impact of the RSP. This shows that historically the RSP function approach allows for a closer reflection of total (long-run) STOR costs in cash-out than existing arrangements, as explained further in our Impact Assessment.

⁶⁴ As a result of the previous BPA approach for allocating STOR availability payments being removed.

⁶⁵ If parties have sight of their potential cash-out exposure ahead of real time, they are more able to factor this into their decisions on whether to trade out an imbalance position in the intraday market. This could result in more efficient wholesale price signal, which (for example) could encourage greater imports into GB, helping to alleviate system stress.

Single cash-out price

Rationale for reform

3.61. Under the imbalance pricing arrangements, if a party is long, they will receive the System Sell Price (SSP) for their surplus energy, whereas if a party is short, they will pay for their imbalance volumes at System Buy Price (SBP). Furthermore, the arrangements currently feature dual cash-out prices, which mean there are two cash-out prices in each Settlement Period – the main price and the reverse price. Table 1 shows how the cash-out price faced by a given party will depend on both the position of the Transmission System as a whole (ie, whether it is long or short), and their position.

- If a party is out of balance in the same direction as the system (ie, if they have an aggravating imbalance), they will face the main price, which is based on the balancing actions accepted by the SO in the relevant Settlement Period.
- If a party is out of balance in the opposite direction as the system (ie, if they have a reducing imbalance), they will face the reverse price, which is based on the prices of trades cleared in the 12 hours prior to Gate Closure.

Table 1: Dual pricing 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)

3.62. The original rationale for dual pricing was as follows. If a party has an aggravating imbalance, they have contributed to the system imbalance and should therefore be exposed to the costs incurred by the SO in balancing the system. If a party has a reducing imbalance, on the other hand, they have lessened the system imbalance and should therefore face a market price, as this is what they would have paid or received if they had foreseen the system imbalance and traded out their position intraday.

3.63. We are concerned, however, that the reverse price is not cost-reflective, and as such drives inefficiency in balancing by over-incentivising parties to balance. This effect materialises as parties with reducing imbalances face a cash-out price that:

- is designed to ensure they gain no additional benefit from these imbalances – compared with achieving balance through trading out their position intraday
- is less favourable than one that reflects the full cost saving their imbalance realises for the SO (and ultimately the consumer).

Stakeholder responses, our analysis and Final Policy Decision

3.64. Our Draft Policy Proposal was to move to a single cash-out price, which means all parties would face the main price, irrespective of their positions or the system position. This set of arrangements is summarised in Table 2.

Table 2: Single pricing arrangements

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

3.65. Single pricing received widespread support in our Draft Policy Decision consultation – with many stakeholders noting the policy is likely to support efficiency and counteract potentially negative distributional and risk impacts of other components of our reform package. We received, however, a mixed assessment in responses of potential impacts on liquidity, with some parties expressing the view it could lessen liquidity and others arguing it would enhance liquidity. In this respect, further qualitative analysis we have conducted since Draft Policy Decision suggests that our reform package as a whole is unlikely to have a significant impact on near-term liquidity. Refer to the Liquidity section in the Unintended consequences and other risks chapter in the accompanying Impact Assessment for more information.

3.66. We consider that a single price is more cost-reflective and does (as opposed to a dual price) not over-incentivise parties to balance under normal system conditions. Under a single price parties with reducing imbalances benefit from the cost saving their reducing imbalance deliver for the SO. We do not consider there to be any significant implementation risks from moving to a single price (such as parties deviating from their physical notifications) as set out in our Draft Policy Decision⁶⁶.

3.67. In view of the significant stakeholder support and further re-assuring analysis conducted since Draft Policy Decision, **our Final Policy Decision is to introduce a single cash-out price.**

High-level impacts

3.68. Single pricing removes an inefficient price spread and a significant complexity from the current arrangement. In addition, for many parties it substantially reduces imbalance costs across parties and counteracts adverse distributional impacts or increases in operational risk caused by the other elements of our reforms. It is therefore a key component of our overall reform package. Our modelling suggests that smaller parties particularly benefit from single pricing, as they have reducing imbalances relatively frequently.

⁶⁶ Paragraphs 4.59-4.63.

Single or separate trading accounts

3.69. BSC parties are assigned production and consumption energy accounts with distinct imbalance volumes. This means a vertically integrated party (ie, a party with both production and consumption accounts) will have two separate imbalance volumes and therefore face two imbalance charges in every Settlement Period.

3.70. Under dual pricing, introducing single trading accounts would decrease the imbalance charges faced by vertically integrated parties where their production and consumption accounts have reducing imbalances (eg, where a party is long on its production account but short on its consumption account), as these imbalance volumes would be netted off and parties would benefit from the removal of exposure to the spread (assuming non-zero) between SBP and SSP.

3.71. Under single pricing, however, introducing single trading accounts would have no impact. Keeping separate trading accounts would, however, help maintain the current level of transparency in trading activities, and would remove the need for changes to industry systems. Given our decision to move to single pricing, **our Final Policy Decision is to maintain separate trading accounts.**

Gate Closure

3.72. Gate Closure is the point up to which parties can submit physical notifications, an indication of what they expect to generate or consume during a given settlement period, and contract notifications, which notify volumes of energy bought and sold between two energy accounts. Gate Closure is set at one hour ahead of real time.

3.73. As set out in our Draft Policy Decision consultation document, we considered the following two changes to Gate Closure:

- moving Gate Closure forward to half an hour ahead of real time
- allowing parties to submit contract notifications after Gate Closure.

3.74. Either of these changes could reduce imbalance risk to an extent. Moving Gate Closure forward would allow parties to submit more accurate physical notifications, whilst allowing parties to submit contract notifications after Gate Closure would give them more time to trade out their position.

3.75. However, through engagement with stakeholders, we concluded that it is unlikely either option would yield significant benefits. On the other hand, moving Gate Closure may significantly limit the ability of the SO to balance the system in an optimal manner. For these reasons, our draft policy proposal for consultation was to maintain the existing rules for Gate Closure. No substantial additional evidence has come to light since our Draft Policy Decision. **Our Final Policy Decision is to maintain the existing rules for Gate Closure.** We may give this further consideration in the Future Trading Arrangements project.

4. Impacts of our policy package

In this chapter we consider the impacts of our reform package as a whole. Our reforms are motivated by our strong qualitative arguments. Qualitative analysis shows us that the sharpening of prices during scarcity (assisted by marginal pricing, costing Demand Control, and pricing reserve appropriately) and the elimination of the dual pricing distortion support efficiency in balancing and security of supply. This helps consumers by ensuring any given level of security of supply is delivered at least cost. We also outline how reform may support security of supply directly. Our reforms support innovation and competition in flexible technologies. This benefits the consumer by ensuring that efficient firms – those that offer innovative low price products that deliver in the interests of consumers – prosper. Finally, reform may drive distributional impacts and transfer risk, with possible contrary effects of different elements of reform. The results of Baringa’s commissioned work in modelling reform impacts, which we use to test – rather than underpin – the case for reform, support our qualitative motivations for reform while presenting comforting evidence in relation to distributional and risk impacts.

4.1. This chapter presents a summary first of our qualitative analysis, then our quantitative assessment. See the accompanying Impact Assessment for more detail on the evidence base that we have used to underpin our decision.

Qualitative analysis

4.2. Our reforms make cash-out prices more reflective of the costs borne by the SO – and ultimately the consumer – of actions to balance energy. They therefore provide for incentives to market participants that are more closely aligned with the consumer interest, and thereby **drive efficiency in balancing and security of supply**, as well as **support competition and innovation in flexible technologies**.

4.3. **Turning first to balancing efficiency**, we note during periods of energy abundance, by removing the inefficient dual price system that presents excessive incentives to balance, reforms support a **more efficient mutualisation of effort between the market and the SO**.

4.4. **On security of supply**, we note the CM is likely to provide the main signal for investment in capacity. Nevertheless cash-out prices impact on the *type* of capacity that the market provides. During times of scarcity, sharper prices will send signals to market participants to provide flexibility – achieved through enhanced responsiveness of interconnectors, removal of a disincentive to offer DSR, and strengthened incentives for the development of other flexible solutions (such as storage). This will help **alleviate scarcity, serve efficiency in wider wholesale markets and support security of supply**.

4.5. EBSCR **reform supports competition** through removal of the distortions that dampen free and fair competition, thereby allowing those parties best able to manage their energy (im)balances to enjoy a competitive advantage that reflects the value they deliver to the consumer. We also expect further dynamic competitive

improvements such as innovation in flexible technologies. Theory also suggests reform may drive distributional impacts and transfer risk, with possible contrary effects of different elements of reform. We expect **potentially negative distributional and risk impacts of sharper prices** to be **substantially mitigated by the introduction of the single price**, which allows parties to face a cash-out price for reducing imbalance that reflects the full value they deliver at the margin.

4.6. Although it has a roughly net neutral impact on wind, **reform ultimately supports sustainable development by removing barriers to the flexibility required to accommodate growing intermittency on the system efficiently.** Finally, while our analysis points to the potential for both negative and positive impacts of our reforms on near-term liquidity, it also suggests that uncertainty and risk will drive parties to adopt trading out as a dominant strategy, and as such **the net effect on liquidity is likely to be positive or at worst neutral.**

Quantitative analysis

4.7. It is important to note that we have used the model mainly to stress-test our very strong qualitative case. The model has confirmed and supported our qualitative arguments rather than being the primary driver of our recommendations. Modelling can only tell part of the story. It is not possible to capture the complexity of the energy market and how generators respond to changing signals and effects in a model. In particular, the modelling of the energy market is complicated by introduction of the CM. We have seen in the modelling that this has a strong effect with small changes in assumptions having very significant impacts in results. It is also difficult to predict how some of these effects will play out in reality in the market and how generators may respond both in the short term and long term. We have therefore always considered modelling of this nature is illustrative and not definite, but as part of wider range of evidence to consider in the round.

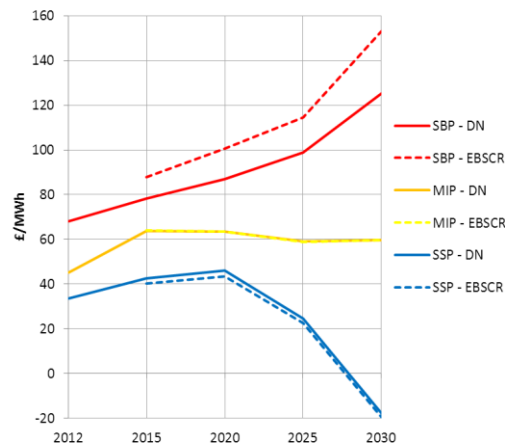
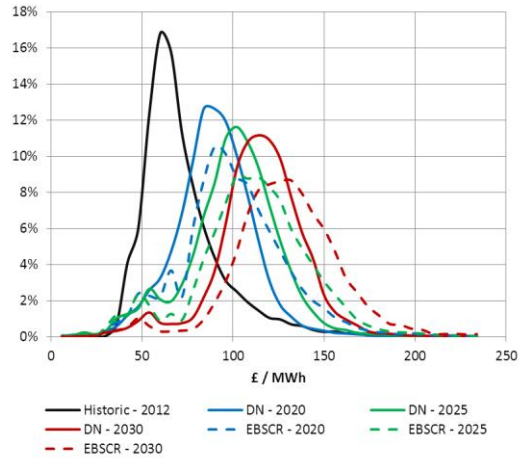
4.8. To assess the impact of our reforms, Baringa developed a forward looking cash-out model, which captures the effects of our reform on cash-out prices and the subsequent effects on balancing behaviour, hedging and investments in reliability. It also captures the amount of balancing that is done by the market versus the SO and the efficiency gains in this area due to improved cash-out price signals.

4.9. The model has also considered effects of our reforms on security of supply, but assumes that the main incentive for investment in capacity is delivered through the CM. We have assessed the potential for the EBSCR to reduce the cost of procuring capacity in the CM.

Impacts on price

4.10. Figure 3 shows modelled average main cash-out prices (SBP and SSP) and market index prices (MIP⁶⁷) over time. Figure 4 shows the modelled SBP (main price) distributions over time.⁶⁸

⁶⁷ The MIP is used to calculate the reverse price under existing arrangements. It reflects the

Figure 3: Average (main only) cash-out prices**Figure 4: SBP (main price) distributions**

4.11. Modelling suggests the effect of reform is to sharpen cash-out prices (ie, increase SBPs and decrease SSPs). This is particularly true for SBPs, since in addition to a lower PAR level⁶⁹ they are also impacted by our reforms to improve reserve pricing. They are not affected by VoLL pricing because according to modelling Demand Control actions are averted under our reforms.⁷⁰

Balancing efficiency

4.12. The **reforms support balancing efficiency**, driven by more cost-reflective price signals in particular the removal of the dual price distortion. The reforms allow for a more efficient mutualisation of effort between the market and the SO, and support efficient investment in technologies and innovation.

4.13. Modelling suggests limited impact of parties changing their hedging strategies. It suggests more significant **benefits of around £15m per annum from 2016, rising to over £30m by 2030 from more efficient incentives to invest in long-term balancing performance** across parties and the SO. Specifically, it suggests imperfections in current arrangements provide excessive incentives to balance during the vast majority of settlement periods when system conditions are relatively benign, whereas dampened prices provide for insufficient incentives to balance in the few periods when the system is stressed. Our modelling suggests the net effect of EBSCR is to incentivise an efficient level of investment that is lower than without reform (as

price in the intra-day market and is meant to be similar to what a party could have attained if it had traded in the market prior to Gate Closure.

⁶⁸ 'DN' is the 'do nothing' no-EBSCR counterfactual. 'P5' is the EBSCR package 5 (our preferred package). 'MIP' is the market index price, a proxy for intra-day wholesale market prices.

⁶⁹ Note further as bid curves in the Balancing Mechanism are relatively flat compared to the offer curve, the lowering of PAR does not make much difference on the sell side.

⁷⁰ 'DN' is the 'do nothing' no-EBSCR counterfactual. 'P5' is the EBSCR package 5 (our preferred package). 'MIP' is the market index price, a proxy for intra-day wholesale market prices.

over the whole year the single prices effect outweighs the effect of sharper prices with respect to balancing investment). This effect materialises as a result of EBSCR's better alignment of party imbalance costs with the SO's underlying costs.

Efficiency in the wider wholesale market and security of supply

4.14. Our modelling does not capture the full extent to which reforms may support efficiency of the wider wholesale market and security of supply (for instance it does not capture potential capacity mix changes as a result of our reform). Modelling does capture however how reforms may lower capacity adequacy costs (see next section).

4.15. With the CM likely to provide the main signal for investment in capacity, the modelling has taken a conservative approach and assumed EBSCR would not deliver any additional investment in capacity. Nevertheless, this is likely to underestimate the impact of EBSCR on security of supply (or the cost of achieving any given level of security of supply). First, EBSCR is likely to impact on the *type* of capacity that will come forward, leading to a more flexible capacity mix overall. This provides for a security of supply 'buffer' during unanticipated events not captured in the CM baseline⁷¹, tight non-winter peak demand periods when plant is on maintenance, or a rapidly unfolding system stress event (eg, plant trip or sudden drop in wind output⁷²). Second, there could also be small additional investment effects – such as forestalled mothballing – from peakier prices in the wholesale market in the years before the CM is introduced.⁷³

Consumer welfare and bills

4.16. Modelling suggests that improved balancing efficiency should unlock **consumer savings with a cumulative NPV of around £200m by 2030** (as shown in 'NPV 1 balancing effects only' in Table 3 below).

4.17. Our additional modelling component on the CM and wholesale prices assesses the EBSCR's impact on wholesale prices and subsequently on CM bids and the CM clearing price. This attempts to unpick two potentially opposing effects of EBSCR. The first is a possible increase in wholesale revenues from sharper cash-out prices (negative effect for the consumer if passed through). The second is a reduction in capacity payments from the CM (a positive effect for the consumer) owing to the plant bidding into the CM expecting to receive more revenue in the wholesale market and hence needing less additional money from the CM. This is difficult to model, as it depends strongly on assumptions of correlation between cash-out prices and wholesale prices, as well as the likely marginal plant type in the CM until 2030⁷⁴.

⁷¹ DECC aim for no more than 3 hours of emergency action based on winter peak demand. However, unexpected stress events could happen at other times.

⁷² The CM applies with a 4 hour warning – some events may unfold more swiftly than this.

⁷³ Some of these more flexible types of capacity could also provide extra competition for the provision of ancillary services to National Grid.

⁷⁴ Our modelling assumes the plant clearing the CM auction moves from a baseload/mid-merit plant in 2020 to a new peaking plant in 2025 and 2030. This assumption draws from DECC's capacity mix and is outlined further in the accompanying Baringa modelling report. We note the clearing plant may vary year on year.

4.18. We conducted further modelling sensitivities. The first explores the EBSCR’s impact on the CM clearing price and wholesale price effects. The second explores the potential impact of DECC employing a higher interconnector de-rating factor assumption – driven by cash-out reform – in its assessment of CM capacity requirement (amounting to a consumer saving of around £5m per year post-introduction of the CM – see fourth row of Table 3). The results of this further, more uncertain modelling suggests the NPV could be as high as around £430m.

Table 3: Simplified Cost Benefit Analysis and annual average domestic bill effect

£m/year (2012 prices) (positive = benefit for consumers)	2016⁷⁵	2020	2025	2030
Balancing efficiency gains	17	14	16	33
Increased electricity market revenues	-166	-17	-360	-426
Reduction in capacity payments	0	27	468	517
Interconnector impact on CM	0	5	3	7
Total	-149	29	127	131
Average annual domestic bill impact (-ve: reduction)	1.60	-0.32	-1.40	-1.32
NPV 1 (balancing effects only)	£202m			
NPV 2 (all effects)	£435m			

4.19. The model results suggest that the savings in the CM outweigh the costs of higher wholesale prices, and therefore that our **reforms complement the CM by reducing the cost of achieving capacity adequacy**. Savings (and costs) are shown in the third (and second) rows of Table 3. A key driver of this result is the pay-as-clear characteristic of the CM auction which rewards all CM plant at the level of the marginal plant. This is material because the marginal plant is likely to be gas-fired power plant. Gas-fired plants are key beneficiaries of EBSCR owing to their flexibility. They will be able to earn more in the wholesale markets at very specific times when the system is tight allowing them to reduce their CM bids, which is likely to reduce the CM clearing price and hence the overall cost of the CM.

4.20. This additional modelling suggests in the short-term EBSCR may incur a ‘higher wholesale price’ cost that is not offset by savings in the CM auction in advance of CM introduction. Modelling suggests this could increase average domestic consumer bills by around £1.60 per annum in advance of CM introduction in 2018. However, this could overstate any negative impact as the ‘with-CM-baseline’ employed by the model does not account for wider security of supply benefits (such as impacts on mothballing decisions⁷⁶, investment in flexibility and DSR) nor does it account for competitive and innovative effects as already noted. Finally, timely realisation of CM savings may be somewhat contingent on parties fully anticipating wholesale market effects in advance, facilitated by early EBSCR introduction. After

⁷⁵ Our model can produce results for 4 spot years; 2015, 2020, 2025 and 2030. However, the full EBSCR package is not due to come into effect until winter 15/16 at the earliest. We have used a model run of the full EBSCR in 2015 as a proxy for 2016.

⁷⁶ Which could potentially lead to knock-on savings through reduced amounts of New Balancing Services purchased by National Grid.

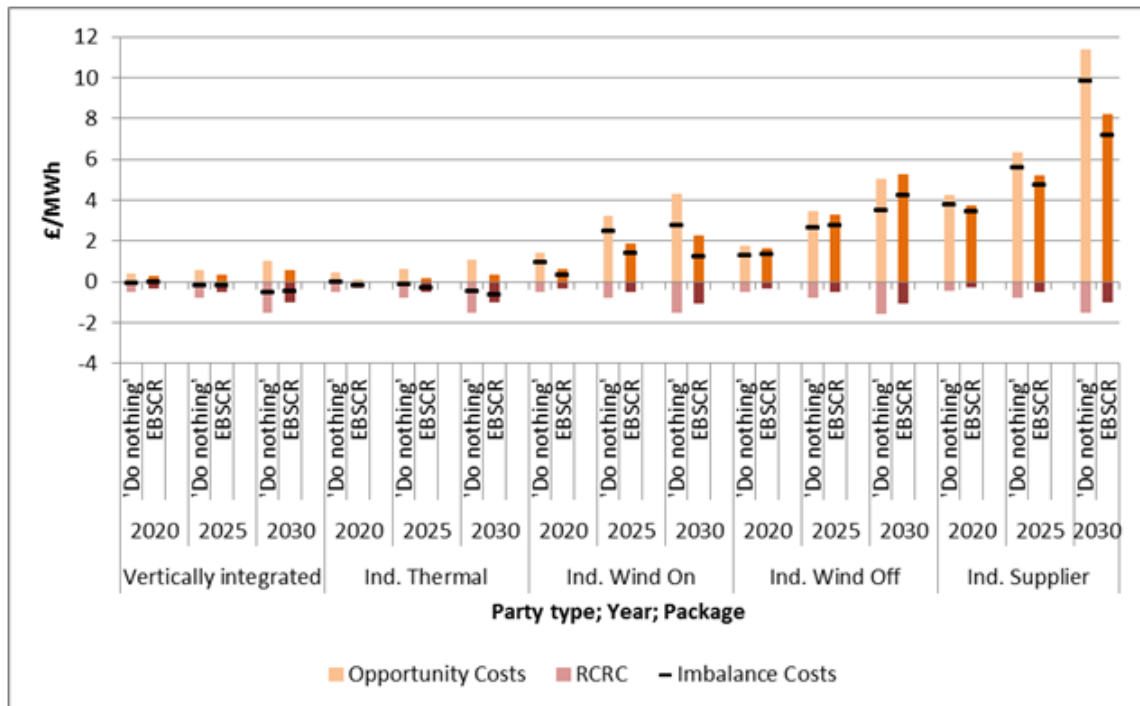
CM introduction in 2018, our model suggests consumer bills will go down as a result of EBSCR, with savings estimated to be around £1.30 per annum by 2030.

Competition, distributional impacts and operational risk

4.21. Our model does not account for dynamic competitive improvements. However we commissioned **detailed analysis of distributional impacts at the party level** in response to stakeholder concerns that sharpened cash-out prices might disadvantage small suppliers and wind parties to the greatest extent, owing to the fact that historically, they incur high imbalance volumes (as a proportion of total credited energy). Modelling results suggest inclusion of single pricing counteracts these effects to the extent that **we expect reforms to lower net costs of imbalance for smaller parties, and have a broadly neutral impact on wind**⁷⁷.

4.22. Furthermore, our analysis presents evidence that **EBSCR does not introduce disproportionate risk for parties** in terms of Imbalance Costs⁷⁸ and credit requirements volatility. Again, this finding is mainly attributable to the reform to single pricing, which allows parties with reducing imbalances to benefit from a more favourable (cost-reflective) cash-out price. See Figure 5.

Figure 5: Expected Opportunity Costs, RCRC and Imbalance Costs per credited energy unit (2020, 2025 and 2030) under 'Do nothing' and EBSCR, by party type



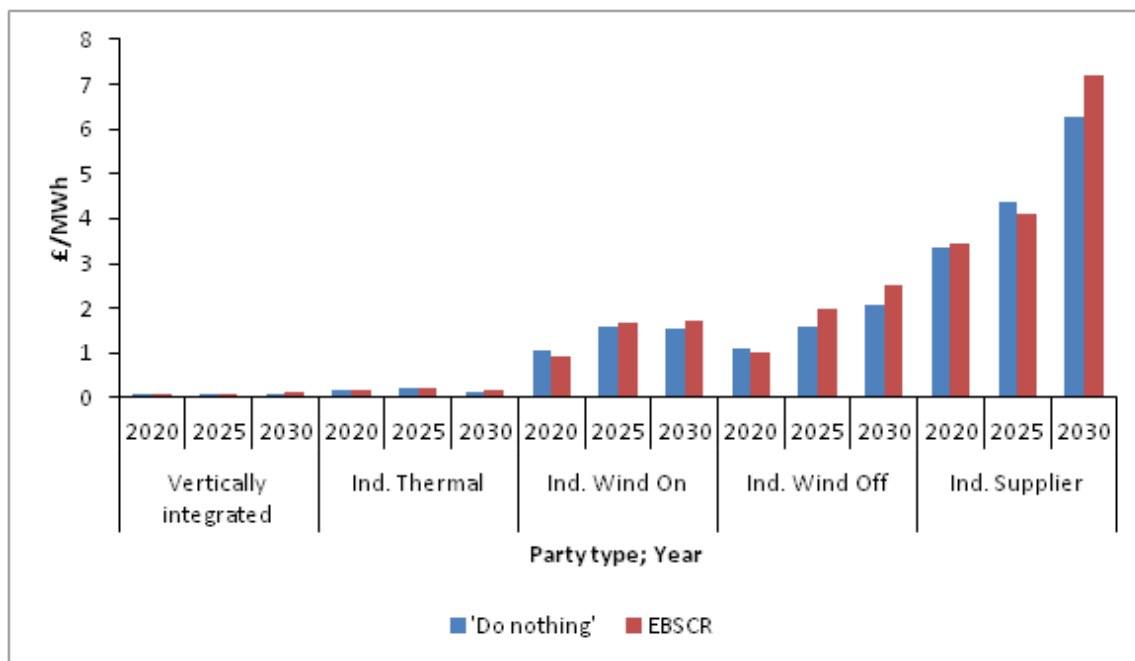
⁷⁷ Indeed the sum of the combined effect on onshore and offshore wind is positive. This result does take into account the correlation between different wind parties.

⁷⁸ We define Imbalance Charges as Opportunity Costs (the amount a party pays for being out of balance, relative to their payments had traded out their position intraday) plus Residual Cashflow Reallocation Cashflow (RCRC).

4.23. Figure 5 shows that for all parties in 2020, 2025 and 2030, Imbalance Charges are lower as a result of EBSCR reforms – most notably onshore wind and independent suppliers – with the exception of vertically integrated and offshore wind, which display a modest increase in Imbalance Charges.

4.24. Figure 6, which shows the expected volatility of credit requirements⁷⁹ by party type, re-enforces the positive message in relation to distributional impacts and operational risk – EBSCR does not cause a significant ‘step-up’ in risk. This effect is chiefly attributable to the introduction of a single price, more benign margins as a result of the CM, and expected behaviour change in response to reforms.

Figure 6: Expected volatility of credit requirements in 2020, 2025 and 2030, under ‘Do nothing’ and EBSCR for different party types



4.25. To assess the potential impact of extreme events, we undertook a severe exposure analysis, looking at a set of repeatedly severe events. This simulated the hypothetical imbalance charges that a given party⁸⁰ would have incurred if the cash-out price was equal to £6,000/MWh in the Settlement Period when that party was shortest from 2010 to 2012, and the subsequent three settlement periods⁸¹. We then added three additional two hour periods before or after this event where the cash-out price was £500/MWh, and the party in question was as short as was the case during the disconnection event. We then compared the sum of these imbalance

⁷⁹ This measures the standard deviation (a measure of the dispersion of data points from the average) of the amount of credit that parties need to post to avoid triggering Exelon’s (Level 1) Credit Default process. See the accompanying Impact Assessment for more detail.

⁸⁰ We looked at imbalance charges for all market parties during 2010-2012.

⁸¹ We assumed the disconnection event persisted for two hours, as this is the amount of time that has to elapse before a party can react to cash-out prices.

charges to annual revenues⁸². For nearly all parties, the value would have been less than 1%⁸³. In view of this, and given the very low probability of these stylised 'severe exposure' events (ie, a party being at their extreme shortest during all 16 settlement periods in question) as well as the steps parties can take to reduce risk we conclude it is very unlikely our reforms will place unmanageable risks on parties.

4.26. We did not simulate a larger number of repeated severe events in this analysis as the more events simulated the less likely it becomes that each event coincides with the party's worst imbalance position. Indeed, it is likely the party would find itself with some reducing imbalances, which would reduce the party's imbalance exposure and lessen the impact of this simulated severe scenario.

4.27. Our conclusions on risk are re-enforced by the additional measures we have put in place to limit any remaining risk from our EBSCR reforms, listed below.

- The introduction of more marginal pricing will be phased. Indicative imbalance prices based on different PAR levels will be published by Elexon as well.
- Indicative Loss of Load Probabilities (LoLPs) will be provided to the market ahead of Gate Closure. This signal to the market helps parties anticipate stress events.
- The LoLP used to determine the RSP price in a given settlement period will be calculated at Gate Closure, rather than at the beginning of that Settlement Period, assisting parties in anticipating high cash-out prices.
- The value of VoLL will increase to £6,000/MWh in two steps, starting with £3,000/MWh in 2014/15 and raising to £6,000/MWh only by winter 2018/19, allowing parties time to adapt to this policy. £6,000/MWh represents a relatively low VoLL figure compared to the range that was suggested by the VoLL study⁸⁴.
- We leave the option for industry to consider whether automatic low frequency demand disconnection should be priced in cash-out.

4.28. Finally, we note the stepped nature of the implementation of our Decision allows time for industry adjustments and for behaviour change at the individual company level. Should residual concerns about risk remain – in particular as they pertain to smaller parties – we would encourage industry to consider changes to the current rules, for example around credit requirements, via a separate BSC mod proposal.

⁸² We compared imbalance charges with revenues for parties where data was available. For independent suppliers, we estimated revenues by looking at customer bill and customer number data. For larger firms with more than one Party ID, and where the constituent parties where shortest in different years, we calculated annual revenue as the average of revenue in the relevant years.

⁸³ The figure would not have been higher than 2.5% for any party.

⁸⁴ See The Value of Lost Load (VoLL) for Electricity in Great Britain, Final report for OFGEM and DECC, by London Economics, July 2013 at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricity_gb.pdf .

5. Interactions

In this chapter we explore links between the EBSCR and other key on-going energy market developments. This reflects our close engagement with other project teams – both within Ofgem and more widely (for instance with DECC). Our joined-up and open approach has allowed other projects to feed into our thinking as well as for our work to influence development of other policy proposals, ensuring our Final Policy Decision is consistent within the wider policy context.

EMR Capacity Market

5.1. Cash-out arrangements and the CM have distinct but complementary roles in ensuring security of supply. The CM is intended to address longer term capacity adequacy by providing capacity providers with a secure revenue stream. Penalties for non-delivery in the Capacity Market will also provide incentives for flexibility. Cash-out reform complements this by providing stronger, efficient signals of the value of flexibility, helping the type of capacity coming forward to respond to increasing amounts of intermittent generation on the system.

5.2. We commissioned a study⁸⁵ jointly with DECC to determine the value of lost load (VoLL – the value consumers place on uninterrupted supplies). We draw from this in our reform of the cash-out arrangements to set the price at which disconnections and voltage reduction are priced in cash-out as well as an input to our RSP function. DECC draw from this in setting its Reliability Standard and, together with the cost of new plant, to estimate the optimal level of security of supply⁸⁶.

5.3. Our EBSCR reforms have the potential to lower the CM clearing price, as parties can expect higher energy market revenues at times of system stress, reducing 'missing money' and therefore reducing the amount required through the CM. Baringa explored this effect in its modelling, together with the negative effect of higher wholesale prices. The modelling suggests the net effect is positive for consumers⁸⁷. We note this effect depends strongly on the assumed correlation between cash-out prices and wholesale prices, as well as on the assumption which plant is likely to be the marginal plant in the CM.

New Balancing Services

5.4. The recently-approved New Balancing Services⁸⁸ (Demand Side Balancing Reserve and Supplemental Balancing Reserve) provide an additional tool to help

⁸⁵ See <https://www.ofgem.gov.uk/ofgem-publications/40961/london-economics-estimating-value-lost-load-final-report-ofgem.pdf>.

⁸⁶ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf.

⁸⁷ This is because the CM auction is pay-as-clear, rewarding all plant with CM payments of the marginal plant in the auction, which is likely to be a gas-fired power station. Gas-fired power stations are among the main beneficiaries of EBSCR as they are flexible and most able to capture additional wholesale market revenues, hence reducing the CM clearing price.

⁸⁸ See <http://www.nationalgrid.com/uk/electricity/additionalmeasures>.

NGET to balance the system given short-term security of supply uncertainty. The EBSCR on the other hand addresses some of the underlying problems that led to greater security of supply concerns. The pricing of the new balancing services in cash-out is out of the EBSCR's scope and will be considered through a separate mod proposal. There are a number of options how the new balancing services could be priced, including pricing them at the level of VoLL, at their utilisation fee or similar to reserve. We encourage industry to consider these options ahead of this winter and are working with National Grid to support a prompt and consistent pricing approach.

Settlement reform and smart meter roll-out

5.5. BSC Modification Proposal 272 proposes to mandate half-hourly (HH) settlement for larger non-domestic consumers. The (distinct but complementary) electricity settlement project under Ofgem's Smarter Markets Programme is assessing options for settling domestic and smaller non-domestic consumers against their HH consumption data. This will place stronger incentives on suppliers to encourage voluntary DSR, and complements the DSR-supporting effect of EBSCR.

5.6. The EBSCR's initial proposal to pay consumers for disconnections would have applied to NHH consumers only. Should Ofgem decide to move all consumers to be settled against their HH consumption data this group would shrink considerably in the long-term. As a consequence, the effect of the EBSCR's initial policy proposal to introduce consumer payments for disconnections would have been limited to the short to medium term only. The temporary nature of such a payment further supports our decision – together with high estimated up-front implementation costs – for not taking forward the payments policy proposal at this time.

Gas SCR

5.7. Gas plays an important role in electricity generation. Gas-fired plants generate around 30-50 per cent of GB electricity and provide an important source of flexible electricity. Ofgem's SCR reforms⁸⁹ of the gas cash-out mechanism aim to sharpen incentives on gas shippers to enhance security of gas supply. These reforms include the introduction of VoLL pricing for the provision of involuntary DSR services (if firm non-daily metered customers are interrupted) in the gas cash-out arrangements.

5.8. The Gas SCR has taken forward a proposal for payments to gas consumers when they are taken off supply. Our decision in electricity is that consumers should not be paid for disconnections. In this context we note the reasons for the differences in our approach to electricity and gas.

- First, consumer payments are not important in providing efficient cash-out signals in electricity, but are important in the case of gas. The main reason for this is that surplus funds from cash-out that are smeared back to industry (and could dampen incentives) are much smaller for electricity than for gas – for the following reasons: (i) the amount of money that is recovered from

⁸⁹ For further information: <https://www.ofgem.gov.uk/gas/wholesale-market/market-efficiency-review-and-reform/gas-significant-code-review>.

short suppliers/generators during a disconnection is lower for electricity than for gas owing to the shorter length of time for electricity disconnections (eg, 30-60 min vs days or weeks in gas where non-daily metered customers are reconnected manually); (ii) our proposal to introduce single pricing in electricity (dual pricing in gas) allows for more favourable price for parties with imbalances in opposite direction to the system, reducing the total funds smeared back.

- Second, for electricity up-front implementation costs (estimated at over £6m) are likely much greater than the sums that would be redistributed to consumers (around £2m in an event like 2008⁹⁰). This owes to the likely relatively low payments in event of disconnection in electricity compared to gas (say £2.50 vs £30) as a result of shorter disconnection periods. In the event that more/longer disconnections occur in electricity, the rota system for disconnection (not present in gas) would assist with distributional fairness.
- Third, payments would likely be a more transitory measure for electricity than for gas, as smart meters have greater scope in the case of electricity in facilitating uptake of DSR, and particularly load-shifting, (around 2020+).

5.9. Gas plays an important role in the electricity market and the Ofgem EBSCR and Gas SCR teams have worked closely together to ensure cash-out policy proposals provide appropriate incentives and price signals. We have also worked with DECC to ensure consistency with developments related to the CM. Central to policy development is the role for market parties to determine their own response to arrangements and actions they may take to mitigate risks. The proposals under Gas SCR⁹¹ and EBSCR in themselves are expected to reduce the likelihood of interruptions in both the gas and electricity markets. However, in the unlikely scenario of a joint gas-electricity emergency, gas plant have a number of options available to manage risks that may arise from such a scenario, including trading in the OCM and the Post Emergency Claims process.

EU Target Model (EU TM)

5.10. The EU TM seeks to integrate European electricity markets. As part of this, European Network Codes are being developed which provide for consistency in balancing and constraint management across member states. Implementation of the European target model may require further changes to GB balancing arrangements. We have therefore been mindful of the interactions between the emerging EU TM and the EBSCR policy considerations. These interactions helped govern our decision to reduce the scope of the EBSCR and to launch the FTA forum. The team has worked closely with colleagues involved in European policy development to ensure EBSCR reforms do not conflict with the EU TM's direction.

⁹⁰ For simplicity we used a number of estimations, such as 580,000 customers eligible for payment (based on the figures reported by National Grid – noting the caveat that not all of these consumers may have been eligible for payment).

⁹¹ See <https://www.ofgem.gov.uk/ofgem-publications/85992/140212gasscrfpd.pdf>.

Future Trading Arrangements (FTA)

5.11. In May 2013 Ofgem formally launched the FTA Forum. The Forum's objective is to seek views on creating a coherent and consistent approach to wholesale electricity trading, in the context of EMR, EU TM, market and technological developments. Developing the FTA Forum was driven by our decision to reduce the scope of the EBSCR in February 2013 in response to stakeholder feedback to our initial consultation. The Forum's scope included some of the longer-term considerations around balancing arrangements and allowed the EBSCR to focus on the more immediate issues with cash-out price signals.

Liquidity reforms

5.12. Ofgem's liquidity reforms⁹² ('Secure and Promote' licence condition) remove barriers to competition in wholesale energy markets. They improve access to the wholesale electricity market by requiring the eight largest electricity generating companies to follow 'Supplier Market Access' rules when trading with small independent suppliers. They ensure the market provides products and price signals needed to compete effectively through a market-making obligation on the six largest vertically integrated energy supply companies.

5.13. There is limited direct interaction between the EBSCR and liquidity project. Our liquidity reforms focus on longer-term forward markets. While effects of the EBSCR's single price reform on liquidity are uncertain⁹³, we note EBSCR proposals could have a positive impact on wholesale market liquidity in the near-term, and thereby complement liquidity reforms. In particular EBSCR reforms which sharpen cash-out prices as a signal of scarcity could improve liquidity as incentives to trade ahead of Gate Closure become sharper, particularly during system stress.

Consultation on a Market Investigation Reference

5.14. There is limited interaction between EBSCR and the consultation on a Market Investigation Reference (MIR)⁹⁴. In our view, a potential MIR and subsequent market investigation by the Competition and Markets Authority (CMA) is unlikely to address the same issues as the EBSCR. The strength of the case for EBSCR reform to ensure cost-reflective signals that support efficiency in balancing and security of supply is not contingent on the outcome of an MIR. Removing distortions that dampen cash-out price signals and incentives for investment in flexible capacity is desirable whatever the outcome of the MIR consultation and any CMA market investigation which could follow. We will keep this issue and any other interactions under review.

⁹² See <https://www.ofgem.gov.uk/ofgem-publications/84508/wholesalepowermarketliquiditystatutoryconsultationonthesecureandpromotelicencecondition.pdf>

⁹³ Some stakeholders have suggested single pricing may lessen the opportunity cost of not trading, while others have suggested it could encourage development of a more robust market reference price and related products that could be more widely traded.

⁹⁴ See Ofgem's "Consultation on a proposal to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain" March 2014 <https://www.ofgem.gov.uk/ofgem-publications/86807/consultationpublish.pdf>

Appendices

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Appendix 1 – Summary of responses to Draft Policy Decision consultation

1.1. Responses to our Draft Policy Decision consultation were broadly positive⁹⁵. Most stakeholders were in favour of moving to a more marginal main cash-out price. A number of respondents requested a phased implementation, to allow parties to adapt to the changes. A number of stakeholders agreed with our rationale for moving to PAR1 rather than PAR50. Concerns with marginal prices as expressed by respondents related in particular to imbalance risk or other risks such as system pollution. A number of stakeholders requested further analysis of possible impacts of our proposals on imbalance costs and risk.

1.2. Most stakeholders were in favour of attributing a cost to non-costed actions in principle. However, a number of respondents argued that this proposal may be difficult to implement, and requested further detail on how this would work in practice. Several stakeholders also raised concerns around the proposals to pay consumers and suppliers for disconnections. More specifically, it was emphasised that the consumer payments policy could result in reputation risk for suppliers, and the benefits of such a policy may be outweighed by the implementation costs, given the likely infrequency of Demand Control actions going forward.

1.3. Several stakeholders voiced support for changing the way reserve is costed in cash-out. There was no consensus however that the use of the proposed RSP function would be the most appropriate way of allocating these costs. A common theme throughout the responses was further detail around the policy would help stakeholders assess this.

1.4. Finally, there was widespread support for the introduction of a single cash-out price – stakeholders noted the policy would benefit relatively small parties. Some parties requested that very marginal prices only be introduced in the presence – or with introduction – of a single price.

⁹⁵ Stakeholder responses can be viewed here: <https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-draft-policy-decision> .

Appendix 2 – Implications of introducing a VoLL Price

VoLL as a cap on bids and offers or on cash-out

1.5. We have made the case that Demand Control actions should be treated similarly to other balancing actions – including that their volumes should be incorporated in the stack for calculating cash-out prices, and a price should be attributed to them (in this case VoLL).

1.6. Introducing a price for Demand Control raises the question of whether VoLL should present a cap on bids and offers in the BM or on the cash-out price.

1.7. From a theoretical view, any bids above VoLL could be considered as not economically efficient as a 'true' VoLL would represent the level above which consumers are not willing to pay for electricity. Theoretically, allowing prices to rise to this 'true' VoLL should incentivise the most efficient level of security of supply.

1.8. However, in practice there are two reasons why it would not be appropriate to use VoLL as a cap on BM offers or cash-out prices.

- We have determined VoLL administratively (starting at £3,000/MWh and set to raise to £6000/MWh by early winter 2018/19). This administrative VoLL is lower than the average domestic VoLL, average weighted SME and domestic VoLL and marginal SME VoLL according to the study we commissioned from London Economics, and therefore would not represent an appropriate cap.
- Price manipulation is less of a concern under a pay-as-bid BM and we are not aware of any evidence that suggests there is a need for capping prices in the BM to avoid manipulation. Furthermore, we consider that VoLL pricing will not act as a target price in the BM (due to pay-as-bid and other factors that impact on pricing into the BM), and that not introducing a cap helps to keep this risk low.

1.9. We therefore do not see a case for VoLL to act as a cap at this time.

Impacts of VoLL on system operation

1.10. We note that the way the SO balances the system, including the way it chooses balancing actions (such as through the merit order) remains unchanged by our changes to cash-out arrangements. This includes actions the SO may take above the level of VoLL.



VoLL as a reliability standard

1.11. A number of stakeholders asked whether the pricing of VoLL into cash-out presents a reliability standard. We do not consider VoLL to act as a reliability standard in cash-out. VoLL pricing simply aims to attribute a cost to actions that are currently uncoded. We note that DECC has established a reliability standard as part of the CM.

Appendix 3 – Treatment of automatic Low Frequency Demand Disconnection

1.12. Industry may wish to consider whether Demand Control achieved through automatic Low Frequency Demand Disconnection (LFDD) can and should be incorporated into cash-out. This could be considered as part of the regular review of the System Management Action Flagging Methodology, ie considering whether LFDD should be SO-flagged and classified as a 'system' action for the purposes of cash-out calculation.

1.13. In this respect we propose the following considerations.

1.14. The method of activation of automatic LFDD (not being manually instructed by the SO) should not necessarily mean that those parties whose imbalance positions contributed to that of the system should be exempted from facing the cost they impose on consumers through demand disconnection.

1.15. In assessing whether it is appropriate to classify LFDD relays as 'system' actions to be excluded from the cash-out price, industry should consider whether or not the positive impact on consumer welfare may be expected to outweigh the expected administrative burden (adjusted for probability of occurrence) of new processes or capabilities required for costing LFDD in cash-out, ultimately borne by the consumer.

1.16. Should industry decide that LFDD should feed in to the cash-out price, this should be treated consistently with other balancing actions. Thus if parties are to face these costs in cash-out this should be subject to normal flagging and tagging rules (including CADL), and the same VoLL should be applied as for other priced Demand Control actions.

Appendix 4 - Glossary

1.17. This section presents a glossary of terms used in this document.

A

[Automatic Low Frequency Demand Disconnection \(automatic LFDD\)](#)

The disconnection of users or customers that automatically operates when the frequency reaches the relay settings by fall in frequency (as described in Section OC6.6 of the Grid Code).

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 Reporting Service \(BMRS\) 15-minute run](#)

A run carried out by the Balancing Mechanism Reporting Agent (BMRA) by Continuous Acceptance Duration Limit plus 15 minutes. Operationally this is approximately 15 minutes after the end of the Settlement Period and produces indicative system prices that are published on the BMRS.

[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 (CM)

Detailed designs proposals for the CM 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.

Continuous Acceptance Duration Limit (CADL)

The CADL defines the minimum length for an acceptance to be included in the imbalance price calculation. It is designed to exclude short duration acceptances which are likely to be issued for system balancing purposes. CADL has been set at 15 minutes since being introduced in 2001.

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.

Grid Supply Point (GSP)

A point at which the Transmission System is connected to a Distribution System.

I

Imbalance

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

Imbalance Costs (ICs)

Imbalance Costs (ICs) can be used to assess how much parties have to pay through cash-out. They are calculated as Opportunity Costs (the amount a party pays for

being out of balance, relative to their payments had traded out their position intraday) plus RCRC.

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.

L

Licensed Distribution System Operator (LDSO)

A licensed business that is responsible for one of 14 regional distribution services areas.

Loss of Load Probability (LoLP)

A measure of reliability indicating the probability that there will be insufficient generating supply to meet electricity demand over a given period.

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.

Market Investigation Reference (MIR)

The process by which markets are referred to the Competition and Markets Authority (CMA) for investigation, which may be used if there are reasonable grounds for suspecting that any feature, or combination of features, of a market is preventing, restricting, or distorting competition.

Meter Point Administration Number (MPAN)

The unique identifier that defines a consumer's point of connection to the distribution network.

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 ('mod')

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 GB, with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits.

Non-Half-Hourly (NHH) Meter

A SVA Meter which provides measurements which aren't on a half hourly basis for Settlement purposes.

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 for Response

As part of its licence obligations, NGET holds frequency response in order to mitigate the risk that a single large unit failure causes widespread disconnections. This response holding is made up (in part) of de-loaded generation in frequency response mode. The total amount of de-loaded capacity is referred to as 'reserve for response'. In accordance with NGET's licence obligations, measures must be taken to ensure that the response holding is maintained.

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 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 5 - Feedback Questionnaire

1.18. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about how our consultations as part of the EBSCR have been conducted. We are also keen to get your answers to the following questions.

1. Do you have any comments about the overall process adopted for our consultations?
2. Do you have any comments about the overall tone and content of our documents?
3. Where our documents easy to read and understand, could they have been better written?
4. To what extent did our document's conclusions provide a balanced view?
5. To what extent did the document make reasoned recommendations for improvement?
6. Please add any further comments.

Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk