

Electricity Balancing Significant Code Review (SCR) – Initial Consultation

Consultation

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Contact: Andreas Flamm / Jamie Black
Team: Wholesale Markets
Tel: 0207 901 7000
Email: gb.markets@ofgem.gov.uk

Overview:

Supply and demand on the system need to be kept in balance at all times. Imbalance pricing or “cash-out” provides market participants with incentives to match their own system input and offtake in real time through contracts or physical production. Cash-out prices should also reflect scarcity on the system and provide a signal to participants to invest in additional capacity if the system is tightening.

The current balancing arrangements are not working as well as they could. Various features dampen balancing and investment incentives and undermine the role of cash-out in providing security of supply. Moreover, inefficiencies in the arrangements potentially increase balancing costs and therefore consumer bills.

We are launching a review to consider ways to improve the balancing arrangements and their contribution to delivering an efficient level of security of supply. This review also allows us to assess whether changes are needed to make the balancing arrangements robust to changes in the generation mix and to implement the European Electricity Target Model.

This document sets out, for consultation, our initial thoughts on the policy considerations in scope of this review.

Context

Ofgem set out concerns with the balancing arrangements in the 2004 and 2007 cash-out reviews and in Project Discovery in 2010. We published a cash-out issues paper in November 2011. In response, stakeholders largely supported our proposal to review the codes that govern the electricity balancing arrangements. In March 2012 we published our intention to launch an electricity cash-out Significant Code Review (SCR). This document represents the first step in this SCR. Given that elements of the scope are wider than the immediate cash-out arrangements, we have decided to launch the review as the Electricity *Balancing* SCR.

The SCR process was designed to allow Ofgem to lead a wide-ranging review of significant issues in the codes. SCRs can result in changes to industry codes and licences. Alongside this initial consultation, we have published a launch statement and preliminary analysis of the most recent modification to the cash-out arrangements (P217A).

We launch the SCR at a time when the European Electricity Target Model is being developed and the UK Government is designing a capacity mechanism for the electricity market. We will ensure consistency by working closely with EU regulators, the European Commission and the UK Government.

This initial consultation aims to inform stakeholders of our decisions on the scope of the SCR and set out our initial thoughts on the policy considerations. We seek stakeholders' views on all policy considerations and the questions we have asked.

Associated documents

Electricity cash-out issues paper (Reference number: 143/11):

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=148&refer=Markets/WhIMkts/CompandEff/CashoutRev>

Open letter: Ofgem decision to launch a Significant Code Review (SCR) of the electricity cash-out arrangements:

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=174&refer=Markets/WhIMkts/CompandEff/CashoutRev>

Code Governance Review – Final Proposals (Reference number: 43/10):

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=297&refer=Licensing/IndCodes/CGR>

P217A Preliminary Analysis (Reference number: XYZ/12):

<http://www.ofgem.gov.uk/Markets/WhIMkts/CompandEff/electricity-balancing-scr/Documents1/P217A%20Preliminary%20Analysis.pdf>

Electricity balancing SCR Launch Statement:

<http://www.ofgem.gov.uk/Markets/WhIMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20Launch%20Statement.pdf>

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Executive Summary

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

Last November we made a case for considering reform of the cash-out arrangements. In our issues paper we noted that a review would also provide an opportunity to consider whether reforms are needed to accommodate the changing generation mix, take better advantage of the role of demand side participation in balancing and to implement the European Electricity Target Model (TM). The TM legislation, aimed at creating a single European electricity market, is expected to enter into force in 2014.

Many stakeholders agreed that there are issues with the balancing arrangements worth investigating. However, views on the timing of a review and the relative importance of issues were mixed. In particular, there were concerns that our reforms may have strong interactions with the capacity mechanism (CM) that the Department of Energy and Climate Change (DECC) is designing as part of its Electricity Market Reform (EMR). Stakeholders were also concerned that any reforms we introduce as a result of this review may need to be revisited post-2014 to implement the TM, adding unnecessarily to the systems and other costs associated with reform.

After careful consideration of these issues, we have decided to go ahead with a review. We have significant concerns with the balancing arrangements and there are significant developments in the industry which might require changes to the arrangements. It would not be prudent to delay a review until EMR is implemented and the TM is finalised. However, we recognise the risks that stakeholders have pointed out and will look to manage them as we conduct our review.

We note that cash-out and the CM have distinct but complementary roles in providing electricity security of supply. We will continue to work closely with DECC to ensure these policies are compatible. In our policy design and before implementing any balancing reforms, we will consider the impact on the effectiveness of the CM carefully.

Throughout our review we will aim to ensure that any changes to the balancing arrangements are compliant with the developing TM. We will also consider carefully the appropriate timing of implementing reform to avoid unnecessary additional costs from repeated market changes. While we are alive to the risks associated with conducting this review while the TM is being developed, conducting a review at this time provides an opportunity for us to start implementing features of the TM in GB markets and improves our ability to provide input to the development of the TM.

We will use the Significant Code Review (SCR) process to conduct this review. The SCR process allows us to undertake a comprehensive review of the suite of codes and licence conditions which govern the current balancing arrangements. Code modifications to date have brought about incremental improvements to the arrangements but the SCR process enables us to introduce more comprehensive reforms if they are needed.

Our objectives in this electricity balancing SCR (“the SCR”) are to:

- incentivise an efficient level of security of supply
- increase the efficiency of electricity balancing
- ensure our balancing arrangements are compliant with the TM and complement the EMR CM.

We propose to consider a broad range of policy options within the scope of this review. With the aim of improving balancing and security of supply incentives, we will consider whether we should use the System Operator’s (SO) more expensive actions to set the cash-out price. We will also consider more accurate allocation of the SO’s costs and inclusion of actions that do not currently affect the price. This could include attributing a cost to actions such as involuntary demand interruptions.

To reduce system balancing costs, we propose to consider the case for moving from dual to a single cash-out price; moving from pay-as-bid to pay-as-clear in the balancing mechanism; and introducing single trading accounts. We will assess whether these changes could reduce distortions and risk, encourage the use of demand side response in system balancing and help participants to better manage their positions.

We propose to investigate more fundamental changes. For example, we will consider a balancing energy market (BEM) to help participants and the SO balance their positions and the system more widely close to real time. We will also consider whether alternative arrangements for renewable electricity would be beneficial for balancing intermittent output.

To ensure consistency between policy considerations, and to make them manageable, we plan to group the potential reforms into packages. These packages range from more mechanistic to more market-based approaches to system balancing. We will assess any proposed reform package against our statutory duties, principal objective and the objectives set out above and elsewhere in this document.

This document accompanies the launch statement for the SCR and the publication of our preliminary analysis of Balancing and Settlement Code (BSC) modification P217A. Through this initial consultation we seek to:

- inform stakeholders of our objectives and decision on scope for the SCR, which we also set out in the launch statement
- set out our initial thoughts on the policy considerations in scope
- ask stakeholders for input and responses to the various policy considerations presented and the questions we have raised.

We are consulting on this publication for 12 weeks during which we will also hold stakeholder events. These events will consider the merits of the potential reform options under consideration. After considering responses to this consultation we intend to publish our draft policy decision in spring 2013. We note that the subject of this review is complex and the scope is broad. We expect to conclude the SCR by early 2014.

1. Objectives and scope

Reasons for the review

1.1. The conclusions of our investigation of GB electricity security of supply, Project Discovery¹, identified issues with the balancing arrangements. In particular, Project Discovery highlighted that dampened and inaccurate prices may provide insufficient incentives to invest and thus lead to insufficient electricity security of supply. Project Discovery suggested that making cash-out prices more marginal could strengthen price signals and making the allocation of reserve costs more reflective of system tightness could improve balancing incentives.

1.2. We believe that failing to consider potential reform to the existing balancing arrangements could harm future electricity security of supply and could unnecessarily increase costs of system balancing.

1.3. We need to ensure that the existing cash-out arrangements remain fit for purpose in light of some large challenges. We need to replace ageing fossil fuel plant with a new generating fleet and integrate an increasing proportion of intermittent renewables into the system. The roll-out of smart and advanced meters and other new technologies creates new opportunities for demand side participation in balancing arrangements. This could help manage intermittency and keep costs down.

1.4. The electricity cash-out issues paper set out our concerns with the current cash-out arrangements. Our key concerns are:

- cash-out prices may not fully reflect scarcity at times of system stress
- cash-out prices may not provide the right incentives for demand side response (DSR)
- cash-out prices suffer from a lack of transparency and predictability
- dual cash-out prices have a large spread, resulting in imbalance risk and hampering the formation of reference prices
- participants are not incentivised to provide accurate physical notifications
- reconciliation cashflows are large and opaque, potentially causing inefficient allocation of costs participants.

1.5. The Electricity Balancing Significant Code Review (“the SCR”) will consider whether these concerns can be addressed through potential reforms of the balancing arrangements, as outlined in chapters 4 and 5.

¹ ‘Project Discovery - Options for delivering secure and sustainable energy supplies’ was published in February 2010. The published document can be found here: <http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Pages/ProjectDiscovery.aspx>

1.6. Conducting a review of electricity balancing now will help us to input into further developments at EU level and consider how to implement the target model (TM) in GB. We note that for some considerations that we have included within the scope of the SCR, regular consistency checks will be needed as both the EU target model and SCR work develop, to ensure we avoid the need for double changes. This could involve, for example, placing certain aspects of our scope onto a slower track.

1.7. Reviewing the electricity balancing arrangements now allows changes to complement the Electricity Market Reform (EMR) capacity mechanism's (CM's) aligned objective of improving security of supply. The SCR allows us to consider whether reform is needed to make the balancing arrangements robust to likely changes to generation mix. More information on interactions with other policy initiatives is set out in the 'wider context' section in chapter 3.

Objectives

1.8. We have reviewed our objectives for the SCR and have identified three high-level objectives and a range of supporting objectives. They are complementary to Ofgem's principal objective and statutory duties. Our objectives for the SCR are:

Incentivise an efficient level of security of supply

- incentivise optimal level of investment (through appropriate price signals)
- pay firm customers appropriately for the DSR service they provide if their demand is involuntary interrupted (to reflect the value they place on security of supply)
- incentivise plant flexibility and DSR

Increase the efficiency of electricity balancing

- Minimise market distortions due to the need for the system operator (SO) to balance the system
- Incentivise participants to balance their position as far as is efficient
- Appropriately reflect the SO's costs for balancing in cash-out prices

Ensure our balancing arrangements are compliant with the TM and complement the EMR CM

- Align GB balancing arrangements with EU balancing and capacity allocation and congestion management framework guidelines
- Work closely with the Department of Energy and Climate Change (DECC) to ensure cash-out arrangements and the EMR CM complement each other.

Stakeholder feedback and our response

Feedback we have received

1.9. We consulted stakeholders regarding the launch of an electricity cash-out SCR. Our November 2011 electricity cash-out issues paper² sought participants' views on whether we should conduct an SCR of the cash-out arrangements, and what the scope and timing of any SCR should be. We have since published an open letter in March 2012 signalling our intention to proceed with the SCR. We held a stakeholder event on 30 April 2012, in conjunction with a workshop on implementing the TM.

1.10. Most respondents to the issues paper agreed that there were issues with the cash-out arrangements, but there was a wide range of views expressed as to what these issues were. Other respondents felt that they did not have sufficient information to comment on whether change was needed.

1.11. Feedback to the issues paper and at the stakeholder event highlighted the interactions that an SCR would have with the Government's work on EMR, the development of the TM, and Ofgem's ongoing liquidity work. Stakeholders noted the importance of considering the compatibility of options for reform with wider market changes. Many stakeholders also felt that the timing of an SCR could be aligned with ongoing projects. All public responses can be found on our website³.

1.12. A range of points and a number of questions were raised in relation to scope and approach of the SCR; however stakeholders broadly accepted the proposed scope.

Our response

1.13. The diverse range of perspectives on the scope for an SCR supports the case for launching the SCR with a wide scope. We agree with stakeholders who, at our 30 April 2012 event, suggested that the scope of the SCR incorporates wider elements of the balancing arrangements than exclusively cash-out arrangements.

1.14. We agree with suggestions that it is important to consider the compliance of any potential design choices made as a result of the SCR with wider market developments, particularly the TM and EMR. We will keep developments in the TM and EMR under close consideration throughout the SCR process. Running the SCR in parallel with other developments gives us the opportunity to begin to introduce some of the TM features to the GB market. It also enables us to influence further TM

²<http://www.ofgem.gov.uk/Markets/WhIMkts/CompandEff/CashoutRev/Documents1/Electricity%20cash-out%20issues%20paper.pdf>

³<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=148&refer=Markets/WhIMkts/CompandEff/CashoutRev>

developments effectively. At the same time we will need to ensure that any proposals we make are consistent with ongoing TM developments and that we avoid reforms that may later need to be undone. We will further address these interactions in the wider context section in chapter 2.

1.15. Following consideration of the stakeholder input received we have concluded on the scope as set out in the launch statement and this consultation document. We do not envisage the need to change the scope at this stage. However, we will take a flexible approach to the review. If the direction of our thinking or the development in the TM makes it sensible to adjust the scope we may consider this in consultation with industry.

Scope

1.16. We have divided the policy considerations into primary and secondary considerations. We will focus on the primary considerations and address the secondary considerations depending on the potential design choices we have made in the primary considerations. Within primary considerations we distinguish between reforms of the existing balancing arrangements (considerations 1-4), improvements to price inputs (considerations 5+6) and new balancing arrangements (7+8). We believe improvements to price inputs could be made independently from other policy considerations.

Primary considerations

1.17. **Consideration 1:** We will consider whether cash-out prices should be 'more marginal'. Current cash-out prices are calculated by averaging a number of most expensive trades made by the SO to balance demand and supply. We could base the calculation on a smaller volume of trades.

1.18. **Consideration 2:** Currently parties who produce or buy more than they need to receive less than the charge for those who produce or buy less than needed. The payment and the charge could be made the same.

1.19. **Consideration 3:** We will consider allowing parties with both generation and supply businesses to net their opposite balances from the two trading accounts. Currently they must balance both their generation and supply sides separately.

1.20. **Consideration 4:** Parties who submit bids and offers to help the SO balance the system are currently paid the price they have bid. We could change this so that all parties would receive the same price, the price of the most expensive bid accepted.

1.21. **Consideration 5:** Currently cash-out prices do not reflect the cost of all actions taken by the SO. For example demand reductions (i.e. when consumers are disconnected) are not included in the calculation. They could be included and consumers could be paid for the disconnection.

1.22. **Consideration 6:** The SO pays some generators to be prepared to generate when it thinks they could be needed in a future period. The inclusion of these costs in the cash-out price calculation could be improved.

1.23. **Consideration 7:** The SO is responsible for balancing the system. For that to happen, bilateral trading stops one hour before “real time”. We will consider introducing a new balancing energy market that allows parties to trade off their imbalances close to real time.

1.24. **Consideration 8:** Renewable generators tend to find it difficult to predict their output. They face uncertainty, for example, around how strongly the wind will blow. Aggregating renewable output and balancing it centrally could improve the overall balancing efficiency.

Secondary considerations

1.25. Depending on the design choices made in the primary considerations, a range of secondary considerations could become relevant. These include looking at ways to improve information available to market participants, changing the way reserve is procured and altering some of the existing reconciliation payments. The full list of secondary considerations is discussed in more detail in chapter 5.

Issues identified and related policy considerations

1.26. In order to ensure our policy considerations address the issues identified we have mapped the two in Table 1 below. We will update these links throughout the SCR when refining the policy packages.

Table 1: Mapping of issues and policy considerations

Issue identified	Potential policy considerations to address issue
Cash-out prices may not fully reflect scarcity at times of system stress	<ul style="list-style-type: none"> • More marginal cash-out prices • Improvements to price inputs
Cash-out prices may not provide the right incentives for DSR.	<ul style="list-style-type: none"> • More marginal cash-out prices • Pay-as-bid or pay-as-clear • Improvements to price inputs
Cash-out prices suffer from a lack of transparency and predictability.	<ul style="list-style-type: none"> • Balancing energy market • Improved provision of information
Dual cash-out prices have a large spread, resulting in imbalance risk and hampering the formation of reference prices.	<ul style="list-style-type: none"> • Single or dual cash-out price
Participants are not incentivised to provide accurate physical notifications.	<ul style="list-style-type: none"> • Improved provision of information • Information imbalance charge • Alternative arrangements for renewables
Reconciliation cashflows are large and opaque, potentially causing inefficient allocation of costs to participants.	<ul style="list-style-type: none"> • Single or dual cash-out price • Single or separate trading accounts • Balancing energy market • Amending Residual Cashflow Reallocation Cashflow (RCRC)I

Purpose of the initial consultation

1.27. Given the issues outlined above we have decided to undertake an SCR of electricity cash-out. This initial consultation document has two main purposes:

1. To inform stakeholders of:
 - our reasons for launching an SCR
 - our decision for the scope of the SCR
 - our initial thoughts on potential design considerations
 - how we plan to conduct the review and how we intend to engage with stakeholders throughout the SCR process
 - how we plan to handle interactions with other reforms of electricity market arrangements (such as TM and EMR CM).

2. To seek stakeholder input on:
 - all aspects of the policy considerations, including industry’s views of our initial thoughts on potential design options and potential benefits and drawbacks identified
 - industry’s suggestions regarding available evidence to support our analysis
 - the SCR process and stakeholder engagement going forward, including suggestions on how to best utilise stakeholder experience and knowledge.

1.28. Alongside this initial consultation, we are publishing a preliminary analysis of modification P217A, which was the most recent modification to the BSC. P217A aimed to remove system balancing actions from the calculation of cash-out prices. The purpose of our analysis is to get an initial understanding of what effect this removal had on cash-out prices. We also looked at the potential effects of making cash-out prices more marginal. The preliminary analysis of P217A is an important input to the SCR. We seek feedback from stakeholders on the preliminary analysis of P217A through this initial consultation.

In chapter 2 we discuss our approach for this review. This includes how the SCR process works, how we plan to engage with stakeholders, how we intend to ensure any potential policy proposals are consistent and what criteria we could use to compare different options. Chapter 3 provides some background to balancing arrangements and explains how the SCR interacts with other ongoing policy developments, such as EMR CM and the TM. Detailed policy discussions of primary and secondary considerations are captured in chapters 4 and 5.

2. Approach

Question box

Question 1: Do you agree with the approach and the proposed stakeholder engagement throughout the Significant Code Review (SCR)?

Question 2: Do you have any evidence that you would like to submit that may be relevant for any aspect set out in this document?

Question 3: What is your view on the interactions between our considerations and aspects of the EU Target Model (TM)?

2.1. In this section we set out our approach to the SCR, in particular how the SCR process works, how we intend to engage with stakeholders as well as how we plan to ensure consistency between the wide range of policy considerations in scope.

Proposed high-level approach

2.2. To seek to achieve these objectives we propose an approach that is:

- a) *comprehensive* - through reviewing a wide range of existing arrangements and considering more fundamental reform
- b) *realistic and practical* - through close and frequent engagement with industry and stakeholders
- c) *evidence-based* - through considering the quantitative and qualitative arguments in an impact assessment
- d) *flexible* - regarding other ongoing policy developments and their implications for timing and scope of changes
- e) *consistent with future market changes* - through close interaction with other projects and initiatives that are related to balancing so as to avoid unnecessary changes and costs
- f) *proportionate and consistent* with better regulation principles.

SCR process

2.3. The SCR process was introduced in 2010⁴. It allows Ofgem to take a leading role in the comprehensive review of significant code-based issues and direct any code changes deemed necessary as a result. The SCR process is intended to take approximately 12 months, after which industry will take forward code changes and the implementation of any approved reforms. Due to the technical nature of the balancing arrangements, and the range of reform options that are in scope, the electricity balancing SCR process is anticipated to take approximately 18 months.

⁴ The SCR process was introduced following the conclusions of the Code Governance Review in 2010. The Code Governance Review Final Proposals document is available here: <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=297&refer=Licensing/IndCodes/CGR>

2.4. We are consulting on this publication for 12 weeks and invite responses to the issues raised. Following consideration of these responses, we will aim to publish our draft policy decision in spring 2013; setting out any proposals for potential reforms that we consider may need to be made to improve the functioning of the electricity balancing arrangements.

2.5. Following a period of further consultation and policy development we will aim to publish our final decision on any potential reform of the arrangements by early 2014⁵. Should we decide to direct that Balancing and Settlement Code (BSC) changes are made, industry will take forward any changes through the normal BSC modification process which may involve further developments of the policy proposals. Should any licence changes be necessary to implement the reforms, Ofgem will consider how to take these forward in a manner consistent with BSC developments.

2.6. Further detail on the SCR process and proposed timings for the electricity balancing SCR can be found in our Electricity Balancing Significant Code Review Launch Statement, published alongside this initial consultation document.

Stakeholder engagement

2.7. It is important we work closely with stakeholders and industry to make best use of available experience and knowledge. The SCR process is intended to be transparent, inclusive and accessible to stakeholders. For the new balancing arrangements to be workable it is crucial to fully consider and reflect input from those working with these arrangements on a daily basis.

2.8. We plan to have a range of stakeholder events during the initial consultation phase. The first stakeholder event will take place in the week beginning 3 September 2012. We will hold additional stakeholder events during the course of next year. We encourage stakeholders to use the consultation process to respond to the questions we have asked in this document so that we can take their answers into account when developing our views on the potential reform options. More details on stakeholder engagement can be found in the launch statement that accompanies this publication.

Potential policy packages

2.9. To ensure consistency between individual policy considerations we started to categorise our primary considerations into potential policy packages. This is not intended to limit the discussion to these particular packages, but to illustrate that there are a large number of possible combinations for all policy considerations. The packages are on a spectrum from more to less 'market-based', illustrated in Figure 1.

⁵ We aim to publish a final decision by then, however, the publication of the final decision may take longer and we may need interim decisions.

Figure 1: Range of potential policy packages

More market-like ↓	Improved price inputs	Single or dual cash-out?	Main price calculation	Pay-as-bid or clearing price in the BM	Single or separate trading accounts?	Important secondary considerations?	
		1	Dual (ex-post)	PAR 500	Pay-as-bid	Separate trading accounts	RCRC, Reverse Price
		2	?	?	?	?	?
		3	Single (ex-post)	Marginal price	Pay-as-clear	Single trading account	Information imbalance charge
		4 "BEM"	Single cash-out price (ex-ante)	Marginal price (based on forecast of imbalance)	Pay-as-clear	Single trading account	Information imbalance charge, forecast of NIV, gate closure

2.10. There are a number of aspects of the current arrangements that reflect specific attributes of the electricity market, for example:

- a dual cash-out price was introduced to encourage participants to balance their positions (not spill additional energy onto the system)
- averaging of the costs of the System Operator’s (SO) actions was considered appropriate, in part to ensure that the costs of addressing non-half hourly net energy imbalances do not unduly distort the cash-out price
- separate trading accounts were introduced to avoid vertically integrated companies having an undue advantage, and to encourage trading
- pay-as-bid for re-despatch by the SO was introduced to reduce the ability of participants offering balancing services to exercise market power.

2.11. Our packages reflect that the arrangements could be made more ‘market-based’ if concerns that led to the current arrangements can be overcome. While we consider improvements to price inputs to be common to all policy packages, we note that there are number of ways to combine the remaining policy considerations. As illustrated above, package 1 leaves many of the key cash-out parameters unchanged. Package 3 adopts more market-based attributes (such as a single cash-out price and pay-as-clear). We note that the most appropriate outcome may be somewhere in between these two options.

2.12. We believe that the ‘more fundamental changes’ can be considered separately to the other parameters, particularly given that these may have interactions with the TM for pre gate closure trading. For example, a balancing energy market would introduce many of the market-based attributes for most of the balancing needs envisaged. There would still be a requirement for a form of balancing mechanism

(BM) afterwards, and we would need to decide what form this should take. Which secondary considerations are most important is likely to depend on the package as illustrated in Figure 1. We intend to refine these potential packages through the consultation and assess their impacts.

2.13. We feel that improving the price inputs for cash-out (i.e. attributing a price to currently un-costed actions and more accurate targeting the cost of reserve to relevant periods) should be investigated regardless of other outcomes and therefore be part of any policy package. They are highlighted as a blue bar in Figure 1.

Criteria for assessing options

2.14. In considering the options, we will undertake an impact assessment which will set out the evidence base of impacts around each option. This will include both qualitative and quantitative analysis, where possible, of the costs and benefits associated with each option. We will seek to establish whether reform would be beneficial and if so, which combination of options is likely to deliver the best outcomes for consumers. While assessing these potential options for reform, we will consider whether they are furthering the Authority’s principal objective and statutory duties, the relevant BSC objectives, and our SCR objectives as set out in chapter 1.

2.15. Table 2 below sets out some of the criteria we could use in our impact assessment, but we will review these as we progress through the SCR.

Table 2: Indicative criteria for the assessment of potential reform options

Criteria	Key Considerations
Ensure a secure and reliable electricity supply	<ul style="list-style-type: none"> • Impact on incentives for parties to balance • Duration, severity and probability of outages occurring
Impact on consumers	<ul style="list-style-type: none"> • Impact on costs of balancing and consumer bills • Arrangements where supplies are interrupted • Impact on vulnerable customers
Efficient balancing	<ul style="list-style-type: none"> • Efficiency of the cash-out price • Cost allocation of emergency balancing actions • Possibility for participation of demand-side response (DSR)
Impact on competition	<ul style="list-style-type: none"> • Impact on liquidity • Barriers to entry including credit requirements
Impact on investment	<ul style="list-style-type: none"> • Incentives for investment in capacity
Risks and unintended consequences	<ul style="list-style-type: none"> • Probability of financial distress for market participants • Potential for gaming of balancing mechanism • Impact on SO incentives to procure balancing services • Impact on gas markets
Integration of European markets	<ul style="list-style-type: none"> • Promotion of the internal market • Compliance with TM
Impact on sustainability	<ul style="list-style-type: none"> • Impact on sustainable development and management of transition to a low carbon economy
Other impacts, costs and benefits	<ul style="list-style-type: none"> • Environmental impacts • Implementation costs • Ongoing administrative costs

3. Background and Context

3.1. In this chapter we provide a short background on how cash-out has evolved over time and explain how it interacts with other current policy developments.

How has cash-out evolved?

3.2. In the electricity market in Great Britain, generators and suppliers have incentives to trade bilaterally to meet the needs of electricity consumers. Due to the physical properties of electricity it cannot currently be stored efficiently on a large scale. For this reason, the electricity system must be kept in balance (supply must meet demand) at all times. National Grid Electricity Transmission plc (NGET) is responsible for ensuring that the electricity system is balanced in real time in its role as System Operator (SO).

3.3. Following privatisation of the electricity industry in GB in 1990 all electricity generation in England and Wales was offered into a gross pool and was dispatched centrally by the SO. The introduction of the New Electricity Trading Arrangements (NETA) in 2001 marked a transition in the GB electricity market from the pool to a bilateral market-based approach. NETA introduced the current balancing arrangements and settlement process. All Balancing and Settlement Code (BSC) signatories were to be assessed to determine whether their metered output or consumption matched the energy they had contracted to sell or buy (their contracted position). If it did not then parties were out of balance. NETA introduced the current cash-out regime, including a dual cash-out price. Parties are paid for excess generation (and/or demand shortage) and charged for generation shortages (and/or excess demand).

3.4. We have previously undertaken two reviews of the electricity cash-out arrangements, in 2004 and 2007. These highlighted a number of ongoing concerns with the arrangements, some of which have since been addressed through the BSC modifications process. Through this process BSC parties propose changes to the BSC Panel. The BSC Panel, which oversees the modifications process, makes a recommendation on each proposed change to the Authority. The Authority then decides whether to reject the proposals or to direct a change to the BSC.

3.5. The modification process has brought about a number of piecemeal changes to the cash-out arrangements in the past. Some of these relate to the removal of system constraint actions from the cash-out price calculation in order to reduce system pollution⁶. For example, modification P18 introduced a tagging process to

⁶ 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.

remove bid-offer acceptances of less than 15 minutes from the price calculation. These actions were seen to be accepted to control system frequency rather than energy imbalance. Modification P217A further revised the tagging process by implementing ex-ante flagging of actions taken to resolve system constraints.

3.6. There have been numerous other modifications to the BSC that have resulted in incremental change. We feel a more comprehensive approach is now required to assess the effectiveness of the arrangements and address the issues identified. Appendix 3 outlines previous modifications relevant to the scope of the SCR in more detail and Appendix 2 summarises the current electricity market and cash-out arrangements.

Wider context

3.7. The electricity market in GB has changed significantly since the introduction of NETA. The factors that influence the design of the balancing arrangements may have changed as GB energy policy looks to deliver secure, clean and affordable electricity. A number of factors may mean that certain aspects of the balancing arrangements should be reconsidered. These factors include:

- the need to replace a large proportion of the existing electricity generation fleet and to integrate an increasing proportion of intermittent renewables onto the system as GB aims to make the transition to a low carbon economy
- an increasing need for peak and balancing power
- the rollout of smart and advanced meters and other new technologies which will create new opportunities for demand side participation in the electricity market and balancing arrangements
- increased cross-border interconnection and a more integrated approach to trading with neighbouring countries.

3.8. There are strong links between the electricity balancing arrangements and other ongoing electricity system changes, notably the implementation of the EU electricity target model (TM), the electricity market reform (EMR) and the initial proposals for SO incentives.⁷

⁷ The initial proposals for the SO incentive schemes from 2013 consider the potential need to change aspects of our trading and system operation arrangements to ensure they are fit for purpose for the future energy market which may be characterised by a different generation mix (i.e. more intermittent generation):
<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=306&refer=Markets/WhIMkts/EffSystemOps/SystOpIncent>

European Electricity TM

3.9. The TM is the main regulatory vehicle for achieving European electricity market integration. It establishes common rules to facilitate efficient use of cross-border capacity and to encourage harmonisation of European wholesale market arrangements. Currently member states have a variety of different approaches to balancing, often reflecting issues specific to the nature of their energy markets. The integration of European electricity markets should allow consumers in GB and across Europe to benefit from lower balancing costs and lower prices as a result of simplified trading conditions, efficient dispatch of plant and sharing of resources such as reserve.

3.10. One of Ofgem’s objectives as the national regulatory authority (NRA) for GB under the Third Package (and which has now been incorporated into our principal objective under the Electricity Act 1989) is to promote a competitive, secure and environmentally sustainable internal market in electricity within the European Community. The Significant Code Review (SCR) objectives are aligned with the principles of the TM. There are significant interactions between the considerations in scope of the SCR and elements of the TM. The Capacity Allocation and Congestion Management (CACM) Framework Guideline and draft Electricity Balancing Framework Guideline (EBFG) set out the basis on which binding Network Codes are being drafted.⁸

3.11. We have also recently published an open letter on the issues around the implementation of the European Electricity TM in GB by 2014⁹. The TM mandates changes to existing market arrangements to remove the barriers to cross-border trade and the implementation of market coupling day-ahead and within day. It also requires us to consider price zones to manage constraints within GB and proposes harmonising the use and procurement of balancing products and cross-border sharing of balancing resources in the form of a common merit order. The implementation of the TM could impact on our balancing and market arrangements:

- harmonisation of certain balancing features and creation of cross-border reserves may require changes to our current cash-out arrangements and provide the system with additional resources and security

⁸ The CACM framework guideline is available here:
[http://www.acer.europa.eu/Electricity/FG_and_network_codes/Electricity%20FG%20%20network%20codes/FG-2011-E-002%20\(Final\).pdf](http://www.acer.europa.eu/Electricity/FG_and_network_codes/Electricity%20FG%20%20network%20codes/FG-2011-E-002%20(Final).pdf)

The CACM draft network code is available here:
<https://www.entsoe.eu/resources/network-codes/capacity-allocation-and-congestion-management/>

The draft EBFG is available here:
http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultations/Open_Public_Consultations/DFGEB-2012-E-004/Consultation_document/DFGEB_2012-E009.pdf

⁹<http://www.ofgem.gov.uk/Europe/Documents1/EU%20Target%20Model%20open%20letter.pdf>

- efficient use of interconnectors through market coupling at day-ahead and within-day could provide further harmonisation of pre-gate closure trading arrangements and make it easier for intermittent generators to export any surplus to neighbouring markets, which will need to be taken into account in any of the more fundamental reforms
- price zones could require balancing arrangements in multiple zones, provide more enhanced incentives on market participants to balance and change the costs for system operator's management of constraints.

3.12. The draft EBFSG sought views on the extent to which imbalance settlement should be harmonised across member states. The framework guidelines are currently being developed in consideration of the responses. The draft EBFSG suggests that the Network Codes should require that imbalance settlement takes place on a non-discriminatory, fair, objective and transparent basis and that there are limited distortions between adjacent markets. The draft EBFSG suggest that imbalance prices shall at least include the SO's costs of balancing and that reserve products and reserve procurement practices should be harmonised through the Network Codes. Harmonisation of reserve procurement is likely to change the way in which the GB SO procures reserve. At this stage, the framework guidelines have not been prescriptive about the ways in which imbalance pricing or reserve procurement should be harmonised. However, they do express a preference for a clearing price to be paid in the balancing market.

3.13. The CACM framework guideline requires that the CACM Network Code(s) will require transmission system operators to propose the boundaries of pricing zones taking into consideration physical constraints, for approval by the NRA. This could result in more than one market price in GB, with market areas split to reflect structural transmission constraints. Market splitting would imply different cash-out prices in different pricing zones when constraints were active. We will take into consideration whether it is necessary to make the cash-out arrangements compatible with multiple zones throughout the process.

3.14. CACM is also concerned with efficient use of interconnectors through market coupling arrangements day-ahead and within-day. We will consider the implications of any reforms for the efficient use of interconnectors.

3.15. The TM will become more clearly defined as the SCR process continues. The relevant Network Code is expected to enter into force in 2014. Doing the review now allows us to begin to align GB market arrangements with features of the TM that have been decided on already. At the same time it improves our ability to provide input in the areas of the TM that are still being developed. In order to mitigate the risk of Ofgem making policy choices that are not compliant with the TM, we will keep developments in the TM under close consideration throughout the SCR process. This way we make sure that any changes are robust and not subject to redesign soon after implementation of the TM. If necessary, some aspects of any reforms to the GB balancing arrangements could be delayed to be aligned with Network Code developments.

EMR

3.16. Cash-out signals are a primary driver in the current “energy-only” market to build and maintain sufficient plant to meet demand. Cash-out reform could further strengthen these signals to improve security of supply.

3.17. The Government intends to legislate for a Capacity Market (CM). Whilst the CM has the same high-level objective as cash-out reform (ie to improve security of supply) the mechanisms are complementary. The CM aims to reduce the risk for investors from collecting all their revenues in the energy market, and instead offers a separate, more certain revenue stream. It also addresses the concern that cash out prices may be insufficient to incentivise the required investment if market players overly discount their exposure to low probability but high impact capacity shortages. Cash-out reform on the other hand focuses on improving the incentives in the energy market itself, including the incentives for flexible generation. Both cash-out reform and the CM are likely to affect investment decisions. However, it is unlikely that cash-out reform would have a large impact in the short term, but is more likely to affect investment decisions in the medium to longer term as the price signals work through the system. Both reform packages are complementary but interact to a greater or lesser extent depending on the final design of the CM¹⁰.

3.18. Two design options for the CM determine the level of interaction with potential cash-out reform: the signal for scarcity, indicating that capacity needs to be available and the penalties which apply to capacity providers if they fail to provide capacity.

3.19. With a signal for scarcity that is independent of market prices and an administratively set penalty, interactions between potential cash-out reform and CM would be relatively limited. However if the signal for scarcity and/or penalty are to be based on a reference price, the interactions are more significant. In either case we will consider carefully the impact on the effectiveness and efficiency of the CM before implementing any balancing reform proposals.

3.20. The Government has welcomed our work on reviewing cash-out and our plans to launch an SCR, and we have discussed the potential effect on some forms of CM of potentially reforming cash-out arrangements at this stage. We work closely with Government at all levels and receive regular updates on CM developments. This will allow us to ensure consistency both with regards to timing and substance of both reform projects.

Liquidity

3.21. Ofgem’s liquidity project is seeking to address the risk that low wholesale power market liquidity is acting as a barrier to entry and competition in the domestic

¹⁰ Find a link to the latest EMR publications here (CM is Annex C):
http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

supply market. In February, we published a consultation document which set out three objectives that the wholesale market must deliver in order to support effective competition. These are:

- availability of products that enable market participants to hedge
- robust reference prices along the curve
- and an effective near-term market.

3.22. In the February document, we suggested that our third objective – an effective near-term market – was potentially being met by market developments. In particular, we highlighted growth in trading on day-ahead auction platforms since late 2011 and the prospect of market coupling with Europe at the day-ahead stage. We also noted the potential interactions with cash-out. Consequently we did not propose any intervention in near-term markets. On 16 July 2012, in an open letter to market participants, we confirmed this view.

3.23. It was the view of some stakeholders that any Ofgem intervention in near-term liquidity should be concluded before the launch of this SCR. However, as noted above, our liquidity project to date has not proposed any interventions in near-term markets. We will continue to consider the interactions between any electricity balancing reform and liquidity as we progress the SCR.

Settlement reform and demand side response (DSR)

3.24. Accurate balancing incentives are necessary for efficient investment in and utilisation of DSR for balancing purposes. Distortions to cash-out prices could deter customers from DSR, or could deter the SO from using DSR for balancing purposes. This could increase overall balancing costs. We therefore aim to ensure that cash-out prices appropriately reflect the costs of balancing as well as the value consumers place on electricity security of supply.

3.25. The rollout of smart and advanced meters capable of recording detailed consumption data can catalyse DSR and improve the accuracy of the imbalance volumes to which cash-out prices are applied. This can strengthen the incentives on suppliers to balance. Settlement and electricity balancing reform are therefore complementary.

Gas

3.26. Gas plays an important role in electricity generation in GB. Around 30-50% of GB electricity is generated using gas-fired stations. Gas is also important in providing flexible electricity. In Project Discovery, we noted our concern that in the imbalance arrangements for both gas and electricity, customers could have their load curtailed before cash-out prices reach their value of lost load (VoLL). Ofgem has published its proposed final decision on the gas SCR on 31 July 2012. This considers these interactions and the potential for introducing measures to reflect gas VoLL in order to sharpen the incentives on shippers to take measures to improve security of supply.

4. Primary considerations

Chapter Summary

In this chapter we set out the scope and the key policy considerations for the SCR. We provide our initial views and what we think the potential options for reform are. We set out the rationale and the design considerations for proposed change and the pros and cons that may be associated with it. At a high level we are looking at the following **primary considerations**:

Changes to existing balancing arrangements

1. More marginal main cash-out price
2. Single or dual cash-out price
3. Single or separate trading accounts
4. Pay-as-bid or pay-as-clear for energy balancing services

Improvements to price inputs

5. Attributing a cost to non-costed actions
6. Improved allocation of reserve costs

New balancing arrangements

7. Balancing Energy Market (BEM)
8. Alternative arrangements for renewables

This chapter assumes some understanding of the workings of the GB electricity market. See appendix 2 for details of these arrangements.

Question box

Question 4: Do you feel there are any further alternatives to the reform options presented under our primary considerations?

Question 5: What other benefits or drawbacks can you identify for each of our primary considerations? Please provide any evidence you may have to support your position.

Question 6: Which of the reform options considered under each of our considerations do you believe would provide the most efficient balancing incentives and why?

Question 7: Alongside this initial consultation we have published preliminary analysis of the last modification to the cash-out arrangements, P217A. Do stakeholders agree with the initial findings of this analysis?

Question 8: What additional analysis could be done as part of the SCR around Modification P217A and the flagging methodology it introduced?

Question 9: Do you agree with our rationale for considering making cash-out prices 'more marginal'?

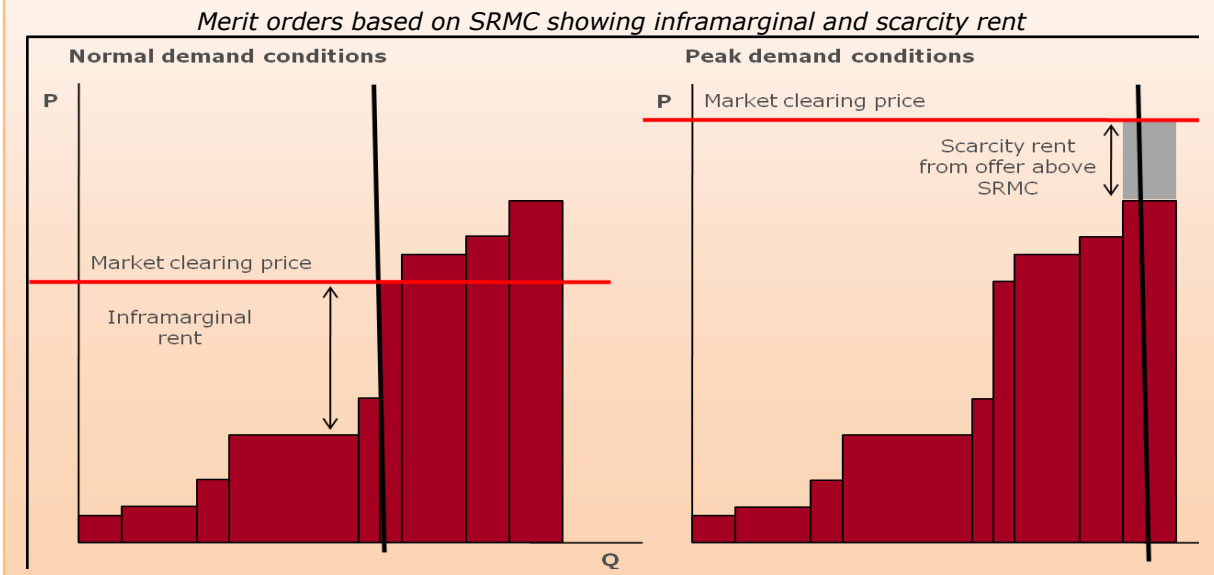
Changes to existing balancing arrangements

1) More marginal main cash-out price

4.1. The main cash-out price is calculated as the average of the most expensive 500MWh of actions taken by the system operator (SO) to overcome the energy imbalance on the system. We have expressed concerns that cash-out prices may not fully reflect scarcity at times of system stress. The incentives for market participants to balance (where they can do so more cheaply than the SO) are dampened by the averaging process used in the cash-out calculation. Dampened cash-out prices also reduce the incentive to invest. This has been argued to be part of the “missing money” problem described in box 1 below. Reducing the volume of the 500MW ‘price average reference’ (PAR) would make the price more closely reflect the cost of the marginal action taken by the SO to resolve the energy imbalance. This would sharpen these incentives.

Box 1 - “Missing money”

The concept of missing money in energy markets is used to describe a shortage of available revenue streams to allow capacity providers to cover their costs. This can discourage further investment, jeopardising security of supply. In energy-only markets, such as the current GB market, capacity providers collect the revenues needed to recover their costs from the energy price. Price taking capacity providers take advantage of the difference between their own short run marginal cost (SRMC) and the SRMC of the marginal capacity provider (who is setting the price) to earn *inframarginal rents*. Price setting capacity providers (those on the margin with the most expensive SRMC) will not earn *inframarginal rents* but look for opportunities to price at a level above their SRMC to collect *scarcity rent*. In figure X below, each generator’s SRMC is represented by a different bar.

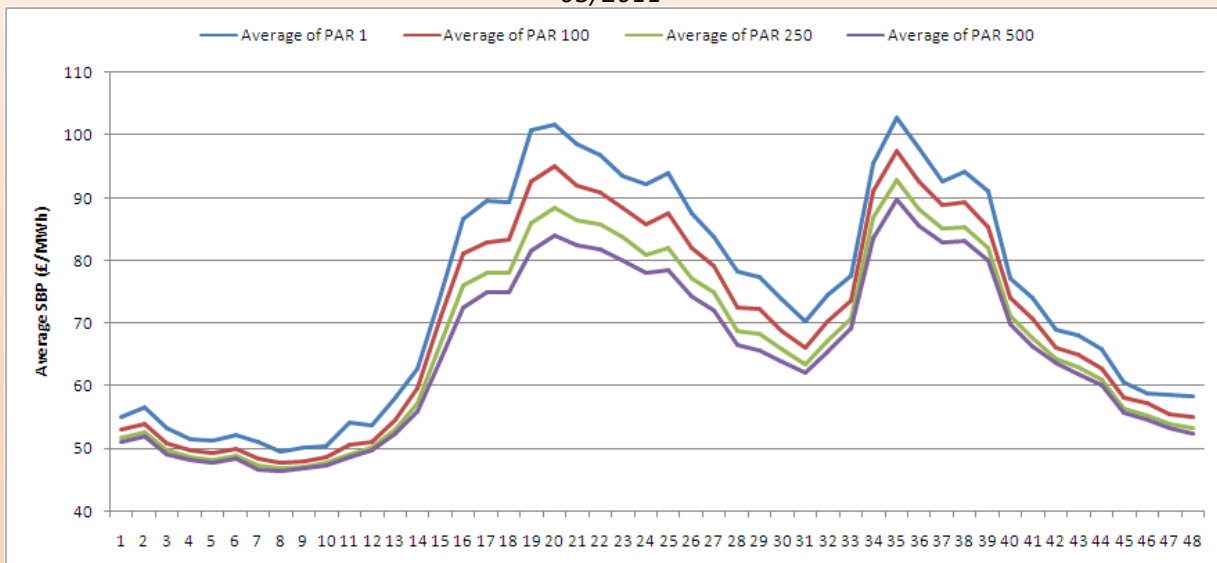


Box 1 - “Missing money” cont.

Capacity providers have a missing money problem if they cannot collect enough revenue above their SRMC to cover their fixed costs. Constraints to collecting these rents can be explicit or implicit in market arrangements. **Explicit constraints** include interventions (or the risk of intervention), such as caps to prices or offers into a market. **Implicit constraints** include inefficient arrangements for charging participants for imbalances, such as mispricing some of the SO’s balancing actions and averaging of balancing costs. These reduce market participants’ incentives to balance (a form of missing money in the forward markets) as the opportunity cost of the imbalance price charged to them is not fully reflective of the costs to balance in real-time.

The current cash-out main price may not be marginal enough. Averaging dampens the incentive on market participants to balance before gate closure. We plan to consider whether a more marginal cash-out price calculation would benefit consumers as part of the SCR. Our accompanying analysis on the BSC code modification P217A shows how a different PAR value (currently at top 500MWh most expensive balancing actions) could increase the cash-out price on average when the system is short.

Average main cash-out price when system is short, different calculated levels of PAR, 04/2009-03/2011



4.2. We have done some preliminary analysis of the impact of Balancing and Settlement Code (BSC) modification P217A’s removal of “system actions” from the cash-out price. We also looked at the impact that reducing the PAR would have. A fundamental assumption under BETTA is that the energy price should be the same across the network (i.e. assumes no constraints). Under this assumption, our PAR level analysis suggests that improving flagging could allow more marginal prices and thus improve incentives to overall energy balancing. However this may not necessarily result in lower costs to consumers when there are structural constraints. We intend to investigate this finding further.¹¹

¹¹ BSC Modification P217A was the most recent change to cash-out arrangements. It sought to reduce system pollution. We have conducted preliminary analysis of the impact of P217A: <http://www.ofgem.gov.uk/Markets/WhIMkts/CompandEff/electricity-balancing-scr/Documents1/P217A%20Preliminary%20Analysis.pdf>

Options for reform

4.3. We would like to consider amending the main cash-out price calculation to make it more marginal by reducing the value of PAR or using the marginal trade to set the cash-out price.

Rationale and design considerations

4.4. At the extreme, failure to balance can result in consumers' demand having to be curtailed. It may also fail to bring about investment that consumers would be willing to pay for. A more marginal price could help to address this.

4.5. The SO takes actions in the balancing mechanism (BM) for many different reasons, not just energy balancing. Non-energy related balancing actions (e.g. system constraints) can "pollute" cash-out prices. BSC modification P217A put in place a method for reducing system pollution by separating 'system' and 'energy' actions. There is a risk that the marginal (price setting) action could be taken for energy balancing reasons but are unrepresentative of system conditions. For example, the SO could take an expensive action shortly after gate closure for energy balancing reasons. It may turn out that the action would not have been taken if the SO had perfect foresight of system conditions. This could expose participants to additional costs unnecessarily. We intend to investigate with industry, whether actions taken for energy balancing reasons are, or can be, sufficiently isolated from other actions to allow that the PAR level could be reduced without significant inefficient distortions to the main cash-out price.

4.6. A more marginal main price could increase both the volatility of and spread between prices. Price volatility (where reflective of fundamentals) and spreads create an incentive to balance as parties seek to avoid the risk associated with uncertainty. However, greater risk and uncertainty could deter some new entrants into the market.

Interactions

4.7. A more marginal main cash-out price would lead to greater differences between cash-out payments and receipts. This difference would be redistributed via residual cashflow reallocation cashflow (RCRC). This may make consideration of changes to the RCRC more important. A more marginal price may also increase the importance of investigating the current reverse price calculation as it would increase the spread between the main and reverse price, other things being equal.

4.8. If we moved to pay-as-clear pricing, this would have the effect of creating a marginal cash-out price.

4.9. Balancing arrangements are based on the fundamental assumption that the value of electricity does not vary with respect of location or network conditions. As a result of that the incentives on market participants are to be balanced across the system regardless of location. This assumption is increasingly being challenged by

the more recent consistent increase of congestions on the network. The EU Target Model (TM) requires the SO to consider structural congestions on the network and to propose price zones to reflect the different value of energy at different location. This approach would reduce the need for SO actions to solve constraints and provide incentives for generators to efficiently take constraints into account when scheduling their production. This could make moving to a more marginal price within zones more appropriate as the potential for system pollution is reduced. In the absence of market splitting with constraints becoming more significant, the number of SO system actions may increase. We would need to consider the implications of this for reducing the PAR.

2) Single or dual cash-out prices

4.10. Participants pay or receive cash-out for differences between the contracted positions and physical volumes they generate or demand. The price that participants face depends on whether they are long or short of physical energy compared to their contracts, and whether this imbalance is in the same or in the opposite direction from the system. An example is shown in box 2.

Box 2 - Dual price – worked example

A participant has a portfolio of several generating units. At gate closure they have contracts to generate 1GW for a settlement period. The participant can meet these contracts using energy from a number of its units. After gate closure, one of the participant's generating units has a fault that stops it from generating. As a consequence the participant generates 200MW less than it is contracted to.

The participant's position is 200MW short; it must pay cash-out for this imbalance. The price it will pay for this differs depending on the cost that this imbalance created for the system. If the system is also short in that half-hour, the participant's short position has contributed to this overall imbalance, and it must pay a cash-out price based on the actions that the System Operator has had to take to resolve the imbalance. If the system was long overall the participant's short position has not contributed to this imbalance. In this case the participant pays a price based on market prices before gate closure. This price is designed to reflect what the participant would have paid for the energy had it foreseen the imbalance and purchased it in the market before gate closure to resolve it.

If the participant had generated more than it had contracted for, it would be paid cash-out for this imbalance. If the system is also long, the price the participant is paid will be based on actions that the System Operator has had to take to resolve the system imbalance. If the system is short, the participant will be paid a market-based price.

In a typical day generators may be short in some periods and long in others. The system overall is typically long, but will also commonly be short during the day.

Options for reform

4.11. We would like to consider the merits of a single cash-out price (paying long parties the same price as short parties are charged). We would also like to consider hybrid options, such as a single cash-out price unless net imbalances exceed a certain level, or a single cash-out price when the system is short and a dual cash-out price when the system is long.

Rationale and design considerations

4.12. The dual cash-out price incentivises participants to balance their positions ahead of gate closure and minimise the residual balancing role of the SO. The partially marginal calculation of the main price and the market-based calculation of the reverse price aim to ensure that participants are not better off by paying or receiving the cash-out price than trading ahead of gate closure.

4.13. Economic theory suggests there should only be one price for one commodity at a time and location. Different prices generally lead to distortions and reduced efficiency. However, some have argued that electricity is not like other commodities and that 'short imbalance' and 'long imbalance' can be seen as different products. It is generally cheaper to turn generation down than to turn it up.

4.14. A single cash-out price per settlement period could be more transparent and easier to understand. It would eliminate spread, which may be creating excessive imbalance risk, especially for smaller participants and intermittent generators. It could encourage the development of a more robust spot market reference price and related products that could be more widely traded, which could improve liquidity.

4.15. With a single marginal price based on the SO's actions, participants could benefit from their imbalances in some instances, creating the incentive to spill energy onto the system. We would need to consider whether this incentive would be appropriate. Participants offering balancing services into the BM may be more efficient.

4.16. A single cash-out price could increase the incentives on participants to go longer on average than with a dual cash-out price. However "spilling" energy would reduce cash-out prices, which in turn reduces incentives to go long. We will consider these dynamic effects.

4.17. We also note that the tendency for the system to be long creates "free headroom" for the SO. We would like to investigate whether this is efficient and the impact that a single price would have on the creation of headroom.

4.18. A single cash-out price would eliminate the spread between the two cash-out prices, System Buy Price (SBP) and System Sell Price (SSP). However the uncertainty with regards to cash-out prices due to uncertainty about whether the system will be short or long may increase with a move to a single price. This is because the difference between the two potential main prices (if the system is long

or short) is larger than the difference between a reverse price and a main price. With a single cash-out price participants would always face a main price but would not know whether it would be based on the SO's actions to address a positive or negative imbalance. Greater uncertainty could increase the incentives to balance (to avoid uncertainty) but could also deter some new entrants to the market.

4.19. If we felt that balancing performance would be adversely impacted by having a single cash-out price, we could consider a single cash-out price only for those settlement periods where balancing volumes remain below a certain level. When volumes in the BM exceeded a certain level, marginal dual cash-out prices, or some sort of performance incentive, could be triggered, similar to the approach taken in the Netherlands.

4.20. We could also consider a single cash-out price when the system is short and a dual cash-out price when the system is long. This could recognise the value of 'helpful' imbalances when the system is short and pay parties for such imbalances, but also reduce the incentive to go long when the system is long, with a SSP based on a market price as currently. However, it may be argued that imbalances in both directions are helpful.

4.21. Further, we could consider a cash-out regime with two pricing systems for production and consumption. This could be similar to the approach taken in the Nordic market. Production imbalances are settled according to a dual price system, whereas consumption imbalances are cashed-out based on a single price. Consumers are therefore compensated by receiving the main price when their imbalance helps to reduce the overall system balance. NordReg has argued that this model reduces risk and simplifies the cash-out process for new entrants and smaller players on the consumption side, which encourages interaction from demand-side participants. It also maintains the current incentives on generators to balance their own positions through the dual-price system. Generators pay or receive the up- or down-regulation price for imbalances in the same direction as the overall system imbalance, and pay or receive the spot market price for imbalances in the opposite direction to the overall system imbalance. The Nord Pool cash-out arrangements are outlined below.

Box 3 – Nord Pool cash-out arrangements

	Up-regulation hours (system short)	Down-regulation hours (system long)
Generation (dual price system)		
Party short	Up-regulation price	Spot price
Party long	Spot price	Down-regulation price
Consumption (single price system)		
Party short	Up-regulation price	Down-regulation price
Party long	Up-regulation price	Down-regulation price

Interactions

4.22. A single cash-out price may also complement a move to pay-as-clear pricing in the BM. A single price recognises and rewards imbalances that help balance the system. This is similar to participants receiving a marginal price (as the main price is currently partially marginal) in situations where they have helped to balance the system. However, participants in the BM currently receive the price they bid for their balancing services. A move to a marginal clearing price in the BM would therefore ensure consistency between the BM and the imbalance arrangements.

4.23. A single cash-out price could make a suitable reference price for some models of the Electricity Market Reform (EMR) capacity mechanism (CM).

4.24. A hybrid pricing system such as that adopted in the Nordic market would mean that participants may have to settle imbalances across separate production and consumption accounts (as currently). This could ensure that vertically integrated companies cannot net their imbalances and that suppliers operating on only one side of the market are not unduly discriminated against.

4.25. Consideration of price calculation/price marginality might also affect the choice of model. In the Nordic market the single price and the main price in the dual-price system is the marginal clearing price in the balancing market.

3) Single or separate trading accounts

4.26. Participants' contracts for energy are submitted to Elexon¹² at gate closure. After the relevant settlement period parties are cashed-out on the difference between their contracted positions and their metered demand or generation. Energy from production BM Units (BMUs) is assigned to a party's production account and energy from consumption BMUs is assigned to a party's consumption account. Participants who operate on both sides of the market are required to balance their production and consumption positions separately.¹³

Options for reform

4.27. We will consider the merits of allowing participants to combine imbalance exposure across production and consumption accounts, i.e. moving from separate trading accounts to a single trading account.

¹² Elexon is responsible for delivering the Balancing and Settlement Code (BSC) including settling imbalances.

¹³ Where production is exports onto the GB system, and consumption is imports off the system.

Rationale and design considerations

4.28. Separate trading accounts were introduced in part to prevent participants on both sides of the market from having an undue advantage relative to those operating on only one side of the market. It was thought that allowing imbalances to be netted could encourage vertical integration. However, it has been suggested that the original rationale underpinning this has been eroded as parties, particularly larger players, have found ways round this separation.¹⁴

4.29. Separate trading accounts were also thought to prevent participants from continually adjusting their physical positions after gate closure in order to 'self-balance', which could make the SO's balancing more difficult and expensive.

4.30. If all participants only had a single energy trading account they could offset generation volumes with demand and would only have to trade to cover their net position. This would leave a smaller volume exposed to imbalance risk. This could also reduce the complexity of balancing arrangements.

Interactions

4.31. We would need to consider the impact on balancing behaviour of participants. Parties may have an increased incentive to manage deviations in expected consumption out-turn by adjusting production. If there was a significant adverse effect on the SO's ability to manage the system, it could support the case for activating an information imbalance charge.

4.32. Netting imbalances across parties would potentially reduce total imbalance charges paid by out-of-balance parties, and reduce the level of RCRC.

4.33. With a single cash-out price, separate trading accounts would not have an effect on participants total imbalance payments. Imbalances in opposite directions on different accounts would pay and receive the same cash-out prices, netting off imbalance charges and payments.

4.34. We would also need to consider whether vertically integrated players supplying their own energy would reduce trading and hence the impact that this change would have on liquidity.

4.35. Modification P282 "Allow MVRNs from Production to Consumption or Vice Versa" is currently being progressed.¹⁵ This would allow a Metered Volume

¹⁴ This is the rationale behind the proposed BSC Modification P282 which proposes to allow MVRNs from Production to Consumption accounts and vice versa. The modification was raised prior to the launch of the SCR.

¹⁵ Available on the Elexon website: <http://www.elexon.co.uk/mod-proposal/p282-allow-mvrns-from-production-to-consumption-or-vice-versa/>

Reallocation Notification (MVRN) to be used to reallocate between production and consumption energy accounts regardless of the BMU's production/consumption (P/C) status, bypassing the requirement to keep production and consumption volumes separate. This modification proposal was raised before the launch of the SCR and hence will continue through the standard modifications process.

4) Pay-as-bid or pay-as-clear for energy balancing services

4.36. The price paid or received for accepted bids and offers in the BM is currently the price participants have submitted ('pay-as-bid'). A pay-as-bid approach was considered to be consistent with the pricing methodology for energy in the forwards and futures markets. It was thought to reduce the risk of price manipulation if there was market power.

Options for reform

4.37. We will consider the merits of using a single clearing price (pay-as-clear) for energy balancing services. With a clearing price, all accepted bids/offers would be paid the price of the marginal accepted relevant bid/offer. This is also being considered by the Electricity Balancing Framework Guidelines (EBFG).

Rationale and design considerations

4.38. In theory, if participants had perfect foresight, outcomes could be similar under pay-as-bid and pay-as-clear auction models. Under pay-as-bid all participants would be incentivised to price at the marginal bid/offer to maximise revenue. Awarding all participants a clearing price set by the marginal plant under pay-as-clear would have the same outcome. The theory behind pay as bid and pay as cleared payment models for balancing is discussed in box 4.

4.39. However, participants do not have perfect information and this could be leading to pricing and despatch inefficiencies. A clearing price could produce the more efficient outcome as participants would be incentivised to bid in at closer to their short-run marginal cost, knowing that if a more expensive energy offer is accepted they will receive that price. Price signals would be based on underlying economics, rather than on participants' imperfect expectations of the system imbalance and the SO's balancing actions. Pricing at marginal cost could make it easier to submit bids and offers as parties no longer need to anticipate the most expensive balancing action in order to maximise revenue. This could create a more level playing field to participate in the BM.

4.40. One of the reasons that the New Electricity Trading Arrangements (including a pay as bid BM) were introduced was due to market power concerns. It was suggested that the England and Wales Pool facilitated the exercise of market power at customers' expense by enabling all generators to receive a uniform price which in practice was set by a few participants. We would need to consider whether market power could result in inefficient clearing prices in the BM.

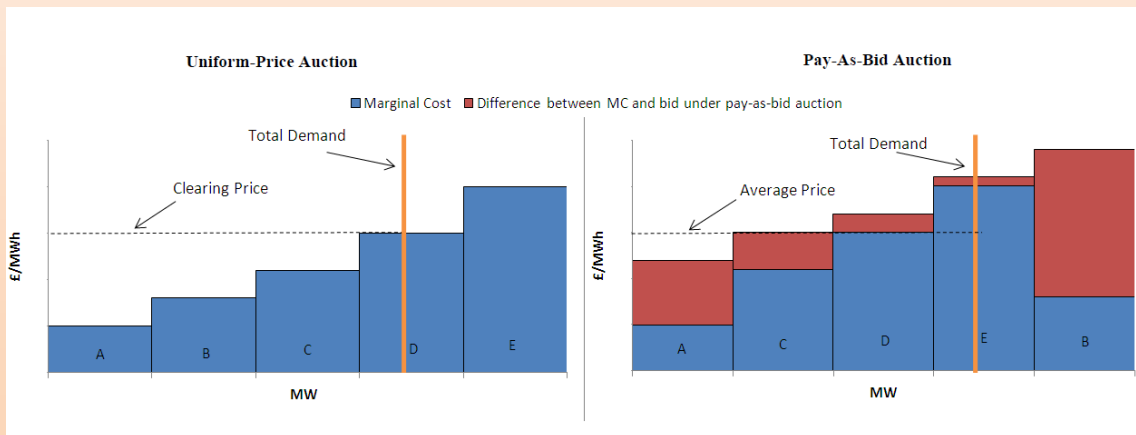
4.41. There are difficulties with establishing a clearing price for energy balancing actions. The BM is used to take a wide range of actions for a range of different reasons (including managing system constraints). It is difficult to derive a single balancing energy product to set the clearing price in a given half-hour. Flagging and tagging mechanisms aim to isolate energy balancing actions in order to set the cash-out price. We could consider whether a similar approach could be used to establish a clearing price for energy balancing actions. However, concerns about distortion of the cash-out price mean we currently have a 'chunky' rather than fully marginal cash-out price. Similar concerns may prevent a fully marginal clearing price in the BM.

Box 4-Pay-as-bid and pay-as-cleared in theory

There has been much academic debate as to whether pay-as-bid or uniform pricing in a balancing market (or balancing mechanism) will result in lower balancing costs. A uniform, or clearing price, would pay all balancing service providers the price of the most expensive accepted offer. Under pay-as-bid balancing service providers receive only the price of the offer that they have submitted.

At first glance, it does seem to make sense that paying all participants a clearing price – even though some participants would be willing to generate for less – would result in high balancing costs. However, in theory, balancing costs should be the same under both models. Participants in a clearing-price auction will be incentivised to bid close to the minimum value they would accept for being dispatched (their short run marginal cost), as they know that will receive profit above this level (unless they are the marginal plant). Participants in an auction with pay-as-bid pricing, on the other hand, increase their revenue by offering in at a price above their short-run marginal cost. In order to maximise their revenue they should offer in at the price that they expect they will be able to receive, i.e. the most expensive offer accepted. In short, the outcomes should be the same as under a clearing price, participants are automatically awarded the price of the most expensive offer accepted, while under pay-as-bid participants are incentivised to change their bidding behaviour and capture it via their offers.

In reality, however, there may be limitations to the extent that participants are able to predict the price of the marginal offer. Estimating the revenue maximising bid can result in inefficient dispatch, as illustrated in the figure below (where generator B should be dispatched before plant C but overestimating the price caused them not to be dispatched). In some circumstances, pay-as-bid could inefficiently increase balancing costs and the complexity of effectively estimating the costs of doing so could deter market entry.



Moreover, lower balancing costs in themselves may not result in more efficient outcomes. If participants can receive more predictable rents in the balancing market/mechanism this could encourage investment. If investment results in more efficient levels of security of supply (i.e. security consumers would be willing to pay for) this could be more efficient than disconnections that could occur in the absence of investment.

4.42. Moving from pay-as-bid to pay-as-clear could impact on the SO's costs of purchasing balancing services. Given imperfect foresight market participants cannot currently bid at the marginal bid/offer. Participants are therefore likely to bid lower than their estimate of the marginal bid/offer to ensure they do not drop out of the chosen stack of bids and offers. The change in costs to the SO depends on how much participants' estimates currently deviate from the true marginal bid/offer and to what extent some participants over-bid.

4.43. It would be necessary to consider whether the SO's other services could continue to be pay-as-bid and the impact that paying these as bid would have for bidding behaviour.

Interactions

4.44. The draft EU balancing framework guideline require harmonisation of the way balancing services are procured but stakeholders have suggested that further analysis of this issue is needed before making a decision for either option.

4.45. A move to pay-as-clear could make it necessary to make cash-out prices reflective of the clearing price, to ensure that the cash-out price is reflective of the SO's costs and to provide appropriate incentives to balance.

4.46. We would need to consider the implications of a single cash-out price for pay-as-bid and pay-as-clear approaches to pricing in the BM. It may not be appropriate for some participants to receive a higher price for spilling than they would from offering balancing services via the BM in some periods.

4.47. The implications of any inclusion of the value of lost load (VoLL) in the balancing arrangements would need to be considered (for example, we would need to consider whether participants would receive VoLL for increasing generating when demand is reduced, and if so, whether this would be reflected in the cash-out price).

Improvements to price inputs

5) Attributing a cost to non-costed actions

4.48. Some balancing actions available to the SO are not currently reflected in the cash-out price. These 'non-costed actions' include voltage control and involuntary demand disconnection. Accurately reflecting the SO's full balancing costs is central to ensuring that participants face the correct incentives to balance their positions. We will consider whether we should reflect prices for these actions in the cash-out price in periods when these actions are taken. Box 5 discusses how the value of lost load (VoLL) could be calculated and used to reflect the costs of disconnection to consumers in the cash-out price

Rationale and design considerations

4.49. Attributing the price of consumers' VoLL to firm disconnections could provide incentives for generators and suppliers to avoid disconnection of consumers. When firm consumers are disconnected, they are effectively providing DSR balancing services. For this reason, we may consider the merits of introducing payments for interrupted firm customers who have been disconnected to balance the system. These payments could be funded by imbalance charges when the cash-out price reaches VoLL.

Box 5 - Using the value of lost load (VoLL) in cash-out price calculation

Application of VoLL

Ideally every consumer would be able to specify how much they would be willing to pay to maintain a continuous electricity supply – their value of lost load (VoLL) – and would stop consuming when prices reached this level. This would allow the efficient level of security of supply to be reached. No consumer would be disconnected at a price below what they would be willing to pay for continued supply, and no consumer would pay more than they wished to for continued supply.

However, most consumers are not able to express their individual VoLL. They cannot react to real-time price changes, and are unable to enter into interruptible contracts with their suppliers. Until all consumers have smart meters and time-of-use tariffs, it would be necessary to establish an administrative VoLL. As discussed below, VoLL can vary widely even for one individual. Even with smart meters it may be difficult to get a meaningful level of sophistication into a tariff that people sign up to in advance given. However, to the extent that useful information can be provided the system operator could then use this information when balancing the system. Any balancing action cheaper than VoLL should be pursued before firm consumers are involuntarily interrupted. VoLL could also be used to estimate the level of payment that customers should receive if they are involuntarily disconnected. Any action taken to disconnect customers could then be included in cash-out price calculation, priced at VoLL.

VoLL is relevant in other areas of the energy market. It is used in the electricity and gas distribution network operators' price control. Also, in the gas SCR it is proposed that cash-out should be allowed to rise to VoLL for all days of firm load shedding (where individual large consumers are required to reduce their gas demand) and the first day of any network isolation (where parts of the network stop receiving gas).

Establishing an administrative VoLL

Establishing an accurate VoLL for GB consumers is a difficult task. There is no single VoLL for all GB electricity consumers – it will differ between different consumers and consumer types, and depending on the specific context even for the same individual customer. Season, time of day and duration of interruption are likely to have an impact.

Given the variation between different electricity consumers in GB, there is a question as to whether a number of different administrative VoLLs for different consumer types (i.e. domestic and non-domestic) should be used. However, there may be practical difficulties in establishing and applying a number of different VoLLs, so there may be an argument for establishing a single VoLL for all electricity consumers in GB.

When setting an administrative VoLL there is a question of how best to reflect the consumers' preferences in that group. Taking the minimum VoLL of the group will result in all but those consumers with the lowest VoLL being interrupted at a price below their willingness to pay. An average VoLL may be most representative by definition, but could still result in consumers being curtailed at a point below their wishes. A maximum VoLL would mean that the vast majority of consumers would remain connected at a price above that which they would be willing to pay, but may create stronger incentives for demand side response. A maximum VoLL may also create incentives for participants to free ride on the security provided by others. This could result in parties underinsuring against the risk of facing a cash-out price incorporating VoLL.

4.50. We may also wish to attribute a price to other non-costed actions, such as voltage reduction, to ensure that effective economic signals are delivered.

4.51. We note that there are methodological difficulties with establishing a price for other non-costed actions. Further, we note that there will be practical difficulties in incorporating VoLL into the balancing as, for example, it is likely to be difficult to establish who should receive payments for their interruptions.

4.52. We would need to consider the criteria under which the SO could take actions to reduce demand to address system-wide supply shortages so they were clear to market participants and the SO.

Interactions

4.53. We note that there are parallels with the ongoing Gas SCR, which is also introducing reforms to introduce payments for the provision of involuntary DSR services.

6) Improved allocation of reserve costs

4.54. In some instances, it is more efficient for the SO to contract balancing services ahead of time. It is then necessary to accurately target the full balancing cost into the correct settlement period. We plan to investigate whether reserve costs can be more accurately targeted into the periods for which they are procured and/or in which they are used.

4.55. National Grid Electricity Transmission (NGET) contracts for a number of reserve services in order to deal with unforeseen demand increase and/or generation unavailability. As there is a single payment associated with 'standard' Bids and Offers in the BM, it is relatively straightforward to target the costs of these balancing actions into the correct cash-out price. Reserve Services, on the other hand, have more complex payment structures, which make it more difficult to target their full costs into the correct balancing periods.

Short Term Operating Reserve (STOR)

4.56. One kind of reserve is STOR; the provision of additional active power from generation and/or demand reduction. STOR provides an example of the issues that Reserve Services create for cash-out. There are two forms of payment that National Grid will make as part of the service: availability payments for STOR providers to be available over a given period, and utilisation payments for energy delivered when STOR providers are called upon.

4.57. Availability payments for STOR, and other reserve services, can be contracted up to a number of years ahead of real-time, and they are paid for in every

contracted period that the reserve provider is available, rather than only when the reserve is used. This makes it difficult to accurately target these costs into the correct periods. They are currently fed into specific settlement periods based on expected usage, which may not coincide with when the reserve was used to balance the system. We would like to consider whether a new ex ante approach (such as basing allocation on extreme peak periods) could improve the targeting of availability payments.

4.58. Utilisation payments for providers who participate in the BM will be affected through the BM. These costs are reflected in the relevant cash-out price. However, some STOR providers (“non-BM STOR”) are not active in the BM. The cost associated with using reserve from these providers is not fed into the cash-out price. This is also the case for other kinds of reserve service (e.g. demand management). Establishing a cost for non-BM STOR and other non-costed reserve, and reflecting these in the cash-out price when this reserve is utilised, would allow the calculation to more fully reflect the SO’s balancing costs.

4.59. Some stakeholders have raised a concern that the pricing of the utilisation costs of contracted reserve may dampen the formation of prices for balancing energy, especially when these resources are the marginal plant used to balance. This could weaken the incentives on parties to balance overall. We would like to investigate other ways of pricing utilisation costs into cash-out to better encourage plant to balance ahead of gate closure. For example, in cases where the marginal bid is a balancing services resource’s utilisation costs, we could investigate pricing the opportunity cost of that plant otherwise not being there.

Reserve creation

4.60. Reserve creation is when National Grid uses the BM to position plant to be able to provide reserve in future periods. The cost of creating reserve is incurred in a settlement period prior to the period where there reserve is being used. This can cause distortion both before and during the settlement period when this kind of reserve is used. Furthermore, because the SO must consider its expectation of the system in subsequent periods when taking balancing actions, creating reserve for future periods implies that the most expensive action may not always be necessary in that period. A mechanism, perhaps akin to SO system/energy flagging, could be used to minimise any distortion these actions may create and potentially target costs into later periods where reserve is used but this could easily suffer from a lack of transparency.

4.61. Interactions

4.62. The introduction of a more marginal main price means participants are more exposed to individual actions setting the price. If the marginal action in a period is an inaccurately targeted reserve action, the price could be distorted.

4.63. A BEM allows anticipated energy imbalance to be cleared ahead of real time, there may be difficulties allocating reserve costs into this market.

4.64. A reserve market could allow more transparency about the price and quantity of reserve the SO procures. It could also make it easier to allocate the costs of reserve into the cash-out price. The nature of reserve products to be purchased by Transmission System Operators (TSOs) and the harmonisation of these products is promoted by the draft EBF.

New balancing arrangements

7) Balancing energy market (BEM)

4.65. A BEM is an arrangement that allows anticipated energy imbalances on the system (and individual participants' imbalances) to be cleared at a point ahead of real time. A mechanism would be required to maintain the incentive for parties to meet their notified dispatch schedules. This may be akin to the current cash-out mechanism or a mechanism altered in light of the considerations listed above. This is described at a high level in box 6.

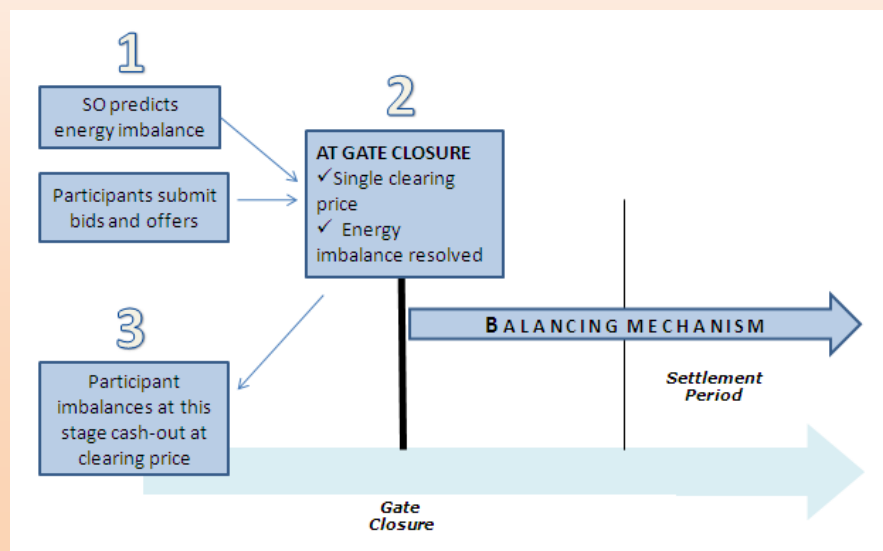
Box 6 - Balancing Energy Market straw-man

Pre-gate closure

The System Operator predicts the overall energy net imbalance volume (NIV) on the system using information submitted by participants (on their expected physical positions) and its own forecasts. The balancing energy market operator (the SO or another party) collects offers and bids from participants. Bids and offers are used to create an unconstrained dispatch schedule for the predicted NIV for each half-hour settlement period, generating a single clearing price. At gate closure, the system is deemed to be energy balanced.

Post-gate closure

The balancing mechanism operates as now with bids and offers to balance any remaining imbalances on the system. An incentive to ensure participants do not deviate from their gate closure positions may be needed. This could come in the form of a charge, linked to system stress, or be derived from the SO's subsequent bids and offers (perhaps similar to the current calculation of cash-out).



Rationale and design considerations

4.66. A BEM would create a market for energy balancing products before the BM, allowing the SO's anticipated energy imbalance to be cleared at a marginal price close to real time. This approach could boost near term liquidity, encourage DSR by providing a price that can be more easily reacted to and allow smaller players to balance their positions. It could also allow a robust reference price to be formed close to real time. It would be important have an accurate Net Imbalance Volume (NIV) forecast as this would be crucial to the price the market cleared at.

4.67. There would need to be incentives on participants not to deviate from the contracted volumes/physical notifications they submit at the point at which the BEM cleared. This could come in the form of a price based on subsequent energy balancing actions taken by the SO, similar to the current cash-out price or through a more administrative charge. Questions would remain as to what form the subsequent BM should take – whether energy balancing in the BM should be paid as bid, and how deviations in output from uncontrollable sources such as wind should be treated following the BEM clearing.

4.68. It would be important to consider the impact on within day liquidity and whether the BEM could pool more liquidity than anticipated and whether this would be problematic.

4.69. It would also be important to consider whether the SO would lose economies of scope given it currently takes some actions for both energy and system balancing reasons. Would it be efficient to take actions that had to be undone to address constraints?

4.70. Introducing a BEM is likely to be a relatively significant change to industry systems and processes.

Interactions

4.71. The introduction of a marginal price would be consistent with the BEM approach which aims at creating a single clearing price for energy balancing actions.

4.72. There may be additional challenges associated with accurately reflecting reserve costs in both the BEM and the BM and dividing them between the two mechanisms.

4.73. A BEM could help create liquidity near to real time, which could improve the reliability of near time reference prices. There is a question as to whether liquidity would be drawn away from the day-ahead market or boosted (i.e. does liquidity in one time frame breed liquidity in others or sap it?). This has implications for the TM, which aims to pool liquidity at the day-ahead stage and within-day as well as for the EMR contracts for differences which may require day-ahead or nearer term reference prices.

4.74. We would need to consider how participants provide information to the SO to inform its NIV forecast. Given the importance of an accurate forecast of the NIV, we may wish to consider an information imbalance charge in conjunction with a BEM.

4.75. We will have to consider consistency of a BEM with the TM. The TM requires intraday platforms across member states to be linked up. We will need to consider the impact on within-day market coupling, which aims to harmonise within-day trading before gate closure at cross-border points.

4.76. Also the TM requires market splitting to be considered. If adopted, more than one BEM could be required. We would have to consider whether it would be appropriate to introduce a BEM before market splitting had been considered.

8) Alternative arrangements for renewables

4.77. The volume of intermittent renewable generation on the GB electricity system is increasing but it is not able to control its output to the same extent as conventional generation. The fluctuations in wind output pose a challenge to balancing the system. At present generators are responsible for managing their imbalances themselves if they are not able to pass this risk on by selling their power to an aggregator. Box 7 provides background to the challenges of integrating renewable generation.

Options for reform

4.78. Industry commentators have raised the questions as to whether it is more efficient overall for power from intermittent sources to be aggregated centrally or whether de-centralised responsibility for intermittent output should be retained. We seek views on this as part of this consultation.

Rationale and design considerations

4.79. One argument is that it could be more efficient overall for power from intermittent sources to be aggregated centrally to take advantage of benefits from pooling fluctuations across a geographically-diverse portfolio. Pooling could help because total GB wind output is less volatile than the output of an individual wind turbine, as weaker wind output in one region can be counteracted by stronger wind output in another region. Pooling may lead to more reliable estimations of overall output and could therefore enable more power to be sold further ahead of real time. This could increase the ability of the market to absorb power from intermittent generation.

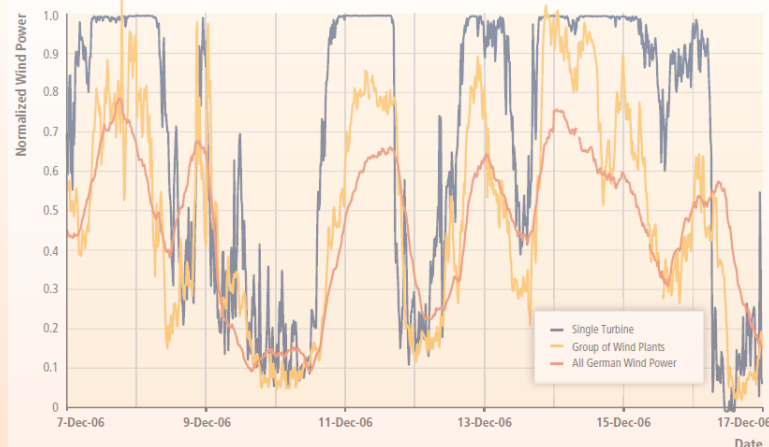
4.80. The potential roles of an aggregator may be in forecasting generators' output, organising the sale of forecast output and submitting balancing and settlement data on behalf of intermittent generators. It may be more efficient to concentrate resources into one central forecasting model. There may also be benefits in aggregating output and selling over a longer timescale than could be achieved by individual generators.

Box 7 - Integrating intermittent generation

Renewable power from wind and solar is intermittent as it depends on the weather to generate electricity. In the case of wind generation, both wind speed and temperature can alter the amount of power generated. The uncontrollable nature of the energy source means generators are unable to adjust their generation in the same way as conventional thermal generators and are therefore more likely to deviate from their forecast output, increasing imbalance exposure. The impact of this exposure could be increased further if we decide to sharpen cash-out prices.

One way to mitigate these issues is to pool individual wind farms in a larger, geographically-diverse portfolio. This aggregation of individual wind farms can lead to lower overall volatility, as shown in the figure below.

Differences in variability of output from different numbers of wind turbines in Germany



Source: Durstewitz et al (2008), reprinted in IPCC (2011, p561)

Another way is to invest in more sophisticated forecasting technologies. Improved forecasting reduces wind generators’ exposure to imbalances, improves the SO’s ability to assess the overall imbalance of the system and could lead to more effective balancing decisions being taken further ahead of real time.

Increased interconnection and intraday market coupling could make it easier for intermittent generators to export any surplus. This will be facilitated if prices in GB signal when there is excess generation. However, these measures may not be sufficient to address the problem entirely. In particular small generators may be less able to use diversified portfolio to balance their positions or to invest heavily in their trading or forecasting capabilities.

Dealing with intermittency in Spain

Spain has seen a significant expansion in the volumes of intermittent wind generation on its system in recent years and has achieved high levels of integration. The main mechanism by which Spain is able to integrate its renewables is through liquid short term markets, both day-ahead and intraday. Spain operates six intra-day auctions which allow parties to adjust their positions close to real time, when forecasts of both generation and demand are more certain. There are high levels of liquidity in these trading sessions, which is seen as the main tool removing the risk of imbalance

4.81. However, there may be a moral hazard issue. Pooling may remove incentives on individual generators to improve their forecasting ability. Also, centralised balancing could crowd out the market for commercial aggregators. Commercial aggregators are likely to be more innovative and flexible in the services they offer.

4.82. It may be appropriate for the SO to manage exposure to imbalance charges resulting from fluctuations in wind after gate closure. However, this would require technical malfunctions to be separated from wind related fluctuations in output. We would also need to make sure to retain the incentives for generators to operate with efficient maintenance schedules.

4.83. We will also consider approaches taken in other countries. In Belgium and Spain, smaller intermittent generators can avoid certain imbalance charges as long as they operate within a defined tolerance zone of forecast output. In France and Germany intermittent generation has the option to be balanced centrally.

Interactions

4.84. A BEM could provide participants an opportunity to trade out any imbalances in the near term in order to avoid cash-out prices, potentially removing the need for further changes to the arrangements.

4.85. DECC is currently looking into issues around Power Purchase Agreements (PPAs) and the route to market for independent generators in general. We work closely with DECC and changes to the balancing arrangements for intermittent generators may provide a possible solution to the PPA issue.

4.86. The draft electricity balancing framework guideline suggests that the network codes should require that generation units from intermittent renewable energy sources do not receive special treatment for imbalances. We will take this into consideration as the SCR and network codes develop. We also need to consider the interaction between pooling renewable generation and market coupling.

5. Secondary considerations

Chapter summary

In this chapter we look at a range of **secondary considerations** which may become relevant depending on the choices made in the primary considerations. Some secondary considerations may also warrant investigation in their own right. The secondary considerations are:

- a. Improved provision of information
- b. Creating a Reserve Market
- c. Amending gate closure
- d. Residual cashflow reallocation cashflow (RCRC)
- e. Reverse price
- f. Setting an information imbalance charge

Question box

Question 10: Do you agree with the circumstances we have identified in which the secondary considerations are important?

Question 11: Do you have any other comment on the secondary considerations presented here? Please provide any evidence you may have to support your position.

a) Improved provision of information

5.1. Improving the information that is provided to the market could improve transparency and competition.

5.2. One way to improve signals to the market would be to improve the imbalance forecast that the system operator (SO) publishes. The SO currently publishes information about 'indicated imbalance' – the difference between the sum of submitted generation Physical Notifications and the SO's demand forecast. Further we noted in our electricity cash-out issues paper that there can be a wide margin of error in participants' physical information, so there could be concerns that this published forecast would also be subject to error. The credibility of this forecast would be tied to the information submitted by participants. An information imbalance charge may be required to improve the SO's ability to forecast system imbalance.

5.3. The draft Electricity Balancing Framework Guidelines (EBFG) suggests that the Electricity Balancing Network Codes (EBNC) describes the necessary information to be provided by market participants to help them balance. We will monitor this.

5.4. We could consider whether there is other information which could help participants balance their positions, for example, information about volume and timing of the SO's reserve actions.

b) Creating a reserve market

5.5. We consider looking at ancillary services, how they are procured and whether there is merit in moving from bilateral contracts to an organised reserve market¹⁶. This could take the form of a day-ahead auction where participants offer flexibility to turn up or down the next day.

5.6. Through this mechanism the SO could procure its daily requirement for upward 'regulating' power and downward 'regulating' power. A reserve market could reduce the need to create reserve through actions in the Balancing Mechanism (BM) or necessarily require BM start-up contracts. The requirement to contract ahead for short term operating reserve (STOR) may still exist but contracted STOR could be offered into the reserve market rather than exercised through the BM.

5.7. It may be possible to allow participants to contract for reserve between themselves through the auction, providing greater access to products that allow certain players to balance their positions. Alternatively, a financially based options market could play a similar role. We would need to consider whether this could be provided by market participants (potentially in response to sharper cash-out prices) without regulatory intervention.

5.8. A reserve market could provide greater transparency about the price of reserve, and potentially allow reserve costs to be more accurately targeted. Consideration would have to be given to how to determine appropriate reserve products to be auctioned, and whether participants and the System Operator's forecasts would be adequate to ensure that a reserve market would be efficient. The nature of reserve products to be purchased by TSOs and the harmonisation of these products is discussed by the EBF. G.

c) Amending gate closure

5.9. Gate closure is the point at which participants cease trading and the BM begins.¹⁷ At this point participants submit Final Physical Notifications (FPNs) (signalling their expected physical position) and contract notifications (signalling the volumes that they have traded). This time is currently one hour ahead of real time.

5.10. We could consider amending gate closure (moving it nearer to or further from the beginning of the balancing period) if this is deemed necessary as a consequence of other decisions. For example, a Balancing Energy Market (BEM) might require an extra "gate closure". The draft EBF. G. suggests that the EBNC requires that TSOs harmonise gate closure as close to real time as possible. Implementation of cross border platforms will require consideration of harmonisation of gate closures at cross-border points. We will take this into account.

¹⁶ Day ahead reserve markets exist in the New England, Electricity Reliability Council of Texas (ERCOT) and the Netherlands.

¹⁷ See appendix 2 for a description of trading up to gate closure and the acceptance of bids and offers in the BM.

Ex-post trading

5.11. We could consider allowing participants to submit contract notifications ex-post, effectively allowing them to trade out imbalances after the balancing period. This may be less significant if participants on both sides of the market were able to net their cash-out exposure though it could allow trading between parties where it was mutually beneficial.

Submitting multiple Final Physical Notifications (FPNs)

5.12. It has been suggested that participants on the supply side only being able to submit a single FPN is a barrier to Demand Side Response (DSR) bidding into the BM. During the New Electricity Trading Arrangements (NETA) consultation there was some support for 'Quiescent FPNs' – one FPN for total generation or consumption, and one for uncontrollable generation or consumption. We would like to investigate whether multiple FPNs would be of value to the extent that they assist DSR.

d) Residual Cashflow Reallocation Cashflow (RCRC)

5.13. RCRC is the reallocation of the difference between imbalance charges paid in and paid out for each half hour. We identified large and opaque RCRC cashflows as a concern in our electricity cash-out issues paper. The extent to which this is a concern may change depending on decisions made on other primary considerations, so we will consider it alongside other changes.

e) Reverse price

5.14. The reverse price is the price paid by participants who are out of balance in the opposite direction to the overall system. It is based on the market price, unlike the main price, which is based on the SO's costs. The spread caused by the often considerable difference between these two prices can lead to excess imbalance risk for participants. Consideration of changing the reverse price would best be done after we'd considered the case for a single cash-out price.

f) Setting an information imbalance charge

5.15. There is a provision in the current market rules to charge participants who deviate from their FPN. It is currently set to zero. We could consider imposing a charge. It could create incentives on participants to invest in forecasting and avoid deviations. It could also help National Grid to improve its forecast of Net Imbalance Volume (NIV) to inform participants' and their own forecasts of anticipated system imbalance

5.16. We are unsure an information imbalance charge is necessary in the current market, but some form of information imbalance charge may be considered in relation to other policy changes, e.g. a BEM.

Appendices

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Appendix 1 – Consultation Response and Questions

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

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

1.3. Responses should be received by Wednesday 24 October 2012 and should be sent to:

Andreas Flamm
Wholesale Markets
Ofgem
9 Millbank
London
SW1P 3GE
0207 901 7000
gb.markets@ofgem.gov.uk

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

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

1.6. Next steps: Having considered the responses to this consultation, Ofgem intends to publish a draft policy decision in spring 2013. Any questions on this document should, in the first instance, be directed to Andreas Flamm or Jamie Black, at the contact details above.

CHAPTER 2: Approach

Question 1: Do you agree with the approach and the proposed stakeholder engagement throughout the SCR?

Question 2: Do you have any evidence that you would like to submit that may be relevant for any aspect set out in this document?

Question 3: What is your view on the interactions between our considerations and aspects of the EU target model?

CHAPTER 4: Primary considerations

Question 4: Do you feel there are any further alternatives to the reform options presented under our primary considerations?

Question 5: What other benefits or drawbacks can you identify for each of our primary considerations? Please provide any evidence you may have to support your position.

Question 6: Which of the reform options considered under each of our considerations do you believe would provide the most efficient balancing incentives and why?

Question 7: Alongside this initial consultation we have published preliminary analysis of the last modification to the cash-out arrangements, P217A. Do stakeholders agree with the initial findings of this analysis?

Question 8: What additional analysis could be done as part of the SCR around Modification P217A and the flagging methodology it introduced?

Question 9: Do you agree with our rationale for considering making cash-out prices 'more marginal'?

CHAPTER 5: Secondary considerations

Question 10: Do you agree with the circumstances we have identified in which the secondary considerations are important?

Question 11: Do you have any other comment on the secondary considerations presented here? Please provide any evidence you may have to support your position.

Appendix 2 – Current Arrangements

1.1. This section outlines the current legal, regulatory and market arrangements relating to the electricity market in GB.

Summary of the Legal and Regulatory Framework

1.2. The Electricity Act 1989 (the Act) contains some of the key provisions relating to the regulation of the electricity market. Section 4 of the Act sets out the activities which are prohibited from being undertaken by persons unless authorised by a licence. Licences authorising those activities are granted by the Gas and Electricity Markets Authority (the Authority). These activities are:

- a) generation of electricity for the purpose of giving a supply, or enabling a supply, to any premises
- b) participation in the transmission of electricity for that purpose
- c) distribution of electricity for that purpose
- d) participation in the operation of an electricity interconnector; and
- e) supply of electricity to any premises.
- f) section 6 of the Act provides the Authority with the power to grant licences for the above activities. The conditions of such licences may include conditions – whether or not related to the activity authorised by the licence- as appear to the Authority to be requisite or expedient having regard to the Authority’s duties.

1.3. The industry codes are more detailed multilateral agreements which licensees are required to comply with and which flow from licence conditions imposed using these powers.

1.4. The principal objective and general duties of the Authority are set out in section 3A of the Act. Section 3A provides that the principle objective of the Authority in carrying out its functions under part 1 of the Act is to: “protect the interests of existing and future consumers in relation to electricity conveyed by distribution systems or transmission systems”. Under paragraph 1A (b) of this section, this includes consumers’ ‘interests in the security of supply of electricity to them’. Undertaking of a review of cash-out arrangements aimed at improving the balancing of the system in certain situations and thereby enhancing security of supply is furthering the Authority’s principal objective.

Electricity Industry Codes

1.5. There are a number of electricity industry codes to which licence holders must accede and with which they must comply. The Balancing and Settlement Code (BSC) is an electricity industry code with which licensees involved in transmission, distribution, generation and supply are required to comply under licence obligations. The BSC is managed by Elexon, a wholly owned subsidiary of National Grid, which was established under the terms of the BSC.

The BSC

1.6. The BSC is a multilateral agreement which defines the rules and governance for the BM and imbalance settlement processes for wholesale electricity in Great Britain and with which licensees involved in transmission, distribution, generation and supply of electricity are required to comply.

1.7. The introduction and maintenance of the BSC is a requirement of standard condition C3 of NGET's transmission licence granted by the Authority under section 6 of the Act. The BSC is made contractually binding on other licensees by the BSC Framework Agreement. Licensees and others wishing to become parties to the BSC must sign up to the Framework Agreement. Non licensees can accede to the Framework Agreement which provides them with the right to notify energy contract volumes and register BM Units (a participating generation or demand unit).

1.8. The BSC defines the obligations on ELEXON, the Balancing and Settlement Code Company (BSCCo), in providing or procuring the services necessary to administer the BSC arrangements efficiently. It also establishes the BSC Panel, which oversees the BSC modification and governance arrangements, and defines its various responsibilities for ensuring that the provisions within the BSC are given effect in such a manner that, amongst other things, promotes competition in the generation, supply, sale and purchase of electricity.

1.9. Modifications to the BSC must be approved by Ofgem unless they are unlikely to have a material effect on matters which are the subject of the Authority's duties.

Current market and cash-out arrangements

1.10. Electricity generators and suppliers have incentives to balance their own positions through bilateral contracting and trading, leaving the SO to resolve the residual imbalance. The arrangements for payments relating to imbalances, referred to as cash-out, are central to the delivery of a competitive wholesale electricity market in Great Britain (GB). The cash-out arrangements are specified in the BSC.

1.11. The electricity market in GB operates on the basis of half-hourly settlement. Participants are expected to balance their own positions by contracting to buy or sell electricity prior to gate closure. At gate closure market participants submit their contracted and expected generation or demand up to one hour before each settlement period. Participants are under no obligation to trade or to balance their

position. NGET is responsible for ensuring real-time system balance in its role as residual balancer.

The Balancing Mechanism (BM)

1.12. The Balancing Mechanism is the principal tool used by National Grid Electricity Transmission plc (NGET) in its role as the system operator (SO) to balance the electricity system on a second-by-second basis. It runs from one hour before real time to half an hour after real time and allows parties to submit bids and offers to turn up/use less or turn down/use more electricity, with the aim to balance the electricity system overall. The SO uses the balancing mechanism for energy balancing and for system balancing actions.

1.13. These bids and offers are stacked in a merit order by NGET, from lowest to highest cost. NGET then accepts the offers that are needed to cover the overall system imbalance at least cost. These participants are remunerated for their accepted bids or offers on a pay-as-bid basis. Further detail on the operation of the Balancing Mechanism can be found in Section Q¹⁸ of the BSC.

Electricity cash-out regime

1.14. Cash-out prices are designed to provide market participants with commercial incentives to balance their contractual and physical positions. They can do this by contracting for supply ahead of time, forecasting demand as accurately as possible, by maintaining the reliability of their generating plant or even investing in new plant. Participants whose metered output or demand deviates from their contracted positions are exposed to imbalance settlement or cash-out.

1.15. Currently there are two cash-out prices – the system buy price (SBP) and system sell price (SSP). The SBP is paid by participants with a negative, or short, imbalance position. The SSP is paid to participants with a positive, or long, imbalance position.

1.16. There are also two calculations of each of the cash-out prices – the main and reverse price calculation. Imbalances which are out of balance the same direction as the overall system imbalance are seen to be contributing to the system imbalance, and are exposed to the main imbalance price. The main price reflects the cost of correcting the system imbalance. Imbalances in the opposite direction to the system do not contribute to the overall imbalance and are exposed to the reverse price. The reverse price reflects the price of wholesale electricity in the short-term market. The calculation of this is set out in the Market Index Definition Statement.

¹⁸ Section Q 'Balancing Mechanism Activities' of the BSC can be found at:
http://www.elexon.co.uk/wp-content/uploads/2011/10/section_q_v22.0.pdf

1.17. The table below provides a summary of existing cash-out prices.

System position		
	Long	Short
SBP	Reverse	Main
SSP	Main	Reverse

1.18. Further information on the current cash-out arrangements can be found in Section T of the BSC¹⁹.

¹⁹ Section T 'Settlement and Trading Charges' of the BSC is available at:
http://www.elexon.co.uk/wp-content/uploads/2011/10/section_t_v20.0.pdf

Appendix 3 - How cash-out has evolved

Early developments

1.19. The Electricity Pool of England and Wales were the market arrangements introduced in 1990 alongside the privatisation of the electricity market. The Pool was a centralised and mandatory wholesale spot market, through which generators and suppliers traded electricity. Each day generators submitted bids for each half-hourly block of the following day. These were used to establish a merit order and generate a market clearing price, the System Marginal Price (SMP). The system operator (SO) despatched all generators based on this merit order. All generators were paid the SMP plus a capacity payment for their generation, and all suppliers paid this same price for purchases from the pool.

1.20. A review of the Pool in 1998 investigated a number of concerns with the Pool, concluding that bids in the Pool were not reflective of underlying costs, and that the trading arrangements facilitated the exercise of market power at the expense of the consumer. This led to the introduction of the New Electricity Trading Arrangements (NETA) in 2001, marking a transition in the GB electricity market from a Pool to a bilateral market-based approach.

The New Electricity Trading Arrangements

1.21. NETA sought to create market-based arrangements more like those in other commodity markets. Generators and suppliers now enter into bilateral contracts, essentially self-despatching to meet the terms of these contracts. The SO then balances the residual imbalance on the system through accepting bids and offers for electricity from generators and suppliers through the Balancing Mechanism (BM), and ensures security and quality of electricity supply.

1.22. NETA introduced a settlement process for charging participants whose contracted positions do not meet their metered volumes of electricity, known as 'cash-out'. As the primary incentive on participants to trade in the forwards markets, this was a critical element of the new arrangements.

1.23. A dual cash-out approach meant that participants paid or were paid a different price depending on whether they were under or over contracted. These prices were based on a volume weighed average of the SO's actions taken in either direction to balance the system. It was accepted that participants who spill electricity on to the system should receive a lower price than if they had been fully contracted, while participants on whose behalf the SO has to procure the flexible delivery of electricity should pay the full costs. This approach was adopted to increase incentives on participants to balance their own positions in the forward markets.

1.24. The cash-out arrangements have developed since their introduction. These changes have mostly focused on improving incentives to balance, and ensuring that cash-out prices reflect the SO's costs in energy balancing only.

1.25. All modification proposals below focus on proposals to modify the Balancing and Settlement Code (BSC).

Modification Proposal P10: 'Eliminating Imbalance Price Spikes Caused By Truncating Effects' - Approved

1.26. Modification P10, approved in May 2001, introduced the De Minimis Tagging rules, removing bids and offers of less than 1MWh from determination of the SBP and the SSP. This reduced price spikes caused by limitations in the settlement systems, making cash-out prices more cost-reflective.

Modification Proposal P12: 'Reduction of Gate Closure from 3.5 Hours to 1 Hour'- Approved

1.27. Modification P12, approved in May 2002, reduced the Gate Closure from 3.5 hours to 1 hour, in order to allow participants better manage their imbalances.

Modification Proposal P18: 'Removing/Mitigating the effect of System Balancing Action in the Imbalance Price Calculations' - Approved

1.28. Modification P18, approved in September 2001, introduced mechanisms to remove or mitigate the effect of 'system' balancing actions in the calculation of cash-out prices. Continuous Acceptance Duration Limit (CADL) tagging rules were introduced to exclude all BOAs with duration of up to 15 minutes as operationally these BOAs tended to be accepted to control system frequency.

Modification Proposal P74: 'Single Cost-reflective Cash-out Price' - Rejected

1.29. This proposal was raised in April 2002 and aimed to introduce a single cash-out price, whereby all parties would be cash-out at SBP or SSP depending on overall market length. Alternative Modification Proposal P74 (P74A) based the direction of system imbalance on Net Imbalance Volume (NIV).

1.30. Both P74 and P74A were rejected. The Authority were concerned that a single price could weaken incentives for parties to balance their positions prior to gate closure and increase volatility in cash-out prices. It was also thought that the change could encourage parties to speculate on the overall direction of the system imbalance.

Modification Proposal P78: 'Revised Definitions of System Buy Price and System Sell Price' - Approved

1.31. Modification P78, approved in September 2002, introduced the concept of a main price, derived directly from costs incurred by the SO in undertaking balancing actions, and a reverse price, based on the market price. The main price would apply to parties with imbalances in the same direction as the overall system imbalance and the reverse price would apply to parties with imbalances in the opposite direction. Net Imbalance Tagging (NIV Tagging) was introduced to define the set of actions that the main would be based on.

1.32. The Authority approved Modification Proposal P78. The Authority noted that there were concerns with the previous calculation of the cash-out price, but noted that a dual cash-out price was still appropriate to incentivise participants to balance.

Modification Proposal P135: 'Marginal System Buy Price during Periods of Demand Reduction' - Rejected

1.33. Modification Proposal P135 was raised in August 2003 and sought to amend the calculation of cash-out prices such that SBP would be calculated using a marginal methodology in periods of demand control and when the system was short. P135 was rejected due to concerns that two regimes for calculation of cash-out price would introduce further scope for perverse incentives on generators to withhold generation, in order to reduce their exposure to a marginal SBP in the event of a plant failure in times of system tightness.

Modification Proposals P136: 'Marginal Definition of the 'main' Energy Imbalance Price' and P137: 'Revised Definition of the System Buy Price and System Sell Price' - Rejected

1.34. Modification Proposals P136 and P137, raised in August 2003, both proposed the introduction of a marginal methodology to calculate the main cash-out price. P136 would calculate the main price as the highest priced energy action in the Net Imbalance Volume (NIV). P137 would calculate the main price as the highest priced energy action after tagging, but removed NIV tagging from the calculation. Both Modification Proposals were rejected. The Authority's view was that in principle, when the system is under stress, the difference between using a marginal or a weighted average price should be small. There were also concerns that a marginal price could create distortions if set by a very small energy balancing action, or by a system balancing action.

Modification Proposals P194: 'Revised Derivation of the Main Energy Imbalance Price' and P205 'Increase in PAR level from 100MWh to 500MWh' - Approved

1.35. Modification P194, raised in August 2005, proposed an alternative calculation for a 'chunky' marginal price based on a volume weighted average of a pre-defined

maximum volume of the most expensive balancing actions. This eligible volume, known as the 'Price Average Reference' (PAR), was originally set at 100MWh.

1.36. P194 was due to be implemented in November 2006 on the grounds that more marginal price signals were required to ensure that parties were taking the necessary actions to balance their positions. However, before P194 was implemented concerns were expressed that a 100MWh PAR could be susceptible to distortions associated with the incomplete tagging of system actions from the price stack. Modification P205 was implemented to increase the PAR level to 500MWh.

Modification Proposals P201: 'Energy Imbalance Tolerance Band' and P202: 'Energy Imbalance Incentive Band' - Rejected

1.37. Modification Proposals P201 and P202 were raised in May 2006 and proposed the introduction of a tolerance band for imbalance charges to supplier consumption energy accounts. The proposals were rejected as there were deemed to reduce the commercial incentive on participants to balance their own positions. There were also concerns that the proposals could lead to a reduction in liquidity and would give an undue advantage to smaller suppliers.

Modification Proposals P211: 'Main Imbalance Price based on Ex-post Unconstrained Schedule' and P212: 'Main Imbalance Price based on Market Reference Price' - Rejected

1.38. P211 and P212, raised in April 2007, both aimed to address the issue of distortion of the cash-out price by 'system' balancing actions, 'system pollution'. Proposal P211 sought to amend the calculation of the Main Imbalance Price so that the SBP and SSP would be based on the least expensive offers or bids that the SO could have utilised on an unconstrained transmission system. Proposal P212 would modify the arrangements so that cash-out prices would be based on market prices rather than SO actions. SBP would be set at a 5% premium and SSP at a 5% discount to the Market Index Price.

1.39. Modification Proposal P212 was rejected as it would mean that cash-out prices would not be reflective of SO actions. A decision on P211 was initially deferred from February 2008 to October 2008. This decision was taken to align with the timetable for decision on Modification Proposal P217. The Authority rejected P211 in October 2008 as it was felt this would lead to significantly less cost-reflective cash-out prices than P217 or P217A.

Modification Proposal P217: 'Revised Tagging Process and Calculation of Cash-out Prices' - Approved

1.40. Modification proposal P217 was raised in November 2007. It sought to improve the Main Energy Imbalance Price calculation by introducing a methodology for 'flagging' Bid Offer acceptances (BOAs) and disaggregating Balancing Services Adjustment Data (BSAD) volumes that are taken to balance the system to resolve transmission constraints, and replacing the price of these where they would

otherwise 'pollute' cash-out prices. P217 also proposed a reduction in the PAR to 100MWh. Alternative Modification Proposal 217 (P217A) retained the 500MWh PAR value, but was otherwise identical to P217.

1.41. P217A was approved on 16 October 2008. It was considered that reducing the effect of system pollution makes cash-out prices more reflective of costs incurred by the SO in balancing the system. P217A was approved instead of P217 because the Authority felt that there was no case for reducing the PAR value at that time. The decision letter stated that that the PAR value should be kept under review. Ofgem also committed to carrying out a post-implementation review of P217A. This review is published alongside this document.

Appendix 4 – European Electricity market integration

This appendix provides a more detailed overview and explanation of the regulatory framework and institutions established by the Third Package and how these relate to GB. In particular, the development of new legislation, the European Network Codes, and the ongoing process to integrate national electricity markets through the Agency of the Cooperation of Energy Regulators (ACER) Regional Initiatives.

The Third Package requires Member States, as well as NRAs, to cooperate with each other and to promote cooperation among TSOs, both at regional and EU level, for the purpose of integrating national markets towards the creation of a fully liberalised internal electricity market. This requirement was affirmed by the European Council commitment to complete the internal market for electricity and gas by 2014.

“Top-down” integration: the European Network Codes

The Third Package established a mandate and process to develop more detailed legislation referred to as the European Network Codes. The European Network Codes will establish common technical and commercial rules governing access to energy networks, to create a level playing field and remove barriers to trade between Member States.

The Third Package also creates new institutions to integrate national markets and deliver a single internal market. These include ACER and the European Network of Transmission System Operators for Electricity (ENTSO-E).²⁰ Ofgem represents the UK at ACER (in liaison with the Utility Regulator of Northern Ireland), chairs the Board of Regulators (BoR) for ACER and is co-chair of the Electricity Working Group (EWG).

The network code development process

The Third Package established the following process to develop the Network Codes. At each stage of the process, except Comitology, stakeholder consultation is required:

- *Framework guideline*²¹: On the request of the Commission, ACER has six months to draft a framework guideline which establishes the scope and objectives for each subsequent Network Code. The final framework guideline is submitted to the Commission.

²⁰ Framework Guidelines set out clear and objective principles for the development of Network Codes and are developed by ACER with input from Ofgem and other NRAs. Network codes are a legally binding set of common technical and commercial rules and obligations that govern access to and use of the European energy networks.

²¹ ACER’s website: http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Activities

- *Network Code*²²: On the request of the Commission, ENTSO-E has twelve months to draft a European Network Code. The final Network Code is submitted to ACER.
- *ACER opinion*: from receipt of the Network Code, ACER has three months to provide a reasoned opinion to ENTSO-E. ACER will assess the Network Code's compliance with the relevant framework guideline. ENTSO-E may amend the Network Code in light of ACER's opinion.
- *Comitology*²³: ACER submits the Network Code to the Commission once it is satisfied that it is in line with the framework guideline. The Commission will then propose the Network Code for adoption via the Comitology process.

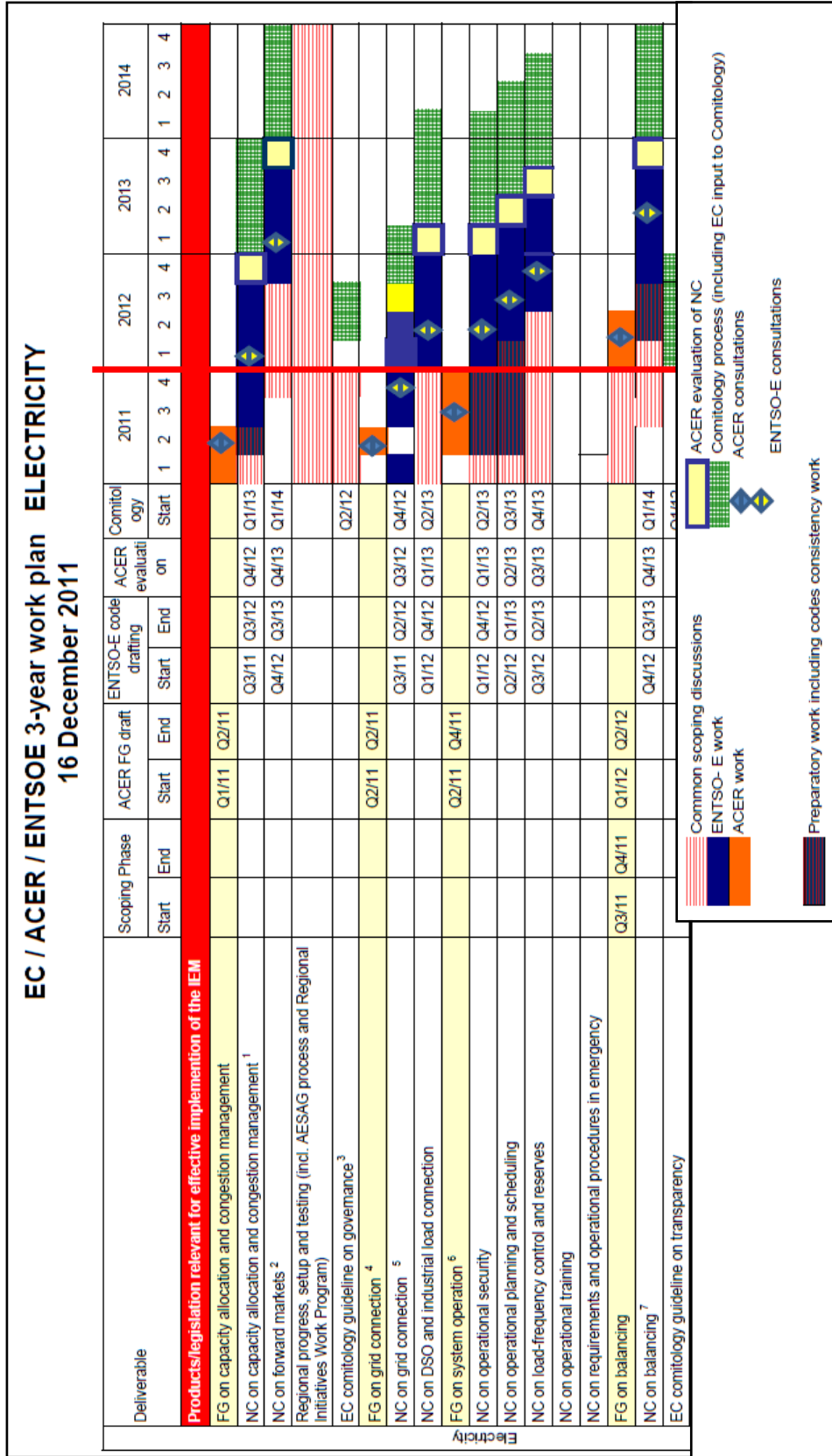
It is important to note that, once adopted via the Comitology, the European Network Codes will take precedence over national legislation, licences and domestic industry codes. The Network Codes will form annexes to the Electricity Regulation and will be directly applicable in all Member States, including the UK. Governments are required to ensure national legislation does not conflict with European legislation. In the UK this can be implemented through the European Communities Act.

Ofgem is required to comply with and implement binding decisions of the Commission and of ACER. Ofgem also has a new power to initiate code modifications that are essential for the implementation of binding ACER or Commission decisions. Further, Ofgem is required to carry out its functions under part 1 of the Electricity Act in the manner that it considers is best calculated to implement, or to ensure compliance with, any binding decision of the Agency or the Commission made under the Electricity Directive, the Electricity Regulation or the ACER Regulation in relation to electricity.

To the extent the Network Codes constitute or lead to binding ACER or Commission decisions, Ofgem will have the power to amend relevant GB electricity codes, and will also have the power to amend licence conditions to give effect to the Network Codes. Implementation of the Network Codes in GB may require further amendment of national legislation and of GB electricity licences and codes. It may also require changes to existing market arrangements.

²² ENTSO-E's website: <https://www.entsoe.eu/resources/network-codes/>

²³ DG Energy's website: http://ec.europa.eu/energy/gas_electricity/codes/codes_en.htm



Network codes currently under development

The figure above provides an overview of the timings for the framework guidelines and Network Codes currently under development. The snapshot is taken from the Commission's three year work plan which it developed with ACER and ENTSO-E. Related to this, the Commission recently issued a stakeholder consultation on its priorities for the development of network codes and framework guidelines for 2013 and beyond²⁴.

For this document, the most relevant Network Codes are those which follow the framework guideline on capacity allocation and congestion management (CACM FG) and the framework guideline on balancing (EBFG). These framework guidelines describe the "European Target Model", agreed by European regulators, for the integration of wholesale and balancing markets.

"Bottom-up" integration: the regional initiatives

In 2006, the European Regulators Group for Electricity and Gas (EREG) launched seven electricity Regional Initiatives (RIs), aimed at bringing together NRAs, TSOs and electricity market participants on a voluntary process to advance electricity market integration on a regional basis²⁵. One of the regions is the France-UK-Ireland (FUI) region comprising of the UK, the Republic of Ireland and France. Ofgem is the lead regulator for the FUI region.

The RIs represent a bottom-up approach to the completion of the internal market. They bring market participants together to test solutions for cross-border integration, carry out early implementation of European legislation and support the development of best practice.

On 18 April 2011, the Commission invited ACER to coordinate the development of a "European Energy Work Plan 2011-2014" to identify key milestones to implement the European Target Model by 2014. To facilitate this, ACER requested lead regulators of each regional initiative to develop a regional roadmap as an input to the European Energy Work Plan.²⁶

The FUI region

As lead regulator for the France-UK-Ireland (FUI) region, Ofgem coordinated the development of the FUI region roadmap to input to the European Energy Workplan.²⁷ The FUI region roadmap, submitted to the Commission and ACER in July 2011, set

²⁴ http://ec.europa.eu/energy/gas_electricity/consultations/20120416_network_codes_en.htm

²⁵ EREG for a list of the seven groups and which countries sit where, and the lead regulators for each region

²⁶ ACER, Regional Initiatives Status Review Report 2011, "Getting to 2014: The Role of Regional Initiatives", 31 January 2012

http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Communication/Publications

²⁷ The final FUI region input is available here:

http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Activities/Regional_Initiatives/Electricity_Regional_Initiatives/Regional%20Roadmaps

out the commitments and steps agreed by FUI regulators to contribute to the completion of the internal electricity market by 2014.

The roadmap was developed in discussion with relevant Member States and TSOs and subject to consultation with the FUI stakeholder group. The roadmap identified participation in the TSO-led North-West European (NWE) projects as a significant milestone for GB to completing the internal electricity market.

North West Europe projects

The NWE projects were established by a group of thirteen TSOs, covering nine countries²⁸, with the objective of developing a common approach to cross-border capacity allocation and implementing a common enduring day-ahead market coupling solution and an interim intraday solution on cables across NWE countries by the end of 2012.

As explained in the FUI region input, the NWE projects will require implementation of day-ahead market coupling and intraday continuous trading on both the BritNed and IFA interconnectors. Ofgem is the lead regulator for the NWE intraday project.

ACER and the cross-regional roadmaps to implement the European Target Model

ACER's European Energy Workplan 2011-2014 consists of four cross-regional roadmaps. The cross-regional roadmaps identify milestones and responsibilities to implement the European Target Model and achieve the internal market for electricity by 2014. The cross-regional roadmaps are:

- *Cross-Regional Roadmap on Day-Ahead Market Coupling* – led by BnetzA (Germany) and AEEG (Italy). The aim is to deliver a single European price coupling, thereby optimising the use of cross-border capacities, reducing day-ahead price volatility and improving confidence in organised price references.
- *Cross-Regional Roadmap on Continuous Intraday Trading* – led by Ofgem (UK). The aim of this is to implement a single European continuous implicit mechanism for cross-border intraday trade, with capacity pricing reflecting congestion. This will, facilitate balancing before the closure of the market and, possibly, short-term arbitrage. The intraday timeframe is seen as increasingly important in the context of growing intermittent generation.
- *Cross-Regional Roadmap on Capacity Calculation Method* – led by CREG (Belgium) and E-Control (Austria). This project focuses on implementing a Flow-Based Allocation Method for short-term capacity allocation in highly meshed networks. This aims to improve the network security and the level of capacity made available to the market, by taking into account the

²⁸ North West Europe brings together TSOs and regulators from Germany, France, Belgium, Netherlands, Sweden, Denmark, Norway, Finland and the UK.

influence of cross-border flows on the congested lines in a more transparent and effective way.

- *Cross-Regional Roadmap on Long-Term Transmission Rights* – led by CRE (France) and EI (Sweden). The main focus is on establishing common European Long-Term Transmission Rights and establishing a single point of contact.

The cross-border projects are led by the respective lead regulators, supported by the NRAs Coordination Group and the ACER Electricity Stakeholders Advisory Group (AESAG) established in March 2011.²⁹

Details of the cross-regional roadmaps, progress to date and the main challenges ahead to establishing a single internal electricity market by 2014 have been published by ACER.³⁰

²⁹ AESAG brings together the European Commission, the Council of European Energy Regulators (CEER), the European network of TSOs for electricity (ENTSO-E) and other relevant stakeholder organisations in the European electricity sector (Eurelectric, CEDEC, GEODE, EuroPEX, EFET, IFIEC, CEFIC) representing electricity companies, distributors, power exchanges, traders and consumers.

³⁰ ACER, Regional Initiatives Status Review Report 2011, "Getting to 2014: The Role of Regional Initiatives", 31 January 2012

Appendix 5 – Glossary

A

Agency for Cooperation of Energy Regulators (ACER)

ACER is a European Union body which cooperates with EU institutions and stakeholders, notably national regulatory authorities (NRAs) and European Network of Transmission System Operators (ENTSOs), to deliver a series of instruments for the completion of a single energy market.

B

Balancing and Settlement Code (BSC)

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

Balancing Mechanism (BM)

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

Balancing Mechanism Unit (BMU)

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

Balancing Services

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

Balancing Services Adjustment Data (BSAD)

Balancing Services Adjustment Data (BSAD) is used to incorporate the costs of the SO's Balancing Services contracts into the calculation of Energy Imbalance Prices.

This is laid out in the BSAD Methodology statement which the SO is required to produce under Standard Condition C16 of the Transmission Licence.

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.

BM Start-up

A Balancing Service giving the SO access to additional generation BMUs that would not otherwise have run and which could not be made available in Balancing Mechanism timescales due to their technical characteristics and associated lead times.

C

Capacity Mechanism

A capacity mechanism explicitly rewards the provision of capacity. Proposals for a capacity mechanism were part of the Government's Electricity Market Reform (EMR) consultation document, and the July 2011 publication of the EMR White Paper confirmed that a capacity mechanism would be implemented. DECC has consulted on the form of the capacity mechanism to be implemented, and has stated that it will publish more detail on the design of mechanism before the end of the year.

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 participant's 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 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 which aims to develop and deliver a new market framework that will ensure secure, low carbon and affordable electricity supplies.

Elexon

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

Energy Imbalance Prices (or cash-out prices)

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

Energy Imbalance

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

Energy stack

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

F

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

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

Final Physical Notification (FPN)

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

Flagging

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

G

Gate closure

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

I

Imbalance

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

Information Imbalance Change

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

Involuntary Demand Side Actions

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

M

Main Price

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

Market Index Price (MIP)

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

Market Splitting

Market Splitting defines the boundaries between price areas according to physical constraints, rather than by national borders.

Metered Position

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

Modification Proposal

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

N

Net Imbalance Volume (NIV)

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

New Electricity Trading Arrangements (NETA)

The electricity market arrangements introduced in 2001.

NGET

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

P

Price Average Reference (PAR)

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

Project Discovery

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

R

Reserve

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

Reserve creation

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

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 pay 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 receive 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 (e.g. 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 6 – Feedback Questionnaire

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

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

Please send your comments to:

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