Electricity Balancing Significant Code Review (EBSCR)

Further analysis to support Ofgem's Updated Impact Assessment

CLIENT: Ofgem

DATE: 14/05/2014

Version History

Version	Date	Description	Prepared by	Approved by
1.0	14/3/2014	Draft final	James Greenleaf Kian Ping Chan Andrew Stiel	Duncan Sinclair
2.1	16/5/2014	Final	James Greenleaf	Duncan Sinclair

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Background

The balancing arrangements are an integral part of any electricity market designed around the principles of self-dispatch and bilateral contracting between generators and suppliers. The arrangements provide the platform by which the System Operator (SO) is able to maintain a physical balance between supply and demand on a second by second basis and at each point on the network, and provide the price signals which incentivise market participants to balance their own energy positions at a half-hourly level.

The primary balancing tool available to the SO is the Balancing Mechanism (BM) in which generators and some providers of demand side response are able to submit bids and offers to increase or decrease generation and demand. The SO also has access to pre-contracted Balancing Services which it is incentivised to use where this can be cheaper than buying in 'real-time' from the BM.

The nature of the Balancing and Settlement Code (BSC) governance arrangements has meant that progress has been relatively piecemeal, and Ofgem has continued to express concerns about the efficiency of the arrangements, most notably in its 2009/10 Project Discovery. The change of governance arrangements with the introduction of the Significant Code Review process allows for a more holistic approach to the future development of the arrangements. Having previously consulted with industry, Ofgem decided to launch an Electricity Balancing SCR (EBSCR) in August 2012. The scope of the review was narrowed in February 2013 to focus on two high-level objectives which need to be addressed in the short term. These are to:

- Incentivise an efficient level of security of supply, and
- Increase the efficiency of electricity balancing

Redpoint - a business of Baringa Partners - supported Ofgem with the initial quantitative analysis that fed into the consultation on the Electricity Balancing Significant Code Review. The analysis ran from December 2012 to the publication of **Ofgem's Draft Policy Decision and Draft Impact Assessment** in July 2013[1]. The Baringa report was used to help assess quantitatively the impacts of different policy options being considered under the EBSCR[2].

Following the close of the consultation, Ofgem has undertaken further work to support its Final Policy Decision and Impact Assessment. The analysis in this report builds directly on the earlier Baringa report, and the Cash-Out Model (COM) developed for this.

Policy options and packages

Ofgem has considered a number of potential policy options as part of the EBSCR including:

- Making cash-out prices more marginal

[1] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

[2] See supporting Baringa report https://www.ofgem.gov.uk/ofgem-publications/82296/baringa-ebscr-quantitative-analysis.pdf

- Single versus dual cash-out pricing
- Including uncosted demand control actions in the calculation of cash-out prices, primarily demand reduction by means of voltage control and load disconnection (unserved energy), at the Value of Lost Load (VOLL), and
- Better allocation of pre-contracted reserve costs via a Reserve Scarcity Price function (RSP)

The updated analysis in this report is focused on Ofgem's preferred EBSCR Package, previously referred to as Package 5 (P5) from the original consultation as outlined in Table 1 below.

Table 1 Policy packages considered

Package	Marginality of price (PAR MWh)	Single / dual price	Uncosted actions	Allocation of reserve costs
Do nothing (DN)	500	Dual	No VoLL pricing	Current
EBSCR (P5)	1	Single	Apply VoLL pricing	Apply Reserve Scarcity Pricing Function (RSP)

Approach

For the quantitative analysis, the impact of different policy packages on cash-out prices, system balancing, security of supply and party cash-flows was explored through three separate modelling 'iterations'. These iterations require increasingly sophisticated analysis, and a corresponding increase in the number of assumptions:

- ***Iteration 1****:* aims to calculate the instantaneous impact on cash-out prices and subsequent party cash-flows under each policy package, assuming no change in parties' behaviour. This is the simplest and most transparent iteration of the analysis and is based on application of the policy packages to historical data. *Ofgem have led this part of the analysis.*
- ***Iteration 2***: aims to calculate cash-out prices in five-yearly spot years from 2015 to 2030 under the different policy packages taking into account change in parties' behaviour. In this iteration it is assumed that in the Short Term (ST) the only tool available to parties to manage their imbalance risk is through systematically lengthening or shortening the bias (hedge) in their positions when entering imbalance settlement.
- ***Iteration 3***: is similar to Iteration 2 in that it estimates forward looking cash-out prices to 2030. However, in addition to any short-term response in systematic bias, it also examines the impacts assuming that parties could invest in Longer Term (LT) measures to allow them to manage better their imbalance risk (e.g. forecasting improvements). In contrast to the original analysis we assume that all investment in new generating capacity and demand side response is stimulated by the Capacity Market (CM). The impact of cash-out reform is to change the cost of procuring capacity through the capacity auctions rather than to lead directly to additional investment. It may also alter the type of investment depending on the impact on different types of plant (e.g. peaking versus baseload or mid-merit) who can bid into the CM, but the subsequent impact of this on cash-out prices is not modelled directly.

Iteration 1 utilises only historic data, whereas Iterations 2 and 3 require a Cash-Out Model (COM) calibrated to historic data that can simulate changing party behaviour. These latter two iterations are the focus of this report and are based around a 'top-down' Monte-Carlo simulation of cash-out prices.

This effectively simulates the balancing accuracy of individual party types to calculate Net Imbalance Volumes (NIV), and compares these volumes to simulated 'Energy Balancing Cost Curves' (EBCCs). The EBCCs replicate the potential BM Bids and Offers available to resolve energy imbalances in a half-hourly settlement period. The simulation is undertaken for a characteristic day in each month across the spot years for 2015, 2020, 2025 and 2030. A Cost Benefit Analysis (CBA) from the perspective of consumers was undertaken for EBSCR and compared to the DN case.

The modelling undertaken for this updated analysis has also been extended in a number of key areas:

- We now capture interconnector flows explicitly in the model to understand better the impact of cash-out reform on their responsiveness.
- We have improved the representation of wind parties within the model, in particular to understand better the correlation of individual independent wind plant to the overall system imbalance and by extension their exposure to imbalance costs.
- We have estimated the impact of cash-out reform on the costs of capacity procured through the CM auction along with wider wholesale market costs; using the output from the EBSCR COM with Baringa's Transmit Decision Model (used to support Ofgem's Project Transmit).
- We have indirectly assessed the impact of cash-out reform on individual parties' credit cover risk, by calculating their rolling credit cover requirements under the BSC.

Results of the updated analysis

In the absence of cash-out reform under the DN case, the changing generation mix, rising average fossil fuel and carbon prices, and tightening capacity margins relative to today[3] will likely drive significant increases in the costs of energy balancing over the next two decades.

For example, the overall cost of energy balancing to the consumer could potentially increase by around 50% to approximately £40m annually by 2020, and potentially increasing by a factor of 10 by 2030. The costs of system balancing, such as the management of transmission constraints, could also rise significantly over this period but this was not a focus of this study.

Figure 1 illustrates the forecast increasing spread of Net Imbalance Volumes over time under the DN case, largely driven by the increases of wind capacity on the system. The modelling also

[3] Albeit stabilising at a level estimated to be equivalent to around 3 hours of Loss of Load Expectation following the introduction of the CM

suggests that under the DN case System Buy Prices (SBPs) will rise significantly over time, and that after 2020 System Sell Prices (SSPs) will start to fall as bids from subsidised low carbon generation are captured within the cash-out price calculation, as shown in Figure 2. By 2030, the average SSP (when it is the main price) is expected to be negative. This will result in a greater spread in cash-out prices which is expected to influence player behaviour. Figure 2 also shows the annual average SBP and SSP (when main price) under EBSCR, with higher SBP than the DN case, and lower SSP. The Market Index Price (MIP), the within day wholesale price, is also shown. The spread between the cash-out prices and MIP provide an indication of the opportunity cost of being out of balance.

It should be noted that the 2015 results assume the full EBSCR package is in place. However, this will not take place until the end of 2015, hence 2015 should be viewed as a proxy for 2016, the first full year after the EBSCR reform.

Figure 1 NIV distributions

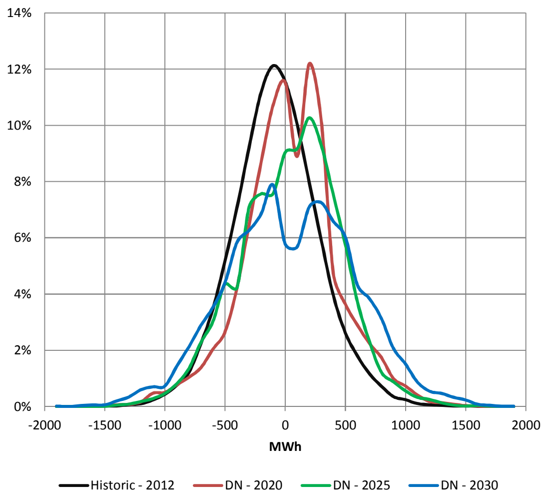
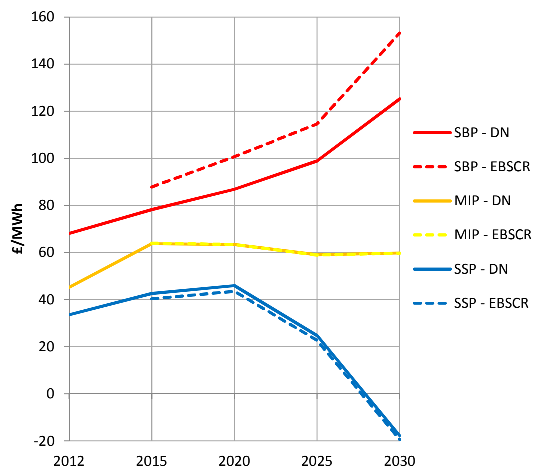


Figure 2 Annual average (main only) COPs



The risk of being exposed to very negative SSPs for being long may become as material as the risk of exposure to very high SBPs for being short, and thus the current incentive to adopt a systematically long position may change. For example, under the DN case the modelling suggests that by 2030 there is a preference to go shorter to avoid negative SSPs, whereas under EBSCR the more marginal PAR, RSP and VoLL pricing mean that the SBP spread is again significantly larger than the SSP spread and sufficiently so that there is a preference to be longer on average under EBSCR compared to DN.

In the intervening period the situation is more complicated due to the single pricing component of EBSCR. Under single pricing parties are rewarded more for being out of balance in the opposite direction to the system compared to dual prices, but are still at risk of the same exposure if they are out of balance in the same direction as the system. Overall the system is still slightly shorter under EBSCR in 2020 even though the SBP spread is larger on average than the SSP spread, compared to the equivalent spreads under DN. This is because the aggregate effect of the benefit of single pricing across the parties[4] (i.e. receiving SBP if they happen to be long when the system is short) outweighs the risk of being by exposed to the spread by being short when the system is short. However the absolute magnitude of the average spread on the SBP versus the SSP side (under EBSCR versus DN in each case) is still smaller than that in 2030 and is not yet sufficient to switch the overall party incentives back to being longer on average.

A Cost-Benefit Analysis (CBA) of cash-out reform under EBSCR in the table below shows a modest disbenefit to consumers in 2015 compared to DN (of around £0.48/MWh), and modest but sustained benefits after the introduction of the CM (of up to around £0.40/MWh) and a positive NPV (Net Present Value) overall of around £435m over the period to 2030. The underlying reduction in imbalance costs is positive for consumers in all years.
The CBA is split into two groups of costs and benefits: those directly related to changes in imbalance costs for parties and the system operator, and those relating to ensuing changes in wholesale costs (electricity and capacity prices). We assume for simplicity that all costs and benefits are ultimately passed on to customers.

The direct imbalance cost impacts include:

- The sum of the changes in NIC and RCRC which are net neutral to the consumer, but can have tangible distributional impacts across different parties.
- Changes to the short term balancing positions of parties (due to their position biases) leading to very small benefits in the total cost of balancing the system[5] in most years, due to the reduction in the requirement for more expensive actions in the Balancing Mechanism.
    - However, the significant drop in SSPs (becoming negative on average) moving from 2025 to 2030, combined with a remaining wider spread on the offer side means that parties still have a preference to be slightly longer under EBSCR. This marginally increases the number of negatively priced bids accepted and the cost of balancing relative to DN.
    - The shape of the bid and offer curves means that the reduced costs of balancing when the system was previously shorter are slightly less than the additional costs from the negative bids (due to the subsidy impact) plus the additional party costs of hedging slightly longer. However the scale of the ST changes across all years is very small and broadly neutral overall.
- Changes to the incentives to invest in LT balancing performance across parties and the SO which are a more significant benefit under EBSCR. Slightly weaker balancing performance from a lower level of investment increases the costs to the SO since Gross Imbalance Volumes increase, but the savings to parties more than offset these additional costs. This is the result of the fact that under EBSCR the aggregate costs to parties of imbalances better align with the underlying costs incurred by the SO, in particular as a result of the single pricing reform.

[4] Note that individual parties will be incentivised to adjust their position bias in different ways given their different shapes of imbalance exposure, but this refers to the combined impact at the system level.
[5] Composed of the change in costs to the SO in resolving the resulting change in NIV, and the change in costs incurred by parties in the wholesale market when adapting their contractual positions.

The wholesale cost impacts include:

- Increases in wholesale prices associated with the knock-on impact of higher SBPs on within-day prices feeding through into day-ahead and forward prices.
- Reductions in capacity prices in the CM as participants anticipate the impact of higher cash-out prices at times of system stress on wholesale prices in their offers to the capacity auction. Aside from 2015 (when the CM is not yet in place) the impact of cash-out reform on the costs of capacity purchased through the CM (via lower auction clearing prices) more than offsets the impact of higher wholesale prices on consumers, leading to a net benefit for consumers from 2020 onwards. This net benefit increases in later years as the plant clearing the CM auction moves from baseload/mid-merit plant to new peaking plant whose expectations of average price captured in the wholesale market are most affected by cash-out reform. This allows them to discount their CM offers driving savings to the consumer.
- Savings associated with higher assumed de-rating factors for interconnected capacity as a result of higher interconnector responsiveness under EBSCR. If interconnected capacity is excluded from the CM, as will be the case for the first year of the CM in 2018/19, this will reduce the capacity requirement in the auction. In subsequent years, if interconnected capacity can participate in capacity auctions, then a higher de-rating factor for interconnectors should increase competition. Either way, this should reduce the capacity auction clearing prices and lead to consumer savings[6].

[6] Alternatively, if the de-rating factors for interconnectors are not increased then the effect of greater interconnector responsiveness would be to reduce the risk and costs of unserved energy from the three hours of loss of load expectation being targeted under the CM. The resulting savings in unserved energy are commensurate with the savings in the CM from assuming higher de-rating factors for interconnectors.

Table 2 CBA summary - domestic consumer perspective (NPV social discount rate of 3.5% real)

£m/year (+ve = benefit to end consumer[7])	EBSCR relative to DN			
	2015[8]	2020	2025	2030
NIC	122	100	162	330
RCRC	-122	-100	-162	-330
ST position bias costs (party and SO)	2	2	2	-3
Party savings from lower LT balancing investment	30	26	21	39
System costs from lower LT balancing investment	-16	-14	-7	-3
Total consumer costs (before wholesale and capacity price effects)	*17*	*14*	*16*	*33*
Wholesale electricity prices	-166	-17	-360	-426
Capacity prices	0	27	468	517
Interconnector de-rating factors	0	5	3	7
Total consumer costs	***-149***	***29***	***127***	***131***
NPV 2016 – 2030 £m	**435**			
Change in average £/MWh	**-0.48**	**0.10**	**0.43**	**0.40**
Annual domestic bill change (£) (-ve = benefit)	**1.60**	**-0.32**	**-1.40**	**-1.32**
Annual domestic bill change (excluding wholesale and capacity price effects) (-ve = benefit)	*-0.18*	*-0.16*	*-0.17*	*-0.33*

Note: totals may not sum due to rounding

Although the CM will be the main tool for ensuring capacity adequacy, cash-out reform should also increase security of supply through increasing the value of flexibility. This should increase incentives to invest in flexible generation and demand side response. However, neither of these potential benefits is quantified explicitly in the modelling.

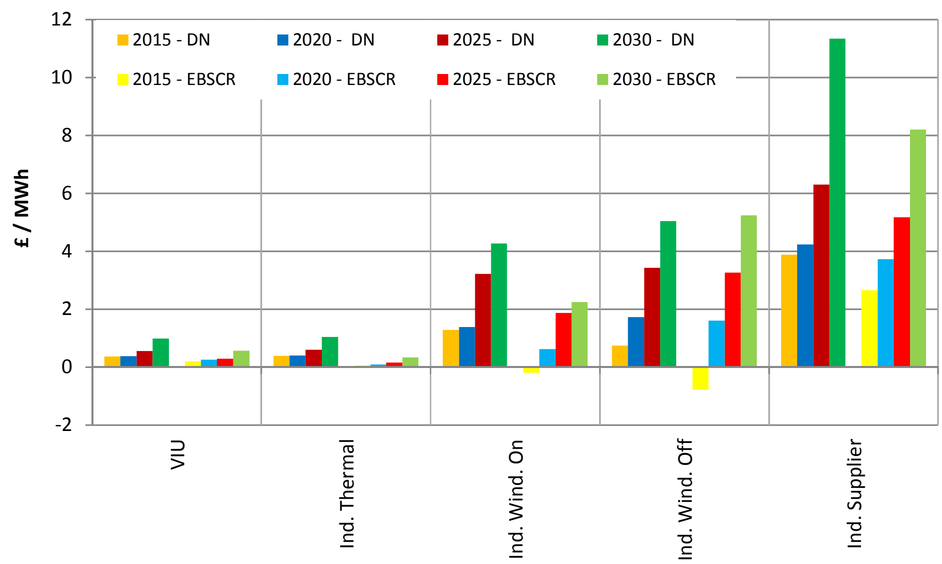
By encouraging a higher volume of imbalance, the effect of single pricing is to increase the costs of energy balancing for the SO somewhat, but this effect appears to be relatively small and the incentives to balance remain strong under EBSCR, and are sharpened under conditions of system stress. The savings to parties of having to invest less in long term balancing performance appear to more than outweigh the additional costs for the SO.

The proposed cash-out reform is likely to have tangible distributional effects and indirectly impact on competition in the market. For example, where the existing cash-out arrangements unduly disadvantage smaller suppliers (due to the impact of dual pricing on weaker balancers), the proposed cash-out reforms could remove some barriers to new entry.

[7] Assumes that all costs and benefits are ultimately pass through to the consumer
[8] This assumes the full EBSCR package is in place. However, this now will not take place until 2016. The NPV is calculated from 2016-2030 with linear interpolation of values between years. Hence 2015 is a proxy for the 2016 value, subject to the linear interpolation between 2015 and 2020.

Looking at the direct distributional effects of cash-out reform from the modelling, Figure 3 below show the opportunity cost of imbalance for different party types. The underlying increases in imbalance costs can be seen when comparing 2030 to earlier years, driven by the changing capacity mix and increasing commodity prices[9].

Figure 3 **Party-level opportunity cost for DN and EBSCR**



However, it can be seen that the opportunity costs of imbalance are typically lower under EBSCR than the DN case. The benefit of single pricing for typically weaker balancers, for example independent suppliers or renewable generators, tends to more than offset the additional exposure to more marginal cash-out prices. An indirect result of this is that single pricing also helps to mitigate against an increase in credit cover requirements under the BSC from sharper cash-out prices.

[9] Note that the opportunity costs of imbalance are lower for some parties, such as independent wind, than in the previous analysis. This reflects the enhancements in the modelling approach, in particular the assumptions surrounding the correlation of independent wind parties' forecast errors to the overall system, along with greater flexibility provided by interconnectors and gas-fired generation.

BARINGA PARTNERS

Baringa Partners is a specialist consultancy of 300 professionals dedicated to the Energy, Water and Financial Services sectors with bases in the UK and Germany. Our work is focused on delivering change within our industries, including supporting our clients in formulating strategy and making key decisions, and in the delivery of transformation programmes across business and information technology.

Since our formation in 2000, we have grown strongly, working with some of the largest energy producers, utilities and banks across Europe, as well as niche and innovative start-ups. We have continued to attract some of the brightest talent across our industries, and have been widely recognised as an employer of choice.

Our Energy Advisory practice, formed through the merger with Redpoint Energy in April 2012, has worked with many of the leading energy companies in Europe, as well as governments and regulators, on issues related to market reform, regulation, strategy, asset acquisition, regulation, restructuring, asset portfolio management, and performance improvement. We are recognised for the depth of expertise in the markets in which we operate and our analytical excellence.

Contact

Duncan Sinclair
Partner
email: duncan.sinclair@baringa.com
tel: + 44 203 327 4220

LIST OF ACRONYMS

Standard	Project specific
- BCV – Bilateral Contract Volume - BETTA – British Electricity Trading and Transmission Arrangements - BPA – Buy Price Adjuster - BM – Balancing Mechanism - BMU – Balancing Mechanism Unit - BOA – Bid Offer Acceptance - BSAA – Balancing Services Adjustment Action - BSC – Balancing and Settlement Code - BSUoS – Balancing Services Use of System Charges - CADL – Continuous Acceptance Duration Limit - CBA – Cost Benefit Analysis - CfD – Contract for Difference - CM – Capacity Market - CSOBM - Cost of System Operation in the Balancing Mechanism - DSR – Demand Side Response - EBSCR – Energy Balancing Significant Code Review - EEU – Expected Energy Unserved - EMR – Electricity Market Reform - ECC – Energy Credit Cover - FPN – Final Physical Notification - GC – Gate Closure - GCV – Gross Calorific Value - GIV – Gross Imbalance Volume - MIP – Market Index Price - NIV – Net Imbalance Volume - PAR – Price Average Reference (volume) - RCRC – Residual Cashflow Reallocation Cashflow - RO – Renewables Obligation - SBP – System Buy Price - SO – System Operator - SPA – Sell Price Adjuster - SRMC – Short Run Marginal Cost - SSP – System Sell Price - STOR – Short Term Operating Reserve - Total Energy Indebtedness - TM – Target Model - UEP – (DECC) Updated Energy Projections - VIU – Vertically Integrated Utility - VoLL – Value of Lost Load - VOM – Variable Operating and Maintenance cost	- COM – Cash Out Model - EBCCs – Energy Balancing Cost Curves - LD – Load Disconnection - LT – Long Term - OC – Opportunity Cost - OB – Opportunity Benefit - RSP – Reserve Scarcity Price Function - ST – Short Term - VC – Voltage Control

1. INTRODUCTION

1.1. Background

The balancing arrangements are an integral part of any electricity market designed around the principles of self-dispatch and bilateral contracting between generators and suppliers. The arrangements provide the platform by which the System Operator (SO) is able to maintain a physical balance between supply and demand on a second by second basis and at each point on the network, and provide the price signals which incentivise market participants to balance their own energy positions at a half-hourly level.

The primary balancing tool available to the SO is the Balancing Mechanism (BM) in which generators and some providers of demand side response are able to submit bids and offers to increase or decrease generation and demand. The SO also has access to pre-contracted Balancing Services which it is incentivised to use where this can be cheaper than buying in 'real-time' from the BM.

The prices for imbalance settlement or 'cash-out' are derived from actions taken in the BM and to an extent from the costs of pre-contracted Balancing Services. The calculations of cash-out prices are necessarily complex given the requirement to extract the value of energy in each period from a set of actions taken in real-time for a variety of reasons, not all of which relate directly to gross energy imbalances at a half-hourly level. A fundamental principle behind the British Electricity Trading and Transmission Arrangements (BETTA) is that the costs of energy balancing should be targeted at those participants that cause the imbalances, but that the costs of system balancing (sub-half-hourly, locational, network services) should be socialised.

As a result of this complexity, the balancing arrangements, which were implemented in 2001, have been the subject of two previous reviews[10], and a number of modifications to the Balancing and Settlement Code (BSC) have resulted. These modifications have helped to improve the accuracy of the cash-out price signal, by reducing 'system pollution' in the energy price signal and reducing excessive volatility.

The nature of the BSC governance arrangements has meant that progress has been piecemeal, and Ofgem has continued to express concerns about the efficiency of the arrangements, most notably in its 2009/10 Project Discovery. The change of governance arrangements with the introduction of the Significant Code Review (SCR) process allows for a more holistic approach to the future development of the arrangements. Having previously consulted with industry, it decided to launch an Electricity Balancing SCR (EBSCR) with a broad scope in August 2012. The three high-level objectives of the review are to:

- Incentivise an efficient level of security of supply, and
- Increase the efficiency of electricity balancing

The outcome of the EBSCR is therefore strongly intertwined with security of supply, the success of EMR in integrating large volumes of (relatively inflexible) low carbon generation, the competitiveness of the market and ultimately the price paid by consumers for their electricity.

[10] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx

1.2. Project context and objectives

Redpoint - a business of Baringa Partners - supported Ofgem with the initial quantitative analysis that fed into the consultation on the Electricity Balancing Significant Code Review. The analysis ran from December 2012 to the publication of **Ofgem's Draft Policy Decision and Draft Impact Assessment** in July 2013[11]. The Baringa report was used to help assess quantitatively the impacts of different policy options being considered under the EBSCR[12].

Following the close of the consultation, in response to some industry input from both Ofgem's Draft Policy Decision consultation responses and queries raised in Ofgem's Technical Working Group, Ofgem has undertaken further work to support its Final Policy Decision and Impact Assessment. The analysis in this report builds directly on the earlier Baringa report, and the Cash-Out Model (COM) developed for this, but extends it in a number of key areas:

- Model functionality has been extended to include:
    - Interconnector response
    - Better treatment of wind
    - Updated Reserve Scarcity Pricing (RSP) function
    - Greater flexibility for gas-fired generators to turn down, i.e. greater BM bid volumes
- Input assumptions have been updated to:
    - Reflect the latest key forward looking assumptions, such as DECC's fuel price and capacity mix projections
    - Consider an extended historic data set (running for 4 years rather than 3 in the previous study) as the basis for calibrating the COM
- Additional analysis has been undertaken to:
    - Explore the impact of cash-out reform on the costs of capacity procured through the Capacity Market (CM)
    - Understand the potential impact on credit cover under the BSC arrangements for different party types

Further details of the modelling approach and assumptions are provided in the original Baringa report[12].

[11] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

[12] See supporting Baringa report https://www.ofgem.gov.uk/ofgem-publications/82296/baringa-ebscr-quantitative-analysis.pdf

1.3. Policy options and packages considered

As part of industry consultation supporting the EBSCR process, Ofgem has provided extensive background material on a number of the policy considerations in reforming cash-out[13], and hence they are only summarised briefly below.

More marginal cash-out prices

At present, cash-out prices in a settlement period are calculated as the volume weighted average of the highest/lowest[14] remaining 500MWh of actions in the Net Imbalance Volume stack, after all preceding flagging and tagging rules have been applied[15]. This is known as the Price Average Reference (PAR) volume. Making the PAR smaller more closely aligns the main energy imbalance price with the price of the marginal energy balancing action.

Single versus dual cash-out prices

At present cash-out operates under a dual-price regime whereby the price faced by a party depends on the direction of imbalance of the party relative to the overall system imbalance direction.

Parties out of balance in the same direction as the system are exposed to the main cash-out price reflecting the costs of resolving the energy imbalance on the system in that period, whereas those in the opposite direction (and hence helping to reduce the energy imbalance on the system) are exposed to the reverse, or Market Index Price (MIP). This reflects the price in the within-day market and is meant to be similar to what a party could have attained if it had traded in the market prior to Gate Closure.

Alternatively, under single pricing the reverse MIP is removed and the main SBP and SSP are used for parties out of balance in both directions to the system. The differences between the two approaches are summarised in the tables below.

Table 3 Dual cash-out price arrangements

		Length of party	
		Short	**Long**
Length of overall system	**Short**	Pay SBP (Main, offer costs in BM)	Paid SSP (Reverse, MIP)
	Long	Pay SBP (Reverse, MIP)	Paid SSP (Main, bid costs in BM)

Table 4 Single cash-out price arrangements

	Length of party

[13] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Pages/index.aspx
[14] Depending upon whether the system is short or long, respectively
[15] See ELEXON Imbalance Pricing Guidance for more details http://www.elexon.co.uk/wp-content/uploads/2013/02/imbalance_pricing_guidance_v4.0.pdf

		Short	Long
Length of overall system	Short	Pay SBP (Main, offer costs in BM)	Paid SBP (Main, bid costs in BM)
	Long	Pay SSP (Main, offer costs in BM)	Paid SSP (Main, bid costs in BM)

Including non-costed demand control actions in cash-out prices

At present the implied costs to consumers of using voltage control[16] to balance the system, or from involuntary load disconnection when it is not possible to balance the system, are not factored into cash-out prices. This is potentially dampening the price signal from cash-out as it not properly accounting for the cost (or value) of balancing the system and maintaining security of supply. The costs of these demand control actions could be included by assigning a price to them in the cash-out price calculation (£3000/MWh before winter 2018/19 and £6000/MWh from this point onwards).

Allocation of reserve costs via a Reserve Scarcity Price Function (RSP)

Due to the practical and technical difficulties of balancing the electricity system in real time, as well as commercial incentives to minimise costs, the System Operator (SO) typically procures a range of Short Term Operating Reserve (STOR) contracts in advance that can be drawn upon as needed. This is comprised of both BM-STOR actions, from parties already active in the BM and non-BM STOR actions from parties who are not.

At present, the costs of both forms of STOR are divided into upfront 'availability fees' and actual 'utilisation fees'. The latter are captured directly in the cash-out price calculation[17], whereas the former are captured indirectly through a Buy Price Adjuster (BPA). However, the disaggregation of the costs of STOR into these components means it is difficult to target their overall costs accurately into the settlement periods in which they are used, potentially reducing the cost reflectivity of energy balancing actions. In particular, the utilisation fees of contracted STOR providers do not reflect the scarcity value of energy when system conditions are tight, potentially dampening cash-out prices at these times.

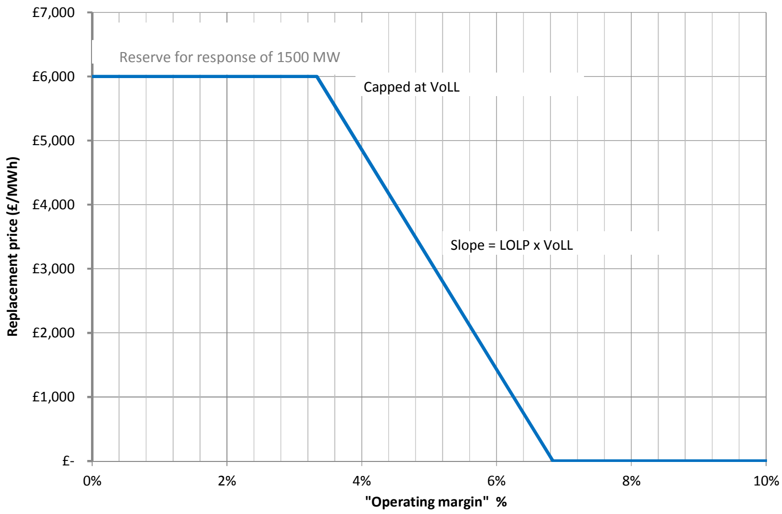
Under the RSP, the BPA is removed and STOR actions are re-priced using a single replacement price for each settlement period where a reserve action is utilised and where the replacement price is greater than the utilisation price offered by the unit. The re-pricing is only carried out for the purposes of the cash-out price calculation and does not alter the price paid by the SO.

This price (Value of Lost Load times the Loss of Load Probability) is a function of the 'reserve margin' at Gate Closure[18] – i.e. the tighter the margin the higher the price. This would cover both BM and non-BM STOR, and would therefore also effectively capture non-BM STOR utilisation fees in cash-out prices, which is not currently the case.

[16] Voltage control is an option that can be adopted by the SO over small time periods that reduces the power drawn (and effective demand) of customers. In addition, it should be noted that the SO can also utilise Max Gen options before disconnections.
[17] With the current exception of non-BM STOR utilisation fees.
[18] The precise definition of the margin is outlined in Ofgem's EBSCR final decision document.

Figure 4 below shows the parameters used for the RSP in the modelling.

Figure 4 **The Reserve Scarcity Price (RSP) function**



Since the Draft Policy Decision Ofgem has held a further industry Technical Working Group session on the RSP. The principal difference for the purposes of this updated analysis is the 'reserve for response' (the level at which voltage control is assumed to take place). This has increased from 500MW to 1500MW, which all else being equal, tends to lead to higher reserve scarcity prices.

Further details on the specification of the RSP function can be found in Appendix A.

Policy packages considered

In the previous Baringa report five potential policy packages were explored (as shown in Table 3 below), with Ofgem setting out a minded-to position on the EBSCR package in its consultation. *Within this further analysis only the EBSCR package and DN (Do Nothing) have been assessed.*

Table 5 **Cash-out policy packages (only DN and EBSCR assessed in this report)**

Package	Marginality of price (PAR MWh)	Single / dual price	Uncosted actions	Allocation of reserve costs
DN	***500***	***Dual***	***No VoLL***	***Current***
P1	50	Dual	No VoLL	Reserve Scarcity Price Function (RSP)
P2	1	Single	No VoLL	
P3	1	Dual	Apply VoLL	
P4	50	Single	Apply VoLL	
EBSCR (P5)	**1**	**Single**	**Apply VoLL**	**Reserve Scarcity Price Function (RSP)**

2. MODELLING APPROACH

2.1. Overview

For the quantitative analysis, the impact of different policy packages on cash-out prices, system balancing, security of supply and party cash-flows was explored through three separate modelling 'iterations'. These iterations require increasingly sophisticated analysis, and a corresponding increase in the number of assumptions:

- ***Iteration 1****:* aims to calculate the instantaneous impact on cash-out prices and subsequent party cash-flows under each policy package, assuming no change in parties' behaviour. This is the simplest and most transparent iteration of the analysis and is based on application of the policy packages to historical data. *Ofgem have led this analysis*
- ***Iteration 2***: aims to calculate cash-out prices in five-yearly spot years from 2015 to 2030 under the different policy packages taking into account change in parties' behaviour. In this iteration it is assumed that in the Short Term (ST) the only tool available to parties to manage their imbalance risk is through systematically lengthening or shortening the bias (hedge) in their positions when entering imbalance settlement
- ***Iteration 3***: is similar to Iteration 2 in that it estimates forward looking cash-out prices to 2030. However, in addition to any short-term response in systematic bias, it also examines the impacts assuming that parties could invest in Longer Term (LT) measures to allow them to manage better their imbalance risk (e.g. forecasting improvements) . In contrast to the original analysis we assume that all investment in new generating capacity and demand side response is stimulated by the Capacity Market. The impact of cash-out reform is to change the cost of procuring capacity through the capacity auctions rather than to lead directly to additional investment. It may also alter the type of investment depending on the impact on different types of plant (e.g. peaking versus baseload or mid-merit) who can bid into the CM, but the subsequent impact of this on cash-out prices is not modelled directly.

Iteration 1 utilises only historic data, whereas Iterations 2 and 3 require a Cash-Out Model (COM) calibrated to historic data that can simulate changing party behaviour. These latter two iterations are the focus of this report and are based around a 'top-down' Monte-Carlo simulation of cash-out prices.

This effectively simulates the balancing accuracy of individual party types to calculate Net Imbalance Volumes (NIV), and compares these volumes to simulated 'Energy Balancing Cost Curves' (EBCCs). The EBCCs replicate the potential BM Bids and Offers available to resolve energy imbalances in a half-hourly settlement period. The simulation is undertaken for a characteristic day in each month across the spot years for 2015, 2020, 2025 and 2030. A Cost Benefit Analysis (CBA) from the perspective of consumers was undertaken for EBSCR and compared to the DN case.

Only a summary of the COM is outlined below, along with a description of the key updates for this study. Further detail on the underlying COM approach is contained within the original Baringa report (see footnote 12*).*

2.2. Cash-Out Model (COM)

The Cash-Out Model (COM) is the heart of the simulation engine. It simulates the balancing accuracy of BM party types (i.e. the contracted position versus metered position on different production and consumption accounts for parties such as vertically integrated utilities (VIUs) or independent generators). This is used to generate a NIV for the system as a whole in each half-hourly settlement period, on each characteristic day by month, in each spot year considered.

Key simulated inputs include the balancing accuracy of parties, which reflects factors such as demand forecast error for consumption accounts and wind forecast error / outage risk for production accounts. A starting (static) estimate of systematic position bias (estimated from historic data) is also applied, which is subsequently updated via the ST response functionality of the model. This bias represents the party's overall bias in position when entering imbalance settlement, to minimise their exposure to cash-out prices.

The simulated NIVs are compared with a set of simulated Energy Balancing Cost Curves (EBCCs), which mimic the (unpolluted[19]) energy only stack of bids or offers to generate the cash-out prices from the COM, under different policy packages in each half-hourly settlement period on a characteristic day.

A base set of EBCCs was estimated from historic data. These are adjusted over time due to exogenous changes in the underlying capacity mix (e.g. new plant or retirement of existing plant), simulated commodity prices (to alter energy balancing costs and the potential merit order) and simulated demand (to mimic the impact of a tighter / looser system on available energy balancing options).

The COM then takes the cash-out prices and combines them with an estimate of the MIP (used to set the reverse Energy Imbalance Price) to generate the imbalance cash-flows (e.g. NIC, RCRC) by party type and for the system as a whole. The calculation of MIP is dynamic and based on a regression model of the link between simulated cash-out prices (and other key simulated and non-simulated variables in the COM) and within-day market prices[20].

The Short Term (ST) response then examines the extent to which each party could act to minimise its *'Imbalance Opportunity Cost'* by adjusting the systematic bias (or hedge) with which it enters imbalance settlement prior to Gate Closure under expected average conditions. The updated party positions are fed back into the core COM to see the combined impact on NIV and cash-out prices for the system as a whole. Changes to expected average SBP / SSP at the system level as a result of the change in bias may then lead to further adjustments in bias, and hence the process is repeated until a broad equilibrium is reached – i.e. parties cannot further improve their position given: their own position, other parties' positions and the overall expected system values from cash-out as a result of these.

---

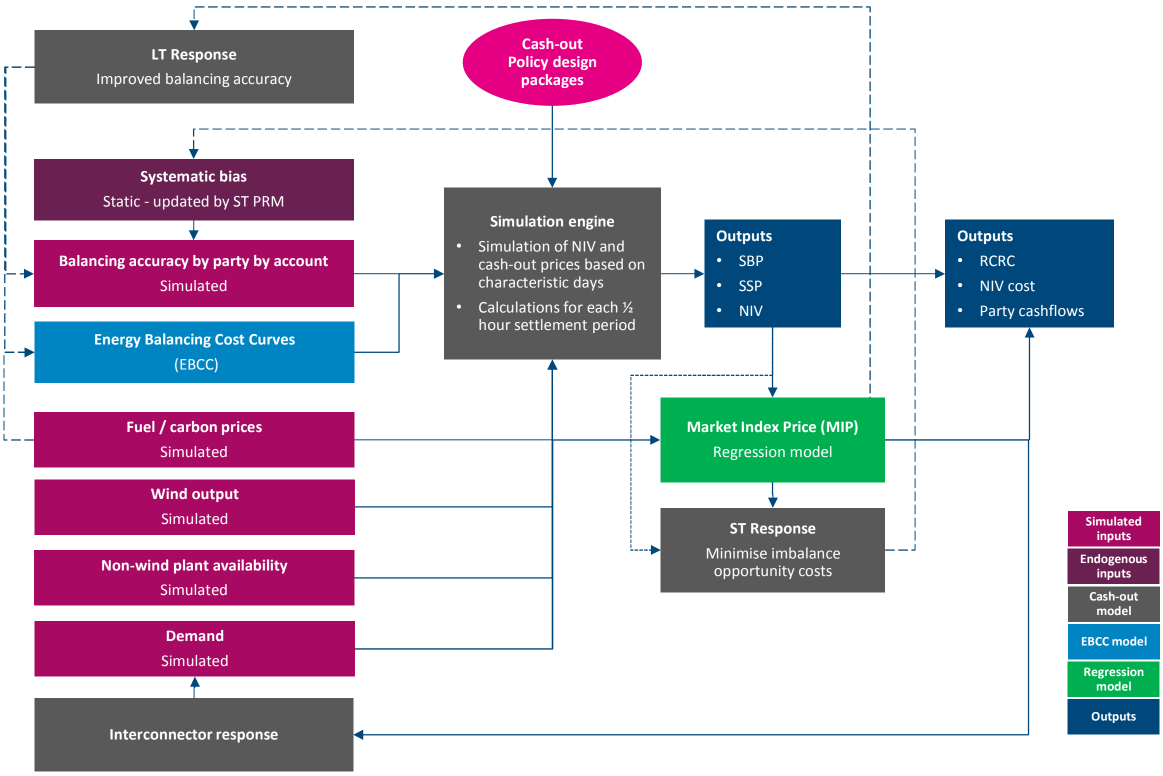
[19] I.e. with system balancing actions stripped out.

[20] Previous academic work (Bunn D, Karakatsani N (2008) Intra-day and regime-switching dynamics in electricity price formation, Energy Economics 30 (2008) 1776–1797) estimated a statistically significant relationship between cash-out prices and MIP. For this study a set of monthly regression models was estimated from historic data to determine the relationship between the dependent MIP variable and key independent explanatory variables (SBP, SSP, demand, reserve margin, wind, gas prices and carbon prices). The coefficients in the regression model were assumed to remain constant over time.

Finally, the impact on long term (LT) balancing incentives (e.g. investing in forecasting accuracy) are overlaid onto the final positions from the ST response.

A schematic over of the COM is provided in Figure 5 below.

Figure 5 Overview of COM



It is important to note that the model does not produce an overall estimate of BSUoS costs as it is focused on 'energy balancing' only, rather than the costs of energy and 'system balancing' actions (e.g. to resolve transmission constraints). NIV cost is calculated to represent changes to the total energy balancing costs in each simulated settlement period.

Party types

The COM directly models the imbalance performance of BSC parties and their ST response to changing cash-out exposure. In the historic data sourced from ELEXON (half-hourly imbalance volumes and party cash-flows for the post-P217A[21] period from 5 November 2009 to end of 4 November 2013) there exist almost 200 individual BSC parties. Many of these have both active production and consumption accounts and some entities may hold a number of different party accounts, e.g. reflecting a number of different legal operating entities within a single VIU.

[21] Modification process to remove system pollution from the cash-out price https://www.ofgem.gov.uk/ofgem-publications/40803/p217a-preliminary-analysis.pdf

The historic data was used to create distributions of imbalance performance scalars, which were used as part of the Monte Carlo simulations[22] to simulate future imbalance as underlying parameters (e.g. wind volumes, demand volumes, etc.) change over time. However, to make the model manageable it was necessary to group the full set of BSC parties into a set of 'party types'. These reflect either:

- A large, clearly identifiable entity (which may be spread across multiple accounts) as its imbalance performance and behaviour to-date will be a function of its overall portfolio, and
- Discrete individual parties that share a similar set of underlying characteristics or plant mix, and which can reasonably be assumed to behave in similar manner.

As a result the following parties were modelled directly in the COM:

- VIUs
  - Centrica, EDF, EON, RWE, SP, SSE
- Independent thermal generators
  - Drax, Intergen, GDF Suez, other independent dispatchable generators
- Independent wind generators
  - This has now been updated to reflect a separate independent onshore wind generator and independent offshore wind generator (both correlated to the overall wind on the system.
- Independent energy suppliers
- Others (e.g. non-physical traders)

2.3. Updates to modelling approach

2.3.1. Interconnector response

In the Phase 1 analysis interconnectors were assumed to be at 'float' within the cash-out model; i.e. neither importing nor exporting at any point. At present, energy sourced through interconnectors does not participate directly in the BM (although this may change in the future under the European Integrated Energy Market proposals). Hence, the impact on cash-out prices will likely in the near term be indirect through market prices.

For example, under times of system stress in GB, market prices will rise and likely encourage greater imports into GB (all else being equal). This increased supply would indirectly increase the range of available energy balancing options in the BM, providing a cheaper set of potential offers in the case of a short system and hence reduce SBPs. Conversely, if the GB system was stressed, but prices in the connected market were even higher encouraging exports, this would likely lead to even higher SBPs. Similar impacts would affect the range of SSPs in a long system.

[22] Correlations in imbalance across parties are estimated from historic data and factored into the simulated balancing accuracy.

The two key issues associated with modelling interconnector flows are:

1. Modelling price formation in the interconnected markets alongside GB, and
2. Establishing an equilibrium position for prices and associated flows across the interconnected markets

To understand better price formation in interconnected markets we first drew on the same analytical framework as applied in Baringa's study for DECC on the *Impacts of further electricity interconnection on GB*[23].

- GB and interconnected markets were simulated in a bottom-up PLEXOS electricity dispatch model for each spot year from 2015 to 2030.
  - To ensure consistency with the EBSCR work the GB capacity mix, fuel prices, and demands were made consistent with the COM assumptions
  - New interconnection capacity was assumed to develop as per the core DECC scenarios, but with the total capacity matching that for the overall GB mix assumptions (rising from 4 to 7 GW by 2030)
  - For carbon prices – we assumed the scenarios the trajectory from scenario 2 from the DECC study whereby post-2020 non-GB carbon prices recover to match the Carbon Price Floor (CPF) by 2040. These are consistent with the overarching carbon prices used in the EBSCR modelling as outlined in Section 3.6.
- The outputs from the PLEXOS model were used to create a set of prices distributions and correlation matrices by month by year, for GB and each interconnected markets.
  - Using this it is then possible to match each simulated outturn GB MIP from the COM model with corresponding prices in the interconnected markets
  - The price differential is then contrasted with loss factors on each interconnector to determine whether the interconnector is importing, exporting or at float

The above process describes how the base interconnector flows are determined. However, changes to flows into or out of GB will change prices in GB and by extension the interconnector flows[24], hence:

- Under the DN case an iterative calibration is undertaken such that new interconnector flows and GB MIPs from the COM are re-estimated until a 'broad' equilibrium position is reached (i.e. no further change in GB prices or flows)
- Under the cash-out reform package it is assumed that corresponding prices in the connected markets are still fixed as per the DN case, but the impact of cash-out reform

23 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

24 We are implicitly assuming that within-day renominations on interconnectors, and in the future within-day market coupling, are possible.

(increase or decrease relative to the DN price) may change the interconnector flow (e.g. if it was previously at float in a period and the price increased this may be sufficient to lead to imports)

  - A small calibration exercise is again undertaken to estimate the equilibrium position for final flows

- The impact of cash-out reform on interconnector flows at peak (assumed to be the January characteristic day averaged across the early evening peak 4-7pm) is also used to estimate the increment in de-rating factor that could be assigned to interconnectors

2.3.2. Treatment of bid volumes in the BM

In the previous COM the volumes of possible offers and bids going into the BM, as a % of capacity for different plant types were calibrated from historic data (applied to both existing and new plant). Separate Baringa modelling of the BM using a bottom-up electricity dispatch model has indicated that this assumption tends to underestimate future bid volumes in the BM, particularly for CCGT plant, given how they are likely to run post-2020 once existing coal plant have retired. With less CCGT volume to turn down than is likely to be available in reality this tends to accentuate lower (and negatively) priced bids, lowering the average SSP.

In the revised COM we have introduced a simple dynamic stack to estimate (using Short-Run Marginal Costs), which plant are likely to be running in a given half hour period. This is used to set the bid *volumes* dynamically for new plant where they are higher than those implied by historic estimates (bid *price* scalars are still based on historic estimates and opportunity cost of bidding of RO and CfD plant as before).

2.3.3. Wind imbalance modelling

The previous analysis demonstrated that cash-out prices are particularly sensitive to assumptions around the correlation of wind forecast errors. With greater correlation in forecast errors and more wind on the system, wind becomes a bigger driver of overall NIV in the future as there is less diversity benefit from offsetting forecast errors canceling each other out. As a result, if independent wind generators' forecast errors are more correlated there is less benefit to them from the move to single pricing, as by definition they are less often in the opposite direction to the system imbalance.

To improve the representation of wind in the COM, wind parties have now been split into 3 types:

- A 'typical' independent onshore wind farm of ~100-150 MW
- A 'typical' independent offshore wind farm of ~200-800 MW
- An aggregate 'wind' party representing all other independent wind on system

The aggregate wind party is used to drive system NIV, whereas the 'typical' parties are used primarily to understand better the impact on individual wind generators whose output and forecast errors are not fully correlated with the wind on the system as a whole.

To estimate the wind parameters we undertook a bottom up calibration exercise outside of the COM[25]. This modelled a set of 41 individual, 'stylised' wind farms representing those existing in 2012 (~2/3 onshore, 1/3 offshore)[26] . By varying the key parameters of each individual wind farm[27] we were able to re-create an approximation of the key factors seen in National Grid's historic system level data for 2012 on wind *speed* forecast error and wind *output* forecast error (average and standard deviation).

This provided a normal distribution of the *output* error for a typical onshore and offshore wind farm (used to estimate imbalanced deviations in the COM) and an estimate of the correlation in their forecast error to the rest of the system. The process was repeated for future spot years, adding additional 'typical' wind farms in line with the overall capacity mix on the system (holding the calibrated 2012 factors constant) to generate the relevant parameters for each of the 3 'wind parties' in the COM.

The final change to the modelling of wind was to alter portfolio players' historic imbalance distribution performance if the *share* of wind in the portfolio increased over time; by adding the incremental imbalance based on wind only rather than the original portfolio. The intention is to reflect that imbalance performance would deteriorate slightly as the share of wind in a portfolio grows.

2.3.4. Impact on CM and wholesale prices

Findings from a number of technical working groups, industry workshops and the consultation process for the EBSCR indicate that many in industry believe that the proposed Capacity Market (CM) is likely to provide a far stronger incentive to invest in new generation capacity than reforms to cash-out.

During the previous analysis the details of the CM had not yet been confirmed and hence the core underlying capacity mix assumptions represented a world without the CM in place. However, the majority of details are now confirmed. To understand the impacts on investment in new plant, the previous EBSCR work took an approach of understanding how the feed through effect of higher cash-out prices into wholesale prices may signal investment for both CCGT and DSR separately.

A sensitivity with the CM in place (with a different underlying capacity mix) assumed no additional capacity driven by cash-out reform and that the impact of higher wholesale prices versus savings from reduced clearing prices in the CM auctions was broadly net neutral.

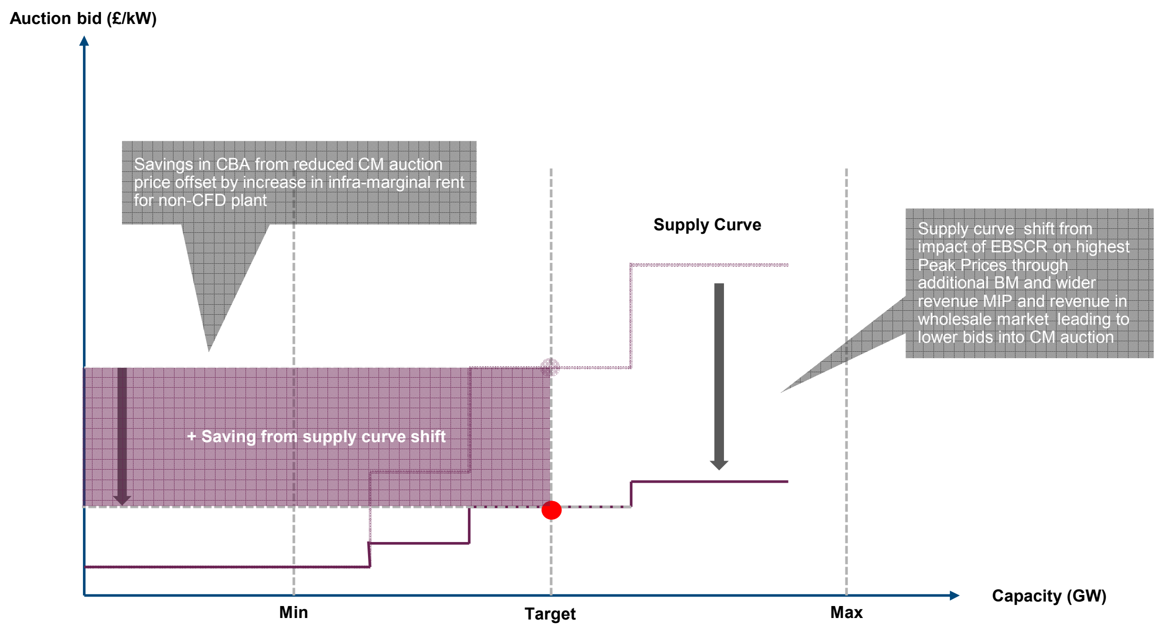
For this analysis our core capacity mix and de-rated capacity margin assumes that the CM is in place. We have therefore attempted to assess more directly the two offsetting effects of cash-out reform in relation to the CM and wider wholesale market for purposes of the CBA.

[25] Historic BSC imbalance data for independent wind parties was also investigated in a similar manner to the previous analysis, using the additional year's worth of available data. However, there was still insufficient additional data to assess accurately correlations between different wind farms.
[26] This implicitly considers correlation between these wind farms, both on and offshore
[27] E.g. profile of wind speed forecast error and correlation in forecast errors between farms, subject to an absolute mean wind speed error factor based on Met Office data.

- A reduction in the CM auction clearing price due to the plant bidding into the CM expecting to receive more revenue in the wholesale market with cash-out reform and hence needing less additional money from the CM (as illustrated in Figure 6). This is separated into two effects:
  - For peaking plant, which DECC assumes will be running for 3 hours each year in its CM analysis, we assume that the increase in expectations of price captured will reflect the expected increase in SBP under EBSCR relative to the DN case.
  - For all other plant we assume this occurs via the impact of cash-out reform on expectations of within-day prices (MIP)
- An increase (or decrease) in wholesale prices from cash-out reform is assumed will lead to a direct cost (or benefit) to consumers, although this will be offset to a degree by the impact of growing proportions of CfD supported plant (since difference payments counter-correlate with wholesale prices).

The above two factors will not necessarily offset each other as the CM auction is based on 'pay as clear', whilst the impact of cash-out reform affects generator revenues (via the impact on MIP) differently across the year – i.e. the overall costs and benefits will change significantly depending on whether it is a peaking plant or baseload / mid-merit plant clearing the auction. Furthermore, the CM does not cover all plant that operates in the wholesale market and hence changes in capacity prices and wholesale prices will not affect all plant equally.

Figure 6 Overview of impact of cash-out reform on CM auction clearing prices



To assess the above impacts we have used Baringa's Transmit Decision Model (TDM), which has been employed as part of Ofgem's Project Transmit analysis. This is an endogenous investment decision model of the wholesale GB electricity market, and now includes an embedded module to simulate the proposed CM auctions. By incorporating the changes in expected wholesale revenues from cash-out reform as outlined above, we have estimated the impact on bids and hence capacity auction clearing prices.

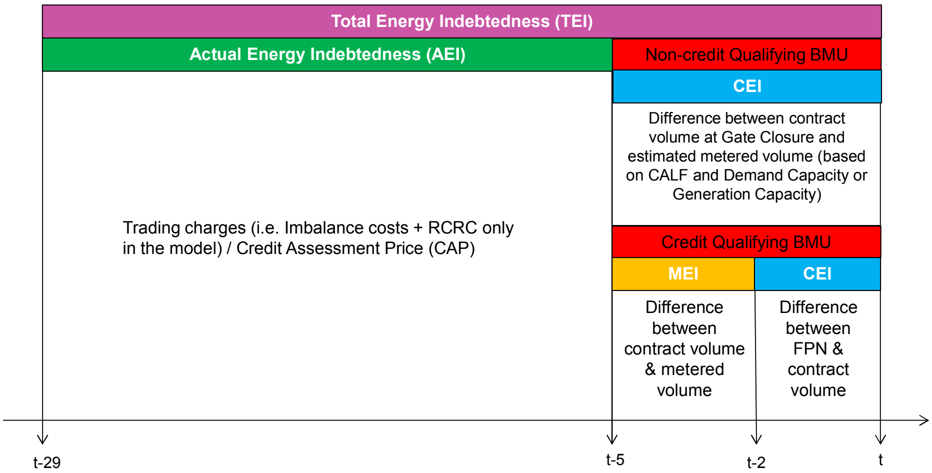
As mentioned in Section 2.3.1, we have also explored the impact of cash-out reform on interconnector flows and the potential for higher de-rating factors to be applied to interconnected capacity as a result.

2.3.5. Credit risk

With imbalance exposure forecast to escalate, smaller independent parties in particular may be at risk of not being able to meet their on-going cash flow requirements under the BSC.

We have focused on the BSC Energy Credit Cover (ECC) requirements[28], which help to ensure that parties have enough collateral to cover their imbalance settlement payments in case of default as these trading charges are settled 29 days after a settlement day as shown in Figure 7 below. To avoid entering the default process under the ECC requirements Total Energy Indebtedness (TEI) must not exceed 80% of the ECC.

Figure 7 Overview of Total Energy Indebtedness



We have used the output from the COM to create an approximation of the rolling credit cover requirements (on a daily basis, across each spot year, for each party type) which would need to be posted to avoid entering the default process. Due to the time lag between settlement day and settlement of trading charges from that day (along with adjustments for estimated and actual data) the required rolling credit cover can change significantly, being offset or accentuated by imbalance charges in the intervening period.

The rolling cover requirements thus provide a good proxy for both the volatility and maximum likely BSC cash-flow exposure under both the DN case and EBSCR. To allow for comparison

[28] http://www.elexon.co.uk/wp-content/uploads/2013/11/credit_cover_guidance_v6.0_cgi.pdf

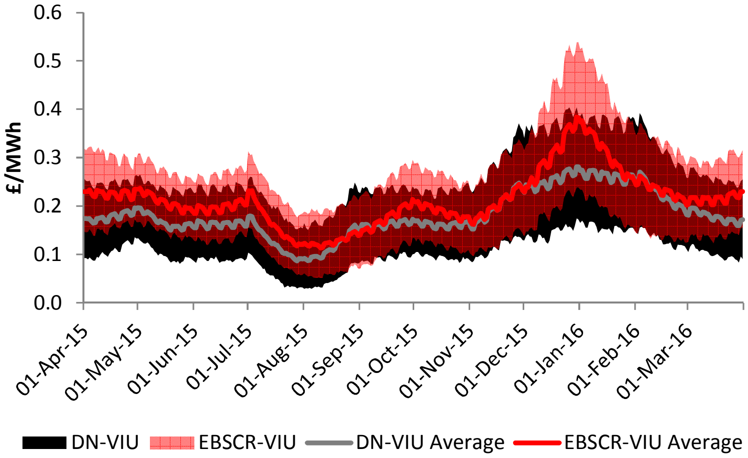
across parties we normalise the credit cover requirements to a £/MWh of Credited Energy Volume (CEV)[29]

The more detailed modelling steps are as follows:

- For a selected spot year, the tool extracts relevant COM's output such as NIC, RCRC, MIP and CEV. We run the credit cover simulation tool for 500 simulations in each spot year.
  - In each simulation, @Risk simulates the daily total NIC (sum of all parties) according to NIC's distribution from COM for consecutive 15 months. Each simulated NIC is matched to the COM's NIC to get the associated closest matched simulation in COM. The corresponding NIC, RCRC and CEV for the associated closest matched simulation in COM are then used to construct the daily credit cover profile in the next step.
  - Rather than simulating NIC, RCRC and CEV individually, this step ensures consistency between data in the same simulation.
- For each simulation and each party, the credit cover calculation starts from 1st Jan of the spot year and runs for consecutive 15 months on a rolling basis. The calculation logic is based on ELEXON guidance notes with some simplification. For the model to accumulate enough data points, only the last 12 months' credit covers (£) and CEVs (MWh) are exported, i.e. April-Mar.
- The daily normalised credit covers (£/MWh) are aggregated by typical party type as a post-processing step. For example, the sum of all VIU's credit cover / the sum of all VIU's CEV gives the normalised credit cover for VIU in each day and each simulation.
  - P10 and P90 (10th and 90th percentiles) are derived from these daily normalised credit cover profiles across 500 simulations, along with the averages, to understand how the credit cover changes under typical versus more extreme conditions

[29] By dividing it through by the sum of the CEVs over the previous 29 Settlement Days (including the current Settlement Day).

Figure 8 **Example of (normalised) rolling credit cover**



Note: the bottom to the top of the shaded areas represents the range of credit cover requirements under the P90 and P10 cases. The dark red shaded area simply shows where these areas overlap under DN and EBSCR.

3. KEY DATA ASSUMPTIONS

3.1. Energy Balancing Cost Curves (EBCCs)

The EBCCs described in Section 2.1 were generated using historic BOA stacks provided by ELEXON covering four years from the implementation of P217A (5 November 2009) to 4 November 2013 (all other historic assumptions used cover the same period). Individual Balancing Mechanism Unit (BMU) properties were based on Baringa assumptions.

Table 6 Key EBCC assumptions use and source

Item	Resolution	Use	Source
Bid/offer acceptance stacks	Period	Used to generate EBCCs that dynamically update with changes to prevailing commodity prices	Historic data provided by ELEXON
BMU level assumptions for current fleet: fuel, heat rate, carbon emissions, VOM, base retirement year, capacity	Fixed		Baringa assumptions

3.2. Capacity mix and de-rated margins

The evolution of the underlying capacity mix affects the model in four ways:

1. Existing generating units that appear in the EBCCs and due for retirement will no longer feature in the EBCCs past their retirement year. Thus the EBCCs in 2030 are comprised of fewer data points than were derived from the historic accepted bid/offer stack data set. All years modelled will have some level of retirement relative to historic data.
2. New build capacity is inserted into the EBCCs as single blocks by technology type. The volume and price strategies with which these generators submit bids/offers are based on the historic strategies for equivalent plant types.
3. The simulation of reserve margin used by the regression model and the RSP is dependent on the total volume of available capacity which is linked to the underlying capacity mix. Reserve margin refers to the short-term operational margin of the system in an individual half-hour period.
4. Implicit to the capacity mix (and demand forecast) assumptions is a corresponding de-rated capacity margin, which determines the volume of Expected Energy Unserved (EEU) in any given year using the Capacity Assessment assumptions.

The source for all assumptions related to the evolution of the capacity mix and de-rated margins is shown in Table 7. Importantly, wind capacity covers licensed generators (parties subject to the BSC) thus it excludes smaller wind generators embedded in the distribution networks which is netted off the demand assumptions[30]. Any reserve actions that were historically taken by National Grid as BSAA, BM-STOR or non-BM-STOR generators are assumed to expand in volume in line with likely increases in the reserve requirements held by National Grid.

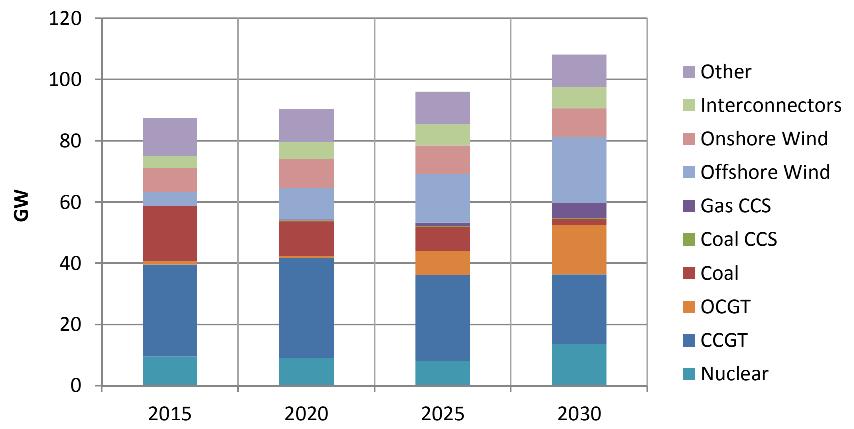
Table 7 Key capacity mix and de-rated margin assumptions use and source

<table>
<tr><th>Item</th><th>Resolution</th><th>Use</th><th>Source</th></tr>
<tr><td>Core plant capacity mix (excluding items below)</td><td rowspan="7">Annual</td><td rowspan="3">New plant capacity used to define new steps on EBCCs, retirement profile of existing plant used to remove capacity from base EBCCs in future years, overall capacity used as part of simulated plant availability which is an input to the reserve scarcity price function and MIP regression model</td><td>Bespoke DECC DDM modelling scenarios – EMR central with CM[31]</td></tr>
<tr><td>DSR capacity and various supporting assumptions</td><td>DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios</td></tr>
<tr><td>Maxgen capacity and various supporting assumptions</td><td>National Grid[32]</td></tr>
<tr><td>Capacity de-rating factors</td><td rowspan="3">Used to assess annual level of EEU</td><td rowspan="3">Bespoke DECC DDM modelling scenarios</td></tr>
<tr><td>De-rated capacity margin</td></tr>
<tr><td>Relationship between de-rated margin and EEU</td></tr>
<tr><td>Embedded wind capacity projections</td><td>Used to adjust DECC total onshore wind capacity numbers as demands, etc. are all net of embedded generation</td><td>National Grid SYS (Seven Year Statement), 2010</td></tr>
<tr><td>Reserve parameters various</td><td>Period</td><td>Used to scale volume of BM/non-BM STOR actions within EBCC in line with increasing system requirement for reserve</td><td>Formula based on data from National Grid, Imperial College, DECC</td></tr>
</table>

[30] Note that the commonly used term "demand net of wind" refers to network variables only; i.e.: all quoted demand values are net of embedded sources of generation and all quoted wind values are net of embedded wind. Thus "demand net of wind" refers to all network demand remaining following that which is satisfied by the level of network wind on the system.
[31] DECC's central EMR scenario (including the impact of the CM) of 16 December 2013
[32] http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/systemsecurity/maxgeneration/

The evolution of the capacity mix under the Core Scenario can be seen in Figure 9. The key difference to the previous EBSCR analysis is that the core capacity mix assumptions include the impact of the CM.

Figure 9 Evolution of capacity mix



3.3. Plant cost and strategies

The price at which capacity is bid or offered into the BM is dependent on three things:

1. The physical properties of the generators: efficiency/heat rate, carbon emissions, VOM and any subsidy (ROCs or CfD).
2. Prevailing commodity prices (discussed further in Section 3.6), which together with the above form the SRMC of the plant.
3. The mark-up strategy that a generator applies to its SRMC when making bids/offers in the Balancing Mechanism. For bids, this mark-up will be a discount to its SRMC; for offers it will be a premium to the SRMC.

The proportion of a generator's volume that it bids or offers into the Balancing Mechanism (as opposed to contracting in the wholesale energy markets) also varies considerably by plant type. The sources for assumptions used to derive plant price and volume strategies are shown in Table 8.

Table 8 Key plant cost and strategy assumptions use and source

Item	Resolution	Use	Source
Efficiency of new plant	Annual	On GCV basis, used to calculate SRMC for new plant additions to inform offer/bid pricing	DECC (2012) Electricity Generation Costs
Base VOM (Variable Operating and Maintenance) costs of new		Used to calculate SRMC for new plant additions to inform offer/bid pricing	

Item	Resolution	Use	Source
plant			
Emission factors		On GCV basis, used to calculate SRMC for new plant additions to inform offer/bid pricing	Defra (2012) greenhouse gas conversion factors for company reporting
ROCs per plant type		Used to calculate SRMC for new plant additions to inform offer/bid pricing	DECC (2012) Renewables Obligation Consultation
ROC price projections		Used to calculate SRMC for new plant additions to inform offer/bid pricing	Assumed to maintain current prices
CfD reference and strike prices		Used to calculate SRMC for new plant additions to inform offer/bid pricing	Bespoke DECC DDM modelling scenarios
Bid/offer strategy for coal, CCGT, peaking plant	Period	Used to inform price/volume offered into BM (i.e. EBCC) by equivalent new capacity additions	Estimated from analysis of historic BOA-level settlement data provided by ELEXON
Bid/Offer DSR		Used to inform price/volume offered into BM (i.e. EBCC) by equivalent new capacity additions	DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios
Average BPA values by characteristic day and settlement period	Period	Adder to cash-out prices under DN	Historic data provided by ELEXON
Transmission Loss Multiplier	Fixed	Adjustment to cash-out prices	

3.4. Historic party shares

Historic market shares by party type were calculated at the monthly level based on the average seen in the historic settlement data provided by ELEXON for the post-P217A period (from 5 November 2009 to 4 November 2013) and is consistent with the other historic data used to construct the EBCCs.

The shares were calculated for:

- % share of demand in energy market
- % share of overall generation in energy market

- % share of wind generation in energy market
- % share of accepted BM offers
- % share of accepted BM bids

The % shares were held constant over time to avoid making additional assumptions about how the market structure might evolve over time. The only exception to this is that the historic % share of wind generation by parties was assumed to take priority over the % share of other generation types. Hence, as the overall volume of wind on the system grows the residual share of non-wind generation in total generation declines, and the % share of total generation by party type is maintained only for the residual generation after wind is accounted for.

3.5. Demand and wind

Projections of demand are used by the model to simulate the total growth in energy contracted either through wholesale energy markets or the BM. Demand is simulated on a half-hourly level and as such is characterised by a daily demand profile that varies by month. Over time, the uncertainty in the magnitude of demand in any given period is simulated using the combination of two parameters:

1. Using a shift parameter that shifts the entire demand profile across the day up or down. Conceptually, this parameter relates to systematic changes in demand due to lower macroeconomic growth or greater substitution to electric heating for example. The demand shift parameter is determined by taking a triangular distribution of demand sampling between DECC's low, central and high annual trajectories.
2. Using a stretch parameter that can accentuate or depress the shape of the daily profile (e.g. make peaks, spikier or troughs flatter). Conceptually, this parameter relates to intra-day variation in demand that may reasonably occur due to variations in weather for example. The stretch parameter was determined using historic distributions of demand around the average.

The simulation of outturn wind is treated in a similar way to demand. A wind variation parameter is used to simulate variations in wind speed and output that could be expected for this wind capacity. This variation is applied to a daily profile with half-hour resolution.

All sources for demand and wind data assumptions are outlined in Table 9. Note that all demand (and consumption accounts) quoted in the model are net of embedded sources of generation.

Table 9 Key demand and wind assumptions use and source

Item	Resolution	Use	Source
Annual energy demand projections	Annual	Used in simulation of energy demand	DECC UEP October 2013
Demand stretch	Monthly		National Grid[33]

[33] INDO http://www.nationalgrid.com/uk/electricity/data/demand+data/

distribution parameters			
Average demand profile shapes	Period	Combined with simulated demand shift and stretch parameters to create overall demand profile within each characteristic day, future changes to core demand profile estimated from DECC study	DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios
Wind variation distribution parameters	Monthly	Used in simulation of wind output	DECC wind capacity mix applied to Baringa's simulated hourly load factor data[34]
Average wind profile shapes	Period	Combined with simulated wind output factor to create within day profile for each characteristic day	

3.6. Commodity prices

The evolution and distribution of commodity price changes is an important input to the model. Commodity prices are one of the input assumptions used to determine the SRMC of generators in the EBCCs. Historic mark-up strategies are then applied to these SRMCs to determine bid/offer prices that are used to form outturn cash-out prices.

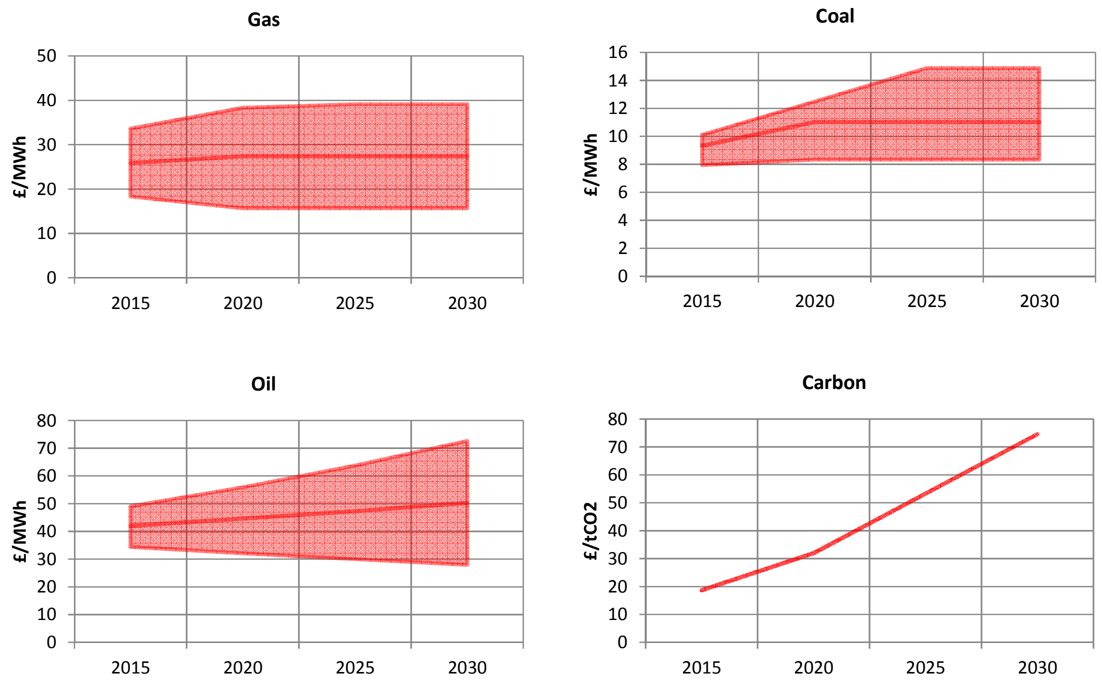
Commodity prices are simulated at an annual level by creating triangular distributions around low, central and high price trajectory assumptions from the sources outlined in Table 10 and illustrated in Figure 10. In the case of gas, capturing seasonality effects was considered important, so monthly scalars are applied in the model that increase gas prices in winter months and reduce them in summer months. We have used the latest commodity and carbon price assumptions available at the time the analysis was undertaken.

Table 10 Key commodity price assumptions use and source

Item	Resolution	Use	Source
Fossil fuel price projections	Annual	Used in simulation of commodity prices	DECC UEP October 2013
DECC carbon price projections	Annual	Used in simulation of commodity prices, low values are bounded by Carbon Price Floor	DECC Carbon Valuation Oct 2013
Biomass prices	Annual	Used in simulation of commodity prices, historic price range maintained	E4Tech 2010 study for DECC
Seasonal gas price scalars	Monthly	Used to adjust simulated gas price data	In-house Baringa commodity price database

[34] Based on hourly wind speed data from Anemos Wind Atlas.

Figure 10 **Evolution of fuel price ranges used in simulation (min, mode, max)**



A key difference to the earlier analysis is that post-2020 the carbon price is set only by the Carbon Price Floor (CPF), whereas previously the high end of the range reached >£100/tCO_2 by 2030 (from DECC's 2012 set of carbon price projections). This lower carbon price in later years effectively leads to a modest reduction in cash-out prices.

It should be noted that this analysis does not reflect the recent freeze on the CPF until 2020 as this was announced after the analysis was undertaken.

3.7. Imbalance deviation

Imbalance deviation represents the departure of a party's outturn position from its contracted position. The characteristics of this imbalance differ according to party types and account type (production/consumption). Two main drivers for imbalance were modelled – position bias, which is any systematic imbalance deviation that a party might adopt to hedge its cash-out price risk pre-Gate Closure, and unanticipated imbalance – both of which used historic party-level data provided by ELEXON to determine input assumptions (Table 11).

Table 11 **Key imbalance data assumptions use and source**

Item	Resolution	Use	Source
Position bias	Monthly Account	Used directly in the model to simulate party hedging strategies	Estimated from historic party-level half hourly settlement data provided by ELEXON
Imbalance deviation distribution parameters		Used in the simulation of imbalance deviation scalars for each party	
Imbalance deviation correlations			

3.7.1. Position bias

A party's position bias refers to its imbalance on account of a deliberate out of balance position adopted to mitigate its exposure to cash-out. The model applies position bias to a party's expected position to determine its Bilateral Contract Volume (BCV). The final imbalance volume of a party is made in reference to its BCV so will include any imbalance on account of position bias.

The historic average of imbalance for each party was taken as its position bias. This was determined on a monthly level and is fixed across years prior to any modelled ST response. Historically, in aggregate, parties have adopted long position bias strategies to mitigate exposure to asymmetric cash-out price spreads which have been greater on the buy side than the sell side of the market.

3.7.2. Unanticipated imbalance

A party's unanticipated imbalance refers to it incorrectly forecasting its position due to the physical characteristics of its account. For example, unexpected spikes in demand, the forced outage of thermal plants or unforecasted changes in wind output would all contribute to the unanticipated imbalance deviation of a party's account.

Where the position bias takes the average of a party's historic imbalance, unanticipated imbalance takes the historical distribution around this average to generate imbalance deviation scalars for model simulations. A separate imbalance deviation scalar is generated for each party account and for each Monte Carlo simulation. These scalars are numbers that deviate either side of 1 at a frequency, direction and magnitude equivalent to historic deviations – i.e. so that absolute imbalance volumes change with the underlying drivers of the system over time (e.g. more wind, higher demand, etc). The correlation of imbalance between different parties and accounts is also estimated from the historic data and used within the simulation of future imbalance scalars.

It should be noted that the imbalance deviation scalars of parties are based on historic imbalances which will correspond to the historic account portfolio. These imbalances are carried forward through time despite changing capacity of individual parties. This is the most neutral position as the alternative would require additional assumptions about the future composition of individual parties' portfolios going, which are assumed to be maintained based on historic shares of generation / production / BM participation going forward.

4. RESULTS

4.1. Introduction

In this section we present the main results of the updated analysis, focusing first on the evolution of system level results (such as NIV and cash-out prices) followed by party-level distributional effects (such as balancing net cashflows,) and finally a Cost-Benefit-Analysis (CBA) of the impact of cash-out reform, from the perspective of consumer costs.

4.2. Evolution of NIV

Even without cash-out reform the combination of the evolving capacity mix (and margin) and increasing commodity prices (including the Carbon Floor Price) are expected to have a significant impact on system imbalances, cash-out prices and wholesale market prices.

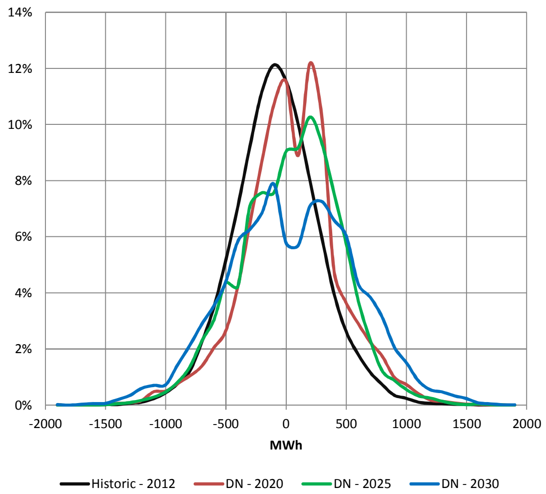
The expected substantial increase in intermittent renewables on the system, coupled with the retirement of coal and older gas plant, which are more controllable, is forecast to reduce the balancing capacity of the system over time. Wind output, which is relatively difficult to forecast compared to conventional plant, will increasingly contribute to imbalance volumes resulting in greater variability as seen by the progressive widening distributions of NIV, shown in Figure 11.

These widening distributions highlight the increasing importance of the BM, and cash-out regime, as they suggest that a greater proportion of energy will be traded through cash-out in the future.

It is important to recognise that parties are likely to respond not only to changed balancing incentives under cash-out reform, but also to changes to the underlying capacity mix and the direction and propensity for the system to be out of balance. Figure 11 shows the change in NIV after including the change in position bias adopted by parties in the modelling[35]. The net effect is to make the system shorter under both DN (and EBSCR), particularly by 2030, than it would otherwise have been had position biases remained constant over time. As explained further below, this is the result of an increasing spread between the SSP and the MIP, making it less attractive to adopt a long position as a risk management strategy against high SBPs.

[35] As a result the EBSCR NIV distribution is marginally different to that under DN, but is not shown on the chart

Figure 11 Evolution of NIV (+ve = system short)



4.3. Interconnector responsiveness

In the previous analysis the flexibility provided by interconnectors was not captured in the modelling, resulting in a tendency for greater occurrence of more extreme cash-out prices. In the updated analysis interconnectors respond to simulated differentials in GB and interconnected market prices. Historically interconnectors have predominantly imported into GB. Under DN imports gradually reduce over time and by 2030 flows are more balanced across the year as shown in Figure 12 (the underlying analysis assumes that carbon prices equalise in connected markets after 2020).

Figure 12 DN Interconnector flows

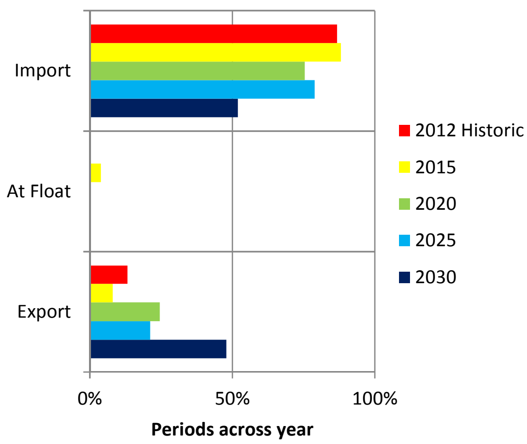
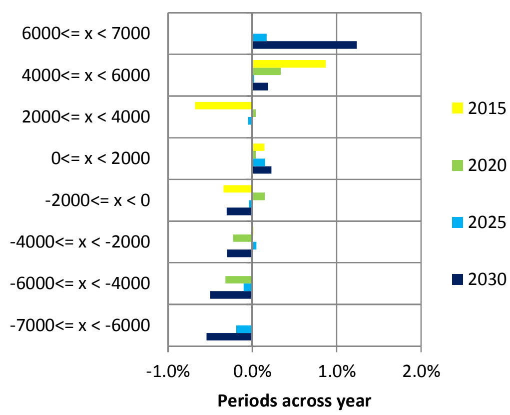


Figure 13 Impact of EBSCR relative to DN on interconnector flows[36]



[36] Negative values reflect export in MW and positive flows import

The impact of more marginal pricing under EBSCR tends to accentuate prices at either end of the spectrum, leading to both greater instances of higher wholesale prices (driven by higher SBPs) and more negative wholesale prices (driven by lower SSPs) in certain periods; and greater imports and exports in these periods, respectively, compared to DN. However, across each year this on average tends to lead to slightly higher imports, with higher levels of import, and lower exports, with around 2% more periods across the year now importing in 2030.

Higher MIPs, driven by higher SBPs under EBSCR also lead to more imports during peak periods. This should allow DECC to assume a higher de-rating factor on interconnected capacity. In peak January periods (EFA5) the impact of EBSCR equates to around ~100-150 MW of additional imports up to around 2025 and ~500 MW in 2030 .If interconnected capacity is excluded from the CM, as will be the case for the first year of the CM in 2018/19, this will reduce the capacity requirement in the auction. In subsequent years, if interconnected capacity can participate in capacity auctions, then a higher de-rating factor for interconnectors should increase competition. Either way, this should reduce the capacity auction clearing prices and lead to consumer savings[37].

Alternatively, if the de-rating factors for interconnectors are not increased (also prior to the CM being introduced) then the effect of greater interconnector responsiveness would be to reduce the risk and costs of unserved energy from the three hours of loss of load expectation being targeted under the CM. This would virtually eliminate the risk of unserved energy, amounting to a reduction in unserved energy of around 100 MWh in 2015 rising to around 900 MWh by 2030[38].

The savings associated with EBSCR in terms of higher interconnector de-rating factors in the CM or lower unserved energy are commensurate.

4.4. Evolution of Cash-Out Prices

In combination with the assumed steadily rising commodity prices, the modelling suggests that greater variability in the magnitude of imbalance volumes will drive increases in both the magnitude and variability of cash-out prices.

4.4.1. Spreads

Of particular note is the evolution of the spread between cash-out prices and MIP. Cash-out spreads are an indication of the magnitude of the exposure that parties have to being out of balance and can be considered in two ways:

[37] For the purposes of the modelling we have translated the higher interconnector de-rating factor under EBSCR into a lower capacity requirement in the CM in all years, regardless of whether interconnected capacity may be able to participate in the CM in the future. This simplification would not materially affect the results to the extent that interconnected capacity always cleared below the marginal capacity. The potential added complication of interconnected capacity being the marginal capacity in the auction was not considered given that there is no policy detail in this area currently.

[38] Note that Expected Energy Unserved (EEU) under DN is calibrated to the DECC DDM capacity mix scenario assumption and is not a direct output of the COM.

- *Main price only spread* (Figure 14) on the buy side, this exposure is measured by the difference between the cost of procuring energy through cash-out (SBP) and what it would have cost if this imbalance was traded in wholesale energy markets (assumed at MIP); thus buy side spreads are equal to SBP minus MIP. Conversely, sell side spreads indicate the difference between selling spilled energy in wholesale electricity markets (assumed at MIP) versus through cash-out (at the lower SSP); the equivalent opportunity cost/spread is MIP minus SSP.
- *Main + reverse spread (*Figure 15) – which consider the SBP / SSP to MIP spread covering all periods - including reverse priced periods. For EBSCR the cash-out price is just a single line since this is a single pricing package.

Figure 14 Average (main only) COPs

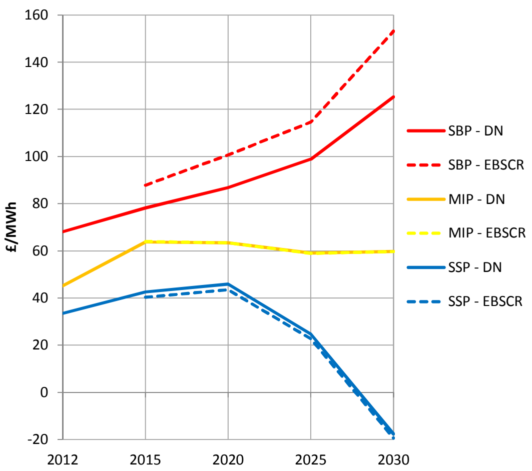
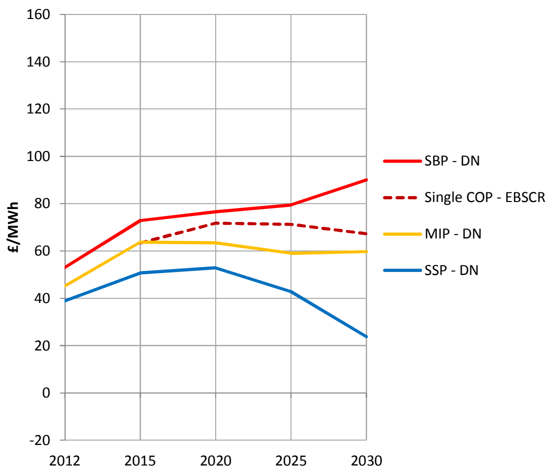


Figure 15 Average (main + reverse) COPs



Under a main price only COP spread the system is currently characterised by asymmetrical spreads where the difference between average SBP (when it is the main price[39]) and MIP is greater than the difference between average SSP (when it is the main price) and MIP. This has largely driven the historical long position bias of parties as buy side exposure to cash-out has been greater than sell side exposure.

Under DN the spread becomes more symmetrical from 2015 to 2025, but post-2025 the spread on the bid-side becomes significantly larger as the incidence of subsidised renewable plant bidding into the BM at negative prices (the opportunity cost of lost subsidy) being captured within the cash-out price calculation increases. All else being equal this would tend to drive parties to hedge less long over time and avoiding negative SSPs will become a strong motive for shortening position biases. By contrast, under EBSCR the more marginal PAR and RSP function help to maintain a greater spread on the offer-side after 2015, more than offsetting the impact of negative SSPs. Hence, parties are less likely to shorten their position bias under EBSCR.

---

[39] Note that the cash-out price results in this report are for the cases when SBP or SSP is the main price, unless otherwise stated.

4.4.2. System Buy Prices (SBPs)

Under DN SBPs rise steadily, driven primarily by rising gas and carbon prices (affecting offer prices) and a widening spread of short NIVs due to increasing wind on the system . In particular, the DECC capacity mix reference case (with the CM in place) shows significant OCGT build from 2025 onwards, which exhibits significant offer price markups above its SRMC in the BM[40], driving up SBPs.

Figure 16 Evolution of average SBP (main price)

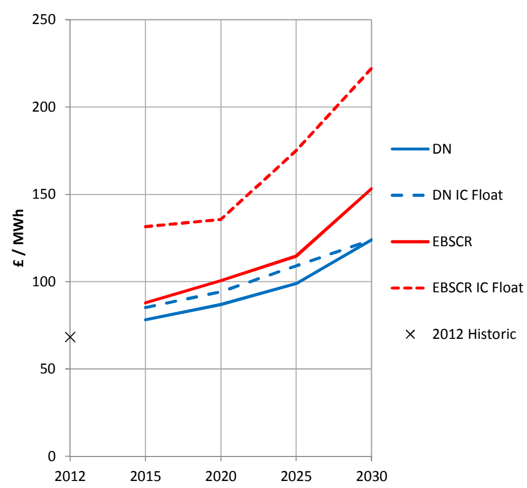
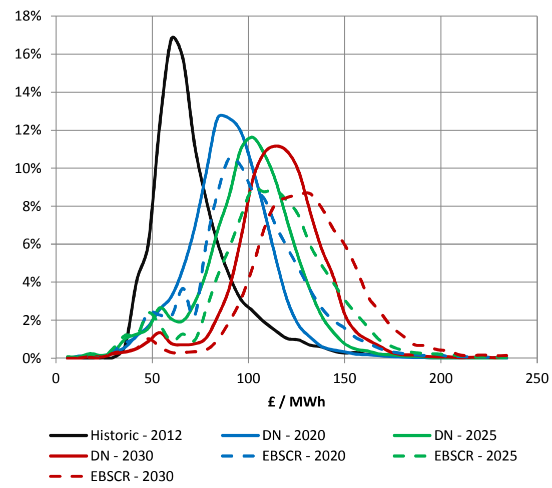


Figure 17 SBP (main price) distributions



The effect of EBSCR is to sharpen cash-out prices (i.e. increase SBPs and decrease SSPs). This is particularly true for SBPs, since in addition to more marginal PAR they are also impacted by the RSP function and costed demand control actions.

The impact of interconnectors is particularly significant. Higher SBPs increase within-day prices which in turn increases imports, which increases the range of available (lower cost) balancing options available in the BM and in turn depress SBPs. Without responsive interconnectors SBP is only slightly higher under DN (with limited difference in 2030 due to more balanced interconnector imports and exports), but under EBSCR increased interconnector imports help to substantially dampen SBPs, by >£50/MWh on average across the years modelled. This helps to counteract the large jump in SBP after 2020 due to the significant quantity of new OCGT deployed in the underlying capacity mix assumptions.

4.4.3. System Sell Prices (SSPs)

In the near term average SSPs (main price) rise slightly driven by rising fossil fuel prices. However, after 2015 they exhibit a steep decline dominated by changes to the underlying system (more subsidised plant in the capacity mix, commodity prices and NIV variation due to more wind) and less so from the proposed policy packages. Therefore, unlike SBP, differences in SSP under EBSCR are expected to be relatively small. This is for the following reasons:

[40] Due to the limited number of running hours per year against which they need to recover their fixed costs. This has been calibrated against historic behaviour and is assumed to continue going forwards.

- Offer (buy side) curves have typically exhibited greater 'shape' than bid (sell side) curves. The relatively flat nature of bid curves makes them less responsive to changes in the marginality of PAR
- In addition to increased PAR marginality, offer curves are subject to the RSP and costed voltage control and load disconnection; bid curves have no equivalent policies, and
- The sharp decline is driven by the increasing presence of subsidised plant in the utilised section of the bid curve (i.e. falling within normal NIV ranges), which is true of EBSCR and DN alike

Figure 18 Evolution of average SSP (main price)

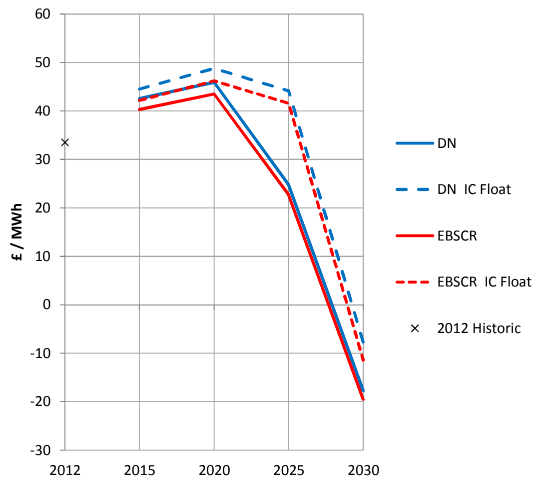
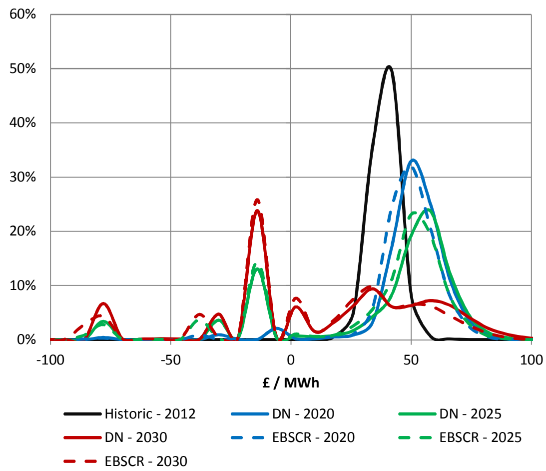


Figure 19 SSP (main price) distributions



The effect of having an increasing proportion of accepted bids from renewables featuring in the cash-out price calculation is that bid curves become characterised by step changes corresponding to the level of subsidy for each type of renewable plant (e.g. the difference between 1 and 2 ROCs for onshore and offshore wind).

In reality it is unlikely that renewable plant receiving the same level of subsidy will all bid at the exactly the same price, not least because generators may include shut down and start-up costs in their bids, which will differ by plant. Furthermore, the modelling relies on the assumption that there will be sufficient competition between renewables generators offering to curtail to drive bids down close to the opportunity costs of the lost subsidy. There is a risk, however, that bids with high negative prices get captured in the cash-out price calculation.

Interconnectors tend to dampen SSPs in a similar manner to SBPs. As prices are generally higher in GB this tends to increase imports, but when the system is long this tends to mean less fossil plant running in GB which can be turned down. This by extension leads to lower and more negative bids being accepted if the system is long and interconnectors are still importing. However, lower SSPs do then reduce the MIP encouraging more exports and hence equilibrium is eventually reached.

4.5. Impact on within-day wholesale prices

Within-day wholesale prices, as represented by MIP, are expected to increase steadily in the near term in line with underlying capacity mix and commodity price changes, before plateauing in later years as the impact of low carbon generation on wholesale prices starts to become material. Figure 20 shows the annual average MIP under DN and EBSCR, and Figure 21 shows the distribution of MIP.

Figure 20 Evolution of MIP

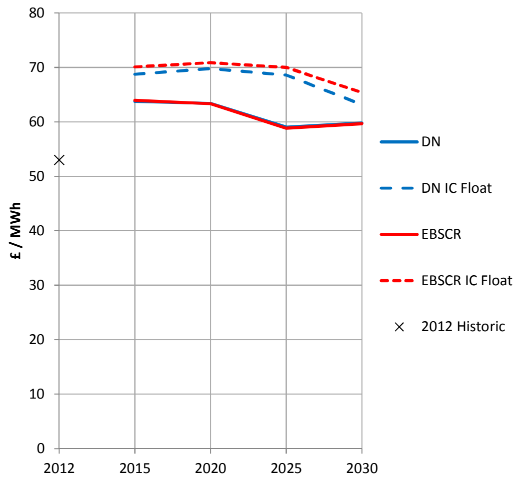
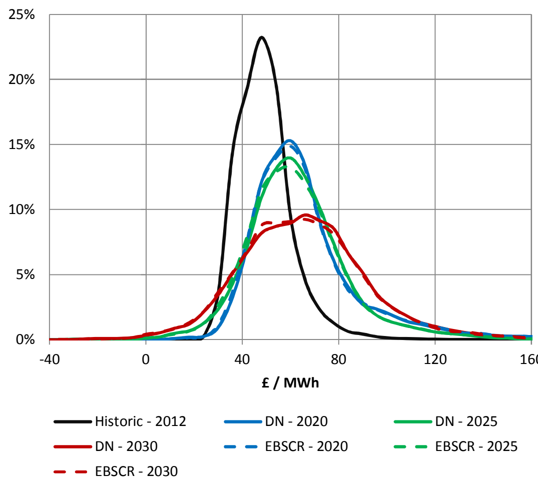


Figure 21 Distribution of MIP



Whilst EBSCR can increase the MIP significantly in individual periods across the year when the system is very short and depresses it in periods when the system is long, the average impact is very small, particularly given the dampening effect of interconnectors. However, given the size of the wholesale market relative to the BM, the larger changes in individual periods can still appear sizeable when set alongside the direct BM impacts as outlined in Section 4.8.

By 2030 there is approximately 100 hours of negative MIPs under both the DN and EBSCR case. The incidence of negative prices is a function of many factors including again the level of interconnection, the flexibility of the demand side and the strategy of the SO in managing the system with large volumes of asynchronous plant. Hence, there is some uncertainty surrounding this figure. DECC, in its EMR analysis, suggested several hundred hours of negative prices in 2030 under its central scenario.

4.6. Party incentives

4.6.1. Short term balancing performance incentives

To understand the overall impact of a cash-out reform on the short term response of parties - in terms of adjusting position biases pre-Gate Closure to try to minimise the Opportunity Costs (OC) of their imbalance exposure - there are three key factors to consider:

1. The impact on cash-out price spreads from the proposed cash-out reform policies alone (i.e. more marginal PAR, the application of the RSP and costing demand control actions).

2. The impact of introducing a single price policy which lowers the 'cost of position biases' for parties and creates incentives to adopt a position whereby parties can most benefit from being out of balance in an opposing direction to the system.
3. The impact on buy/sell spreads from the system moving longer or shorter as a result of different position biases. This has two opposing effects: if the system is moving shorter, there is potential to increase SBP due to an increase in average NIV; concurrently, if the system is moving shorter there will be an increase in the availability of lower cost offers in the BM as this energy is no longer contracted in wholesale energy markets.

In addition to a party's consideration of its own imbalance position, these three factors will combine to affect the aggregate position bias. The net effect of hedging positions will influence system imbalance outcomes which in turn will influence cash-out prices and within-day prices.

Importantly, the changes in position biases are generally very small when compared to total system movements ~1-2% of average Bilateral Contract Volumes (BCVs) in 2020, rising to ~5% of average BCVs in 2030. Thus, at a system level, position bias changes offer very little differentiation between DN and EBSCR. The two main reasons for the small volumes are, first, the cost of over-hedging in either direction which eventually starts to increases opportunity cost[41]; and second, significantly over-hedging in one direction (compounded across multiple parties) can start to flip the frequency with which the system is long versus short reducing the effectiveness of the position bias and increasing opportunity costs[42].

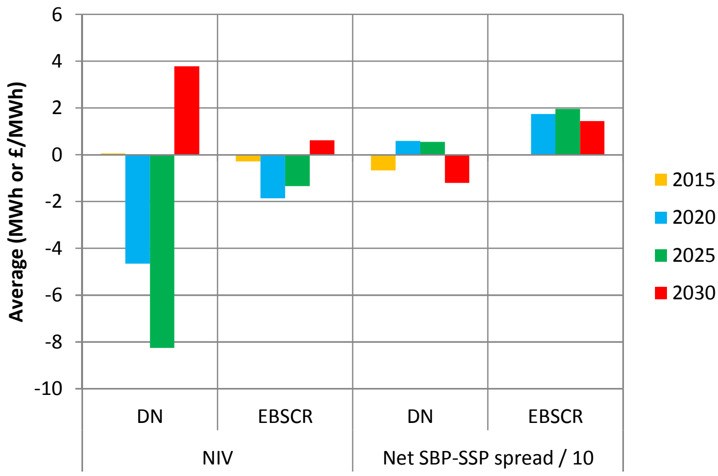
Figure 22 illustrates some of these effects. Whilst the overall equilibrium impact of more marginal (dual) prices would be to push the system longer (in order to reduce the impact of the increasingly positive buy side spread), the effect of single pricing is stronger in the medium term (~2020-2025) and leads to a shorter system under EBSCR relative to DN, due to the second of two competing incentives:

1. A lower cost of adopting any given preferred position bias as some of the cost of this position will be recovered when the party is out of balance in an opposing direction to the system. Single pricing may exaggerate the magnitude of any directional position bias adopted under the equivalent dual price package (going even longer when already going long).
2. The potential for parties to alter their position bias in order to benefit from spreads. This may result in a reversal of the direction of the position bias adopted under the equivalent dual price package.

[41] For example, by a supplier contracting for increasing amounts of power relative to its overall demand position itself (i.e. to make its position longer at Gate Closure) carries a cost, which will eventually exceed the benefit of a reduced chance of being short and not having to incur the SBP.

[42] E.g. hedging long to the extent that the system becomes long more often, and hence the party is more exposed to the MIP minus SSP opportunity cost rather than the avoiding the SBP minus MIP opportunity cost when the system is short (which by extension now happens less frequently), and which was the original purpose of the long hedge.

Figure 22 **Change in key system parameters (+ve NIV = short)**



Individual parties will respond to one of these incentives to different extents according to their own physical characteristics and the response of other parties. In the example above, moving from DN to EBSCR, the net effect of all party responses is to move to a relatively shorter system (i.e. less long) under EBSCR in the medium term from 2020/2025, even though the offer-side spread is larger compared to DN.

By 2030 under DN the bid-side spread (i.e. MIP to SSP) is larger than the offer-side (i.e. SBP to MIP) and the system is short on average. However, the offer-side spread has increased sufficiently that the first of the incentives described above takes priority and the system is now less short on average under EBSCR relative to DN.

This complex interplay between opposing incentives and aggregate system effects makes the directional outcomes with respect to NIV difficult to predict and attribute to any single dominant cause.

4.6.2. Long term balancing performance incentives

As well as providing signals to parties to balance in the short term, cash-out prices should signal the value of investing in improving future balancing performance through for example better forecasting systems or contractual arrangements such as PPAs which help to reduce imbalance risk. For this investment to be efficient, imbalance costs for parties should closely mirror the costs imposed by their imbalances on the system. If imbalance costs are dampened relative to the actual costs imposed on the system, parties will make insufficient investment, thus increasing the costs to the system operator, and ultimately consumers.

If, however, imbalance costs are too high (i.e. more than cost reflective), parties may over-invest to achieve high levels of balancing accuracy, which collectively do not improve the system level imbalance to a degree justified by the costs of the investment by the individual parties..

To assess how well the signals from the policy packages align with the underlying costs to the SO, we have plotted the relationship between opportunity costs of all parties (the additional costs of being cashed-out rather than closing positions in the wholesale market at prevailing market price) against the Gross Imbalance Volume (GIV), and compared this to the 'optimum' investment point in terms of NIV opportunity cost for the SO (the additional costs from resolving the system level energy imbalance through the BM rather than at market price)[43].

The change in NIV opportunity cost as you move up or down the curve represents the 'real' cost savings for the consumer from a reduction in system imbalance volumes, whereas the party opportunity cost represents the *individual* party benefits from improved imbalance. However, because of the distributional effects within cash-out, as a result of the flows of imbalance charges and RCRC, a benefit for one party from improved imbalance can lead to a negative impact on another (as improved balancing reduces the money flowing back through RCRC).

The costs of the investment in improved balancing still ultimately need to be paid for by the consumer, but the distributional impacts within cash-out across parties mean that real net consumer benefits only materialise if the overall SO cost of system balancing is reduced by a level that exceeds the cost of the investment across all parties.

The results for 2020, 2025 and 2030 are shown in Figure 23 to Figure 25 below. As the relationship has been estimated from the available simulation results, they are most valid close to the average GIV (one standard deviation +/- the average is equivalent to 35-65, 40-70 and 50-80 GWh of GIV for 2020, 2025 and 2030 respectively).

Figure 23 Long term imbalance incentives 2020

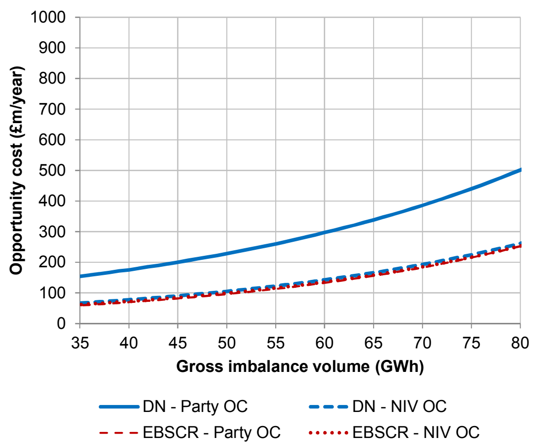
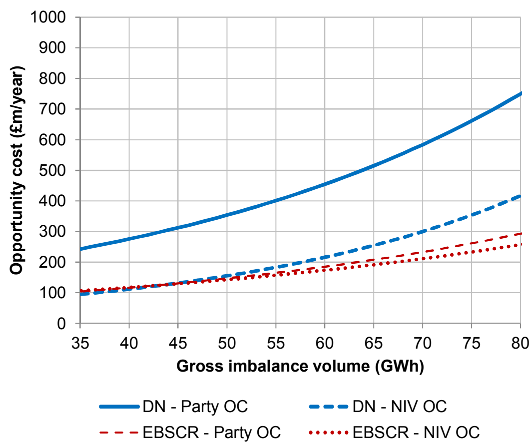
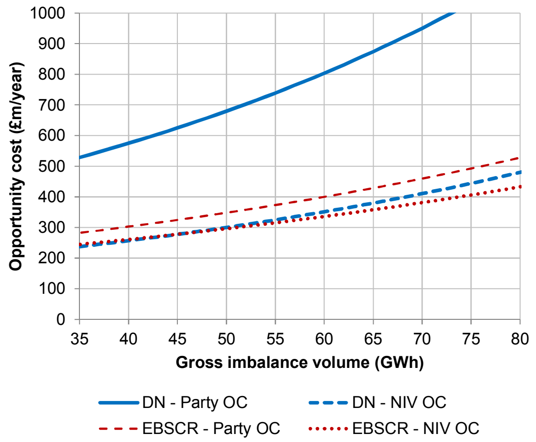


Figure 24 Long term imbalance incentives 2025



[43] For more information see previous report in footnote 12

Figure 25 Long term imbalance incentives 2030



The curves represent the best fit through the simulation results. As GIVs increase the opportunity costs of the imbalance also increase according to an exponential relationship. This is particularly true in 2030 under a tighter system. The NIV opportunity cost lines under DN or the EBSCR package[44] reflect the 'efficient benchmark for investment' against which we compare the party opportunity costs lines.

The party exposures under EBSCR more closely align with the underlying NIV opportunity costs, but does not exactly align since the RSP, for example, may not be 100% accurate (in terms of reflecting the actual costs to the SO of using STOR). It can be seen that for the DN case the opportunity cost curves for parties are significantly in excess of the underlying NIV cost, suggesting that on average the imbalance costs charged to parties are in excess of the costs that they impose on the system, particularly under dual cash-out prices.

This is not to say that dual (in presence of more-marginal) cash-out prices do not provide strong incentives for parties to balance when the system is under stress conditions, given the significant opportunity cost of being short when the system is short, but rather that dual pricing imposes imbalance costs in excess of the costs to the SO under normal or benign operating conditions. As a result parties may invest or take actions to avoid 'spilling' into imbalance in benign periods which are not justified in terms of added benefit to the system and which do not result in net improvement in overall balancing costs.

The above suggests that the incentives to invest in long term balancing performance are slightly weaker under average conditions for single prices under EBSCR than dual prices under DN, but actually incentivise more efficient overall outcomes (as shown in the CBA below). EBSCR leads to slightly more spill on the system than the DN case, but not dramatically so since there is still a strong incentive to avoid cash-out where possible, particularly with more volatile and spikier prices predicted.

[44] These are slightly different between DN and the EBSCR package due to the difference in short term position bias.

Table 12 Relative change in GIV for DN and EBSCR after long term imbalance investment

Year	Delta GIV DN to EBSCR[45] (GWh)
2020	+6
2025	+5
2030	+5

It is also important to note that the incentives for parties to cover their positions under peak conditions are strengthened by sharper cash-out prices under both dual and single price packages (under single pricing this is potentially stronger given the additional benefit from receiving the SBP[46] when long in a short system rather than just the reverse price). Hence, lower incentives to balance under normal conditions do not necessarily mean that parties would invest less to cover exposure to peak conditions.

4.7. Party-level results

4.7.1. Balancing net cashflows

Net cash flows from balancing are taken here to be the sum of incoming and outgoing cashflows from three sources[47]:

- Net Imbalance Charges (NIC) which represents the charges to a party due to its imbalance. In periods when the party is short this equates to procuring its imbalance at the SBP so will be an outgoing cashflow. In periods when the party is long this equates to selling its imbalance at the SSP so will be an incoming cashflow.
- Residual Cashflow Reallocation Cashflow (RCRC) which recovers or returns differences in the aggregate NIC according to the total credited energy volumes of parties. Parties with low imbalance will typically be net beneficiaries, with RCRC being more positive than their own NIC, and vice versa for parties with high imbalance.
- Balancing Mechanism Earnings (BME) which represent the revenue from accepted offers and bids into the BM. Note that we are only including those actions that contribute to energy balancing, and not actions taken to support system balancing, such as resolving transmission constraints. As the BM currently operates a pay-as-bid market and the model is not agent-based, all BMEs are calculated using a single weighted average pay-as-bid price.

---

[45] Improvement in imbalance is assumed to be to the maximum of the rational cost-benefit indifference point or 10%. This recognises that there will be physical limits to which imbalance improvements can occur. However, it is difficult to say with certainty what the upper limit will be.
[46] Which is likely to be high under system stress conditions
[47] As mentioned in Section 2.2 it should be noted that the model does not produce an overall estimate of BSUoS costs as it is focused on 'energy balancing' only, rather than the costs of energy and 'system balancing' actions (e.g. to resolve transmission constraints).

From a cashflow perspective, independent suppliers and wind parties tend to have the greatest imbalance exposure (Figure 26 and Figure 27) as a proportion of their volumes as historically they have been less able to balance their positions. This is true under both DN and EBSCR as underlying system changes and the physical properties of these parties result in large imbalances. This becomes increasingly the case moving from 2020 to 2030 as changes to underlying system conditions drive larger variation in NIV and corresponding increased imbalance exposure.

However, NIC and RCRC only provide a partial picture of the cost of balancing for an individual party and it is more instructive to consider the opportunity cost of imbalance as outlined in Section 4.7.2.

Figure 26 Party-level net cashflows for DN and EBSCR, 2020[48]

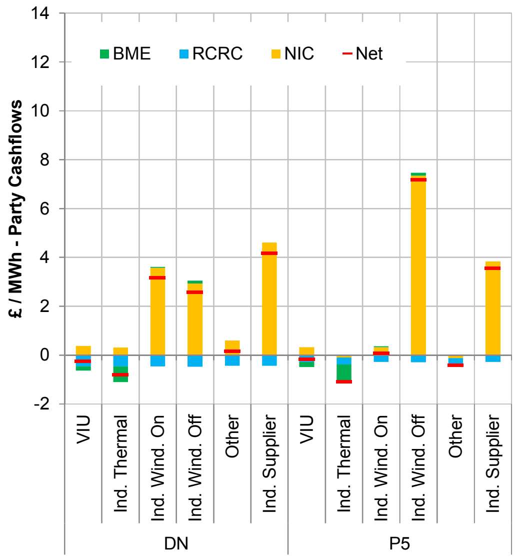
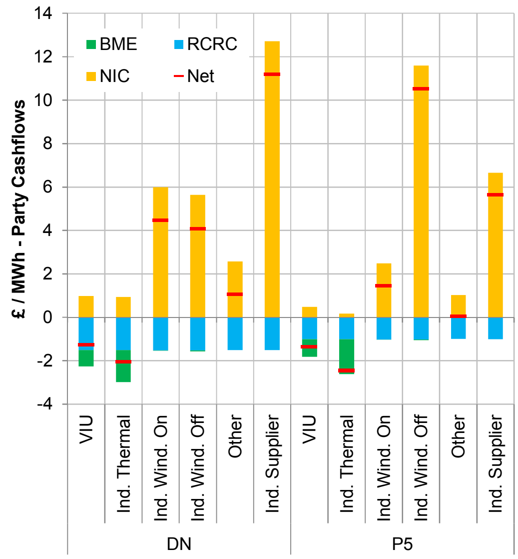


Figure 27 Party-level net cashflows for DN and EBSCR, 2030



4.7.2. Opportunity cost

We use the term opportunity cost here[49] to represent the loss to a party that is incurred by being out of balance as opposed to settling its entire position in the wholesale energy market. For instance, a short party in a short system will have to procure energy through cash-out at a price equal to SBP. This price is typically greater than the price at which this energy could have been procured ahead of Gate Closure, which for the analysis we assume is equivalent to the MIP. Likewise, for long positions in a long system, the price received for spilling energy (SSP) is less than what could have been received had the position been settled in its entirety in the wholesale energy market (again, assumed to be at MIP).

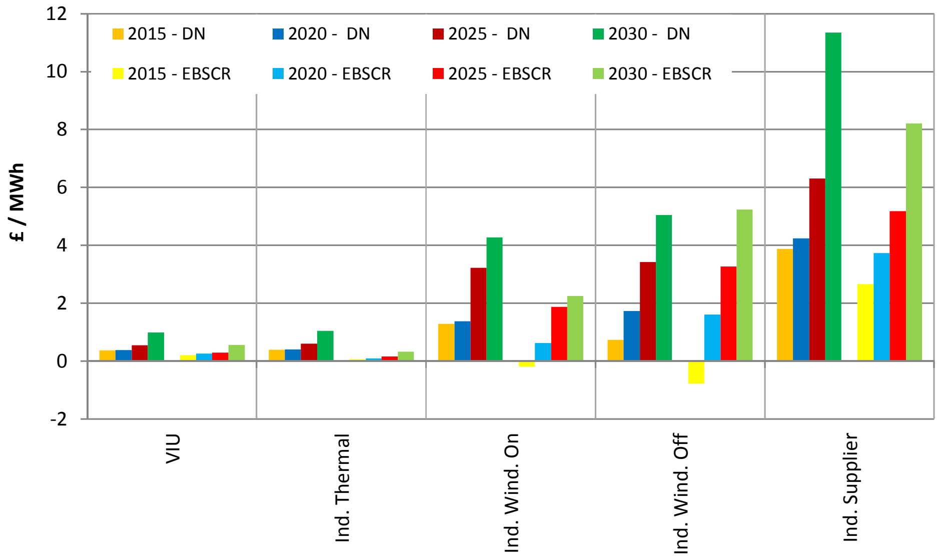
[48] Positive values represent outgoing cashflows

[49] This is the same as the "Imbalance Charges" metric used by Ofgem in the accompanying policy decision and Impact Assessment documents with the exception of omitting RCRC.

These differences in price represent a cost to the party of being out of balance. Under packages with single pricing, this opportunity cost also accounts for the lost benefit of not receiving a better price than MIP for helping the system by being out of balance in the opposite direction.

Like the balancing net cashflows described above, the opportunity cost is greatest for those parties that are poor at balancing their positions (Figure 28).

Figure 28 Party-level opportunity cost for DN and EBSCR



Imbalance opportunity costs increase significantly over time for all parties under both DN and EBSCR given the increase in the underlying evolution cash-out price spreads described in Section 4.4. On an opportunity cost basis, most parties gain from the move to single pricing under EBSCR, significantly for onshore wind and independent suppliers[50]. This is because single pricing allows these parties to capture benefit when their imbalance is in an opposing direction to the system, whereas currently they only pay or receive the reverse price based on MIP when they are 'helping' the system. For offshore wind in 2030 the effect is broadly neutral (i.e. benefits from single pricing offset the increased costs from marginal cash-out prices) when considering the full opportunity cost of being out of balance as opposed to just the settlement cashflow impact.

The overall opportunity costs for wind are lower than the previous analysis due largely to the revised bottom-up estimate of the correlation of an individual wind farm's forecast error to the system, which has reduced its exposure.

It should, however, be noted that this reflects the correlation for an individual wind farm. If an independent operator owned multiple wind farms (particularly if clustered in a similar location) or used aggregation services (which could more systemically produce inaccurate forecasts) their individual forecast errors will move to correlate more closely with the overall system, reducing

[50] Although as noted above, stronger balancers will lose out through lower RCRC rebates in the settlement process.

the benefits of single pricing (as they are less often out of balance in the opposite direction to the system) increasing their imbalance opportunity costs.

4.7.3. Credit risk

As outlined in Section 2.3.5 we have used the output from the COM to create an approximation of the rolling credit cover requirements (on a daily basis, across each spot year, for each party type) which would need to be posted to avoid entering the BSC default process.

The average annual requirements over time normalised to a £/MWh of CEV[51] by party type under both DN and EBSCR are shown in Figure 29; whilst the relative change in volatility of credit cover (as estimated by the standard deviation of requirements from day-to-day) under EBSCR versus DN is shown in Figure 30.

Figure 29 Party-level average credit cover under DN (solid line) and EBSCR (dashed line)

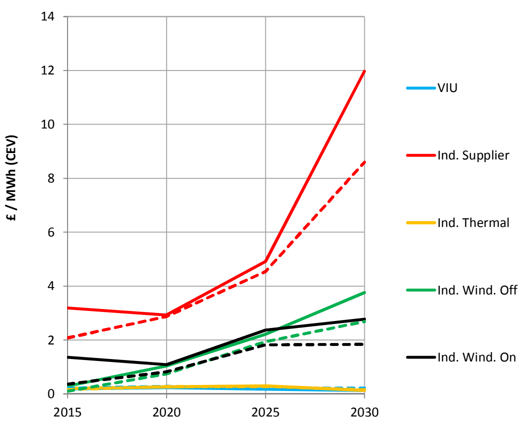
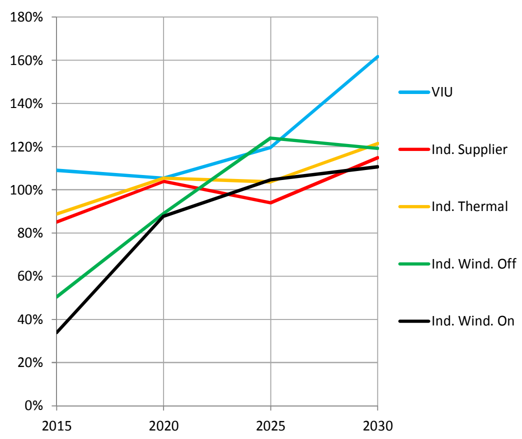


Figure 30 Party-level change in volatility (% of st.dev) under EBSCR relative to DN



Poorer balancers, particularly independent suppliers and wind generators have significantly higher absolute credit cover requirements than VIUs and independent thermal generators. This is exacerbated over time under DN due to the significantly widening spread of SBP and SSPs, which in turn leads to higher net imbalance charges and average credit cover requirements. However, under EBSCR the benefits of single pricing tend to offset the more marginal cash-out prices, leading to lower average credit cover requirements for independents, whereas for VIUs it tends to increase the average credit cover over the period to 2030 (from a very low starting point per MWh).

More marginal cash-out prices tends to increase somewhat the volatility in credit cover requirements for parties after 2025. However, this increase tends to be lower for independents in earlier years due to the benefits of single pricing under EBSCR, i.e. from being in the opposite direction to the system imbalance more often than other parties, offsetting the impact of more marginal pricing. Illustrative within year rolling credit cover profiles by party type in 2020 to 2030 are shown in Appendix B.

[51] By dividing the credit requirement on the settlement day through by the sum of the CEVs over the previous 29 Settlement Days (including the current Settlement Day).

The expectation is that credit cover requirements are likely to increase over time for independents, given the underlying trends in cash-out prices under DN. However, EBSCR will not compound this and the benefits of single pricing may more than the offset the increase due to sharper cash-out prices.

4.8. Cost-Benefit Analysis

An annualised cost-benefit analysis (CBA) for each modelled year - along with a Net Present Value (NPV) calculation from 2016 to 2030[52] - was undertaken to assess the net impact on consumers of EBSCR relative to DN.

This section:

- Outlines the overall approach to the CBA and its key components
- Presents the main results table
- Provides a discussion of the impact of the key components and the overall impact on consumers

A fundamental assumption made for this analysis is that all costs and benefits incurred by parties on account of cash-out reform will be passed onto consumers. In reality the extent to which the costs and benefits get passed through to customers will depend on the competitive dynamics of the market, but we have not attempted to model this effect given the inherent uncertainties out to 2030.

The CBA is split into two groups of costs and benefits: those directly related to changes in imbalance costs for parties and the system operator, and those relating to ensuing changes in wholesale costs (electricity and capacity prices). Some of the impacts assessed are direct outputs of the model whereas some are ex-post calculations using the model outputs.

The direct imbalance cost impacts include:

- **Net imbalance charges (NIC) and RCRC**: These are direct outputs of the model and represent the costs of imbalance charges to parties and the redistribution of these charges through RCRC (as discussed in Section 4.7.1). These charges are equal and opposite.
- **Short Term (ST) position bias net costs (parties and SO)**: This represents the net change in the total costs of balancing the system resulting from a change in parties' position biases. This is composed of the change in costs to the SO in resolving the resulting change in NIV, and the change in costs incurred by parties in the wholesale market when adapting their contractual positions (as discussed in Section 4.6.1).
- **Party savings from lower Long Term (LT) balancing investment:** As discussed in Section 4.6.2 changes to cash-out are likely to change the incentives for LT investment in balancing performance. This item presents the difference in investment costs that result from changing balancing incentives.

[52] The NPV is calculated from 2016-2030 with linear interpolation of values between years and a 3.5% social discount rate. Hence the 2015 result provides a proxy (subject to interpolation to 2020) for 2016.

- **System costs from lower LT balancing investment:** Linked to the above, any change to investment in LT balancing performance will, by extension, affect the overall costs of balancing to the SO (and indirectly the cost to parties' of their position biases).

The wholesale cost impacts include:

- **Wholesale electricity prices:** As discussed in Section 2.3.4, cash-out reform is expected to affect wholesale prices and increase costs to suppliers, particularly for peak cover. Note that it is assumed that CfDs will insulate suppliers from higher wholesale costs resulting from cash-out reform for the proportion of their demand covered by CfDs.
- **Capacity prices:** As discussed in Section 2.3.4, this represents the reduction in CM auction clearing prices that result from participants anticipating higher revenues in the wholesale market as a result of cash-out reform.
- **Interconnector de-rating factors:** As discussed in Section 2.3.1, this represents the savings associated with higher de-rating factors assumed for interconnected capacity under EBSCR.

The costs and benefits are summed to show the annual impact on consumers in £m. This is also shown as an average £/MWh cost for all customers. In addition, an estimate of the change in annual domestic consumer bill in £/year is included (assuming average annual consumption of 3.3 MWh).

Table 13 CBA summary - domestic consumer perspective (NPV social discount rate of 3.5% real)

£m/year (+ve = benefit to end consumer[53])	EBSCR relative to DN			
	2015[54]	2020	2025	2030
NIC	122	100	162	330
RCRC	-122	-100	-162	-330
ST position bias costs (party and SO)	2	2	2	-3
Party savings from lower LT balancing investment	30	26	21	39
System costs from lower LT balancing investment	-16	-14	-7	-3
Total consumer costs (before wholesale and capacity price effects)	*17*	*14*	*16*	*33*
Wholesale electricity prices	-166	-17	-360	-426
Capacity prices	0	27	468	517
Interconnector de-rating factors	0	5	3	7
Total consumer costs	***-149***	***29***	***127***	***131***
NPV 2016 – 2030 £m	**435**			
Change in average £/MWh	**-0.48**	**0.10**	**0.43**	**0.40**
Annual domestic bill change (£) (-ve = benefit)	**1.60**	**-0.32**	**-1.40**	**-1.32**
Annual domestic bill change (excluding wholesale and capacity price effects) (-ve = benefit)	*-0.18*	*-0.16*	*-0.17*	*-0.33*

Note: totals may not sum due to rounding

NIC and RCRC

NIC and RCRC rise significantly over time due to increasing SBPs and lower SSPs (particularly negative SSPs), but are net neutral from the consumer perspective. They do, however, have important distributional implications as shown in Section 4.7.1, which will impact on the competitive market dynamics.

ST and LT balancing costs

Variations in the costs from parties adapting their position biases (see ST position bias costs row of table) are modest due to the natural offsetting effects described in Section 4.6.1. In the near to medium term there is a very small net benefit due to slightly more efficient balancing overall. However, the significant drop in average SSPs from 2025 to 2030 means that although the slightly longer position under EBSCR relative to DN is preferable for individual parties this leads to more negatively priced bids being accepted and a marginal disbenefit in terms of the overall system costs of balancing. In 2030 the shape of the bid and offer curves (which are the same

[53] Assumes that all costs and benefits are ultimately pass through to the consumer

[54] This assumes the full EBSCR package is in place. However, this now will not take place until 2016. The NPV is calculated from 2016-2030 with linear interpolation of values between years. Hence 2015 is a proxy for the 2016 value, subject to the linear interpolation between 2015 and 2020.

under both DN and EBSCR) means that the reduced costs of balancing when the system was previously shorter under DN are slightly less than the additional costs from the negative bids (due to the subsidy impact) plus the additional party costs of hedging slightly longer under EBSCR. However the scale of the ST changes across all years is very small and broadly neutral overall.

There is more significant benefit under EBSCR when considering the net effect of incentives to invest in LT balancing performance across parties and the SO. Slightly weaker balancing performance from a lower level of investment increases the costs to the SO since GIV increase, but the savings to parties more than offset these additional costs. This is the result of the fact that under EBSCR the costs to parties of imbalance better align with the underlying costs incurred by the SO.

Wholesale electricity and capacity price effects

Layering in the impact of cash-out reform through the CM and wider wholesale prices tends to accentuate the benefits in later years. However, it is important to note the key assumption that parties are explicitly factoring in wholesale market expectations into their CM bids.

In 2015 the CM is not yet in place and there is a small disbenefit through slightly higher average wholesale prices. However, we have not quantified any potential indirect benefit of EBSCR in terms of deferrals of plant retirements or moth-balling decisions ahead of the introduction of the CM. Furthermore, introducing EBSCR earlier on provides time for market participants to learn and adapt to changing wholesale market revenues, increasing the potential for the estimated savings from 2020 onwards to be realised.

From 2020 onwards the effect of higher peak and wholesale prices from cash-out reform leads to a reduction in CM auction clearing prices (as participants discount their bids into the CM driving savings to the consumer), which more than offsets the price impact for consumers.

The effect is accentuated as the plant clearing the CM auction moves from a baseload/mid-merit plant in 2020 to a new peaking plant in 2025 and 2030. The reduction in the auction clearing price under EBSCR increases from ~£1/kW in 2020, to ~£10-15/kW in later years. The reason for this is that the impact of cash-out reform is more material on peaking plant. For baseload or mid-merit plant the improvement in wholesale price captured is fairly small, whereas for peaking plant the impact of cash-out reform on prices in the peak few hours it expects to be running is much more material. As the CM auction is pay as clear this leads to a significant saving for consumers when spread across ~35-40 GW of eligible CM capacity.

Interconnector de-rating factors

The increase in de-rating factors for interconnectors under EBSCR yields an annual saving of around £3-7m. Prior to the introduction of the CM in 2018/19 the greater interconnector responsiveness would lead to a reduced risk of unserved energy, but the cost savings are negligible and not shown in the CBA table.

Overall impact on consumers

The analysis shows a small disbenefit to consumers in 2015 compared to DN (of around £0.48/MWh) driven by higher wholesale prices, and modest, but sustained benefits after the introduction of the CM (of up to around £0.40/MWh) and a positive NPV (Net Present Value) overall of around £435M over the period to 2030. The underlying reduction in imbalance costs is positive for consumers in all years.

These results should be caveated in terms of the uncertainty in assumptions. This is both in terms of the range of key input assumptions that we have explicitly modelled (e.g. the spread of fuel prices or demand) as well as uncertainty in elements of the modelling approach, such as the extent to which the MIP regression model holds going forwards.

Although the CM will be the main tool for ensuring capacity adequacy, cash-out reform should also increase security of supply through increasing the value of flexibility. This should increase incentives to invest in flexible generation and demand side response. However, neither of these potential benefits is quantified explicitly in the modelling.

4.9. Summary of other Impact Assessment criteria

4.9.1. Security of supply

As discussed above, it is now assumed that the CM will be the main mechanism for promoting security of supply in the GB market, certainly from the perspective of capacity adequacy. However, cash-out reform will likely also provide benefits in terms of security of supply:

- Improved signals for the dispatch of flexible generation and utilisation of demand side response from cash-out prices being more responsive to system conditions, and
- Greater responsiveness of interconnectors to conditions of system stress in the GB market

Figure 31 shows the top 0.5% of SBPs in 2020 and 2030 under EBSCR compared to DN. It can be seen that in a tight market, prices would rise up to VoLL before load disconnection, which should ensure that interconnectors are importing at maximum before customers are disconnected, which may not necessarily be the case under DN (assuming that the response due to sharper price signals is more reliable than potential SO emergency interconnector actions). This also suggests that customers with lower VoLL than the administrative level would self-interrupt sooner, enhancing security of supply for customers with higher VoLLs.

More marginal pricing, RSP and VoLL pricing under EBSCR would also likely make SBPs far more responsive to system conditions, and increase their volatility. This should signal the additional value of flexible generating capacity and demand side response. Figure 32 shows the standard deviation of SBP under EBSCR relative to DN, demonstrating a significant increase particularly in 2030.

Figure 31 High SBP cumulative distribution

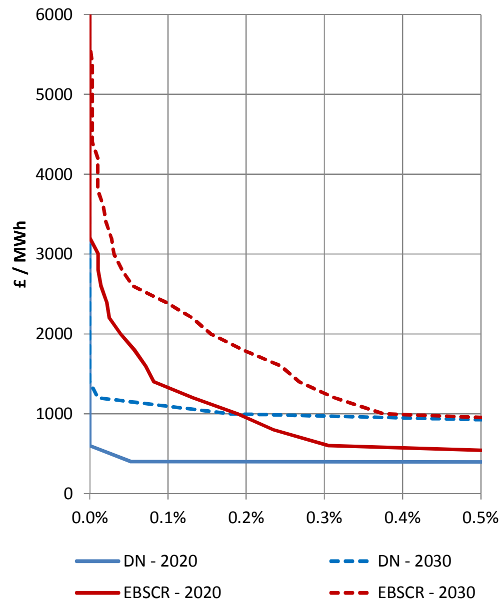
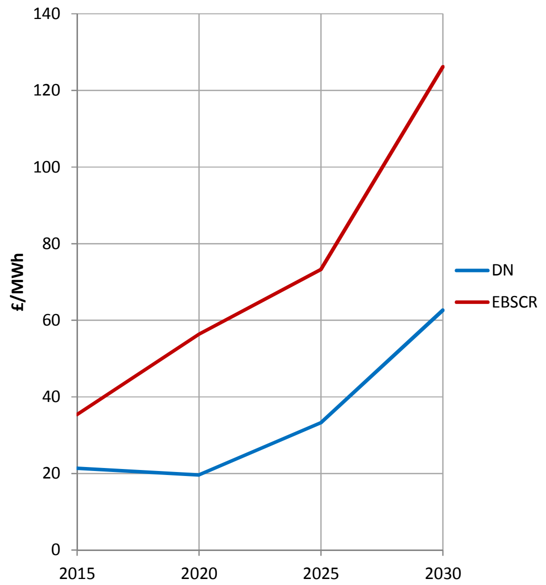


Figure 32 Evolution of standard deviation of SBP



4.9.2. Competition and sustainability impacts

The proposed cash-out reform is likely to have significant distributional effects and indirectly impact on competition in the market. For example, where the existing cash-out arrangements unduly disadvantage smaller suppliers (due to the impact of dual pricing on weaker balancers), the proposed cash-out reforms could remove some barriers to new entry.

Sharpening cash-out prices is expected to disadvantage independent parties to the greatest extent, which could have a negative impact on competition. This is primarily due to the fact that historically, they have been the poorest balancers. However, as outlined in Section 4.7.2 the inclusion of single pricing in EBSCR leads to a net improvement, for independent (onshore wind) generators and suppliers relative to the DN case. For offshore wind, there is a broad offsetting effect as offshore wind farms are assumed to be larger and have greater correlation with overall system imbalance over the longer term, leading to limited benefits under single pricing compared to onshore wind.

By potentially reducing the costs of imbalance compared to the DN case for some forms of renewables such as onshore wind (and better aligning them with the costs they impose on the system), this should reduce the cost of supporting low carbon generation. For example, by not requiring them to balance as strongly, at disproportionate cost, when system conditions are relatively benign this could reduce the discounts associated with imbalance risk in Power Purchase Agreements.

This could lead to a saving for consumers or allow more low carbon generation to be deployed for the same level of funding. In addition, EBSCR could support improved sustainable development through the provision of better incentives for flexible generation, thus helping to accommodate growing levels of intermittent generation on the system more efficiently.

A further sustainability consideration of cash-out reform is whether the risk of more marginal pricing encourages greater amounts of part-loading, and hence higher emissions. However, such an effect may be assumed to be relatively small, particularly over time as remaining coal plant is retired and the efficiency penalty for part loading gas plant is lower. This is a potential risk, but strategies to reduce the risk of non-delivery penalties under the CM are also a consideration here.

5. CONCLUSIONS

In the absence of cash-out reform under the DN case, the changing generation mix, rising average fossil fuel and carbon prices, and tightening capacity margins relative to today will likely drive significant increases in the costs of energy balancing over the next two decades.

For example, the overall cost of energy balancing to the consumer could potentially increase by around 50% to approximately £40m annually by 2020, and potentially increasing by a factor of 10 by 2030. The costs of system balancing, such as the management of transmission constraints, could also rise significantly over this period but this was not a focus of this study.

An increasing spread of Net Imbalance Volumes over time is expected under the DN case, largely driven by the increases of wind capacity on the system. The modelling also suggests that under the DN case System Buy Prices (SBPs) will rise significantly over time, but that after 2020 System Sell Prices (SSPs) will start to fall as bids from subsidised low carbon generation are captured within the cash-out price calculation. By 2030, the average SSP (when it is the main price) is expected to be negative. This will result in a greater spread in cash-out prices which is expected to influence player behaviour. The results also show that the annual average SBP and SSP (when main price) under EBSCR, has a higher SBP than the DN case, and lower SSP.

A Cost-Benefit Analysis (CBA) of cash-out reform under EBSCR in section 4.8 shows a modest disbenefit to consumers in 2015 compared to DN (of around £0.48/MWh), and modest but sustained benefits after the introduction of the CM (of up to around £0.40/MWh) and a positive NPV (Net Present Value) overall of around £435m over the period to 2030. The underlying reduction in imbalance costs is positive for consumers in all years.

Although the CM will be the main tool for ensuring capacity adequacy, cash-out reform should also increase security of supply through increasing the value of flexibility. This should increase incentives to invest in flexible generation and demand side response. However, neither of these potential benefits is quantified explicitly in the modelling.

By encouraging a higher volume of imbalance the effect of single pricing is to increase the costs of energy balancing for the SO somewhat, but this effect appears to be relatively small and the incentives to balance remain strong under EBSCR, particularly under conditions of system stress.

Under EBSCR, and due primarily to the impact of single versus dual pricing, the savings to parties of having to invest less in long term balancing performance appear to more than outweigh the additional costs for the SO, from slightly weaker balancing and an increase in GIVs. This is because under single pricing the incentives for parties to balance relative to their overall impact on the costs of balancing the system are much more closely aligned.

The proposed cash-out reform is likely to have tangible distributional effects. The benefit of single pricing under EBSCR for typically weaker balancers (e.g. independent suppliers or renewable generators[55]) tends to more than offset the additional exposure to more marginal

[55] Note that the opportunity costs of imbalance are lower for some parties, such as independent wind, than in the previous analysis. This reflects the enhancements in the modelling approach, in particular the

cash-out prices. An indirect result of this is that single pricing also helps to mitigate against an increase in credit cover requirements under the BSC, due to sharper cash-out prices. This suggests that the proposed cash-out reforms may be beneficial in terms of distribution effects (particularly for independents) as well as security of supply.

assumptions surrounding the correlation of independent wind parties' forecast errors to the overall system, along with greater flexibility provided by interconnectors and gas-fired generation.

APPENDIX A – RESERVE SCARCITY PRICING FUNCTION

The Reserve Scarcity Pricing Function (RSP) assigns a value to STOR actions as a function of the level of margins in each period (the “ STOR replacement price”). If implemented, the RSP would be used to re-price STOR actions when they enter the calculation of cash-out prices, replacing the current buy price adjuster (BPA). Ofgem has been developing the details of the definitive form that the RSP function will take in consultation with industry.

For the purposes of quantification of the impacts as part of this model, the following RSP was developed. Historical data was used to determine a relationship between margin on the system, and what LOLP may have been, based on assumptions about likelihood of demand forecast error, and plant failure at gate closure. This simple representation of ‘LOLP’ was then multiplied by the value of loss load (VoLL) to determine the STOR replacement price.

Expected available capacity for a settlement period was calculated at gate closure, and based on the following assumptions:

- Available capacity in each settlement period is based on the Maximum Export Limit (MEL) of spinning plants, reflecting synchronisation times.
    - For non-spinning CCGT 20% of MEL capacity was also included based on discussions with National Grid
- For pumped storage, hydro and OCGT plants, the full MEL is assumed available (even if they had zero FPNs in that period).
- As non-BM STOR is not counted in the MEL dataset, 1000MW was assumed to be available and this is added to margins.
- Total available capacity (net of wind) is assumed to comprise a number of equally sized units, with equal but independent probabilities of failure. A probability of cumulative plant losses is also estimated.
- Interconnectors are assumed to flow at outturn values.

The calculation of the LOLP assumes that demand forecast errors are normally distributed, with a mean of zero and a standard deviation of 1.2%. This assumption is based on the historic demand forecast errors observed in 2011 and 2012. Using this distribution, it is possible to calculate different possible levels of expected demand in each settlement period.

All generating units are assumed to have equal and independent chance of failure. Each plant is assumed to have a 3% of failure, and the average plant size is assumed to be 500MW.

Using the estimated margins (based on historic data) and the LOLP calculated for each level of margin, an RSP was constructed as a linear relationship between margins and LOLP multiplied by VoLL. In the preliminary RSP, the maximum value for the replacement price is set at £3000/MWh before winter 2018/19 and £6000/MWh from this point onwards, corresponding with the price for Demand Control actions under the ‘with CM’ scenario. The function assigns this maximum value when the margin is on or below 1500MW. This figure was selected to represent a minimum reserve for response level, and it is assumed that the SO will instruct voltage control when the reserve margin falls below this threshold. The form of the RSP used for the model is shown in Figure 4 (Section 1.3).

APPENDIX B – WITHIN YEAR CREDIT COVER RESULTS BY PARTY

The charts below represent the simulated (normalised £/MWh CEV) rolling credit cover results - for each party type across the spot year - needed to avoid the BSC default process (*as outlined in Section 2.3.5*) under both DN and EBSCR

Note that the bottom to the top of the shaded areas represents the range of credit cover requirements under the P10 and P90 cases. The dark red shaded area simply shows where these areas overlap under DN and EBSCR.

Overall credit cover requirements tend to increase over time under DN. However, across the parties, typical requirements are significantly lower for VIUs and Independent Thermal generators given their better balancing performance. Across the year, credit cover requirements vary significantly for all parties even under average DN conditions, by potentially more than a factor of two comparing the lowest to the highest requirements.

Under the EBSCR reform package the VIUs and independent thermal generators are affected more by sharper prices and less by benefits of single pricing compared to the other parties; as more of their risk tends to be on the short side from plant failure, whereas other parties' risk is slightly more symmetrical in terms of demand / wind forecast error. Hence, they have more opportunity to benefit from being in the opposite direction to the system imbalance under single pricing.

The impact of more marginal pricing on credit cover requirements is most pronounced in later years for the VIUs, particularly under the P90 case given more extreme balancing conditions. However, even here, the highest expected requirement per normalised MWh for the VIUs is still below that of the average requirement for the independents.

By contrast, for the independent wind generators and suppliers the impact of single pricing under EBSCR tends to offset the impact of sharper cash-out prices in this reform packages. This tends to hold true across the year and across the average, P10 and P90 cases. The minimum and maximum values across the year along with the volatility are relatively similar under both DN and EBSCR for these parties.

Results for 2020

Figure 33 VIU (£/MWh)

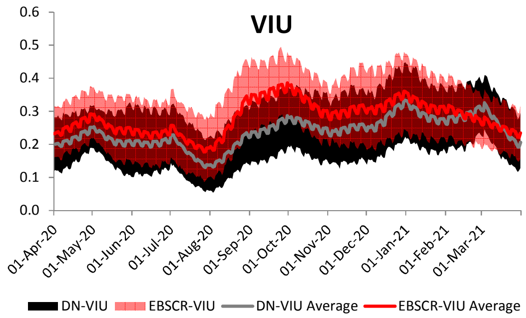


Figure 34 Ind. Thermal (£/MWh)

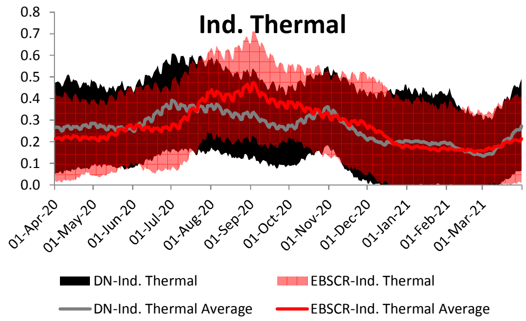


Figure 35 Ind. Onshore Wind (£/MWh)

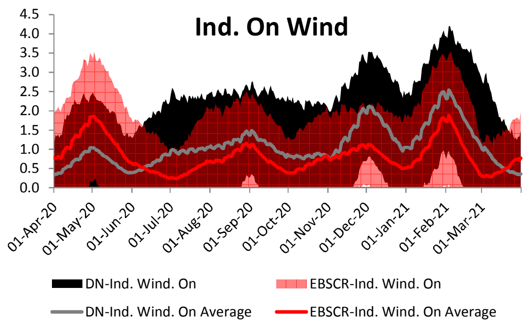


Figure 36 Ind. Offshore Wind (£/MWh)

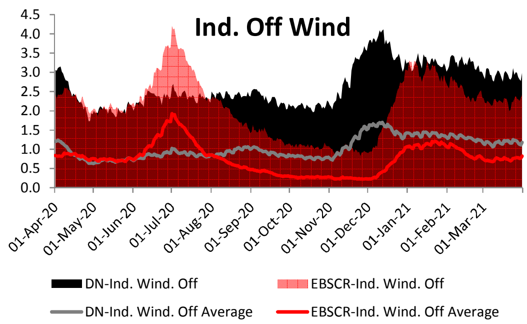


Figure 37 Ind. Suppliers (£/MWh)

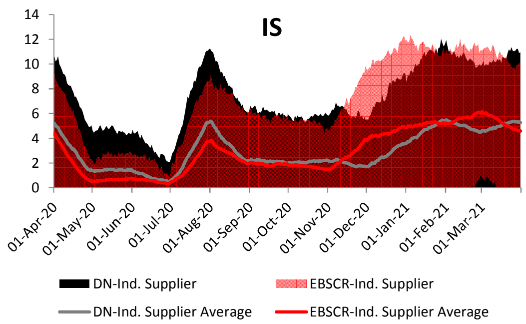
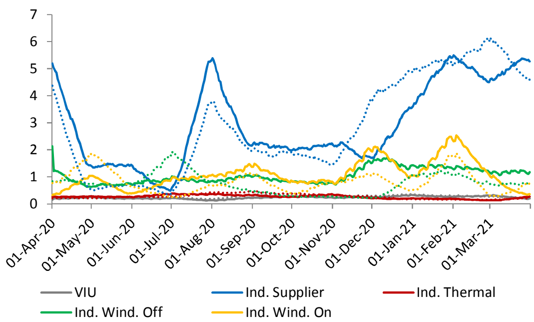


Figure 38 Average (£/MWh) DN / EBSCR (Dashed)



Results for 2025

Figure 39 VIU (£/MWh)

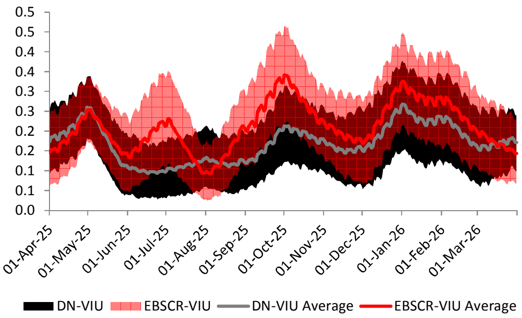


Figure 40 Ind. Thermal (£/MWh)

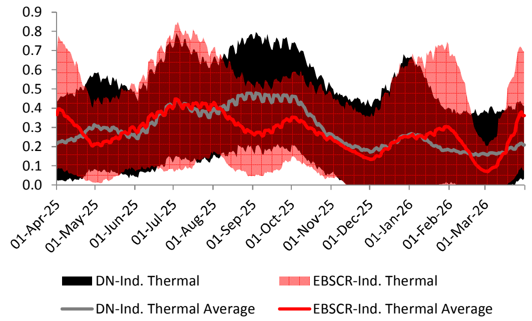


Figure 41 Ind. Onshore Wind (£/MWh)

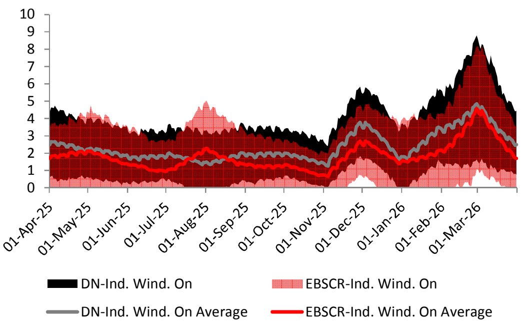


Figure 42 Ind. Offshore Wind (£/MWh)

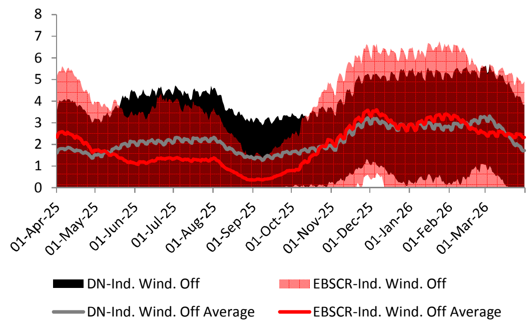


Figure 43 Ind. Suppliers (£/MWh)

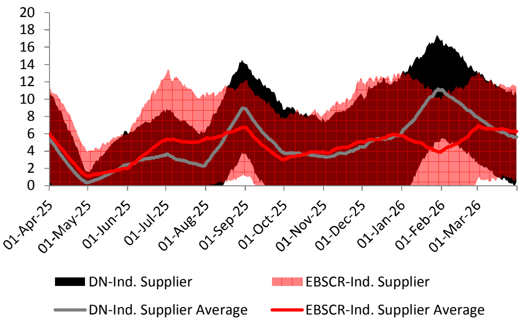
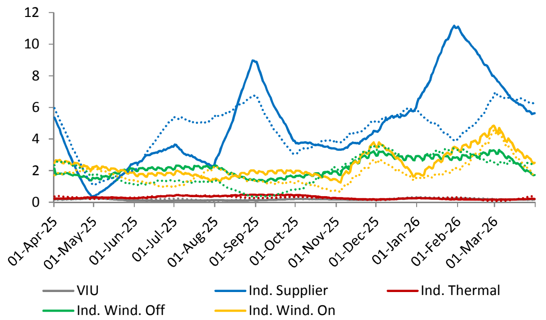


Figure 44 Average (£/MWh) DN / EBSCR (Dashed)



Results for 2030

Figure 45 VIU (£/MWh)

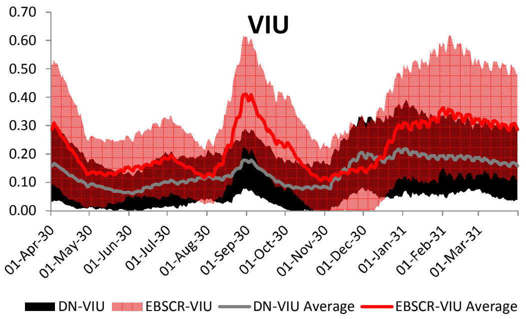


Figure 46 Ind. Thermal (£/MWh)

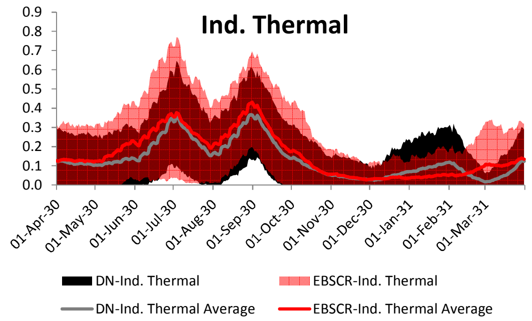


Figure 47 Ind. Onshore Wind (£/MWh)

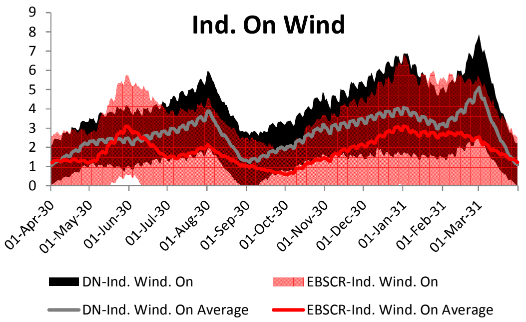


Figure 48 Ind. Offshore Wind (£/MWh)

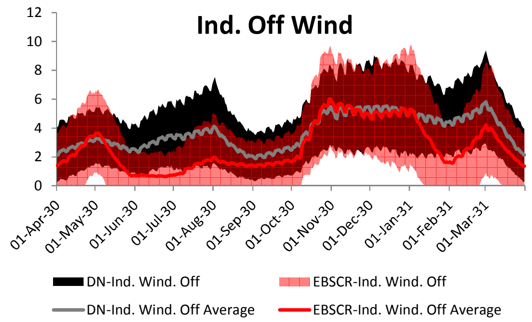


Figure 49 Ind. Suppliers (£/MWh)

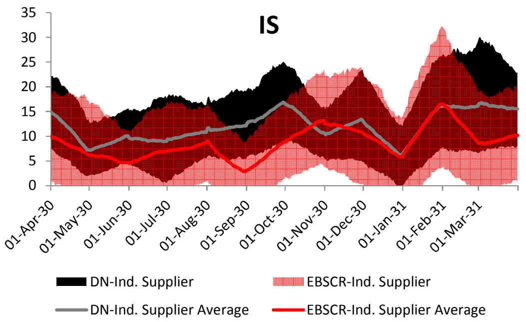


Figure 50 Average (£/MWh) DN / EBSCR (Dashed)