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Research Report

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Empirics of Intraday and Real-time Markets in Europe: Great Britain

Christos Vasilakos Konstantinidis¹, Goran Strbac

1. The elements of Intraday and Real-time Markets in GB

The GB wholesale market is largely based on bilateral trading between generators, suppliers, traders and customers across a series of markets. As depicted in Figure 1 [1], the wholesale market can mainly be divided into bilateral Over The Counter (OTC) trading and power exchange trading, followed by Balancing Mechanism (BM) activity and imbalance settlement. Electricity is traded in half hour settlement periods with Settlement Period 1 equivalent to 00:00 to 00:30 through to Settlement 48 (23 :30 to 00:00).

In that sense, there is no explicit intraday market administered by the Transmission System Owners (TSO) or the System Operator (SO) (we have 3 TSOs and one GB SO), but rather intraday trading is facilitated through continuous trading in the power exchanges and OTC markets until one hour before settlement period.

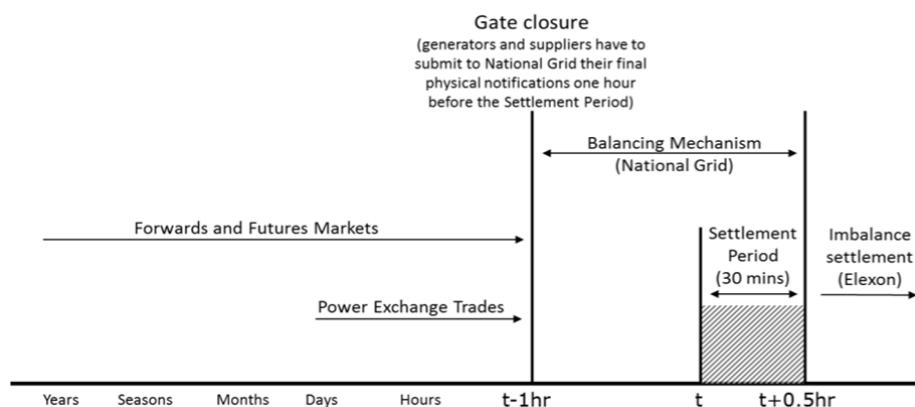


Figure 1: Overview on GB Power Market, Source: <http://www.nao.org.uk/wp-content/uploads/2014/05/Electricity-Balancing-Services.pdf>

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In 2013 [2], a total of 939.7 TWh of wholesale electricity was traded in GB with a total energy consumptions of 317TWh. Total OTC trading was 768.3 TWh representing 82% of total trading. Volumes traded on the exchanges in 2013 were 171.4 TWh; the APX exchange is usually associated with intraday trading, while the N2EX exchange sees the bulk of Day-Ahead and future trading. Total traded volume on the APX Power UK exchange in 2013 was around 22.4 TWh whereas N2EX traded volumes were 138.9 TWh for its Day-Ahead auction.

The total cost for balancing activities and ancillary services in 2013/2014 was £950mln [3], which represents only 4% of total power market costs. As depicted in figure 1, the majority of these costs represents balancing actions aiming to alleviate constraints, with the total cost of ancillary services amounting to around £500mln per year.

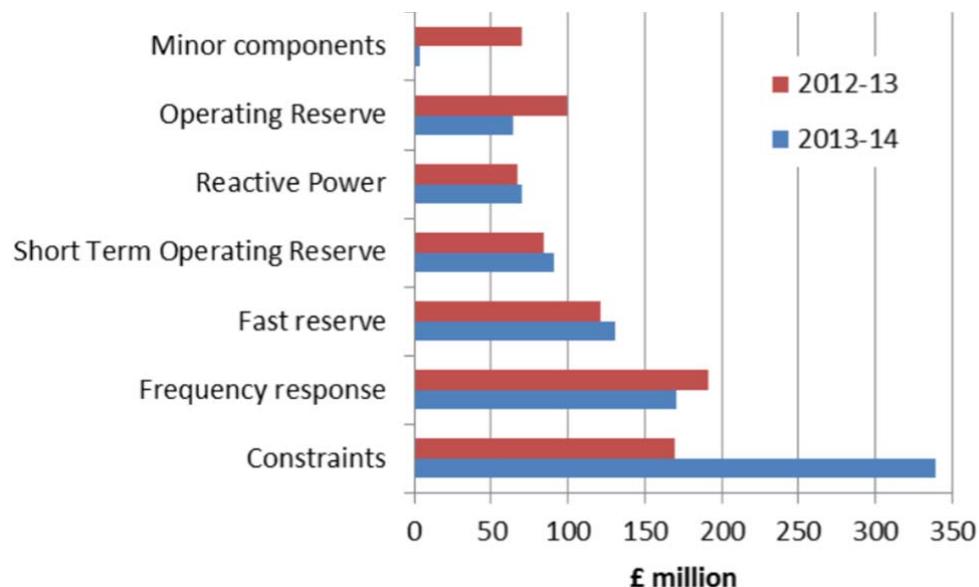


Figure 2: GB Balancing Mechanism and Ancillary Services Cost (£mln), Source: <http://www.nao.org.uk/wp-content/uploads/2014/05/Electricity-Balancing-Services.pdf>

A key concept in the GB power system is the Balancing Mechanism Unit (BM Unit). Each BM Unit accounts for a collection of plant and/or apparatus, and is considered the smallest grouping that can be independently controlled. As a result, most BM Units contain either a generating unit or a collection of consumption meters. Overall, there are four main types of BM Units: (i) transmission connected generation (ii) interconnectors (iii) suppliers and (iv) embedded generators. In practice,

BM Units are mainly suppliers and transmission connected generators, whereas distribution connected small generators or consumers are usually unable to qualify as BM units and tend to trade under a supplier's account as demand side.

1.1. System forecast

According to the GB Grid Code [3], BM Units are required at 11:00 hours in D-1 to submit Initial Physical Notifications (IPNs) for each settlement period of the following operational day. The data submitted under IPN are the following:

- Projected active power injections/withdrawals;
- Balancing mechanism bid and offer data (volume and prices);
- Maximum export/import limits; and
- Dynamic parameters of units.

IPN's are not binding for market participants, but any deviations from these must be notified to the SO as soon as these are known. These deviations can be due to contractual or any other reasons and in general they do not carry any penalties as long as they do not represent false information intended for market manipulation, in which case market participants may be found to be in breach of the grid code. In addition to IPN's, generators communicate to the SO their planned outages as part of the grid code requirements together with their Maximum Export Limit (MEL) which determines the generator availability.

Based on these forecasts, the SO can engage in pre-gate closure energy trading if it deems that this will lower its balancing mechanism or ancillary services utilisation costs. The SO tends to trade within-day/day-ahead for general energy balancing; and may trade up to two weeks ahead for constraint management purposes (having taken a view on generator running and outage certainty). The trades are considered a balancing activity and are costed the same way as any other ancillary service so as to make sure that market prices are not distorted.

One hour before real-time, at gate closure, bilateral trading ceases and market participants submit to the SO, their final intended schedule (comprised by similar data as the IPN), called Final Physical Notification (FPN). After gate closure, parties are expected to adhere to their FPNs and should only deviate from this position at the instruction of the SO or due to uncontrollable events such as plant breakdowns. Failure to do so might be considered a breach of the grid code and in turn breach of the generator and supplier licence conditions.

1.2. Balancing Mechanism

Following gate closure, the SO is able to evaluate the net imbalance of the transmission system. The SO does this by assessing the FPNs of the generators and suppliers and comparing that assessment to its own forecasts for the settlement period. The transmission system's net imbalance is also called the transmission system length. A 'long' transmission system is one where there is more generation than demand. A 'short' transmission system is one where there is more demand than generation. In addition to the net energy imbalance, the SO will also evaluate the expected transmission constraints and reserve requirements for this settlement period and accordingly balance the system.

The primary balancing tool available to the SO is the 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. Participation in the BM is optional, and parties that choose to do so must submit Bids and Offers before gate closure for each settlement period. For each BM unit, a party can submit up to ten Bid-Offer Pairs.

Each Bid-Offer Pair includes:

- An Offer Price - the price a Party wants to be paid per MWh for an increase in generation or decrease in demand;
- A Bid Price - the price a Party wants to pay per MWh for a decrease in generation or an increase in demand (although it is possible to submit negatively priced Bids, i.e. a Party is paid to reduce generation);
- The Settlement Period for which the Bid/Offer applies;
- The upper and lower power levels between which the Bid/Offer applies (for example, Bid-Offer +1 applies from FPN to 50MW above the FPN, Bid-Offer +2 applies from 50MW above FPN to 100MW above FPN).

In effect the BM is a residual energy pool administered by the SO aiming at resolving both energy and system constraints. The format of the balancing mechanism is pay-as-bid.

Based on historical data analysis, for dispatchable plant bid prices are close to 60% of short-run marginal costs, whereas offer prices close to 160% [4]. For plants receiving subsidy, mainly wind generators, bid prices reflect their opportunity cost of being constrained off and are usually equal to their level of subsidy on a per MWh basis.

The SO also has access to pre-contracted ancillary services which it is incentivised to use where this can be cheaper than buying in 'realtime' from the BM. These are presented in the next section.

1.3. Ancillary Services

In addition to BM bids and offers acceptance, the SO procures various ancillary services either via public tenders or bilateral contracts. Whereas procurement of this is performed ahead of real-time the utilization of any of these services will be considered against BM bids and offers, based on the contract utilization prices. In total, there are 22 individual balancing services available. A number of these would only rarely be used as they would be called on only in exceptional circumstances. The main categories are summarised below:

1. Frequency Response

Table 1: Overview of Frequency Response Ancillary Services

	Frequency Response		
Service	Mandatory Frequency Response	Firm Frequency Response	Frequency Control by Demand Management
Technical Requirement	Mandatory service provided by large generators (>100MW) to automatically change their active power output in response to a change in system frequency	Same as mandatory frequency response but open to any market participant	Provision of frequency response through the interruption of customers that use large amounts of electricity (over 3MW) from the transmission system (demand customers)
Eligibility	All power stations larger than 100MW	BM and non-BM units subject to pre-qualification with capability to deliver a minimum of 10MW of response	<ul style="list-style-type: none"> - Minimum of 3MW but aggregation possible - Available continuously for declared periods - Demand reduction must take place within 2 seconds and be sustained for a minimum of 30 minutes
Procurement	Mandatory for all eligible power stations	Monthly tender	Bilateral
Payment	Availability (monthly price submission) and utilization fee (determined by industry code)	Availability, nomination and utilization fees determined through monthly auction	Only availability fee in £/MWh based on the aggregated metered MWh of demand during the periods of accepted availability

2. Reserve

Table 2: Overview of Reserve Ancillary Services

Reserve				
Service	Fast Reserve	Short-Term Operating Reserve (STOR)	BM Start Up	STOR Runway
Technical Requirement	<ul style="list-style-type: none"> -Active power delivery within 2 minutes of the despatch instruction at a delivery rate in excess of 25MW/minute -Reserve energy should be sustainable for a minimum of 15 minutes (around 800MW capacity contracted) 	<ul style="list-style-type: none"> - Offer a minimum of 3MW generation or steady demand reduction (aggregation is possible) - Maximum response time of 240 minutes (typical contract for 20 minutes or less) - Ability to deliver for a minimum of 120 minutes - Have a recovery period after provision of reserve of not more than 1200 minutes - Able to deliver at least 3 times per week (around 2800MW capacity contracted) 	BM Start-up Service gives SO on-the-day access to additional generation BM Units that would not otherwise have run, and which could not be made available in the BM timescales due to their technical characteristics and associated lead-times	STOR for 2015/16 for which only demand side can participate (200MW) so as to incentivise new market participants
Eligibility	Must be able to deliver a minimum of 50MW, only BM units	BM and non-BM units subject to pre-qualification (around 1200	Ability to prepare the generator towards a state of readiness in order to synchronise the unit upon instruction within Balancing Mechanism timescales (89 minutes from instruction)	Only new demand side sites, with no existing STOR contracts, max size per site of 30MW
Procurement	Monthly tender	Three annual tenders for various contracts of	Bilateral	One-off tender

		different duration		
Payment	Availability, holding and utilization fees determined through monthly auction	<ul style="list-style-type: none"> -Availability fee determined through auction -Utilization fee of BM units through BM offer prices - Non-BM units utilization fee through auctions 	Payment (£/h) associated with the cost of preparing the unit to be able to participate in the BM	Similar to STOR

3. System Security Services

A variety of procured ancillary services compliment system reserves so as to ensure adequate supply and intact operation of the transmission system. The most important ones are summarized below:

Table 3: Overview of System Security Ancillary Services

	System Security				
Service	Transmission Constraint Management	Maximum Generation	Intertripping	Black Start	SO to SO services
Technical Requirement	Constraint management contracts depends on a number of factors including the nature of the flows on the transmission system, the duration of the requirement, the local level of generation output, and the local level of system demand	Access to capacity which is outside of the Generator's normal operating range in emergency circumstances	Automatic disconnection or reduction of generation or demand following a system fault event	Procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again	Mutually provided services with other SOs connected to the GB Transmission System via interconnectors
Eligibility	Depending on	The service is	Requires specific	The provider is required	Bilateral

	specific need	provided on a non-firm basis and is part of industry code	installation	to be able to start up its main generator(s), carry out initial energisation of sections of the National Transmission System and distribution network, and support sufficient demand to create and control a stable power island	agreements
Procurement	Ad hoc and usually on a bilateral basis unless significant competing service providers	Bilaterally on a needs basis by SO instructions	SO will approach individual parties on a needs basis	Bilateral basis	Bilateral agreements
Payment	Depending on specific need but usually will involve a settlement period availability fee and a utilization fee	Only utilization payment - extremely high offer prices	Fee per settlement period of arming/availability and a fee per trip	Providers are paid a fee per settlement period for their availability and a utilisation payment both for actual service provided and for testing purposes	Bilateral settlement

In addition to the above services, due to projected reduced de-rated margins over the coming winters, in 2014, the SO launched two new balancing service products to help keep the electricity supply network in balance during the 2014/15 to 2017/18 winter periods after which the first capacity agreements from the newly introduced capacity market will be in place. **Demand Side Balancing Reserve (DSBR)** will pay large energy users to reduce their demand by an agreed amount during evenings between November and February, when National Grid suspects demand will be significantly outstripped by supply. **Supplemental Balancing Reserve (SBR)** will pay for moth-balled or would-be closed generating plants to remain available over the winter periods to provide backup power in the event of a spike in demand or the loss of a generating unit. These services are only deployed in worst-case scenarios after all other balancing services have been utilized.

Overview of DSBR

Under DSBR large energy consumers will be paid to reduce their demand during winter weekday evenings (between 4pm and 8pm) in response to instructions from the SO. To provide the DSBR service, organisations will need to meet the following criteria:

- Half-hourly metered site
- Ability to reduce load at two hours' notice and to sustain load reduction for a minimum of

two hours between 4pm and 8pm, non-holiday weekdays between November and February Capacity must be provided in 1MW tranches or smaller aggregated units. DSBR is another product aiming to promote new demand side management which are already committed to STOR contracts for the winter periods. DSBR is competitively tendered through annual auctions and there is only a utilisation fee (£/MWh) ranging from £250/MWh up to £15,000/MWh. For winter 2014/15 319MW of DSBR were procured.

Overview of SBR

SBR involves the SO contracting with a generation plant which is due to be closed or mothballed. SBR plants are held in reserve and are not otherwise permitted to run. In theory, SBR capacity is only despatched when all other balancing actions (including DSBR) have been exhausted. In reality, though, it may be necessary to despatch SBR ahead of need in anticipation of a supply shortfall caused by, for example, severe weather. Around 2GW of SBR plant was contracted for winter 2014/15. Remuneration includes a capability fee (£/kW/Year), a utilisation fee (£/MWh), a start up fee (£/h) and a hot standby fee (£/h).

4. Reactive Power

According to the grid code all transmission connected generators over 50MW are obliged to provide reactive power at the request of the SO. The SO pays all service providers for utilisation in £/MVAh. This value is updated monthly but has averaged around £2.7/MVAh the past few months for a total utilization volume of around 2,220 GVAh per month.

In addition to this obligatory service that large generators provide, the SO can procure additional reactive power if needed through commercial tenders. However, the past few months no commercial reactive power has been procured.

1.4. Balancing Incentives

The SO will administer the balancing mechanism and decide on the activation of any ancillary services subject to the Balancing Services Incentive Scheme (BSIS) currently in place. The philosophy

of BSIS is to set up some targets for energy imbalance, constraint and black start costs. If the SO overspends/underspends then it will receive/pay 25% of the achieved savings/extra costs subject to a cap of £25mln per year above/below the target. Based on the above incentive scheme it is assumed that the SO has clear incentives to minimize the cost of balancing.

The total cost of balancing services (BM, ancillary services and energy trading costs), which is projected to be around £950mln (£1.8/MWh of demand) for 2014/15, is socialized among market parties and eventually paid by consumers. As such there are no incentives for balancing cost minimization to market participants and in particular to the parties that actually create the imbalances since they do not face the costs of the balancing actions. This potentially creates incentives for the so called inc-dec game where market participants behind specific system constraints will submit inflated bids/offers in the knowledge that they need to be constrained on/off. There are licence conditions that theoretically prevent that but enforcing them is difficult and the main deterrent seems to be reputational risks, especially for wind generators getting paid to turn off.

Ancillary service providers will usually face penalties for non-delivery which are laid out in their service contracts and typically these will involve availability or capability payment withholding and/or exclusion from future auctions.

Finally, market parties are incentivized to adhere to their contractual positions, which are submitted to the settlement body before gate closure for each settlement period, since they face imbalance charges if their actual volumes divert from the contracted ones. Given that imbalance prices represent the real-time price of energy, the next section presents in detail how these prices are calculated.

1.5. Imbalance pricing

Currently in GB a dual imbalance pricing system is in place, which calculates two prices per settlement period:

1. System Buy Price (SBP); and
2. System Sell Price (SSP).

If a party has under-generated or over-consumed compared to its contracted volume, it will have to buy that shortfall of energy at SBP. If a party has over-generated or under-consumed compared to its contracted volume, it will have to sell that extra energy at SSP.

In order to calculate SBP and SSP two methodologies are used:

1. The **main pricing method** sets the imbalance price equal to the average price of the marginal 500MWh of actions that the SO procured through the BM in order to resolve energy imbalances, whether these are acceptance of bids and offers or activation of reserves²
2. The **reverse price method** sets the price equal to the average price of intra-day trades on the power exchanges.

When the system is long the SSP is calculated using the main pricing method and SBP using the reverse pricing method. When the system is 'short' (not enough power), SBP is calculated using the main pricing method and SSP using the reverse pricing method. Imbalance prices for parties are summarised in Table 4:

Table 4: Imbalance Pricing Summary

		System Length	
		Long	Short
Party Imbalance	Long	Paid SSP (Main Price)	Paid SSP (Reverse Price)
	Short	Pays SBP (Reverse Price)	Pays SBP (Main Price)

In summary, market parties have strong incentives to adhere to their contractual volumes since usually SSP will tend to be lower than energy market prices whereas SBP higher.

However, there are number of factors that currently dampen imbalance prices. First, the main imbalance price is calculated using an average of the top 500MWh of the SO actions taken to balance the system, rather than the marginal action. Secondly, prices do not include the costs to consumers of involuntary demand disconnections (blackouts) and voltage reductions (brownouts). Thirdly, the way reserve capacity is costed does not allow imbalance prices to rise to reflect tight margins. Finally, the current dual imbalance price system creates unnecessary balancing costs since a party will always aim to be balanced even if actually its imbalance helps the system. As such it is widely recognised that the current arrangements do not sufficiently value flexibility. For this reason it has been recently

²Note that most reserve providers are required to submit offers in the BM for their activation

decided to change the current imbalance arrangements as described in section 2 together with other recently introduced changes in GB market so as to better value flexibility.

2. Envisaged developments

Similarly to other European markets with large scale integration of intermittent generation the key challenge that the GB market is facing is to effectively remunerate asset capacity and flexibility in light of the reduced utilization that is expected as more intermittent generation connects to the system.

In order for this transition to take place a number of policy developments are under-way the most important being:

1. The introduction of the GB capacity mechanism with energy delivery obligation; and
2. Changes to imbalance pricing.

Beyond these fundamental changes in the GB market which are expected to be fully implemented by winter 2018 and are presented in detail below, a number of other policy areas are being considered as part of an industry forum [6], which provide an indication of the policy priorities in GB. It should be noted that no firm regulatory change is yet envisaged for any of the following topics:

1. Introduction of locational pricing as a priority area of work in light of the bidding zones review requirement of the electricity Target Model CACM;
2. Managing intermittency by examining measures to promote liquidity close to real-time and to consider measures and tools for market participants to better manage imbalance risk;
3. Ancillary services, wider balancing and reserve review by considering whether the SO has the correct tools to ensure the most efficient dispatch of the system overall is achieved. This workstream could also consider whether the division of responsibilities between the market and the SO is correct; and
4. Longer-term market arrangements with a view to 2020 and beyond.

2.1 Electricity Market Reform and Capacity Mechanism

The Electricity Market Reform (EMR) programme was first introduced in 2011 with the aim of attracting investment in low carbon and conventional generation so as to meet the renewables targets and retain an adequate security of supply. Integral to this was the introduction of the

Capacity Market, which is a volume based, central buyer capacity remuneration mechanism. The main features of the Capacity Market are summarized below:

- Government determines the security criterion currently set at 3 hours of Loss of Load Expectation (LOLE)
- The SO translates that to a target capacity in GW and the government sets minimum and maximum capacities to be procured at different price levels around the target capacity
- Plants receiving subsidy (mainly RES) and under long term STOR agreements are excluded from the capacity mechanism but their capacity contribution is taken into account by the SO when calculating the target capacity
- Existing plants receive annual capacity contracts, new plants can bid for a capacity contract of up to 15 years and refurbished plants (determined by the amount spent on refurbishment) up to 3 years
- The majority of capacity is procured through annual auctions four years before the delivery year (i.e. for delivery in 2018/19 the auction is held in 2014) whereas some residual capacity (a minimum amount is specified in Y-4) is procured through year ahead auctions
- The capacity payments are contingent to an energy delivery obligation at times of system stress. In particular, the SO will give four hour warnings to the market and specify a level of target capacity (as a % of the total procured capacity), which market participants are required to deliver based on their capacity agreements (on a pro-rata basis) until the system stress warning is finalized. Market participants are not paid any energy costs and as such must have sold their energy during those hours or face imbalance prices. Failure to deliver on the energy obligation results to penalties which can reach up to 100% of the annual capacity payment.
- Interconnected capacity will be able to participate in the second T-4 auction in 2015 although the exact details are still under consideration

A major criticism of the capacity mechanism has been the potential discrimination against demand side. Whereas the government has earmarked that 2.5GW of capacity agreements in the T-1 auction will be allocated to demand side, in practice extra sources of demand side management than those already in the market (around 1.8GW participating in transmission charging avoidance and STOR) are unlikely to come forward. This is for a number of reasons:

- Demand side cannot secure long term contracts similar to new generation which would allow it to project finance investments in new capability;
- The capacity obligation for demand side is based on comparing average consumption profiles over similar periods to the stress periods so as to ensure delivery. This implies that demand side cannot participate in transmission charging avoidance, which constitutes a very

- significant revenue stream for DSR and distributed generation, and also receive a capacity payment whereas distributed generation can; and
- One might argue that the structure of the capacity mechanism favours inherently conventional generators and as such it is expected to displace DSR which might have been developed otherwise.

In that respect, it is unclear whether the capacity mechanism will actually lead to an increase of overall system flexibility and whether this will be procured in an efficient manner. In fact, the results from the first auction, held in December 2014, provide mixed signals with 49.3 GW of capacity procured at a clearing price of 19.40 £/kW, which was close to half that of market consensus expectations. From a capacity perspective the auction result headlines are that:

- **8.4 GW of existing plants failed to secure agreements: comprised of**
 - 3.9 GW of older CCGTs
 - 4.5 GW of older coal plants
- **2.6 GW of new plants secured agreements:**
 - The 1.8 GW Trafford CCGT project
 - 0.9 GW of smaller scale peaking plants (e.g. diesel gen sets, reciprocating engines)
 - 0.2 GW of unproven DSR capacity

In that respect one might argue that the capacity mechanism resulted at a quite low clearing price and that it was still possible to incentivize 2.6 GW of new flexible generation and demand side at the expense of 8.4GW of older and less flexible generation. However, the fact that only 0.2GW of DSR was able to secure contracts at T-4 indicates the difficulty that DSR will face in securing capacity agreements.

2.2 Review of Imbalance Pricing

In August 2012, the GB regulator launched the Electricity Balancing Significant Code Review (EBSCR) which aimed to address the inefficiencies with the current imbalance pricing regime described earlier. The review was concluded in May 2014, with the following policy decisions:

- **Move from dual to single imbalance prices:** under single pricing the reverse market price is removed and the main SBP and SSP are used for parties out of balance in both directions to the system.
- **Move from average to more marginal pricing of balancing actions:** at present, cash-out prices in a settlement period are calculated as the volume weighted average of the highest/lowest remaining 500MWh of actions in the BM. 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.

- **Including non-costed demand control actions in imbalance prices:** at present the implied costs to consumers of using voltage control to balance the system, or from involuntary load disconnection when it is not possible to balance the system, are not factored into imbalance prices. This is potentially dampening the price signal from 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 imbalance 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):** At present, the costs of STOR are divided into upfront 'availability fees' and actual 'utilisation fees'. The latter are captured directly in the imbalance price calculation, whereas the former are captured indirectly. 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, 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 imbalance 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 as depicted in Figure 3. This would cover both BM and non-BM STOR, and would therefore also effectively capture non-BM STOR utilisation fees in imbalance prices, which is not currently the case.

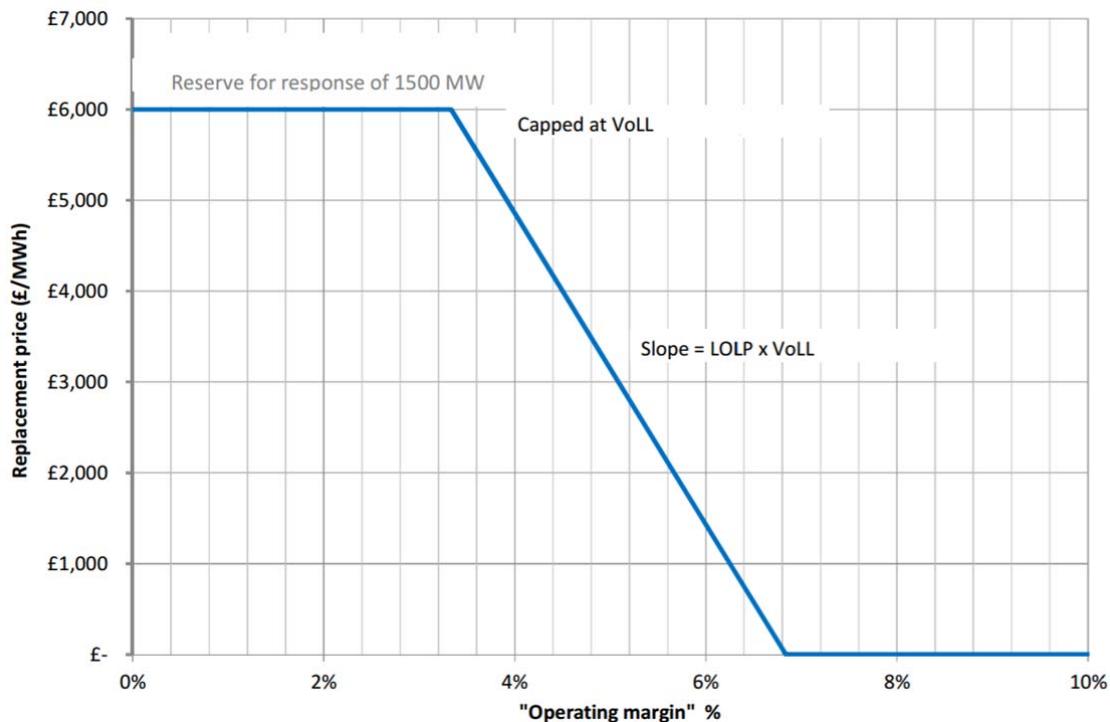


Figure 3: Reserve Scarcity Function

All the changes presented above will be gradually introduced by winter 2018. The main effects of the EBSCR will be to lead to significant price spikes in SBP's in periods that the system is significantly short, whereas SSL's are not expected to be affected. Simultaneously, the move to a single cash-out price implies that parties that can help alleviate system imbalances through their own imbalances (by spilling or being short in real time) can gain a significant benefit in these settlement periods during which imbalance prices, spike or become very negative compared to the energy market.

In summary, the introduction of the capacity mechanism may have an effect of system balancing and reserve procurement given the energy delivery obligation and may suppress price spikes to a certain degree. On one hand, application of scarcity pricing may reduce the clearing price in the capacity mechanism. On the other hand, the capacity mechanism does not place significant flexibility requirements on parties due to the four hour warning for energy delivery, this is unlikely to deter inflexible plant from seeking capacity payments. Moreover, if the government's envisaged efforts to promote DSR participation in the capacity mechanism are unsuccessful then one might argue that the capacity mechanism will also act as a hinder of demand side development.

With respect to the changes in system imbalance pricing, GB has followed a text-book approach and completely aligned with the Target Model Electricity Balancing Network Code, which is expected, subject to other key policy areas, to deliver better signals for the value of flexibility.

Emerging challenges

In the context of the UK response to climate change challenge, GB system is facing significant technical challenges since the volume of non-synchronous generation (wind and solar power plants and interconnectors) connected to the system is expected to increase rapidly and significantly over the coming decades, which will have an impact on system operability [7]:

- Reduction in system short circuit level;
- Greater variability of power flows;
- Changes in system inertia;
- Changes in system damping and susceptibility to device interactions;
- New dynamic control challenges associated with new and existing technologies;
- Changes in generation and demand characteristics.

System strength is a measure of the ability of the system to remain stable during and following disturbances and variations in system parameters. Both factors of system strength; system inertia and short circuit level will reduce as the changes in generation and demand materialise.

Due to the fundamental principles of their operation, synchronous generators naturally provide particular characteristic support to the system by contributing to system inertia, reactive power regulation, rapid response, voltage support and short circuit level above and beyond the load current of the machine.

Non-synchronous generators (NSG), on the other hand, are connected to the system via power electronics and the level of support available depends on the technology and the settings employed in the connections; NSG generally has a lower and different contribution to system strength compared to synchronous generation. From this it therefore follows that the lowest system strength is expected during times when a high proportion of demand is met by NSG.

As laid out in a recent document from the regulator [5], there are also a number of new technologies that can provide significant system flexibility by responding to price signals through participation in the energy market, balancing mechanism and ancillary services markets:

- Demand Side Response;
- Distributed generation; and
- Storage.

Enabling these new technologies through market based mechanisms and attracting new providers of system flexibility and system strength is the key challenge that GB will be facing in the coming years, as demonstrated in [9]. It is apparent that these technologies can bring benefits to several sectors in electricity industry, including generation, transmission and distribution, while providing services to support real time balancing of demand and supply and network congestion management and reduce the need for investment in system reinforcement [5]. These “split benefits” pose significant challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in flexible technologies are adequately rewarded for delivering these diverse sources of value. It is therefore important that appropriate market and regulatory frameworks are in place to facilitate a cost-effective evolution to a low carbon future.

3. Short summary and conclusions

Given the basic market design (net pool, non-locational specific wholesale energy market) one might argue that GB has established some sound principles with respect to how balancing markets are operated or will be operated in the near future and the arrangements are closely aligned to those envisaged under the Target Model Balancing Network Code. In particular:

- The SO has strong incentives to balance the system at minimum cost by optimizing ancillary services procurement and activation vs balancing mechanism bids/offers acceptance as well as limited energy market trading activities;
- All market parties are exposed to imbalance costs;
- Balancing actions (procurement and activation costs), following the introduction of the imbalance charging changes will be priced correctly; and
- Market participants are incentivized to optimally choose between committing themselves in the energy market, the BM, provide ancillary services or be imbalanced.

On the other hand, there are a number of policy areas that fall outside the scope of balancing markets but have profound effects on the overall value of flexibility in the system as well as market parties incentives. These are:

- The introduction of the capacity market and its specific design based on the energy delivery obligation will likely affect reserve procurement and asset investment, potentially favouring traditional assets which might hinder demand side participation;
- Participation in the BM is by definition only allowed to BM units, which is difficult for embedded assets to qualify for although these same assets can bid for ancillary services and be controlled directly by the SO. Review of the grid code to address this issue should be promoted;

- Lack of locational transmission pricing creates the need for some balancing services and the possibility for the so called inc-dec game in the BM;
- Efficient distribution charging will also have very profound effect on the value of distributed assets; and
- The role of the SO as operator of the system and owner of transmission assets (onshore and interconnectors) will need to be reviewed as competition between transmission and generation solutions for capacity and flexibility develops.

Finally, significant system flexibility and promotion of new technologies can also be provided by the extensive deployment of smart grid solutions. However, this would require a paradigm shift in the current regulatory and commercial network regimes. In particular it will be necessary to:

1. Strengthen the incentives for development & implementation of cost effective smart grid measures – from the stick to a carrot approach – e.g. linking rate of return with cost effectiveness
2. Whole systems approach to network operation and design - from silo to whole systems concept based network operation and planning
3. Facilitate investment under uncertainty From scenario only driven investment to dealing with uncertainty - option value of smart and traditional investment
4. Facilitate strategic investment in smart T&D networks - Need to coordinate existing and future user's needs by balancing strategic and incremental investment
5. Enhancing market integration – Ensure that DER flexibility can access their whole-system value by providing services across different sectors and timescales (operation & investment)
6. Recognise increased risk and complexity associated with innovation and deployment of new technologies - Need to establish provisions to allow network operators to account for increased risks
7. Review the role of the regulator - From acting as a buyer of network services to developing appropriate incentive mechanisms

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