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Market Design Driven Negative Imbalance Prices

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***Abstract*—Many countries have experienced a rapid increase in the share of renewable power in electricity generation. This increases the need for system flexibility due to their limited controllability and predictability. Besides challenging the ability of power systems to meet peak demand, this gives rise to downward adequacy problems, i.e. the ability to cope with high renewable power injections during low demand. The need for downward flexibility is observed in Belgium during periods with negative electricity prices. This issue is referred to as the incompressibility of power systems and challenges further renewable power integration. The objective of this paper is to identify the regulatory mechanisms affecting negative imbalance prices. It is confirmed that negative prices in the balancing market result from the activation of negative downward reserve capacity bids from renewables generators, inflexible conventional power plants, the balance-incentivizing α-component in the settlement mechanisms, and expensive inter-TSO downward reserve capacity.**

Keywords—balancing market, negative prices, forecasting, reserve market design, renewable energy, regulatory framework

I. INTRODUCTION

Under Directive 2009/28/EC, binding goals are set for 2020, in which renewable energy will have to hold a 20% share in the final European energy demand, in which electricity generation is expected to bear the largest burden with 34.3% of total electricity demand with renewable energy sources (RES) [1]. Annual installations of RES, being wind, PV, hydro, and biomass, have increased significantly over the past decennia in Europe, resulting in a total installed capacity of respectively 101.6 GW, 67.5 GW, 159.6 GW and 19.1 GW at the end of 2012 [2]. Table 1 displays national RES statistics for the EU-28 accompanied by Norway and Switzerland in terms of the installed capacities by the end of 2012. The mean penetration is defined as the annual electricity generation relative to total electricity consumption, and the maximum penetration as the installed capacity relative to minimum consumption levels (theoretical statistic). When analyzing the variable RES data, being wind and PV, as these are the RES affecting flexibility needs, it can be noted that Denmark, Germany, Ireland, Portugal, and Spain are leading the way, covering respectively 30%, 14%, 16%, 21%, and 23% of their electricity consumption with variable RES. When comparing the installed capacity to the minimum demand, this may already result in instantaneous renewable generation levels that exceed the demand for Denmark, Germany, Italy, Portugal and Spain. However Table 1 shows that other countries face lower penetration levels, trajectories show that they are also rapidly increasing their renewable generation mix taking into account the policy targets towards 2020. In addition, according to 2013 ENTSO-E projections it is expected that total installed RES capacity in Europe will reach more than 500 GW by 2020, representing an enormous growth relative to the 2013 level of 340 GW [3].

TABLE I. RELATIVE INSTALLED CAPACITY [%] AND PENETRATION [%] OF VARIABLE RES IN THE EU-28 + NO + CH [2].

	RES statistics				Penetration RES		Penetration var. RES	
	P_{wind}/P_{inst} [%]	P_{solar}/P_{inst} [%]	P_{hydro}/P_{inst} [%]	P_{bio}/P_{inst} [%]	Mean [%]	Max [%]	Mean [%]	Max [%]
AT	6%	1%	58%	2%	64%	332%	4%	32%
BE	6%	12%	1%	6%	10%	83%	5%	62%
BG	5%	7%	16%	0%	15%	148%	6%	65%
HR	2%	0%	--	0%	30%	7%	2%	7%
CY	13%	--	--	--	4%	52%	4%	52%
CZ	1%	11%	5%	0%	13%	81%	4%	56%
DK	30%	3%	0%	4%	37%	246%	30%	218%
EE	10%	--	0%	3%	17%	69%	5%	54%
FI	2%	0%	18%	12%	32%	104%	1%	5%
FR	6%	3%	18%	1%	17%	116%	4%	35%
DE	18%	19%	2%	3%	25%	227%	14%	198%
GR	9%	9%	1%	0%	10%	104%	9%	96%
HU	4%	0%	1%	2%	6%	22%	2%	13%
IE	19%	--	3%	--	19%	113%	16%	100%
IT	7%	13%	15%	--	17%	204%	10%	117%
LV	2%	0%	60%	2%	55%	433%	2%	15%
LT	7%	0%	3%	1%	11%	69%	5%	43%
LU	3%	5%	0%	0%	3%	40%	2%	38%
MT	--	--	--	--	--	--	--	--
NL	8%	0%	--	3%	11%	44%	5%	31%
PL	7%	0%	3%	2%	9%	40%	3%	25%
PT	23%	1%	30%	3%	37%	320%	21%	132%
RO	9%	0%	33%	0%	28%	202%	5%	45%
SK	0%	6%	19%	2%	20%	103%	2%	23%
SI	--	--	30%	--	26%	115%	--	--
ES	23%	6%	17%	1%	32%	260%	23%	161%
SE	10%	0%	43%	8%	67%	250%	5%	40%
GB	7%	0%	1%	1%	5%	34%	4%	25%
NO	2%	--	94%	--	111%	357%	1%	8%
CH	0%	1%	68%	2%	60%	454%	0%	8%

The presence of variable RES increases the need for system flexibility, due to their output variations and prediction errors [4]. Expected power variations are covered in the forward market by means of flexible conventional power plants adapting their generation schedule to the predicted renewable generation. In contrast, unpredicted variations are to be compensated for in real-time, by means of the balancing market. The necessary system flexibility here comes from balancing service providers (BSPs) able to bridge this mismatch in supply and demand in real-time through (1) flexible demand through demand response technologies, (2) flexible generation capacity that can deviate from their scheduled output profile, (3) flexible generation or demand from other control zones, (4) flexibility provided with energy storage, (5) and flexibility procured from the output control of RES.

The impact of increasing shares of RES in the generation mix on security of supply has been a relevant point of discussing for a long time. Traditionally, focus of the debate was upward adequacy, i.e. the ability of power systems to meet peak demand and thus avoiding demand shedding and black-outs [5]. Today, increasing attention is paid towards the issue of downward adequacy, raising the question if the current power system is able to cope with periods of high renewable generation while facing low demand. In other words, is the power system able to adapt its generation or demand levels to maintain the balance between demand and supply. Today, limited downward flexibility is observed due to renewable generation with low marginal prices and generation support mechanisms such as priority dispatch or green certificates (e.g. wind), inflexible conventional power plants bound by technical ramping constraints (e.g. nuclear power plants), conventional power plants bound by must-run conditions due to the provision of ancillary services (e.g. combined-cycle gas turbines). In contrast to high electricity prices when facing limited upward flexibility, limited downward flexibility results in low or even negative electricity prices, indicating an excess supply. The latter is referred to as the incompressibility of power systems and is observed in Belgium with hours showing negative electricity prices on day-ahead, intra-day, and the real-time imbalance market [6], reflecting the difficulty to cope with periods of high renewable generation during low demand periods. The ability to accurately forecast these negative price periods can obviously prove to be profitable, thereby facilitating the business case of new flexible technologies.

As multiple studies [7-9] have already analyzed negative prices on forward and day-ahead markets, this paper focuses on the real-time Belgian imbalance market. This market reflects the deviations of the day-ahead and intra-day market expectations in the forward markets, and is bound by regulatory measures. First, section 2 discussed the Belgian imbalance market. Afterwards, section 3 provides a literature overview of negative electricity prices, while section 4 provides an overview of available electricity price forecasting tools. Finally, section 5 analyzes the occurrence of negative imbalance prices in Belgium, and section 6 states the conclusion of this paper.

II. THE BELGIAN IMBALANCE MARKET

In European power systems, prediction errors on both the demand and supply side of the electricity market are dealt with on the balancing market. The Belgian TSO 'Elia', operates on both the procurement and the settlement side of the balancing market. On the procurement side it calculates the total system imbalance resulting from the aggregated imbalances of all Balance Responsible Parties (BRPs), and compensates this imbalance by activating reserve capacity provided by BSPs. Reserve capacity is periodically procured from mainly conventional power units, and can be quickly activated in real-time to cover system imbalances. Next to these "guaranteed" contracted reserves, additional capacity "free bids" can be contracted on day-ahead basis. This results in a merit-order representing the activation cost of reserve capacity [10-13].

On the settlement side, the TSO settles imbalances with the BRPs by applying a tariff, the imbalance price, to their imbalanced positions. This settlement mechanism determines how balancing costs are distributed and how incentives are given to BRPs. In Belgium, a single-pricing scheme is applied, in which the imbalance price reflects the marginal activation cost of reserves, being downward or upward reserves depending on the status of the system. Thus the 'same' imbalance price is applied for short and long positions[1]. However, this price is not always the same for long and short positions, as imbalance prices must provide an incentive to BRPs to maintain balance in their perimeter. Therefore, in the event of big structural imbalances, an additional incentivizing α-component is applied to 'punish' the BRPs causing the system imbalance, calculated on the basis of the total system imbalance. This may result in a different imbalance price for BRPs facing a negative imbalance and BRPs facing a positive imbalance. The Belgian imbalance prices are calculated every 15 minutes.

In contrary, when using a dual-pricing scheme (e.g. in France), a different price is used for positive and negative imbalances. While imbalances contributing to the system imbalance are usually settled at prices based on the average procurement costs of balancing services, BRP imbalances counteracting the system imbalance are settled based on wholesale power exchange prices [12-14]. In a dual pricing-scheme, negative imbalance prices can thus only occur in periods experiencing a negative weighted average price, which only occurs in extreme circumstances. Thus, average pricing typically results in less negative prices. However, marginal pricing is believed to reflect the current market situation better than average pricing.

Negative imbalance prices, in which the TSO pays the BSP, can only occur in case of a positive system imbalance, in which downward reserves are activated. These reserves represent power plants willing to lower their power output, and since their energy is already sold in the forward market, they are usually willing to pay the TSO an amount representing their saved operating costs. In this case the TSO compensates the BRP having an excess supply. However, downward flexibility providers may also bid negative activation prices, through which they are paid for lowering their power output. In this case the BRPs facing a positive imbalance have to compensate the TSO instead of being paid for their excess supply [10,14,15].

These negative imbalance prices are then applied to BRPs experiencing an imbalance in their perimeter. If its imbalance reduces the general imbalance in the control area (a negative

[1] BRPs facing a negative imbalance in real-time hold a short position, BRPs facing a positive imbalance hold a long position.

imbalance), it has to pay the negative imbalance price to the TSO for his generation shortage, leading to a revenue. If its imbalance contributes to the system imbalance (a positive imbalance), it receives the negative imbalance price from the TSO for his excess generation, leading to a loss. If in this case there is a major structural system imbalance, the price is further decreased by applying the additional incentivizing price α-component [14].

III. NEGATIVE ELECTRICITY PRICES

Previous studies concerning negative electricity prices [8,9,16] attribute the occurrence of these prices to either high renewables generation, low system load, opportunity costs for inflexible conventional power plants with limited ramping capabilities, or a combination of the previous factors. According to the Belgian TSO, limited downward flexibility is also induced by the fact that not all excess energy can be evacuated because of limited export capacities [16]. Finally, as conventional power units are currently mainly used for balancing and providing balancing power, and as they are being replaced by renewable generation capacity, limited downward reserve capacity is observed in electricity markets, leading to negative imbalance prices [11].

The ongoing large-scale RES deployment increases the need for additional balancing needs, both upward and downward [17]. Concerning the inflexible conventional power plants, the studies emphasize that there will be less flexibility as there are more base-load units operating, as these units require a high utilization rate to cover high capital costs, and are not designed for ramping up and down regularly. In addition, tight downward flexibility can also occur when the units that are online cannot shut down because they have to provide reserve capacity, have very high start-up costs, or have opportunity costs because of prices above variable costs in the following hours and the fact that the inflexible units cannot start-up in time. The occurrence of negative imbalance prices can be seen as a market signal representing a relative scarcity of cheap downward flexibility when facing positive system imbalances.

IV. FORECASTING ELECTRICITY PRICES

This section provides an overview of electricity price forecasting techniques, which could be applied to forecast and analyze the occurrence of negative imbalance prices. The most recurring models can be attributed to regressive, autoregressive, neural network, or unit commitment techniques. However, it should be noted that forecasting electricity price movements remains a complex challenge, arising from a multitude of distinctive electricity market characteristics [18-20].

A. Regressive techniques

A regression analysis tests a set of independent variables X_i (e.g. load) for their impact on the dependent variable P_t. It show the presence of a positive/negative relation between the independent and dependent variables, and the percentage of the variance in the dependent variable that is explained by each independent variable. The significance of the independent variables is identified through a correlation analysis [21,22].

$$P_t = c + a \cdot X_1 + b \cdot X_2 + d \cdot X_3 + \cdots \quad \forall t \tag{1}$$

B. Autoregressive techniques

Autoregressive (AR) forecasting models are based on the assumption that future price levels P_t can be predicted based on past price levels P_{t-i}, as many observed time series exhibit serial autocorrelation. These models are described in [23-25]. An AR model depending on 'm' past observations is called an AR model of degree 'm', and has regression parameters a, b, c, d depending on the weights and sign of the previous price levels. The basis of these models is shown by (2), in which the number of lags depends on the used data. In addition, such models can be extended with j exogenous variables $X_{j,t-k}$, represented by (3). Exogenous variables could for example be the demand, generated wind power, gas price, etc. Inaccuracies increase as the degree 'm' increases.

$$P_t = c + a \cdot P_{t-1} + b \cdot P_{t-2} + d \cdot P_{t-3} + \cdots \quad \forall t \tag{2}$$

$$P_t = c + a \cdot \sum_i P_{t-i} + b \cdot \sum_j \sum_k X_{j,t-k} \quad \forall t \tag{3}$$

C. Neural network techniques

Neural Networks (NN) can model complex nonlinear systems, and are composed of an input layer, one or more hidden layers, and an output layer (Fig.1). They are mathematical models that resemble the functioning of the human brain. Two similarities are the fact that knowledge is gained by looping through a learning process, and that the network is connected through a set of nodes, called neurons. NNs consist of 2 parts, being a training phase and a forecasting phase, which are both improved through a feedback mechanism. The two methods for selecting the 'best' days for the training phase are the similar days method, based on a predetermined parameter (e.g. system load), and the identical days method (e.g. training an NN by previous Fridays when forecasting the next Friday). These models are described in [26-28].

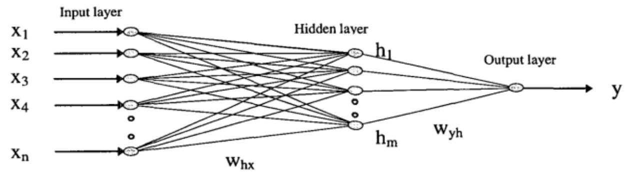

Fig. 1. Illustration of an NN model with n inputs, one hidden layer, and 1 output [29].

D. Unit commitment techniques

Unit Commitment (UC) models can be described as short-term power plant scheduling models with inelastic demand and a single objective representing optimizing behavior [30,31]. They decide when to start and shut down units as to minimize total electricity generation costs and maintain reliability, given demand forecasts and available units. The scheduling of power plants is constrained by their maximum and minimum output levels, ramp rates, and minimum up and down times.

The UC model determines the scheduling of power plants according to a merit order ranking, being the power plants with the lowest variable costs, but considering technical constraints. The price can be forecasted as the marginal cost of the system, as it is the cost of producing the marginal MW which ultimately is the market-clearing price. In other words, the price is the dual value of the market-clearing constraint.

Generally, the objective function (4) minimizes the total generation costs to meet demand by taking into account the fuel, CO_2 emission and start-up costs. The fuel consumption $F_{t,i}$ (expressed in [GJ]) in terms of electrical output represents the input-output characteristic of a generating unit i in hour t. Based on this, the variable generation costs are calculated by means of the fuel cost fc_i and CO_2 emission cost cc_i per GJ for each technology. Next, every time a generation unit is started a technology specific fixed start-up fuel $SUF_{t,i}$ is consumed. This variable is only positive when the commitment of the generating unit i in hour t changes from 0 to 1, compared to the previous period. Again, the total start-up costs are calculated by means of the fuel and CO_2 emission cost.

$$\text{Min Cost} \sum_{t,i} F_{t,i} \cdot (fc_i + cc_i) + \sum_{t,i} SUF_{t,i} \cdot (fc_i + cc_i) \quad (4)$$

These electricity price forecasting tools are based on either historical data, explanatory parameters, or underlying technical characteristics. However, they are unable to take regulatory measures and market design into account, which influence imbalance prices to a large extent. As optimal imbalance price forecasting needs to take both algorithmic and market design aspects into account, section 5 analyzes the reserve market design drivers for negative imbalance prices in Belgium.

V. ANALYSIS OF NEGATIVE BELGIAN IMBALANCE PRICES

When analyzing the Belgian imbalance prices during the one-year period from the 1st of January 2013 until the 31st of December 2013, it can be noted that the imbalance price for positive imbalances is negative in 6.58 % of the time, and for negative imbalances in only 1.25 % of the time. As explained in section 2, the difference between both prices is the α-component, punishing the actors causing the system imbalance. Fig.2 illustrates the negative imbalance price duration curve for 2013 for both the imbalance prices. The α-component is thus responsible for the area between both curves. The dark gray curve shows the negative imbalance price relating to a short position of the BRP. It reflects the price of the marginally activated downward reserve bid. The light gray curve shows the negative imbalance price relating to a long position of the BRP. It reflects the price of the marginally activated downward reserve bid, further reduced by the α-component [32].

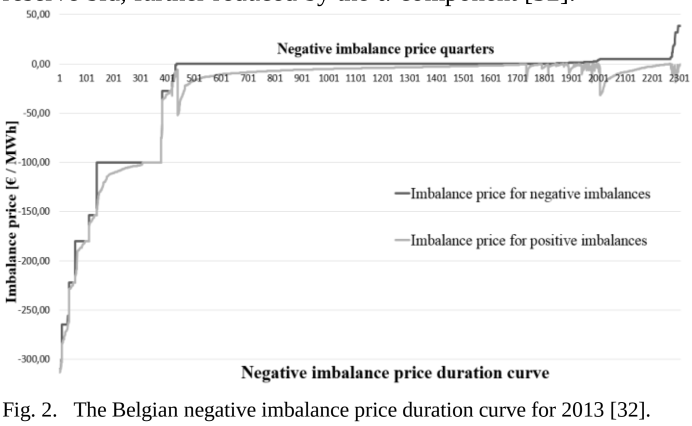

Fig. 2. The Belgian negative imbalance price duration curve for 2013 [32].

In order to identify the reserve market design factors causing the negative imbalance prices, the different downward reserve product categories are identified and briefly discussed.

First, since October 2013 the Belgian system imbalance is netted with other control zones through the International Grid Cooperation and Control (IGCC) framework. This framework currently avoids counteracting activation of balancing resources through real-time imbalance exchanges between control areas [10,33]. Instead of activating secondary reserve capacity (R2), the imbalance is exchanged via IGCC, but the theoretical R2 activation price defines the imbalance price. As the R2 activation prices may not be negative, no negative imbalance prices can occur by activating downward IGCC reserve capacity [34].

Second, contracted downward secondary reserves (R2) are activated. As indicated in the previous paragraph, the activation prices for the R2 downward reserve product are capped by a floor of 0 €/MWh, and thus no negative imbalance prices can occur by activating downward R2 capacity, even after the IGCC imbalance netting potential is fully exploited [34].

Third, non-contracted downward regulation reserves are being activated. Such decremental free bid can include both a positive and negative activation price. A positive sign implies that the BSP pays Elia for lowering its power output, and a negative sign implies that Elia pays the BSP for lowering its power output. The possibility for negative decremental bids is necessary during situations experiencing incompressibility of the power system, because the costs for ramping down can be significantly large [34]. Thus negative imbalance prices can occur by activating downward non-contracted reserve capacity.

Fourth, downward tertiary reserves (R3) are activated, which are defined as emergency contracts with neighboring TSOs in Belgium. These reserves are only activated as a last resort, if the other reserve capacities are not sufficient to cover the system imbalance. If Elia activates this non-guaranteed downward reserve capacity from a neighboring TSO, the imbalance price is automatically set at at least a flat-rate of -100 €/MWh [34]. This measure has been active since June 2012 [33]. Thus negative imbalance prices occur by activating this downward reserve capacity product.

The above described downward reserve products showed that negative imbalance prices can only occur by activating non-contracted downward regulation reserves and emergency downward R3 reserve capacity from a neighboring TSO.

In addition, by studying Fig.2, it can be noted that in the majority of negative imbalance price quarters, the negative price is directly caused by the α-component instead of the activation of a marginal downward reserve at a negative activation price. As stated in section 2, the α-component is applied to 'punish' the BRPs causing the system imbalance when facing large system imbalances (larger than 140 MW).

To conclude, three market design factors responsible for the occurrence of negative imbalance prices can be identified for Belgium: (1) negative decremental bids from non-contracted reserve capacity, (2) Activated downward emergency capacity from neighboring TSOs, (3) The α-component turning positive or close-to-zero imbalance prices into negative ones.

When analyzing the reasons for the occurrence of negative imbalance prices from non-contracted decremental bids to a deeper level, it can be noted that negative decremental bids are submitted by BSPs not willing to lower their power output temporarily, except if their activation results in a positive cash flow. Renewable power generators have such an incentive because they lose a tradable green certificate (TGC) when curtailing the power injections from the renewable energy source. Also inflexible conventional power generators have this incentive because they face restricted ramp rates, minimum up and downtimes, and high startup costs for starting their power generation again after having shut down their plant. In Belgium these renewable power generators are wind power plants, as no large scale PV power plants are present. Table 2 displays the minimum guaranteed price for TGCs of onshore and offshore wind power, which they receive for each generated MW. It is easy to understand that these wind power plant operators are only willing to lower their power output if they are paid more than what they would receive for generating wind power.

TABLE II. FINANCIAL SUPPORT FOR WIND POWER IN BELGIUM [35,36].

	Federal level €/MWh	Flanders €/MWh	Wallonia €/MWh	Brussels €/MWh
Offshore wind	107 / 90[a]	--	--	--
Onshore wind	--	80 / 90 / 93[b]	65	65

[a] € 107 for generation coming from the first 216 MW of installed capacity, €90 for generation coming from installed capacity above the first 216 MW; [b] € 80 for generation capacity in operation from before 2010, € 90 for generation capacity in operation since 2010, € 93 for capacity in operation since 2013.

When analyzing the wind power data publicly available at [37], it can be noted that the activated decremental bids of offshore and onshore wind amounted to respectively 24 quarters and 104 quarters for 2013. The 24 activated offshore wind decremental bids were activated on four different days (08/09, 17/09, 25/12, and 29/12), while for onshore wind they occurred during 14 days between September and December 2013.
When combining this data with the imbalance price for negative imbalances at those moments, it is noted that when decremental bids of only onshore wind were activated the imbalance price was -100 €/MWh in 90% of the cases, leading to the conclusion that they bid downward reserve capacity at this price and were the marginally accepted bid. When examining Table 2, this seems valid as the financial support (< -100 €/MWh) is lost by curtailing, but 100 €/MWh is received for curtailing. When combining the decremental bids data of offshore wind with the imbalance prices at those moments, it can be observed that when decremental bids of offshore wind farms were activated the imbalance price was -180 €/MWh, -265 €/MWh, -310 €/MWh for respectively 38 %, 38 %, 21 % of the cases, leading to the conclusion that they bid downward reserve capacity at this price and were the marginally accepted bid. When looking at Table 2, this seems valid as the financial support (107/90 €/MWh) is lost by curtailing, but more than this support is received for the curtailment of their power output.

The inter-TSO emergency downward reserve capacity was activated in 52 quarters during the one-year period of 2013 [32]. As this activation results in an imbalance price of -100 €/MWh, it can be deduced that when the imbalance price amounted to this level at those moments, this downward reserve product was the marginally accepted bid. For 62 % of the quarters this was the case, and during the other quarters the price reached -265 €/MWh or -180 €/MWh. Thus, in 38 % of these quarters these downward reserves were activated but were not the marginally accepted bid.

When analyzing Fig.2 and the above described responsible market design drivers for the occurrence of negative imbalance prices, different segments along the duration curve can be identified based on these drivers, i.e. negative decremental bids, downward emergency capacity from neighboring TSOs, and the incentivizing α-component. Fig.3 displays the resulting segmented duration curve of the negative imbalance price for negative imbalances. If the α-component was the driving factor, no negative reserve capacity bids were activated, but activated positive or close-to-zero bids were converted to negative imbalance prices. This segment is displayed in black. If the inter-TSO downward reserve capacity was the driving factor, this resulted in an imbalance price of -100 €/MWh, illustrated in yellow. If the negative decremental bids were the driving factor, 3 sub segments can be identified. First, the activated onshore wind decremental bids were responsible for part of the observed imbalance prices of -100 €/MWh, illustrated in orange. Second, the activated offshore wind decremental bids were partly responsible for the -180 €/MWh, -265 €/MWh, and -310 €/MWh imbalance prices, illustrated in blue. Third, the remaining negative imbalance prices can be attributed to the activated negative downward reserve bids from inflexible conventional power generators. They are illustrated in gray.

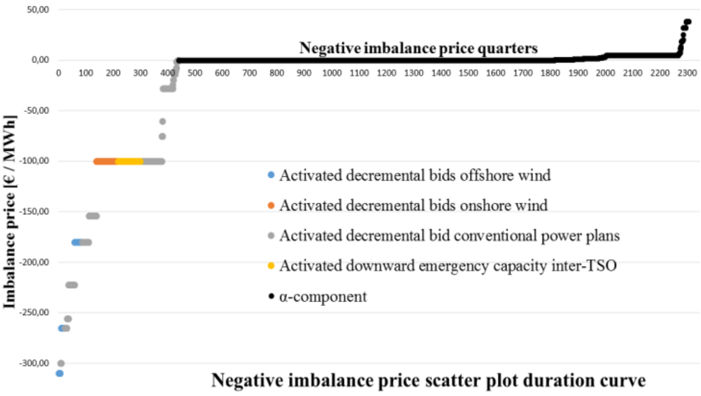

Fig. 3. Segmented negative imbalance price duration curve for 2013 [32].

VI. CONCLUSIONS

Because of the ongoing increase in variable RES, the need for power system flexibility is rising. Periods experiencing negative imbalance prices occur due to limited downward power system flexibility, also referred to as incompressibility. Multiple techniques exist to forecast these periods in order to take advantage of this phenomena, however they fail to include important regulatory-based reserve market design drivers. These are identified as (1) activated negative decremental bids from non-contracted reserve capacity, (2) activated downward emergency capacity from neighboring TSOs, and (3) the balance incentivizing α-component turning positive or close-to-zero activated decremental bids into negative imbalance prices. Therefore, optimal imbalance price forecasting tools should include both mathematical algorithmic and reserve market design parameters, which is identified as further research.

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