A Study of Electricity Market Design for Systems with High Wind Power Penetration

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Abstract—This literature review investigates the influence of intermittent wind power on the electricity market pointing out the importance of the market design along with presenting the Nordic, the German and the Spanish electricity wholesale market. Adaptations in the market design could improve the performance of systems with high wind power penetration levels. As a conclusion promising key-issues are listed.

I. INTRODUCTION

In many countries wind power generation has reached a significant share in both the installed generation capacity and the energy generated. Today, the technology itself is mature. Now, being deployed on a larger scale, issues concerning the integration into nowadays power systems are becoming pressing. Integration is the challenge of operating the whole power system efficiently, considering the intermittency of renewable energy sources (RES) [1]. Two issues are in the centre of interest: technical achievements paving the floor for the introduction of intermittent RES and combined with that a market design leading to the deployment of those sources. Inappropriate market designs will counteract technical efforts. E.g. [2] points out that the load-following capability of thermal power plants would allow for a more efficient integration of intermittent renewables, but due to the market rules that do not allow for sub-hourly scheduling, this flexibility cannot be used. This illustrates the crucial role of electricity market design.

According to [3] the relation between wind energy generation and the national electricity demand, i.e. the energy penetration level (cf. [4] or [5]), varied in Denmark, Portugal, Spain and Ireland in 2009 already between 10 and 20 %. In particular Portugal, Spain and Ireland have only very limited transmission capacities to their neighbouring countries. Impacts from the wind power generation on the system can be observed [6] but do not cause operational problems [3].

Especially in liberalized electricity markets, integration of renewable energy sources is a challenge not only from a technical point of view but also for the market, as the market is the medium through which the players are interacting. Even though it looks as if market designs are quite similar, important differences exist, leading to significantly different situations. For example, the degree of penalizing imbalances from RES is one factor deciding upon the actual contribution of renewables to the efforts of balancing the system. Many design parameters turn out to have considerable effects on the

players' behaviour. They either contribute to a more efficient use of the system resources or counteract it.

In this paper, some aspects of the market integration of fluctuating renewable energy sources are studied. The aim of the paper is to find key-issues either being promising to facilitate the integration of renewable energy sources or being regarded critically. First, a general description of electricity markets is provided. This is extended by summaries of existing electricity market designs in the Nordic countries, Germany and Spain. These three markets are especially suitable to serve as examples for the following sections and they provide a variety of experiences that are reviewed. The starting point for the analysis will be price and merit order effects in section IV. Then, section V explores the main function of the price serving as a signal to all actors. This important function can be distorted by many settings, for example national support schemes. Their impacts are analysed in section VI. Already here, questions concerning the regulating power market are raised. To address those and to go further into the matter the imbalance settlement and possible balancing responsibilities are discussed in section VII. The findings are summarized in the conclusions within section VIII.

II. ELECTRICITY MARKET DESIGN

The entire electricity market of a country or a region consists of numerous submarkets covering electricity trading (we focus on wholesale trading), allocation of transmission capacity and – in some cases – the provision of balancing reserves on capacity markets. In this section we describe the submarkets for electricity trading, go further into design options for spot markets and present ways of handling scarce transmission capacity.

A. Electricity Wholesale Trading

The electricity trading itself is organized in different submarkets depending on the time distance between trading and physical delivery, see Fig. 1. They consist of different types of forward markets, a real-time market and an ex-post imbalance settlement.

Forward markets cover all trading possibilities before the actual period of delivery. They can be divided into a financial market, a trading place for day-ahead energy purchases and sales and an intraday market(s) right before the actual period of delivery. Through trading of financial derivatives like futures,

forwards or options, players (both sellers and buyers) can hedge against price risks. The prices of those long-term contracts display the expectation of the actors towards the future energy prices. Liquidity on long term financial markets is also important to reduce market power in the succeeding submarkets because powerful actors that have traded financial contracts cannot profit from price changes on those markets anymore [7].

Coming much closer to the hour of delivery, producers, retailers and consumers start trading energy on the day-ahead market. Energy is sold or purchased in an auction for fixed periods (most commonly one hour each) of the following day. If these contracts are not fulfilled, this will lead to financial obligations for the actors, but not to physical consequences (curtailments etc.) as the system operator will balance load and generation. In this meaning, the day-ahead market – as well as the intraday market – is a financial market [8], [9]. On the other hand, all trades on the day-ahead market are being reported to the system operator who uses them for operational planning purposes for the next day. Hence, in contrast to the long-term financial trading before, this market is a market for physical delivery [10].

As a next step, intraday market(s) cover the time from the closure of the day-ahead market up to a short while before the actual hour of delivery. They allow market actors to adjust their plans and consider new information that have not been available before the gate closure of the day-ahead market. Often both, the day-ahead and the intraday markets are called spot markets emphasizing the short time between trade and delivery of the commodity, e.g. in [10]. Another definition is used by [8] calling only markets with immediate delivery, spot markets. We stick to the former definition and use spot market to refer to financial markets for physical delivery where the time between trade and delivery is short, i.e. day-ahead and intraday markets. The common practice of labelling markets is again not coherent with those definitions: in Europe the label spot-market is often used for day-ahead markets, e.g. Elspot (Nordic) or EPEX Spot (Germany, Austria, France, Switzerland) but not for intraday markets, e.g. Elbas (Nordic) or EPEX Intraday (Germany, France).

After trading on the spot markets, imbalances will always occur on a single player's level due to fluctuating electricity demand, intermittent power generation or outages (unplanned tripping of transmission lines, power plants and large power consumers) but they can be minimized. Within the hour of delivery, they are balanced by actions of the system operator. The immediate balancing (primary control) is handled by

frequency control which is bilaterally contracted between the system operator and participating power generating companies. In addition, the system operator can use other reserves within minutes (secondary and tertiary reserves) by activating bids that have been put on the real-time balancing market which is the only physical market in the stricter definition of [8]. Here, the system operator is the only actor the balance providers can trade with and it organizes this market.

Later, after the hour of delivery, commitments and compliance of each player can be assigned and an imbalance for each actor can be calculated. It is the task of the parties that are balance responsible to fairly distribute the costs for regulating power in a post-delivery imbalance settlement [11].

B. Design of Spot Markets

In Europe, day-ahead markets for electricity are all designed as power exchanges [12] where dispatch decisions are left to the actors. In contrast to that, the unit-commitment problem could also be centrally solved in a power pool with the use of side-payments [8]. Power pooling is for example applied in Pennsylvania – New Jersey – Maryland (PJM), New Zealand, Australia, Canada and Russia [12]. It is not considered in this paper because it is not in line with the European Commission's preference of market solutions. To only trade bilateral, without a power exchange or a power pool, is not a viable option: spot markets must be cleared in short time and bilateral trading takes too long [12]. Nevertheless, participation at the power exchange is generally not mandatory. Bilateral short-term trades have to be reported to the system operator though. Having alternative trading possibilities introduced some competitive pressure on the design of the power exchange [12].

References [12]-[14] give a good overview on auction design and bidding protocols. The power exchanges Nord Pool Spot (NO, SE, FI, DK, EE), EPEX Spot (DE, AT, FR, CH) and OMEL (ES, PT) all use non-discriminating day-ahead auctions with marginal pricing. Alternatives would be pay-as-bid auctions that have non-uniform prices or Vickrey auctions where the price is depending on the losing bids of other actors. The only power exchange in Europe using pay-as-bid pricing is the British APX UK [10], [12]. Vickrey auctions are not used in electricity markets because they lead to extremely different revenues even in cases of similar production costs [12]. In electricity markets sealed bid auctions are dominating [13]. Here, bidders have no possibility to react on other bidders' bids (static auction) compared to dynamic auctions with open bids.

Fig. 1. Submarkets of the electricity wholesale market

Special care has to be taken to choose an auction format that reflects the technical restrictions and the resulting costs in power generation, e.g. start-stop constraints, minimum generation levels or ramping restrictions. To consider them in a sufficient way, block bids are introduced which allow actors to connect conditions to their bids. Still, the combinations of different hours to blocks are restricted and the maximum amount of block bids limited in order to reduce complexity of handling the bids. Algorithms calculating the auction results are second-best algorithms that find a solution close to the optimum in reasonable time [12].

Another important design parameter is the possible bid range. It could be limited by caps and/or floors. Bid caps on not mandatory power exchanges – as stressed in [12] – are only limiting the maximum bid price but not the electricity price because a higher price might be gained in bilateral trading. A real price cap is helpful to prevent incentives to abuse market power by reducing generation capacity. In addition accidental bidding mistakes might be prevented and the cap can serve as a signal to the regulator indicating possible market power abuse [12]. Price floors are sometimes set to zero to exclude negative prices.

C. Allocation of Transmission Capacity

An efficient allocation of transmission capacity is of high importance because it is a complementary commodity to the electricity traded: to transmit the power, a grid infrastructure is necessary. As soon as transmission capacity becomes scarce, power flows that would result from electricity trading are not feasible anymore. Three methods for handling congestion – explicit auction, re-dispatch and implicit auction – are especially relevant for European electricity markets: a first possibility is to separate electricity trading and transmission capacity allocation totally, either by introducing explicit auctions (transmission capacity is auctioned separately to electricity auctions) or any form of bilateral contracts or rationing (channels, first come-first serve, pro-rata). This can hinder efficient allocation of one of the commodities because each is limiting the other one. Power flows from low price into high price areas, are a good example for inefficiencies due to missing or inappropriate links between the submarkets. The second methods are remedial re-dispatch methods including counter-trading, a “more market-oriented form of re-dispatching” [15]. But it will also come at additional costs [16]. Methods combining the allocation of transmission capacity with the electricity trading constitute the third group. Implicit auctioning is one method for that. Both complementary commodities are then traded simultaneously. In case the demanded volume exceeds the transmission limits, a surcharge is added on electricity bids triggering the congestion. Those surcharges drive some bids out of the market until the congestion is relieved. Implicit auctioning can be applied both on interconnectors between markets and on bottlenecks within the same market. The latter case is referred to as market splitting or area pricing because the market is split into several price areas if congestion occurs [15], [16]. In [12] a slightly stricter definition is used calling it market splitting only in case the price areas are not predetermined (as

the price areas are in the Nordic electricity market, for example) but endogenously set depending on the location of the bottlenecks. We follow the more general definition.

III. THE NORDIC COUNTRIES, GERMANY AND SPAIN

Many similarities can be found between the Nordic, the German and the Spanish electricity markets, e.g. the general structure depicted in section II. Other criteria are different:

- market architecture: interconnection/timing between submarkets, internal congestion management,
- concerning the design of the day-ahead market: requirement of participation, bid caps and floors, design of the intraday market(s),
- degree of market coupling (between countries),
- congestion management on interconnectors between markets,
- system characteristics & political environment.

First, it should be noted that the system itself as well as the environment are different, too, as shown in Table I: Germany and Spain are dominated by thermal power generation whereas in the Nordic system about 58 % of the electricity is generated in hydropower stations [17]. The storage possibility of considerable amounts of water and energy, introduces an “inter-temporal” aspect [18]. The sizes of the systems, the amount of RES generation as well as the strategies chosen to encourage RES deployment are different, too.

TABLE I
OVERVIEW (DATA FROM [17] AND [19]-[27])

	Nordic	Germany	Spain
Power generation	hydro-thermal	thermal	thermal
National consumption (2009)	376 TWh	527 TWh	259 TWh
Share non-conventional RES / national consumption (2009)	FI: 10.5 %, NO: 0.8 %, SE: 9.8 %, DK: 19.3 %	13.0 %	16.0 %
Primary RES support scheme	SE, NO: green-certificates, DK: mix feed-in tariff and feed-in premium, FI: fiscal incentives	Feed-in tariffs	Option Feed-in premium or feed-in tariff
Approx. Inter-connection capacity (in relation to peak load)	5910/5410 MW (export/import) (9.5 %)	13600/16900 MW (21 %)	1600/1400 MW (6 %)
Day ahead bid cap/floor	2000/- 200 EUR/MWh	3000/- 3000 EUR/MWh	n.a.

A. Nordic electricity market

The Nordic electricity market ([11], [26] and [28]) includes Norway, Sweden, Finland, Denmark plus Estonia. Transmission bottlenecks do not only occur on national borders but also inside the countries. To handle some of these,

the market is split into predefined price areas in case congestion occurs. Currently, there are ten price areas out of which five are in Norway, two in Denmark and one each in Sweden, Finland and Estonia. Implicit auctioning implies that the power exchange has to be mandatory for electricity trading between price areas while within one price area over-the-counter trading is a possible alternative. Congestions within a price area (occurring especially in Sweden and Finland that consist of only one price area) are handled by the TSOs through counter-trading. From November 2011 the Swedish TSO will introduce four price areas within Sweden [29]. In Finland the introduction of a second price area has been discussed but rejected. Here, a major argument against area pricing was the inherently higher risk of market power abuse: in case of congestion the number of competitors in each separated price area is reduced significantly [39].

In the spot markets, bidding is done on one common power exchange, NordPoolSpot. They provide day-ahead trade (Elspot) and intraday trading (Elbas). As all inter-area trading will go through the spot markets, the bid cap constitutes a price cap as long as transmission is not congested. Continuous intraday trading on Elbas is possible from 14:00 (i.e. after publication of the day-ahead market's results) until one hour prior to delivery. Purchase and sale orders fulfilling the minimum bid size are given to the power exchange, made anonymous and settled if possible [31], [32]. Hence, this is not an auction and the prices are not uniform but as agreed on. On Elbas, Germany is designated an additional price area.

Balancing load and generation is done by the TSOs based on one common list of bids. As long as there is no congestion, the cheapest bids will be activated if necessary. In that case, a Finnish balance provider can, for example, balance an outage in a Norwegian power plant. A certain amount of reserve power is also rewarded a capacity payment [33].

The Nordic market is coupled to the German electricity market in a way called tight volume coupling which is sometimes presented as an interim approach until prices could be coupled, too [34], [35]. During the bidding procedure on both power exchanges, the welfare-optimizing power flow is calculated. Then additional bids are placed on both exchanges to reflect the coupled flows after which each exchange calculates the electricity prices itself [26]. This way a more efficient allocation of interconnector capacities is ensured. Only capacities to Russia and Poland are still contracted [36]-[38].

B. German Electricity Market

The day-ahead market covers Germany and Austria. Trading on the power exchange is not mandatory and the major part of the electricity generated is traded bilaterally. Therefore, an overall congestion management approach cannot be integrated into the electricity trading. Instead, the TSOs use re-dispatching. In the past, grid capacities were sufficient to enable all trades settled on the power exchange. Only if that is not possible, market splitting with five predefined areas corresponding to the balancing areas of the TSOs would come into force [12].

Financial long-term trading (EEX Power Derivatives), day-ahead trading (EPEX Spot) and continuous intraday trading (EPEX Intraday) are possible. After gate closure of the day-ahead market, continuous trading on the intraday market is possible between 15:00 until 75 minutes prior to delivery (pay-as-bid pricing). It covers Germany only and bids are limited to ± 9999 EUR/MWh [27]. A special characteristic of the German real-time balancing market is its low liquidity and its comparatively high price level [1].

In addition to volume coupling with Nordic spot market, EPEX Spot recently got price-coupled with the French, Belgian and Dutch electricity markets that also cover Luxembourg. This way, a bid in one of the countries is automatically included in the other countries and congestions between them are handled implicitly.

C. Spanish Electricity Market

The Spanish electricity market was merged with the Portuguese one in 2007 forming the Iberian electricity market called MIBEL [39]. The internal bottleneck between Spain and Portugal is handled by splitting the market splitting into a Spanish and a Portuguese price area [40]. Bilateral trading is only possible before the closure of the day-ahead market. But even though the participation at the power exchange is not mandatory, additional capacity payments which are rewarded to those generators trading through the power exchange, lead to a quasi-mandatory power exchange [25], [41], [42].

The market operator OMEL operates a day-ahead market which is followed by trading possibilities on six consecutive intraday markets that are cleared after each other, see Fig. 2. Each auction uses marginal pricing and covers a decreasing number of hours the later the session starts. The first trading possibility is the auction starting at 16:00 in which electricity for all hours of the next day plus the last three hours of the actual day can be traded. The session closes at 17:45. In the following session starting at 21:00 and closing 45 minutes later electricity can be traded for the hours between 1 and 24. Hence, the minimum time lag is always $3\frac{1}{4}$ hours. The next sessions close at 1:45 (hours 1-24), 4:45 (hours 8-24), 8:45 (hours 12-24) and 12:45 (hours 16-24) [25], [41], [43]. Trading on the intraday market requires trading activities on the spot market (either through the exchange or bilateral) for the same hour [44].

In addition to the combination of intraday markets and the real-time balancing market the system operator has the possibility to open an additional so-called deviation market with marginal pricing right before the hour of delivery in case it is likely that the difference between forecasted load and traded energy is exceeding the reserve capacity [25].

Fig. 2. Consecutive auctions – a different intraday design

The interconnector capacities to neighbouring countries are low. Hence balancing has to be done mainly within the market area [25]. The French-Spanish interconnector capacities are auctioned explicitly [45].

Two peculiarities can be found: First, tariffs for final consumers are regulated by the government [12], [42]. Second, an interim rule (intended to end in 2010) entitles incumbent generators (before liberalization in 1997) to additional payments that protect companies from price signals and market risks. For details on those so-called “Competition Transition Costs” see [42]. Both peculiarities are likely to cause inefficiencies as also emphasized by [12].

To conclude this section, we can list characteristics of market design facilitating the market integration of RES: first, liquid spot markets allow trade close to delivery, which is especially suitable as forecast errors significantly decrease with time [46]. Second, congestion management that is combined with electricity trading can efficiently allocate the transmission capacity. The Spanish case offers an interesting design approach for the structure of the intraday market that could also be applied in other countries. It should be analysed further whether it could lead to efficiency gains, e.g. in hydro-thermal systems. Another interesting issue could be an obligation or fostering of trading on a power exchange.

IV. IMPACT OF INCREASED RES ON THE SPOT MARKETS

The impact of nonconventional RES generation on the spot markets is not due to the wind power feed-in itself, but the forecasted wind power penetration level, as emphasised correctly in [XX].

References [23], [47] and [48] examine the effects of increased RES feed-in on the electricity market: When wind power is introduced to a conventional power plant mix its low variable costs (nearly zero [23]) will decrease the number of hours the incumbent power plants with higher marginal costs are setting the price and hence reducing the average price. In addition to this direct effect [47] states an indirect effect via the emission trading scheme: A reduced demand for emission rights will lead to lower prices for CO₂ allowances which decreases the marginal costs of conventional power plants resulting in lower average electricity wholesale prices. The direct effect is backed up by analysis of historical data from Germany [23] and Spain [47], [48]. Reference [48] uses a non-parametric regression model to show the price decreasing impact of the forecasted wind power production on average day-ahead spot prices. Reference [47] performs a simulation of the power plants’ dispatch for the Spanish case using one “no-wind” scenario and one scenario with wind power feed-in for 2005 – mid-2007. Electricity prices result from the dispatch and the model is validated comparing the “with-wind” scenario prices to the observed market prices. Finally, they compared the differences between the two scenarios’ prices with the costs for the Spanish RES support scheme resulting in considerable net savings. In contrast, their findings which are based on historical data for a period of three consecutive days, indicate savings but those are not high enough to balance the RES costs spread out on the consumers.

For the German case, [23] provides no comparison to the total costs of the RES support scheme.

In general, it is difficult to quantify the price decreasing effect of wind power introduction, because there are many factors influencing the spot market prices besides the wind power feed-in. Simulating dispatch as in [47] is highly complex and many assumptions have to be made. Nevertheless, the findings indicate a price reducing direction of the effect.

In the long run, the merit order changes by wind power introduction are expected to start an adaptation process as explained qualitatively in [23] and [47] and shown for a case study in [48]: RES power generation is fluctuating and so is the residual demand that has to be met by conventional power plants. This can lead to increased volatility of electricity prices. In total, they expect flexible generation (e.g. thermal peak power plants, pumped hydro storage, compressed air power storage or flexible hydro power plants) to profit from highly volatile prices and drive the most inefficient base load and medium load power plants out of the market. [23] and [47] illustrate qualitatively that after this adaptation, prices rise slightly again because peak power plants are more often on the margin. Concerning support schemes, this would imply that the RES support period should be shorter than the transition period.

Merit order changes might lead to the politically desired fuel shift towards a more sustainable power generation and might lower electricity spot prices during the adaptation period. Volatile prices are expected to boost quick start and fast ramping units and also encourage price-responsive load as well as energy storage [49].

V. PRICE SPIKES AS MARKET SIGNALS

While negative prices are quite a unique characteristic of electricity markets [50], high prices signalling scarcity are common for most commodities. The increased price volatility on the one hand encourages investments in more flexible generation and demand if price spikes are allowed to occur freely both in magnitude and in frequency [46]. On the other hand, price volatility conflicts with investment decisions because scarcity rents that are needed to recover fixed costs are more difficult to predict. The later point is especially critical for reserve capacity. First, we want to point out that bid floors must not suppress market signals reviewing experiences with negative prices and their effects on the German electricity market. Second, we have a look at investment uncertainties in energy-only markets.

The occurrence of negative prices on the German power exchange EPEX Spot caused a lot of discussion [51]. Reference [52] presents an empirical study of the price-generation relation on the German day-ahead and the real-time balancing market for tertiary reserves. Analysing the response of thermal power plants on negative prices, their findings support that a shut-down of nuclear or lignite power plants is the very last option. For those, technical restrictions result in high opportunity costs. Hence it is economically profitable to receive losses accepting low or negative electricity prices

during a short time as long as they are lower than the costs for dispatch adaptations. In case the wind power feed-in is high and the residual load close to the border of conventional power plants' flexibility, [52] claims that negative prices can efficiently balance load and demand. A qualitative analysis in [51] shows that a too high bid floor would lead to a dead-weight loss for society and this way proving the efficiency of negative prices.

Reference [46] claims that also positive price spikes are necessary. The argumentation is based on the fact that most European electricity markets are energy-only markets on which reserve capacities only receive payments based on EUR/MWh when they are in use. This way recovering the fixed costs is only possible in situations with high electricity prices. Positive price spikes are likely to occur if prices are not limited and when the residual load is very high and close to the border of maximum generation, hence displaying scarcity. In contrast to this argumentation, the political acceptance of positive price spikes is often low [46].

Regarding the appropriate height of bid caps, a balance has to be found between the two contrasting issues, investment incentives and market power (competition might also be fostered by higher interconnection capacities [14] and market coupling).

As investment decisions are of central importance for the system, the question has to be answered whether they can in general be driven only by signals from energy-only markets [46]. Given highly volatile prices, long construction times and high sunk costs, investments on energy-only markets would be very risky because positive price spikes occur only for short times. In addition, [53] claims that every incentive is destroyed if more capacity is added than demanded by the market. To increase predictability of revenues, capacity payments (EUR/MW) are discussed. An overview on different setups can be found in [33]. In general, they could also mitigate positive price spikes [46]. But due to general difficulties in the design of capacity payments (cf. for example [53]) there is no unanimous assent yet [49].

VI. SUPPORT SCHEMES' IMPACT ON ELECTRICITY MARKETS

In this section the interaction between the support scheme and the electricity market is presented. Support schemes are not the only part of a nation's RES strategy: they often go along with feed-in priority, balancing rules and locational signals such as grid connection charges or network tariffs.

In addition to a sustainable electricity supply, RES support strategies aim at reducing the cost of RES technologies by encouraging innovation, using learning effects and, e.g. in Germany, at creating a competitive industry [54]. Due to market failure (external effects, very slow structural changes) support schemes are necessary as shown in [55]. In a "carbon-constrained era" [54], it is also necessary to foster possible back-stop technologies for the future [55].

As listed in Table I, both the choice of support scheme and the success in attracting renewable deployment vary between the Nordic countries, Germany and Spain (see [21] for other European countries). The extent to which renewables under

different support schemes are exposed to market risks, investigated by [9], gives some explanations. Feed-in tariffs isolate RES from market signals, showing the temporal valuation of energy. This way, uncertainties for wind power generators are significantly reduced. The tariffs reflect the long run marginal costs including capital costs of the RES technology [51]. Feed-in premiums – another support scheme – are paid on top of market prices and represent the value of positive externalities, i.e. they are lower than feed-in tariffs. Hence, RES generators are exposed to market signals and market risks, similar to conventional power plant operators. Often, e.g. in Spain, caps and floors are used to limit this income risk. The use of tradable green certificates (rewarded for each MWh) in combination with an overall quota obligation introduces a premium payment to RES which is market-based. Hence, RES generators face uncertainties on the forward markets plus a volatile remuneration. This significantly increases investment uncertainties and transaction costs which might hinder RES deployment. Due to that, a higher financial support would be required [1], [9]. Nevertheless, the exposure to market signals leads to a more efficient use of system resources (e.g. by siting or planning maintenance). Reference [21] adds one criteria missing in [9]: feed-in tariffs and premiums can allow for technology specific support deploying a broad RES portfolio and not only encouraging today's lowest cost technologies. This could e.g. increase the overall RES capacity credit [23].

From an institutional point of view [55] regards green-certificate systems the most suitable, but [9] concludes that feed-in premiums might be the best compromise regarding investment uncertainties and the efficient integration of wind power. Other support possibilities are fiscal incentives (e.g. in Finland) or tender-schemes where the quota is auctioned, cf. [54]. Reference [46] stresses the need for harmonization within Europe to trigger investments where they are best from an overall perspective. E.g. Norway and Sweden are introducing a common certificate market [10].

Support schemes are often blamed to trigger negative price spikes. According to qualitative reasoning in [51], it is though not the RES generation itself but the technical constraints of conventional power plants. Nevertheless, high RES feed-in increases the probability significantly. This is explained by the priority feed-in of renewables: even though there is an oversupply on the market, wind power is pushed into it and this causes a dead-weight-loss to society. To reduce welfare losses, [51] suggests restricting priority feed-in to "normal" situations where the market price is positive.

A balance has to be found between the exposure to market risks, i.e. also the exposure to market signals, and the predictability of revenues. To be effective the support strategy must be based on clear long term institutional settings [21] and the total costs should be kept in mind, especially if they are spread out on the final consumers as in Germany or Spain, because otherwise those costs could endanger the popularity of renewables [54]. The final success in fostering RES depends on the support strategy, the market design and the interaction between both areas [1].

VII. BALANCING POSSIBILITIES AND IMBALANCE HANDLING

Regarding market design, not only the trading but also the handling of imbalances is fundamental. Imbalances should be kept as small as possible because reserves are expensive and larger imbalances difficult to handle [56].

Reference [57] indicates that it is better to use a two-price system, which prices imbalances that contribute to the systems' total imbalance higher than it rewards those that support the system. This asymmetry might cause an incentive especially for wind power generators not to game but to bid the energy which they expect to generate. A contradicting conclusion is given in [10]. But the latter one seems to be valid for up-regulation situations only. To base trading on shorter time periods (sub-hourly scheduling) might also increase the markets' efficiency [48] by decreasing the total imbalances. It should be investigated further to which extend sub-hourly scheduling could improve the use of system resources.

A more general question is whether the same imbalance rules as for conventional power plants should also be apply to wind power plants. In the Spanish and the Nordic market, wind power generators are fully responsible for their imbalances [1]. This gives e.g. incentives to improve forecasting quality [46]. In Germany RES are not exposed to imbalance costs and all balancing is left to the TSOs. If necessary the TSOs can direct curtailments to keep the balance. It might be more efficient from a system's perspective not to isolate RES from essential market signals but to penalize their imbalances. This would, at a first glance, significantly reduce profits for wind power generators and increase profit volatility. But [58] shows that it is possible to derive bidding strategies for wind power producers that result in low imbalance cost at the price of only small decreases in the expected revenue. The application of their linear multistage stochastic optimization model in a case study also backs-up the positive impact that liquid intraday markets have on wind power producers' revenues.

Having the same obligations, wind power plants should also be able to provide regulating power and participate in the real-time balancing market. This is technically possible [23], [49], [52] especially if economically attractive [25] or obligatory. In situations of low electricity prices and high wind power generation the production could be decreased and the change sold on the real-time market as negative regulating power. Later – if forecasts continue to be high – the spilled capacity might be sold as positive regulating power. The market design has to allow for participation of RES on the real-time balancing market, e.g. by appropriate minimum bid sizes (small enough) [52]. Participation in the real-time balancing market could increase the markets' efficiency, e.g. by reacting on price spikes they could be smoothed [52] and balancing by peak power plants less necessary. It should be studied which combination of market situations and market designs could trigger RES to provide regulating power.

It could also be beneficial if individual generating companies would use their own portfolio for self-balancing to

a larger extent. E.g. incorporating wind generation in hydro power scheduling could result in additional benefits as [59] indicates for mid-Norway. That might be generalized for hydro-dominated systems. A major disadvantage of self-balancing is pointed out by [10]: intraday and real-time internal balancing will be the more profitable the bigger the company. This is critical because most European real-time balancing markets already show a lack of competitiveness [10]. Larger balancing areas might reduce this problem [49]. Internal balancing will be stimulated by economically attractive intraday and real-time prices but it could also be fostered by the TSO. Possible efficiency gains should be studied more in detail.

VIII. CONCLUSION

This paper analyses market design for systems with high wind power penetration and identifies important issues for an efficient integration of RES. As [2] states, there is an economic, not a technical limit to which extend fluctuating power sources can be integrated. An efficient integration is encouraged by:

- trading possibilities close to delivery, i.e. on liquid day-ahead and intraday markets,
- penalizing RES imbalances applying asymmetric imbalance settlement rules and allowing RES to provide regulating power,
- adaptation of support schemes (e.g. feed-in tariff with only limited priority in-feed or better predictable revenues in case of green-certificate schemes),
- efficient allocation of transmission capacity,
- coupling of markets along with higher transmission capacity on interconnectors (regional markets),
- competitive markets with unbiased price signals.

Studying adaptations to facilitate the integration of RES, both the whole design and the specific characteristics of a country's electricity market have to be considered, as the actors' behaviour is very sensitive to them.

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