Power Markets with Renewables: New Perspectives for the European Target Model

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ABSTRACT

We discuss at the European example how power market design evolves with increasing shares of intermittent renewables. Short-term markets and system operation have to accommodate for the different needs of renewable and conventional generation assets and flexibility options. This can be achieved by pooling resources over larger geographic areas through common auction platforms, realizing the full flexibility of different assets based on multi-part bids while efficiently allocating scarce network resources. For investment and re-investment choices different technology groups like wind and solar versus fossil fuel based generation may warrant a different treatment – reflecting differing levels of publicly accessible information, requirements for grid infrastructure, types of strategic choices relevant for the sector and shares of capital cost in overall generation costs. We discuss opportunities for such a differentiated treatment while maintaining synergies in short-term system operation.

Keywords: Power market design, Regulation, Investment framework, Intermittent renewables

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1. INTRODUCTION

The electricity sector was liberalized to create incentives for efficient operation and investment (Pollitt, 2012). In Europe the individual Member States have developed in this process a power market design that reflects their national generation mix, network topology, and industry structure. With this article we explore, how the electricity market design needs to evolve as the share of wind and solar power is increasing.

The European Commission has been a strong driver for the liberalization and has focused on enhancing trade between Member States and competition (see e.g. Sector Inquiry in 2007 by DG Competition). The Commission is pursuing the vision of a 'Target Model' using a European governance process (Third Energy Package, Directive 2009/72/EC) which is centered on day-ahead auctions operated by power exchanges that implicitly allocate transmission capacity between pricing zones. The Target Model also envisages a common order book for intraday trading and ultimately aims at integrating balancing markets. De facto, however, Member States retain flexibility in the

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design of balancing mechanisms and transmission system operators (TSOs) retain discretion in re-dispatching the system to correct for violations of transmission constraints. Furthermore, countries like Spain, Italy, Poland or Ireland with scarce transmission capacity or limited generation flexibility have 'delayed' the implementation of elements of the Target Model, for example continuous intra-day trade until gate closure an hour before real time.

The US Standard Market Design differs significantly from the vision of the Target Model. In the US design, the center resides in a real-time instead of a day-ahead auction. The real-time auction is preceded by a financial firm day-ahead auction and multiple intraday updates. Transmission constraints are internalized in the clearing algorithm of the auction. Market participants can provide their full flexibility to the market by submitting multi-part bids including information on start-up costs, part load, and ramping constraints. Thus a secure system operation is achieved without the need for re-dispatch measures.

With increasing shares of intermittent renewables, all EU countries have to focus on an effective use of flexibility options and transmission capacity. This creates an opportunity for European policy to move beyond the traditional focus of facilitating trade between Member States towards aligning the operational and market approach of countries. We explore how a market design can accommodate the needs of conventional assets, like the early coordination of start-up of plants, while also realizing the shorter-term flexibility potentials and needs of wind and solar power.

With respect to investment choices, it is often argued that all generation assets need to be treated equal. We discuss why wind and solar might constitute a different good from conventional technologies warranting a differentiated treatment. For wind and solar, capital costs dominate the cost structure, and therefore costs to consumers are especially dependent on financing costs. Consumers can therefore benefit from lower and stable energy cost if renewable remuneration mechanisms eliminate or reduce market and regulatory risks. Governments benefit from largely public information on technologies, and can build on renewable deployment targets that are used as basis for network expansion. For conventional technologies fuel, carbon, operational and maintenance costs are more important and less predictable in particular for policy makers. Also the anticipated investment volume in fossil generation assets is smaller. Hence it might be anticipated that incumbent utilities can pursue investments based on mid-term contracts (1–3 years) and a somewhat sticky retail customer base.

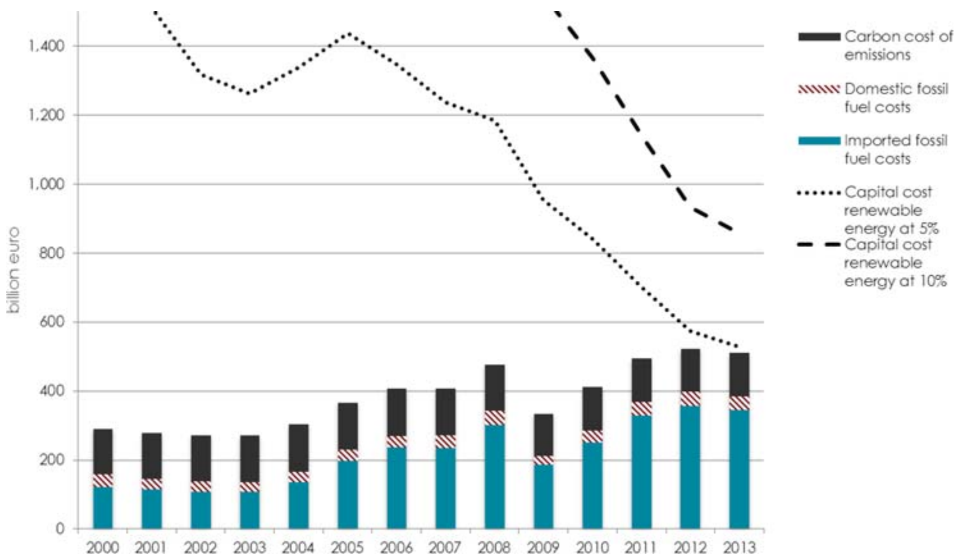
The joint discussion of changes to the operational and investment paradigm is important for several reasons. A good operational paradigm can provide robust real-time and day-ahead prices as reference for mid-term contracts to back investments in generation and flexibility. It also does not discriminate against smaller or less strategic market participants and thus creates flexibility for the design of renewable remuneration mechanisms.

The paper is structured as follows. Section two discusses specific needs of conventional and renewable (wind and solar) generation technologies and illustrates that each group warrants a different regulatory treatment. Section three explores how the further design of short-term market design can address the needs of all technologies while realizing synergies from their integration. Section four then discusses potential implications for investment frameworks for conventional as well as renewable technologies. Section five concludes.

2. DISTINCT TYPES OF GENERATION TECHNOLOGIES NEED TO BE CONSIDERED

Power systems in most European countries traditionally comprised large shares of fossil fuel based generation. The rapid reduction of wind and solar PV costs allows for the replacement of power generated from conventional plants with low carbon choices, thus reducing carbon emissions while avoiding dependency on gas imports. This is also reflected in a renewable contribution of at least 60% to power generation in all decarbonization scenarios of the EU Energy Roadmap 2050 or IEA (2012).

Figure 1: Illustrative comparison of European fossil fuel bill and capital costs for renewables (at purchasing prices in each year, excluding system costs)



The economic viability of this perspective is illustrated in Figure 1. Assume all energy generated from fossil fuel assets in the EU was substituted with renewable energy. In 2013, the annualized investment cost in wind turbines and solar panels to deliver the same final energy would have been of the same size as the fossil fuel bill including a €30 per ton carbon price. This assumes that the renewable generation mix consists of onshore wind power (two-thirds) and PV (one-third), and that the final energy demand in all areas of use – including the transport sector – can be fully served with electricity.

The comparison is only illustrative and of course very simplified. In a comprehensive system analysis, further aspects have to be considered. All energy transition strategies envisage a strong emphasis on energy efficiency to reduce energy demand as compared to the business-as-usual development (e.g. IPCC, 2014). This would not only reduce energy bills and CO_2 emissions, but also investment costs. Moreover, besides onshore wind power and solar PV, several other low-carbon technologies complement the optimal portfolio supporting the transition to a decarbonized economy. In addition, the costs of energy storage devices, market flexibility, and additional grids, that become relevant in the case of high shares of fluctuating renewable generation, cannot be neglected, and for the evaluation of a system focused on renewables and energy efficiency, the opportunities to save on future infrastructure investment for fossil fuels also need to be taken into account.

In principle fossil generation technologies and wind and solar energy offer good complementarities, but specific needs have to be considered in operation and (re-)investment frameworks.

Operation: Unit commitment, e.g. start-up and shut-down decisions of conventional power stations require planning several hours before real time with limited flexibility on very short time frames (ramping and minimum run constraints). On the other extreme, generation of technologies like wind and solar can be adjusted – within available wind and solar resources – within seconds and is therefore highly flexible on the short-term, but increasingly uncertain to predict in longer time frames.

Investment: Table 1 explores differences between these two technology groups by comparing the main strategic choices faced for the different generation technologies. In the case of solar and wind power, volume and location of new investments remain the most important decision parameters. Effective investment choices increasingly need to be pursued with a system-wide perspective on the suitable generation mix and require strong coordination with grid expansion. Deployment has to date been successful where supported and guided by government deployment targets (RE-Shaping, 2011). In contrast, for fossil fuel plants across Europe the prominent questions relate to re-investment/retrofit enhancing lifetime, to plant efficiency and flexibility parameters, to closure/mothballing decisions, and to suitable fuel contracting with only limited new investments largely in gas-fired power generation expected in the foreseeable future.

Table 1: Differences among wind and solar PV as compared to conventional technologies

	Wind and solar PV	Fossil fuel based generation
Capital costs	~ 80%	~ 30%
Main strategic choices	New investment decision Location and dimensioning	(Re-)investment and retrofit decision Closure Fuel contracting
Capacity for government to decide	High (homogenous technology, competition for entry)	Low (inhomogeneous assets, large incumbent players, information asymmetries)
Other aspects	Trajectory required for - Grid investment - Supply chain / planning	Government choices politically contentious
Strategic choices	**Policy-driven deployment**	**Private-sector determined (financed on balance sheet)**

Also the capacity of governments to take a stronger part in such strategic decisions varies. In the case of renewable technologies, information about costs is largely in the public domain, and can be solicited through competitive market arrangements like auctions or responsive feed-in mechanisms. In contrast, information about re-investment needs of individual conventional plants is in private hands, and regulators face challenges of asymmetric information if they attempt to involve in related re-investment or closure decisions. Hence, in the case of renewables, there is both a need and a capacity for public agencies to take a stronger role in strategic investment choices. In the case of fossil generation assets there is less capacity for public actors to get involved in such choices. In addition, it needs to be considered, that for successful wind and solar deployment, network expansions are necessary. Politically determined renewable deployment targets are the basis for planning of transmission and distribution system expansion by operators, approval by regulators, and public acceptance.

Capital costs linked to initial investment costs constitute around 80% of total power generation costs of wind and solar PV. In contrast, the share of capital costs for conventional mid-merit and base-load fossil fuel power generation assets was typically in the order of 30% (Schroeder et al., 2013). Therefore, a policy framework that aims to minimize costs to final consumers would need to focus on minimizing the financing costs for the capital in the case of renewables, while other operational incentives and fuel supply strategies might be equally or even more important in the case of fossil fuel based generation plants.

The financing costs for wind and solar will largely depend on the exposure to regulatory risk and opportunities for long-term hedging between consumers and generators: First, the *secure net-revenue* determines the share of debt that can be used to finance a project and to reduce financing costs due to the lower return requirements for debt than for equity (see also Tisdale et al., 2014). Second, the *complexity of the regulatory framework and financial structure* necessary for the implementation of a project can increase transaction costs and reduce the level of competition because fewer actors will have the capacity to engage and fewer actors will be prepared to endure the costs of making offers for a complex financing structure, which in turn reduces competition among finance providers and increases the cost of finance.

The importance of financing costs for wind and solar is illustrated in Figure 1. The level of financing costs will be critical for the economic viability of a transition to a low-carbon economy. If the weighted average cost of capital increases from 5% to 10%, for instance due to political or regulatory risks and market imperfections that limit bilateral long-term contracts, the costs of renewable energy would, in this calculation, not be in the order of magnitude of fossil fuel expenditures. Credible and stable conditions for investors are key to limit financing costs (see e.g. De Jager and Rathmann, 2008). This argues for the continued use of remuneration mechanisms able to (i) compensate for insufficient carbon prices delivered by the EU emissions trading scheme and to reflect public benefits of reducing fossil fuel import dependency (Borenstein, 2012); (ii) to reduce regulatory risks and manage market risks so as to facilitate access to low-cost finance (Bürer and Wüstenhagen, 2009); and (iii) to accelerate the investment pace into a portfolio of renewable technologies towards a decarbonized power system beyond the natural replacement rate (Kramer and Haigh, 2009).

The above reasoning affects all EU power systems and as the share of intermittent renewables is increasing and accelerating these developments, the requirements for the corresponding organization of short-term markets converge throughout Europe.

3. REQUIREMENTS FOR SHORT-TERM POWER MARKETS WITH LARGE SHARES OF INTERMITTENT RENEWABLES

A functioning internal electricity market should allow for unlocking flexibility resources across national borders and pricing zones. In what follows we discuss how the bidding format, procurement of reserves, the role of balancing groups, and allocation of transmission capacity, can support a power market with large shares of intermittent renewables.

Suitable bidding format

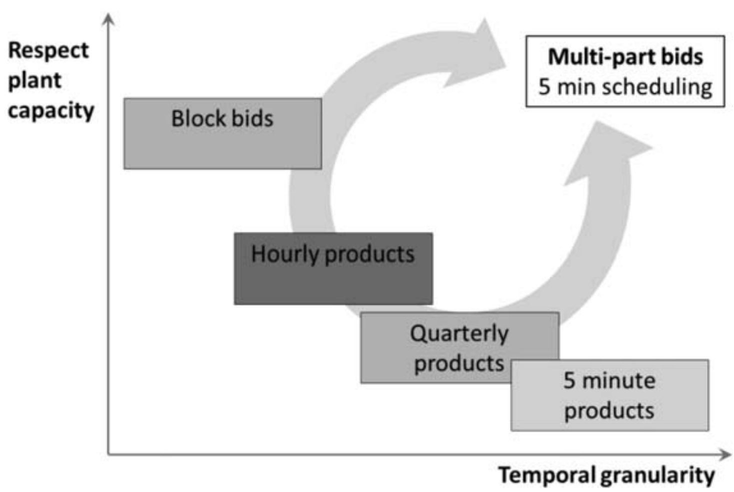
Historically, vertically integrated utilities largely balanced their own demand and supply schedule and used trading opportunities to fill generation gaps or arbitrage opportunities from different plant efficiencies or fuel costs. With increasing shares of intermittent renewables in third party ownership, the coordination function of the market increases in importance. This has resulted in pressure to both enhance the temporal granularity of products but at the same time to mirror the plant capabilities in the bidding process.

Temporal granularity: If a generation plant needs to increase production to match growing demand during the morning period, or to react to declining solar generation in an afternoon hour, then a typical energy contract for one hour cannot meet the low output volume at the beginning and high output volume at the end of the period. Hence, some market participants and transmission system operators were interested to enhance the temporal granularity of products in order to improve the match of supply and demand on 15 or 5 minute intervals.

Respect plant capacity: Coal, nuclear and many combined cycle gas turbines require several hours to start-up and can only be ramped gradually to full output (VDE, 2012). These technologies therefore will struggle with energy markets with market clearing processes for individual hours. This is less of a concern for utilities with a portfolio of generators across which they can optimize, or for longer time horizons within which generators can use bilateral trading opportunities to re-trade generation schedules that are infeasible.

Hence, different bid formats have been developed that link the output of several hours or include bid components for start-up and ramping to allow effective participation of less flexible generation assets. Figure 2 illustrates recent developments in European electricity markets. With regards to the temporal granularity on the horizontal axis, the traditional hourly bid format has in some countries, like Germany, been disaggregated at intraday stage into intervals of 15 minutes, thus facilitating a closer match of supply and demand within an hour. The smaller the interval, the less adjustments individual power stations can offer due to technical constraints limiting how quick they can adjust production (ramping rates). To accommodate for this, many countries allow for block bids that can bundle the production profile of several hours to facilitate the participation of less flexible plants, but possibly increasing the ramps (and thus imbalances) at the margins of the blocks. This development is depicted on the vertical axis in Figure 2. The different formats of block bids used in the Central-Western European (CWE) market region have posed one of the biggest challenges for the implementation of market coupling and the clearing algorithm Euphemia.

Figure 2: Recent developments in the bidding format



The perceived conflict between the objectives of increasing temporal granularity on the one hand, while at the same time respecting for plant capacity in the bidding structure can be resolved with a multi-part bid format. Market participants here submit bids reflecting not only marginal generation costs (or value of load for demand), but also inter-temporal constraints including minimum output levels, feasible ramping rates as well as start-up costs (Reguant, 2014). Thus countries like Spain or Poland, but also many US states ensures that the auction clearing produces a feasible generation schedule that can be balanced on short-term (e.g. 5 minute) intervals. This can also avoid the challenge of paradoxically rejected block-bids. However, experience in the US with multi-part bids shows that the allocation of start-up costs needs to be equally carefully considered.

Procurement of reserve and response products

TSOs contract different reserve and response products to balance the system in real time. The Target Model has envisaged so far the definition of common reserve products and procurement rules. Reserves can be shared by TSOs based on algorithms for the transfer of balancing capacity and activation optimization. The joint procurement of minute reserve by the four TSOs within Germany alone results in annual savings of 870 Mio Euro (Haucap et al. 2014).

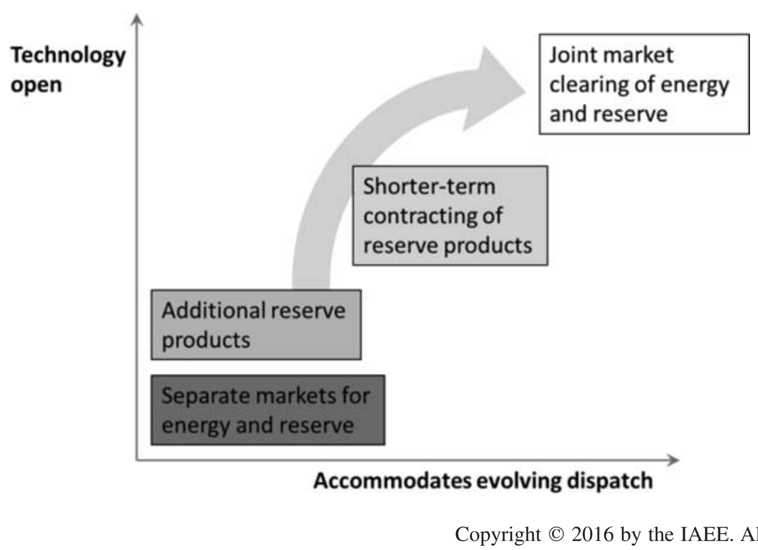
This pooling of reserves offers efficiency gains, but raises the question of whether the standardization of products has been implemented based on a suitable procedure. Otherwise the standardization might risk further progress towards openness for new technologies and shorter-term adjustment of reserve requirements and contracting, let alone joint optimization across energy and reserve.

Technology open: Reserves have historically been defined according to the response speed and capability of conventional generation assets to sustain additional production. With new generation technologies and demand options, the definition of reserve products needs to adjust to allow for their participation. This raises the question of whether the appropriate reserve products have been defined, or even if it is suitable to separately define and trade reserve products. If energy and reserve markets clear jointly, then reserves can be contracted more flexibly.

Accommodating evolving dispatch: With increasing shares of intermittent renewables on the system, the maximum volume of reserve required for a certain hour depends, for example, on the share of wind generation operating at a wind speed close to 25 m/s and thus close to potential shut-off. Increasingly, TSOs are adjusting the volume of reserves contracted to the specific needs. An additional reason motivates shorter-term contracting of reserves: The production of intermittent sources and therefore also the operation of conventional generation assets that "fill the gaps" cannot be predicted on the time frames (weeks and month) on which reserve had been traditionally contracted.

As illustrated in Figure 3, the increasing interaction between energy and reserves markets indicates the efficiency improvements that can flow from a joint market clearing of the coupled energy and reserve products.

Figure 3: Energy and reserve markets

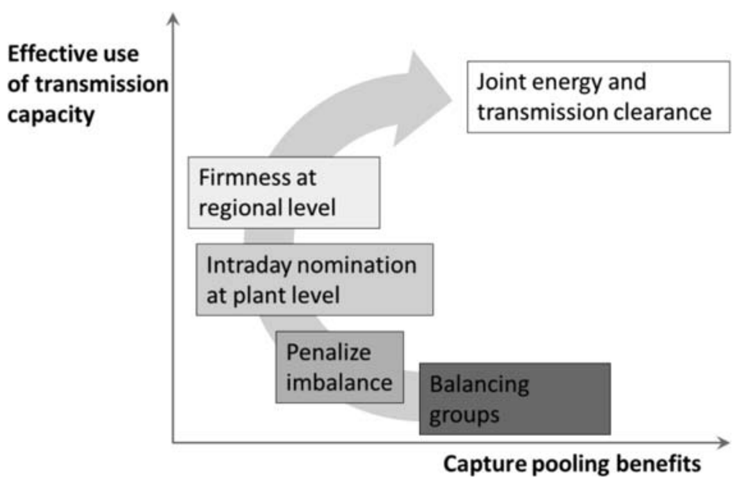


The role of balancing groups

Several European countries have implemented the concept of balancing groups. Deviations by individual plants can be compensated by other plants within the same group. However, as TSOs have no visibility of reserve and response provision within balancing groups they continue to acquire at all times reserve and response to avoid the risk of potential imbalances. Thus, synergies of the system-wide pooling effect are lost with the balancing group. Figure 4 depicts selected balancing principles and how they are able to capture pooling benefits.

Penalties for imbalances encourage excessive adjustments at the intraday stage and thus increase overall costs (Henriot, 2014). Balancing groups that are in imbalance are exposed to explicit imbalance penalties in some countries, and face implicit penalties in all countries. Implicit penalties arise because the concept of balancing groups encourages balancing within groups and thus limits the liquidity of the balancing (real-time) market, increasing the spreads and costs of imbalance. The concept also allows large market participants to leverage the benefits of their generation portfolio: The larger the portfolio, the more imbalances within the portfolio will be canceled by the pooling effect or can be balanced or compensated by operational decisions. Consequently, imbalance volumes and costs as share of total sales revenue are smaller for large firms providing some competitive advantage. The structure of imbalance tariffs can partially attempt to compensate for this effect. Ultimately, small firms either have to contract with large firms or with other aggregators to reduce their imbalances – creating market opportunities for incumbents and traders.

Figure 4: Balancing groups



The philosophy of balancing groups assumes unlimited transmission capacity within a pricing zone so as to allow for any changes in production or demand to be balanced at any physical location in the zone. In practice, transmission capacity within each pricing zone is limited, and hence the German regulator, for instance, has in 2014 introduced the requirement that market participants nominate their generation and load schedules for each location at day-ahead stage and inform the TSO about any intraday changes. This is a first step towards redesigning the concept of balancing groups. An even more far-reaching solution has been implemented in Belgium, where a color coding system is used to coordinate re-nominations at intraday stage in response to internal transmission congestion.

If transmission capacity is limited, then pooling within balancing groups is no longer possible in the entire pricing zone, but only in smaller geographical areas. This increases the value of sharing flexibility beyond the balancing group with other generation and load in the smaller geographical area, and thus the value of an effective short-term and real-time market.

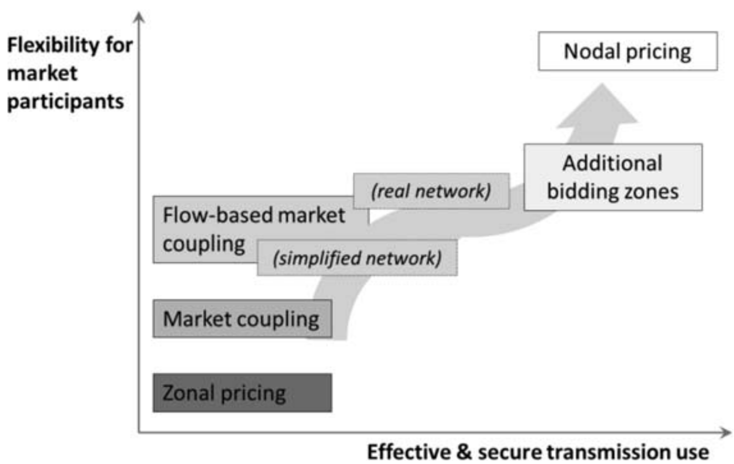
Effective use of transmission capacity

The European transmission grid exhibited only limited constraints within countries as long as the generation mix had not changed. Therefore, the market design often abstracted from any transmission constraints (zonal pricing in Figure 5). While in theory optimal electricity pricing over space and time needs to take account of all transmission constraints (Bohn, Caramanis and Schweppe, 1984), in Europe pricing zones sometimes cover part of a country (Italy, Norway, Sweden, Finland), sometimes several countries (Germany and Austria) but in most cases are defined by the geographical boundaries of a country.

Flexibility for market participants: Crucially, trade between European pricing zones required access to transmission capacity that was initially grandfathered to incumbents, then allocated on first-come-first-serve basis and eventually auctioned as physical transmission capacity to market participants.

The separate clearance of transmission and energy markets, however, reduced the effectiveness of transmission use. Therefore, the majority of EU day-ahead markets are coupled with implicit auctions that jointly allocate transmission and clear energy markets. In a next step, flow-based market coupling is being currently implemented. This approach creates additional flexibility for the utilization of transmission capacity – to be allocated to transactions between countries/pricing zones where it offers the highest value. TSOs, however, struggle to provide robust information on the transmission capacity that can be made available for flow-based market coupling between pricing zones, as they have to provide this information before the day-ahead market clears and, therefore, at a time when the generation pattern within pricing zones is still uncertain, not least because it is a function of day-ahead market clearing.

Figure 5: Spatial dimension



Effective & secure transmission use: This has triggered additional interest revisiting the question of the geographical definition of pricing zones (see e.g. Breuer and Moser, 2014; Burstedde, 2012). Smaller pricing zones offer two benefits: First, they reduce the likelihood of transmission constraints occurring within a zone and thus the need for reserving transmission capacity between zones and the need for redispatch. Second, they reduce the uncertainty about generation and load patterns within a zone, and thus allow for more accurate grid modelling (generation shift keys become less volatile). Thus transmission capacity can be used more effectively and the system can be operated more securely. Without a detailed understanding of the location of load and generation, the TSO otherwise has to provide for very uncertain outcomes of flow patterns, resulting typically in a combination of higher security margins and higher risks of exceeding the security margins.

It is often incorrectly argued that with smaller pricing zones also the liquidity is declining. Just the opposite, as long as markets are coupled through implicit auctions, at any time at which transmission capacity is not fully utilized, the market clearing price remains responsive to demand and supply in all coupled pricing zones. With flow-based transmission allocation, even at times of transmission constraints the allocation of transmission capacity to the most valuable use implies that markets remain coupled and mutually responsive. In consequence, the liquidity is maximized, however, restricted only to the feasible transaction. For the same reasons, smaller pricing zones do not lead to increasing the issue of market power if applied both to energy and reserve products.

Creating additional (smaller) pricing zones to allow for more effective and secure transmission implies that also trade between zones (relative to trade within a zone) will increase. Such trade requires transmission contracts to hedge for price risk. While currently transmission contracts are only issued for one year in advance, there are good reasons to expand this period. Hence, it might be considered to directly shift to a high-level zonal resolution, e.g. nodal pricing. In the Californian market for instance, a change from zonal to nodal pricing in 2009 resulted in a more efficient operation of flexible peaking plants (Wolak, 2011). Experience in the US has furthermore shown that liquidity of forward markets matches the most liquid European market (Germany) and transmission risk can be effectively hedged with transmission contracts that can be implemented for long periods.

A key element for progress across these different elements are auctions, which have already become prominent at day-ahead stage and are now being discussed for the intraday and real-time (balancing) market. Such auctions can allow for the use of multi-part bids, thus create depth and liquidity for subsequent system wide (rather than balancing group) pooling of reserves. Auctions can then also facilitate joint acquisition of energy and reserves. Finally, intraday and real-time auctions can allow for the implicit allocation of transmission capacity between pricing zones (or nodes), and are thus the basis for effective and secure transmission use. The price emerging from intraday or real-time auction platforms can then create an additional reference point for financial contracts to the day-ahead market, and thus allow flexible resources to offer option contracts to capture the value of their flexibility.

Progress on implementing the Target Model with flow-based day-ahead market coupling and subsequent continuous intraday trade across the entire pricing zone was largest in Central Western European countries with abandoned flexibility from dispatchable generation and largely unconstrained internal transmission capacity. In contrast, countries like Spain, Italy, Poland or Ireland with scarce transmission or limited generation flexibility have not been able to facilitate a pure zonal market model. Their TSOs would struggle to balance the system and resolve transmission constraints in the short period left after gate closure, for example because internal transmission constraints and therefore redispatch needs are more severe, or because less flexible generation capacity is available to provide the suitable response (decision to start up thermal units is needed 6 to 8 hours ahead). Instead, these countries have developed different types of solutions based on centralized auction platforms or coordination mechanisms for intraday adjustments that can reflect transmission constraints, ramping constraints and reserve requirements (Chaves-Ávila and Fernandes, 2015; Sikorski, 2011).

4. INTERACTIONS WITH POLICY FRAMEWORK FOR (RE-)INVESTMENTS

The design of short-term markets will not only determine efficient operation, but also impacts revenue streams and provides reference points for financial hedges that will determine investment decisions. In what follows we explore the opportunities of well-designed short-term markets for hedging strategies for conventional assets and flexibility options, and for renewable energy.

Mid-term (re-)investment framework for conventional assets and flexibility: Maintaining generation adequacy with a generation technology mix that is compatible with security of supply and environmental and flexibility requirements of the evolving power system is of central concern for policy makers. For conventional assets this – for the next decade – will largely be a question about (re-)investment and closure choices, but may in some markets also involve investment in additional plants. Past investments in liberalized power markets illustrate the value of mid-term forward contracting (i.e. more than 1 year ahead). Means of risk mitigation in the electricity market traditionally are vertical integration and forward contracting (Aïd et al., 2011). In the past, investors in generation assets were willing to undertake investments based on forward contracts and a vertically integrated retail customer basis with small switching rates of retail customers. Forward contracts are equally important for demand side response and for enhancing flexibility through interfaces with industry, heat and transportation, as contracts can translate uncertain revenues from occasional periods of peaking prices into more stable revenue streams.

Incentives to sign forward contracts, however, differ by types of agents. The demand side is interested in signing contracts to stabilize fuel costs and to avoid volatility in household or public expenditure or firm profitability, as well as to secure (re-)investment choices in energy-intensive industries (Bessembinder, 1991). Generation is interested in and relies upon signing mid-term contracts to hedge price volatility. Forward contracting volumes and durations, yet, differ across the EU (Eurelectric, 2010), reflecting variations in market structure, consumer preferences and regulation. In addition, retail competition is usually based on provisions allowing retail consumers to switch suppliers on short notice. As a result, retail companies face inherent uncertainties about their customer base, and will thus not be in a position to sign many contracts for a duration beyond the contract duration with their customers (Neuhoff and de Vries 2004).

In addition to stabilizing revenue streams for individual power stations, forward contracts can reduce the risk of regulatory intervention in response to high spot prices during scarcity periods. If consumers are directly – or through their supplier – covered by mid-term contracts, then the total electricity bill will not increase during periods of high spot prices and thus pressure on regulators to intervene is limited, while incentives for adjustments to demand and production are preserved. Furthermore, forward contracts contribute to a more predictable market outcome by providing price signals and longer visibility.

For multiple reasons the current market design does not yet fully remunerate all assets for the value they provide to the system.[1] This needs to be corrected to provide appropriate (re-)investment signals. In particular, regulators and system operators like to avoid disconnecting loads. Thus, in situations with scarce generation capacity, operational or transmission reserve margins may be reduced so as to meet demand. Any reduction of operational reserve margins, however, comes at a cost for system security that should be priced to the market. Therefore, several US power markets have now implemented "operational reserve demand curves" so as to reflect the full system costs in short-term prices (Hogan, 2012). As a result, power prices are now more frequently in the

1. Demand side often can offer flexibility on other time frames than primary, secondary and tertiary reserves, and hence cannot bid its full flexibility in these categories.

range of hundreds of dollars per MWh, a price level easily acceptable for consumers while creating suitable incentives for demand side response and contributing to fixed-cost recovery for generation.

As the share of intermittent renewable energy is increasing, so is the value of flexibility (Schill, 2014). An increasing value is anticipated for flexibility that can accommodate for variations between day and night, or even for spells of low production and high demand during a cold winter week (Bertsch et al. 2015). A largely US-based survey by Fenrick et al. (2014) finds that time-varying programs can lead to a reduction of 16% to 34% of peak demand, with the high response linked to a combination of in-home displays and smart thermostats (air conditioning etc.). Di Cosmo et al. (2014), however, estimate only 5% reduction potential for Irish households. Larger-scale and industrial consumers offer substantial remaining economic potentials (Ecofys 2014). Further potentials are e.g. linked to interactions with the heating/cooling sector and e-mobility. However, to date power markets may not provide access to or not fully remunerate the value of demand side flexibility, for example because of bid formats in reserve and response tailored for the capabilities of generation assets (Ruester et al., 2013).

European Member States are at different stages of debating, advancing the implementation, and abandoning comprehensive capacity mechanisms. As the share of intermittent renewables and flexibility options changes, so does their capacity value for the system. For comprehensive capacity mechanisms, therefore, regulators have to define und update capacity values for different technologies. This creates regulatory uncertainty for new flexibility technologies and business models as much as for overall scarcity in the regulated capacity market and thus revenues to be expected by conventional assets. Limited coordination of capacity mechanisms proposed by individual EU Member States can result in further distortions and uncertainties (Meyera and Goreb, 2015). Hence, countries like the UK aim to offer long-term contracts to reduce regulatory risk. However, this constitutes a difficult regulatory and inherently political decision based on uncertain and asymmetric information on flexibility and storage provision, asset quality and operational costs. Hence, several countries like Germany have abandoned the idea of using a comprehensive capacity mechanism (Federal Ministry 2015). As alternative, certain countries like Belgium, Germany, Poland and Sweden use strategic reserves to re-assure policy makers about available generation capacity and reduce market participants' concerns about interventions in the case of shortage (Neuhoff et al., 2015).

Long-term contracting opportunities for renewable energy: In principle, generators and consumers benefit from long-term contracts as they allow generators (consumers) to avoid low (high) wholesale prices. Such long-term contracts would reduce financing costs for investors and thus at the same time also lower electricity costs and prices (Rathmann et al., 2011). Consumers in particular can benefit from hedging the cost of their uncertain future demand, and renewable generators from hedging their uncertain future output, neither of which are likely to exactly match. However, due to counterparty risks, mobility of households and firms, as well as EU guidelines, contracts of the necessary type and duration are unlikely to evolve without regulatory backing of different forms, such as feed-in tariffs, with tariff levels determined by the regulator or in auctions.

Fixed feed-in tariffs lock-in remuneration levels for renewable generation and are an effective hedge against volatile prices. The difference between the remuneration level and the wholesale price level (be it positive or negative) is passed on to consumers and, thus, the instrument comprises a component of the hedging portfolio of consumers, too, hedging their exposure to the spot price variance for the share of power that is provided through the feed-in tariff.

With a shift from feed-in tariff to market premium systems, some of these benefits are lost. A *fixed premium* exposes the developer to the full market risk on energy sales. Investors therefore have to find private counterparties for their energy output to provide for stable enough revenue streams. As already mentioned above, in practice, only incumbent utilities have been buying renewable energy on such contracts, arguably at unfavorable terms reflecting the risk, their monopoly position and increasingly the limited capacity of their balance sheet to back such contracts.

This motivated the development of sliding premium systems. A *sliding premium* pays to generation the difference between the envisaged remuneration level and an average wholesale power price. While a plausible theoretical concept, sliding premiums raise a set of questions about the future remuneration level to be expected that could significantly impact access to finance and increase financing costs: Does the computation of the reference price match the generation profile and timing of energy sales; how will evolving intraday market design impact revenues and costs related to balancing and system services; and how will the system evolve if new pricing zones are introduced? From the perspective of consumers, it needs to be clarified if premium systems should merely hedge investors against low power prices, or if they should equally provide a hedge to electricity consumers against high power prices.

With respect to *quota systems*, evidence on past experiences shows that countries which have deployed quota systems, such as UK and Sweden, had to provide higher remuneration levels than countries which implemented feed-in tariff schemes like Germany or Spain, but despite these higher remuneration levels usually achieved less deployment (see e.g. Ragwitz et al., 2012). This effect was often attributed to the need of project developers to sign long-term off-take contracts so as to provide sufficient revenue certainty to access finance. The only available counterparties for such contracts are incumbent utilities (Baringa, 2013).

Avoiding distortions of short-term markets is a further important design criterion for any renewable remuneration mechanism. Feed-in systems are often criticized for negative prices in spot markets. It is, however, the priority dispatch rule that contributes to negative prices. This rule has been formulated to avoid discrimination against renewable technologies by incumbents and to ensure that investors do not face undue delays in commissioning projects where institutions and regulation have not been adapted to the needs of renewables. With increasing renewable shares in the power system, the priority dispatch rule results in hours of negative prices if inflexible generators (including not only wind and solar, but also conventional resources) continue to be dispatched. Accordingly, this rule has been gradually adjusted across Europe.

The further development of the EU emissions trading scheme will determine whether renewable remuneration mechanisms can develop into effective risk hedging instruments, or whether – in the absence of a sufficient carbon price – they will retain a support component reflecting a shadow price of carbon. The large-scale deployment of renewables will only be cost-competitive against coal-fired power generation if the last bears an adequate carbon price.

5. SUMMARY AND CONCLUSIONS

In today’s EU power market, intermittent low-carbon generation and dispatchable fossil fuel based generation complement each other. The two technology groups are fundamentally different, concerning not only the relevance of upfront investment costs, but also investors’ main strategic choices and the capacity of governments to take a stronger part in those decisions. We have discussed how these differences between technology groups could be reflected in one potential power market design in a consistent manner.

First, for operational choices in the short-term, an adequate market design needs to recognize the complementary, though different nature of renewable and conventional assets. Short-term power markets need to evolve to accommodate large shares of intermittent renewable energy sources for guaranteeing system security in an efficient manner. This may involve pooling of resources over larger geographic areas in auction platforms; multi-part bids could resolve the perceived conflict between increasing temporal granularity of products, while at the same time respecting technical plant capacity in the bidding structure; and flow-based transmission allocation and smaller pricing zones can enhance efficiency in the use of transmission capacity. The European Target Model so far leaves TSO operation as a 'black box' risking secure system operation and efficient cooperation. It remains open whether common market protocols suffice to ensure secure and efficient operation of the European power system. It is likely that further refinements of market protocols and some regulatory guidance for TSOs are needed in order to avoid increasing divergence in TSO processes that already to date differ among EU power systems.

Second, debates on the financial viability of existing conventional assets as well as on the capacity to finance new conventional plants are ongoing. Equally important is the appropriate remuneration for flexibility options within the power sector and at the interface to heat, industry and transport sectors. Forward contracting can provide a mean of hedging fuel costs and stabilizing revenue streams. It allows to hedge against high price volatility, and also to protect consumers against high-price periods.

Third, the economics of wind and solar PV projects are dominated by up-front investment costs. Thus, sufficiently stable revenue streams are required for a longer-term horizon in order to allow for investments by risk-averse actors. There are tangible benefits of a differentiated treatment of wind- and solar PV investments as compared to conventional generation assets, linked to capital cost and governance. This suggests a continued role for renewable remuneration mechanism, which can play an additional role by facilitating an accelerated transition to a decarbonized economy.

While each of these aspects is often discussed individually, this article aims to contribute to the debate by demonstrating that a policy framework for the efficient short-term operation of the overall system also strengthens the investment framework. Efficient and liquid short-term markets also ensure that small and large, public and private sellers obtain the same price for produced energy, and thus avoid the need for complex provisions in renewable remuneration mechanisms. An efficient market design can also provide market prices as reference for financial contracts that reflect the value of flexibility.

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