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Flexible Short-Term Power Trading: Gathering Experience in EU Countries

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Abstract

EU power market design has been focused on facilitating trading between countries and for this has defined interfaces for market participants and TSOs between countries. The operation of power systems and markets within countries was not the focus of these developments. This may have contributed to difficulties of defining or implementing a common perspective in particular on intraday and balancing approaches. This motivated us to pursue an in depth review of six European power markets to contribute to a better understanding of the common elements, differences and the physical and institutional reasons for these. With this paper we aim to present the main insights emerging from the reviews and to identify where there is a need for alignment of operational aspects and short-term trading arrangements, taking into account system requirements individual member states face in operating their power system.

Key words: Electricity trading, Power system operation, Institutional analysis

JEL: D40, D80, G24, L94

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1. INTRODUCTION

With rising shares of renewable energy (RE) the value of exchanging power intraday and in real-time increases as new information on RE generation has to be balanced vis-à-vis trades scheduled day-ahead. Equally, timely and reliable information on generation patterns becomes increasingly important for TSOs to ensure secure system operation and avoid the need for excessive reserve margins.

Regulatory effort on the integration of European national power markets has to date however mostly been spent on day-ahead markets which have been integrated through market coupling of day-ahead markets. Power trading on shorter notice such as in intraday and real-time markets is aligned to lesser extent. Progress on the XBID project from European TSOs (via ENTSO-E) and Power Exchanges (via Europex) to integrate continuous intraday trading is slow, with a implementation of a common solution envisaged for 2017.

In this article, we explore based on the country-specific short-term market designs where there is a need for alignment of operational aspects. In particular, we are interested in requirements for a consistent common approach for short-term trading arrangements that take into account system requirements individual member states may face in operating their power system.¹¹

The analysis is based on empirical evidence from case studies on different design elements in six European power markets (Spain, UK, the Netherlands, Italy, Germany and Poland)¹². For each of these markets we analyze six different short-term market elements, comprising

- i) how trades are conducted (bidding formats, bid evaluation and pricing rules)
- ii) on what platforms trading takes place (bilateral, power exchanges, with or without system operators)
- iii) who is held responsible for scheduled trades and delivery (definition of balancing responsible parties)
- iv) how system operators interact with the market to acquire energy, the capacities for instantaneous matching of trades and system security (reserve procurement)
- v) how deviations from schedules are priced , and last,
- vi) how trades and clearing prices may represent underlying network constraints (spatial price differentiation across and within EU markets).

¹¹ Weber (2010), for example, addresses whether the European electricity markets can absorb large amounts of renewable energies.

¹² Working paper versions of each country case can be found on www.diw.de/fpm.

From the analyses of all countries, we derive common elements that ensure all country-specific technical requirements (including countries with weak grids, high shares of RE, large shares of inflexible conventional generation) can be met. Such common elements allow for further European integration of market and operational protocols so as to realize system wide synergies while securing system operation.

We then discuss interdependencies between the different short-term market elements to find the requirements so as to explore opportunities where initial progress can be pursued on individual elements. This can also help to identify requirements that initial improvement steps for short-term market elements have to meet in order to facilitate subsequent institutional progress on other elements of short-term markets.

2. SIX ELEMENTS OF SHORT-TERM MARKETS AND THEIR NATIONAL DIFFERENCES

2.1. BIDDING STRUCTURE AND CLEARING PROCESS

The purpose of intraday markets is to allow market participants to optimize their portfolio of generation assets so as to reach efficient production levels of all plants vis-à-vis updated forecasts on weather conditions, availability of conventional generation and demand patterns. To facilitate this optimization process, countries have implemented different intraday market designs (for Spain see for example Chaves-Avila, J.P., and C. Fernandes, 2015). They may differ because of variations across systems in underlying technological properties (network constraints, differences in generation technologies, e.g. ramping rates and start-up cost), flexibility requirements (e.g. linked to RE shares) and market structures (e.g. to address risk of market power).

At the core of short-term optimization of asset operation close to delivery is the price formation on short-term markets and thus the bidding structure and the clearing process. Not surprisingly, given different system-specific properties, different approaches to short-term pricing mechanisms have been developed and applied in different power systems across the EU. These different mechanisms for the short-term price discovery entail choices on, first, the bidding format (e.g. various forms of multi-part bids or block bids), second, the granularity of energy products and timing of markets (frequency of bidding and market clearing), and third, the pricing rule (e.g. uniform or pay-as-bid).

BLOCK BIDS AND MULTI-PART BIDS

The bidding format may be defined in various ways. In bilateral trades the two trading partners can freely select the bidding format. For instance, a small generator may negotiate in addition to the

energy price per MWh also a delivery schedule of power in several consecutive hours that is compatible with part-load and ramping constraints of its generation asset.

Bids and offers on power exchanges (PX) in Central Western Europe have traditionally only comprised a volume and price for energy delivered in a specific hour (day-ahead). This scheme based on price-quantity bids (known as simple bids) was sufficient to allow for marginal adjustments of generation between companies that could optimize production within their internal generation portfolio. Simplicity and transparency are two strong points of using simple bids and simple auctions. The drawback is that the absence of any type of inter-temporal link among the hourly bids obliges agents to fully internalize all production costs and technical constraints in their hourly price-quantity bids; this exposes them to the risk of unfeasible or uneconomic scheduling.

In an attempt to reduce the previous risk, a block bid specifies that a bid involving production over some consecutive hours (block) may only be executed if the average price over the specified block is at least as high as the price in the block bid. Traditionally, these intervals could match daily load profiles, but with increasing shares of intermittent renewables on the system, other countries introduced smart blocks, flexible blocks or profiled blocks that allow for more flexibility to match generation capacity and demand requirements.

A second well established bid format that reduces the risk associated to simple bidding and improves efficiency of the market outcome is multi-part bidding. In Spain (Reguant, 2014), Italy (for ancillary services only), Poland (start-up costs can only be recovered in case being called for ancillary service) and Ireland multi-part bidding allows market participants to account for start-up costs, minimum load requirements, and ramping rates as part of their bid.

So far market coupling has only been integrated at day ahead stage, and thus only from this time frame experience with clearing different bid-formats can be gathered. The algorithm employed for this purpose, EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm), can incorporate simple bids, block order formats such as profiled block bids, linked block bids, flexible block bids or exclusive block bids and also the two previously mentioned multi-part bids¹³(Load gradient and Minimum Income Constraint).

Comparing block bids with multi-part bidding helps to identify for fundamental challenges for block-bids:

First, block-bids require market participants to express their flexibility in a standardized format, and thus properties of different types of demand-side flexibility cannot be fully reflected in the block bids.

¹³ In the terminology used by EUPHEMIA they are referred to as “complex bids”.

Second, the types and parametrization of block-bids differ across member states (number of hours covered, number of conditionalities formulated, flexibility of when during the day called etc.). The failure to align these bid formats has created a major challenge for market coupling at day-ahead in the EUPHEMIA project.

Third, startup-costs cannot be represented explicitly in most block bids and hence need to be included in mark-ups of the bids. This reduces the efficiency of the market outcome, increases transaction costs, can discriminate against less informed (smaller) participants, and increases uncertainty for market participants. In this vein, Cramton (2003) argues that poor market design has oftentimes arisen in regulatory attempts to oversimplify problem, for instance by using single-part bids. O'Neill et al. (2007) to this end propose a multi-part discriminatory pricing mechanism. Martin et al. (2014) propose another solution algorithm.

In contrast, multi-part bidding allows all market participants to formulate their flexibility offer with a precise representation of actual technological capabilities. Experience across all liberalized US markets has demonstrated the benefit reflecting physical properties into the auctions.

The flexibility needs of the system will increase with increasing shares of wind- and solar power. Thus it will also be increasingly important that all generation assets and demand can offer their full flexibility to the market and are not limited by the share of flexibility they can reflect in block bids. A further refinement of block bids may provide some improvements – but risks further differences between the designs across member states. An agreement to use multi-part bids with a set of agreed parameter choices (e.g. start-up costs, ramping rates, minimum run constraints, variable costs at different production levels) would allow for the full integration of plant or unit constraints in market coupling algorithms, and thus allow for a better integration of day-ahead, intraday, and balancing markets between countries while realizing the flexibility potentials within countries. For an overview of balancing market designs in Europe see ENTSO-E WGAS (2015).

In the US markets, market participants can choose to only submit bids specifying energy prices for hourly products, but voluntarily select to provide additional details of a multi-part bid so as to maximize the value of the flexibility they can offer. Equally one could envisage that EU member states may select to simplify the specifications of some bid components if they are considered to be not necessary to realize the flexibility of their portfolio.

The bidding formats currently implemented in European power exchanges are not sufficiently harmonized and different types of block bids cannot fully represent the technological capabilities of generators and other flexibilities. This holds for the day-ahead and the intraday markets. Multi-part bidding allows all market participants to submit both financial and technical parameters on units to the auction platform, as in balancing markets. Thus the full flexibility of all assets can be realized, and a common format facilitates market integration.

GRANULARITY OF ENERGY PRODUCTS AND TRADING INTERVALS

Traditionally power has been traded in hourly products and market participants had to align generation and load in hourly slots. However, with increasing shares of wind- and solar generation also the variations of production within hours are increasing. TSOs charge for imbalances between supply and demand measured in 15 minute intervals (Germany, Netherlands, in Italy for qualified units¹⁴), 30 minute intervals (UK) and hourly intervals (Spain, Poland, in Italy non-qualified units).

To allow market participants to balance their positions, intraday trading arrangements now also account for correspondingly higher granularity. In Germany for example EPEX is trading 15 minute products on the intraday platform. However, this higher granularity has not been translated to trading at day-ahead stage, probably reflecting two aspects. First, market coupling at day-ahead stage has been aligned on hourly products according to framework guidelines and grid codes, thus illustrating the capacity of such alignment but also the potential risk of lock-in. Second, if day ahead trading would be of shorter products, then this would limit the opportunity for conventional generation assets to provide energy and flexibility. For example a large coal plant that is operating above minimum run constraint can adjust production by, say, 300 MW in 10 minutes. If only 15 minute products are traded, then the coal plant could only offer a fraction of 300 MW into the market, as it cannot instantly adjust production volumes. For an hourly product the coal plant might offer 300 MW, and would subsequently compensate for the failure of fully match committed sales with production in the first (and last) 15 minute time slot by acquiring additional power from more flexible plants in 15 minute products.

Currently exchange based intraday trading volume in Germany exhibit a peak after market opening (in addition to the peak in the hours prior to gate closure) reflecting market participants need to align their hourly positions from the day-ahead market with 15 minute products. Such trading reduces forecast/planning errors to a potential challenge of misalignment between granularity at day-ahead

¹⁴ In the Italian electricity market, “qualified units” are represented by generating units with more than 10 MW (and not intermittent renewables) respecting some specific requirements defined in the Italian grid code. Demand and generation with less than 10 MW are classified as “not-qualified units” (see Oggioni and Lanfranconi, 2015).

and intraday trading, e.g. quarterly versus hourly products. An additional challenge is the misalignment of the granularity in the final trading period, and the period over which energy needs to be balanced. Such differences of granularity occur where in the absence of multi-part bids energy products and imbalance measurements remain coarse. Once multi-part bids allow market participants to reflect for example ramping rates, then also conventional power stations using multi-part bids can offer the full flexibility in markets that clear for 5 minute intervals, as the auction clearing algorithm will only acquire power from a power station according to a time profile that compatible with its physical capacity. Products of higher granularity also better reflect and reward the value of flexibility for the system, as the variance of the price of 5 minute products will be higher than of hourly products.

With increasing penetration of wind- and solar power, TSOs will have to require that market participants align demand and supply not only at an hourly average, but at increasingly higher granularity to reflect higher gradients of residual load. Otherwise deviations within demand and supply that could have been resolved early on with many different generation and load options have to be resolved last minute with reserve power that can only be provided by the often more expensive flexible assets.

To facilitate trading across countries, a common granularity will be important. If markets trading products of different granularity are integrated, it needs to be ensured that gaming opportunities are avoided where price differences in consecutive 5 minute products are arbitrated by trading with a country that only considers the balance across 15 minute intervals. However, if a country only offers 15 minute products, this suggests that in this country flexibility constraints on 5 minute products are not binding, and that it could in principle offer flexibility to neighboring countries if products of 5 minute timeframe could be traded.

As the share of wind and solar increases, demand and supply schedules need to be balanced in shorter time intervals, to reduce reserve requirements to balance within time intervals. To align price signals, this higher granularity is required not only in real-time, but also in intraday and possible day-ahead time frame. This increasingly will require multi-part bids to ensure efficiency of market outcomes.

PRICING RULE: PAY-AS-BID AND MARGINAL PRICING

Central to the incentives to adjust generation portfolios and demand patterns is the pricing rule. Auction based trading (e.g. power exchanges) can be based on pay-as-bid and marginal pricing, while pricing in bilateral and continuous trading is specific to each transaction and thus pay as bid.

The standard auction format for electricity trading in power exchanges day-ahead or intraday is marginal pricing (CWE, Poland, Spain, Italy and Ireland). All energy is traded at the marginal clearing price at which sufficient supply bids are available to meet demand bids (thus also referred to as uniform pricing). When the network is represented it also allows for efficient allocation and pricing of transmission capacity between pricing zones.

Auction can also be cleared according to the pay-as-bid format. Each bid is paid at the bid price, and the cheapest supply bids (and most expensive demand bids) are selected until demand matches supply. In this case the margin between high demand and low supply bids remains with the auction platform and may be redistributed, for example by lowering transmission tariffs.

In continuous trading arrangements hosted on exchange platforms, outstanding bids and offers are matched on a first-come-first-serve basis. Thus market clearing is also pay-as-bid including some first-come-first-serve rule. When the market is not liquid enough, this mechanism may not ensure the maximization of the social welfare.

Continuous over the counter trading (OTC also referred to as bilateral trading) allows participants to reflect power plant or individual unit technical constraints like ramping rates that are difficult to reflect in exchange based continuous trading. Both in continuous exchange based and OTC trading, cross border transmission capacity is allocated on first-come-first serve basis, thus transferring scarcity rents to traders (or robots that are trading quicker) rather than to capture these rents to finance transmission investments. In a flow-based approach, the first-come-first serve approach also cannot ensure that transmission capacity is used to serve the highest value for the system.

Procurement of system services is pursued in some countries based on marginal pricing and in other countries based on pay-as-bid. Also, some countries combine both clearing algorithms depending on the particular market. For example in Italy the day-ahead and intraday market clears according to marginal pricing, whereas the ancillary services and the balancing markets run by Terna clear pay-as-bid (Oggioni and Lanfranconi, 2015). In the Dutch market the capacity auctions for all reserve products are settled using pay-as-bid prices.

The challenge for an integration of European energy markets relies in the very different bidding strategy that market participants have to select according to the market clearing algorithm. In competitive markets with marginal pricing the profit maximizing bidding strategy is to bid variable costs. Thus in all instances with market clearing prices above variable costs the market participant will be selected and can capture the margin between the market clearing price and variable costs to recover fixed costs. In contrast, if a market participant would bid the variable cost into a pay-as-bid mechanism, then she would never recover more than variable costs. Thus pay-as-bid mechanisms require participants to mark-up bids so as to maximize the product of likelihood of participation and

mark-up recovered. If all generation assets have the same variable cost, then according to the revenue equivalence theorem the same revenue is obtained as in a marginal price auction. However, as if generation units are not symmetric but have different variable costs this creates the inherent risk of inefficient production choices in pay-as-bid auctions, as not the units with the least cost but the units with the lowest bids are selected.

Pricing rules vary between pay-as-bid and marginal pricing within countries and across Europe. As pricing rules determine the bidding strategy, harmonization is necessary for further integration of markets. Marginal pricing improves efficiency of outcomes and allows for market based transmission allocation.

2.2. INTRADAY TRADING ARRANGEMENTS (BILATERAL / PX PLATFORM / TSO)

Different trading platforms can facilitate continuous and auction based trading. In this section we discuss whether intraday transactions are traded bilaterally, via exchanges, or auctions executed by the TSO.

Bilateral intraday trading directly between market participants is inherently continuous and particularly strong in the UK and the Netherlands, likely reflecting the strong presence of brokers facilitating such transactions and the challenge for conventional generation assets to offer flexibility for 15 minute time slots. Also in Germany conventional generation is largely using bilateral transactions in the intraday timeframe for large scale adjustment (e.g. power plant outages). The 15 minute products traded on the EPEX exchange are too short for significant changes of production with coal and combined cycle gas power stations and block bids are rarely used, likely because of insufficient liquidity and depth (number of open bids/offers) in continuous trading to allow for simultaneous matching of multiple bids to comply with the constraints of a block bids. However, overall trading volumes are larger in continuous trading at the EPEX than bilateral, reflecting the increasing volumes of marginal adjustments to forecasts for renewable energy production and demand.

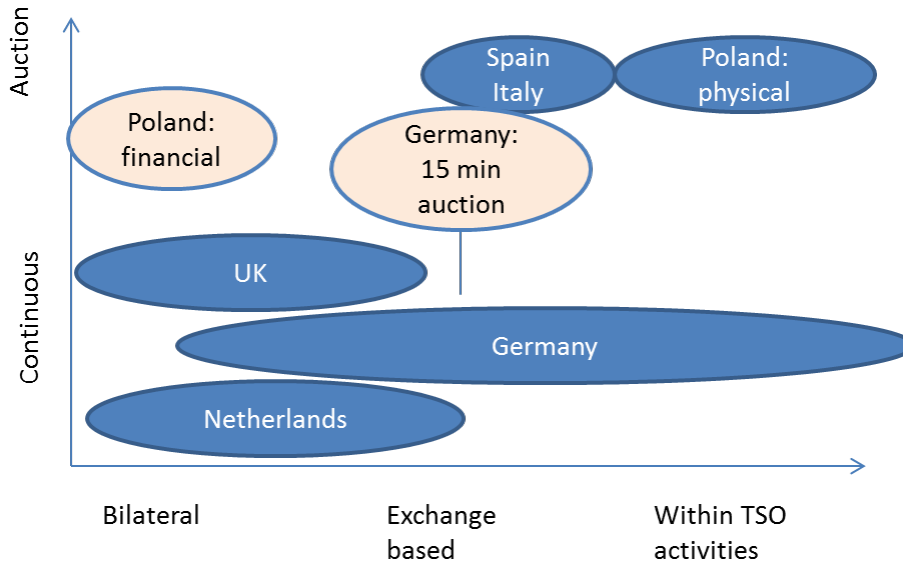


Figure 1: Intraday trading arrangements in European countries covered by case studies

Exchanges facilitate continuous anonymous trading combined with clearing services like for example EPEX or APX–Endex. They have captured the largest market share of continuous intraday trading. Exchanges in countries previously prominent for continuous intraday trading have recently introduced intraday auctions (Germany December 2014) at the opening of the intraday trading period. Exchanges can also execute intraday auctions, like in the case of Spain (OMEL). The auction results in the intraday horizon are adjusted in Spain to comply with network constraints (largely modest) informed by the SO (REE) after the day-ahead market.

In Spain and Italy all intraday transactions are auction based. In Italy where the internal transmission constraints are more prominent, the market operator GME uses the zonal representation of the network for clearance of both the day-ahead and intraday markets.¹⁵ Information on accepted bids and offers is communicated to the transmission operator Terna to update flows schedules and to calculate residual transmission capacities between zones for subsequent market sessions.

In Poland, all market participants have to nominate hourly schedules by 2:30pm day ahead and commercial contracts need to be allocated to production at individual units. From 2:30pm the TSO operates the balancing market auction for all hours of the next day, based on mandatory multi-part bids from all qualifying units (connected to high voltage grid). Thus market participants receive early information about balancing requirements allowing for access to a wide portfolio of resources. Balancing schedules are updated based on bids submitted to initial auction on 15 minute intervals to incorporate updated information until real time. Generation and load is remunerated for balancing

¹⁵Currently the Italian electricity market is split into six national geographical zones and five national virtual zones. In addition, the zonal representation accounts for other eleven zones, representing neighbouring countries, for a total of 22 zones (Oggioni and Lanfranconi, 2015 for the details on zones).

services provided, and deviations are charged for imbalances at the single system clearing price. In parallel, in Poland intraday trading and nominations are possible until gate closure (1 hour), but with very limited liquidity.

Given the increased operational challenges the question emerges which of the described approaches is best suited for the emerging European power market design. Experience suggests that both a TSO based platform (Poland) and a platform operated by a power exchange (Spain, Italy) closely integrated with system operation may be suitable. Thus solutions may emerge from some combination of TSOs, coordination platforms of TSOs (CORESO, TSC) as well as power exchanges. CORESO, TSC and power exchanges already demonstrate an increasing level of international integration and would seem to be capable of supporting an integrated operation of intraday markets at the regional or pan-European level.^{16, 17} The only constraint that needs to be considered is that hosting this auction will constitute a natural monopoly position that requires regulatory oversight, and should thus be institutionally separated from competitive elements of longer-term trading arrangements, as has now been implemented by separating EEX (derivative trading in Leipzig) and EPEX (day-ahead and intraday trading in Paris) as well as APX-Endex.

With intraday auctions constituting an important part of trading arrangements, their timing will have to be aligned to facilitate further integration of markets. In Spain, intraday auctions are held every four hours, thus offering six options to update generation assets according to information on outages and renewable and demand forecasts (Rodilla and Batlle, 2015). In Italy, since February 2015, five intraday auction sessions exist, with different closing time and in sequence (Oggioni and Lanfranconi, 2015).

If the structure of market coupling is to be replicated at the intraday period, combining market based allocation of 'public resources' with realizing efficiency gains from their flexible use (flow based approach), then this will require intraday auctions that are synchronized across countries. Between such coordinated auctions, it needs to be assessed to what extent countries may continue to facilitate additional continuous or auction based trading.

As intraday auctions become more important, their timing needs to be harmonized across Europe. As a close interaction with TSO is obligatory, new institutional arrangements may emerge between TSO and PX where the current cooperation platforms may serve as a basis.

¹⁶ In terms of ownership, integration of TSOs and PXs is currently moving forward. In April 2015, after the integration of the businesses of APX Group and EPEX SPOT, the three TSOs Elia, RTE and TenneT – together through the holding HGRT – own 49% of the new EPEX SPOT capital.

¹⁷ Rekk-Kema (2011) provides an overview of the current state of the European market integration.

2.3. BALANCING RESPONSIBLE PARTIES (OR GROUPS)

European countries differ in whether individual units or portfolios are responsible for imbalances. For example in Poland and in Italy units above 10 MW are responsible for deviations of production from announced schedules. In Spain, generators have to disaggregate their contract positions into schedules on a unit-by-unit basis to allow the system operator to ensure system security, but imbalances are settled for aggregated groups of generation assets.¹⁸ On the contrary, the Netherlands, UK and Germany allow for pooling of deviations from individual units. The balancing responsible party only is liable for the aggregate deviation of the portfolio.

Countries that have implemented plant level balancing responsibility usually also define de-minimis rules to provide flexibility for participants while ensuring sufficiently reliable information for the TSO. In Poland wind plants can be pooled within one of the 5 network regions (OAZW in Poland) while in Italy aggregation is possible within zones for non-qualified units, i.e. generation with capacity lower than 10 MW and load.

The variety of approaches to define and incentivize balancing responsibility in EU countries is striking – and might reflect the strong role of incumbent utilities during the liberalization process. The concept of balancing groups allowed vertically integrated utilities in Germany and the UK to continue integrated operation in their territory. However, the concept is not seen to be compatible with the system requirements with significant internal transmission constraints that can only be managed effectively if TSOs have reliable plant level information. To date experience suggests that plant level balancing responsibility offers incentives for the provision of reliable and timely plant level schedules. Without such incentives, the requirement for provision of plant-level information on generation in Germany has not resulted in reliable information.

Eventual alignment of balancing responsibility across neighboring countries at plant level can offer a set of benefits. It contributes to reliable and timely information that improves the capacity of TSOs to anticipate flow patterns, and can thus also has benefits for neighboring countries (avoiding unannounced loop flows). Overall it can (i) reduce costs for reserves (ii) increase network and generation assets utilization as reserve margins can be reduced (iii) reduce risks for system operation from unanticipated system configurations.

Finally it needs to be noted, that unit-level balancing approaches have implemented de-minimis rules on the level of aggregation for which imbalances are accounted for (e.g. generation exceeding

¹⁸ These groups are currently: Generation with Automated Generation Control owned by a market agent, Generation without Automated Generation control owned by a market agent, renewables with market based remuneration and renewables with regulated remuneration). At the time of this writing the definition of these groups is being reviewed by the system operator.

certain size). With increasing shares of distributed generation these de-minimis rules will require further refinement.

Balancing group approaches differ between the analyzed countries. Where balancing responsibility is not at unit level, it is difficult for the TSO to gain sufficient information to secure system operation.

2.4. RESERVE PROCUREMENT

Across European countries, reserves are acquired in national wide reserve procurement auctions, either separate to the day-ahead energy market or notified two days ahead about availability requirement and then called jointly with energy in day-ahead and subsequent intraday auctions (Poland).

Countries apply different rules for different reserve categories and may thus mandate different actors to procure the reserve, but may also mandate both regulated system operators and private actors to manage/procure the same reserve category in parallel. For instance in the UK and Germany, tertiary reserves are also acquired and procured at the level of individual balancing groups.

RESERVE PRICING STRUCTURE AND COST RECOVERY

In different European countries, the opportunity costs for generation staying available for reserve provision instead of participating in energy market can be recovered in four ways.

First, capacity payments may be granted (e.g. based on marginal price auctions in Spain or pay-as-bid in Italy) for assets with additional remuneration based on variable costs. Submitting tertiary reserves bids for all available tertiary energy is mandatory in Spain, Italy (for qualified units in both the secondary and the tertiary reserve) and Poland (generation connected to high voltage).

Second, assets may bid energy prices with a significant mark-up above variable costs in pay-as-bid type pricing mechanisms so as to recover fixed costs through the mark-up (UK).

Third, if market clearing algorithms are based on marginal pricing, then the margin between clearing price and variable costs provides revenues to contribute to fixed cost (Spain, Italy). This secures efficient operational choices.

Fourth, countries that have implemented balancing responsibility at portfolio level may create incentives for market participants to also hold reserves at the portfolio level. Costs of such reserve provision are then allocated to the customers through energy prices.

RESERVE PRODUCT DESIGN

Across EU countries the product design for reserves may increasingly deviate. The traditional reserve products frequency containment, frequency restoration and replacement reserves were designed to match the technical capabilities of fossil generation plants with system requirements and thus have

similar specifications across countries in the ENTSO-E regional group continental Europe. However, these three reserve product categories do not allow capturing the full value of flexibility provided by demand side or new generation technologies that may for example respond quicker and more persistent. Hence member states may develop new categories and might in the process diverge in the reserve product design.¹⁹ Furthermore, reserves that have been procured can be activated as part of a joint energy and reserve market clearing process, according to full flexibility specified in multi-part bids (Poland).

TIMING OF RESERVE PROCUREMENT

The timing of reserve procurement also differs across EU member states. In the Netherlands, secondary and tertiary reserve types are procured on a yearly base (with an ambition to shorten the time horizon), while in Italy and Spain ancillary services are procured once wholesale markets are already cleared, based on a forecast of the system state.²⁰

A further convergence of reserve procurement in European power markets will have to respect system characteristics of individual member states. Countries with high shares of wind and solar power need to allow for short-term procurement of reserves (within time horizon of wind- and solar forecast) to allow these generation assets to contribute to reserves. Countries with scarce generation capacity or flexibility in the system need to realize a large share of the reserve in the system, and will thus require mechanisms that allow for joint energy and reserve procurement and ensures efficient pooling across all reserve provision (as implemented in Poland).

APPROACHES FOR RESERVE POOLING

To allow for reserve exchange and thus realize synergies from pooling across countries, one could envisage three approaches.

First, countries, may participate in the procurement pursued within a neighboring country by the local TSO. For example TenneT NL currently procures one third of its primary reserve in Germany as part of the auction implemented by German TSOs. This requires alignment of the reserve products, suitable network conditions for flexibility to be accessible when required, and is operated as part of TSO-TSO cooperation.

Second, countries may directly invite market participants in neighboring countries to bid in their tender, like implemented by German TSOs for network reserve contracted in adjacent countries.

¹⁹ For example the use of old fossil fuel power plants with derogation due to LCP Directive for provision of restoration reserve.

²⁰ In Italy, reserves are acquired through a sophisticated algorithm, based on a nodal configuration of the network, that takes into consideration all system requirements and dynamic constraints of generation facilities. The Italian TSO, Terna, thus activates resources on the basis of the algorithm outcomes and the received bids/offers.

However, such direct contracting with neighboring generation assets needs to be accompanied by a clear understanding between the involved TSOs about the operational approach. It should also avoid creating uncertainties for generation adequacy forecasts in the respective neighboring countries if generation assets are suddenly no longer providing energy in response to national market clearing prices but respond to reserve dispatch protocols in neighboring countries.

Third, countries may procure reserves nationally, and then share the pooled reserves with neighbors. If the price at which reserves are shared is not cost recovering, then countries may attempt to free-ride on neighboring reserve provision. In the past this has been addressed through UCTE requirements on the response capacity required by each country. This third approach retains more flexibility on national definition of reserve products than the first two approaches that require alignment of the definition of reserve products, but requires instead a closer alignment on pricing of reserves provided to consumers (and neighboring TSOs).

Reserve pooling across national borders can be an important benefit of European power market integration. In order to achieve this, pricing structure, product design, and timing need to be further aligned. A closer integration of reserve procurement with short-term energy markets will allow to capture benefits of co-optimization.

2.5. IMBALANCE PRICING

We will discuss first single vs dual imbalance prices, then the allocation of reserve costs and finally options for additional penalties for imbalances.

SINGLE VS DUAL IMBALANCE PRICING

In dual pricing systems, a higher price is charged for market participants that are short of power in real time than is offered to market participants that are long in the same instance (e.g. Spain). This aims to create incentives for market participants to provide accurate schedules and nominations. However, dual imbalance pricing discriminates against smaller generation units and where companies can aggregate imbalances within a portfolio also against smaller portfolios.

In single price systems, positive and negative schedule deviations are charged the same price. The incentive for accurate positions in the case of single price systems results from increasing price volatility closer to real time, which is caused by fewer system assets that can respond on short notice. Thus companies will aim to balance their position as early as possible to reduce exposure to volatile prices. With a single imbalance price, market participants do not need to physically pool imbalances across a portfolio to reduce exposure to imbalance, but can equally address this exposure by financial hedges. Thus also the concept of a balanced responsible part is irrelevant. Financial

hedging against imbalance costs is possible with a portfolio as well as with contractual positions, irrespective of the definition of balancing responsible party at plant versus group level.

ALLOCATION OF RESERVE COSTS AND MARGINAL VERSUS AVERAGE IMBALANCE PRICING

Across European countries, reserves are procured usually day-ahead and paid for their availability. Primary and secondary reserve kept for system stability (and protected if necessary by disconnecting additional load) is allocated to transmission tariffs. The procedure for allocating costs of tertiary reserve between transmission tariffs and parties imbalance differs across countries. In addition, some countries procure reserves to address transmission constraints. Different mechanisms attempt to allocate costs of individual bids to imbalance charges and network charges (e.g. classification of accepted balancing bids in the UK and Poland).

The costs for holding and using reserves used to correct for imbalances, should in principle be allocated to parties in imbalance to ensure imbalance (or real time) energy prices reflect the full opportunity costs and thus provide appropriate incentives to balance demand and supply. However, this does not imply that the costs of paying for availability of reserves should be allocated to the imbalance of the specific hour, e.g. by spreading the availability costs for the hour across the parties that are in imbalance in this hour. Otherwise imbalance prices may be very high at times of low imbalance volumes (example Germany). Most availability costs for reserves are thus born by demand and intermittent generation that creates frequent but small scale deviations rather than large generators that may cause large imbalances that motivated the scale of reserve provision, but are only infrequent in imbalance.

A further refinement of the allocation of reserve costs is operational demand response curves. They have been implemented in some of the liberalized US power markets. Imbalance price mark ups are imposed and increase as function of the depletion of reserves. This reflects the increase in the probability of load shedding and the associated cost as less reserves are remaining. The approach has had the additional benefit of delivering more hours of high but not excessively high balancing prices, increasing incentives for demand response and generation investment.

In principle the underlying reasoning also starts to penetrate European power market debates. For example in Germany imbalance prices are linked since 2012 to the intraday price. If more than 80% of contracted reserves are activated, a penalty of 1.5 the intraday-prices charged, if a balancing group party contributes to imbalance, while in Poland TSO can introduce penalization factor to the settlement price calculation if balancing market price deviate from day ahead DA market price.

ADDITIONAL PENALTIES FOR IMBALANCES AND LEGAL OBLIGATIONS

In the Netherlands provisions for an additional incentive component to penalize imbalances in case of large imbalances exist but the incentive component is currently inactive (i.e. set at €0.00/MWh), as the system is considered to be sufficiently stable.

In Germany balancing groups receive additional incentives and are legally obliged to minimize schedule deviations and to achieve a German policy objective of encouraging reserve provision at the balancing group level and avoid arbitrage between intraday markets and imbalance/real-time markets. Whenever it can be proven that a balancing responsible party deviates intentionally from schedule they can lose the framework contract with the TSO. However, this penalty has not yet been imposed.

2.6. SPATIAL CLEARING STRUCTURE

The spatial granularity of markets differs across EU countries and timeframes of day-ahead, intraday and real-time market.

Within the UK, Germany, Spain, the Netherlands, and Poland trading at day-ahead and intraday time frame can be pursued as if transmission is unconstrained. The imbalance charges from the national balancing mechanism are also applied undifferentiated at the national level, while transmission constraint may be considered by TSOs when calling upon assets to provide reserves to meet imbalance requirements. However, the market outcome resulting from a single pricing zone may not be compatible with transmission constraints, and requires in this case the TSO to pursue redispatch measures. In the UK and Poland the TSO (NGT and PSE) can use bids from the balancing market to adjust generation and demand so as to resolve such transmission constraints (see Konstantinidis and Strbac, 2015). The limited number of generation available for redispatch and its opportunity to first create congestion and then receive remuneration for resolving this congestion (Inc-dec game)²¹ can however significantly increase costs. Hence NGT and PSE aim to contract ahead of anticipated congestion to obtain better prices.

²¹ For a description of the inc-dec game see Neuhoff et al. (2011).

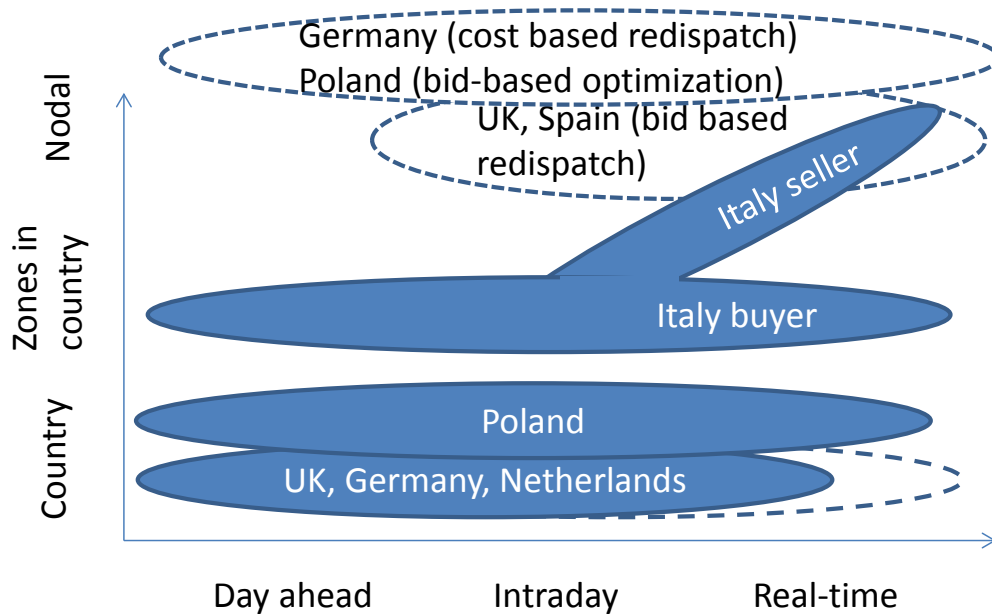


Figure 2: Spatial clearing structure of countries in different time frames (Blue energy markets, white relating to transactions to address transmission constraints)

In Germany an alternative approach was pursued. The TSOs have the mandate to request power stations to stay available for redispatch measures and to adjust their production level. The respective generators are only remunerated at variable costs. However, a recent court judgment requires that the mechanism in the future also considers the opportunity costs of not being able to participate in the energy market. Also the cost based redispatch fails to provide incentives for generation with local market power to remain available, requiring additional regulatory intervention to keep such generation on the grid.

Italy has implemented different pricing mechanisms depending on agent type and considered market. In the day-ahead market, Italian power producers are remunerated at zonal prices, while load pays a single unique price (PUN) applied at national level. In the intraday market, all market participants, both supply and load, face zonal prices. However, in order to avoid that national load may take advantage of biased arbitrage opportunities between the PUN paid in the day ahead and the zonal prices applied in the intraday market, GME always applies a non-arbitrage fee to all accepted bids/offers pertaining to consumers. Generating units that are qualified to participate to the balancing market and provide flexibility services in real time are remunerated at nodal basis.

In Poland, if the dispatch resulting from the single market clearing price of the balancing market is incompatible with network constraints, then a market clearing based on nodal representation of the network is calculated. Any adjustment this implies for qualifying generation units is remunerated based on a variable cost defined for each unit in the grid connection agreement. In addition, the TSO pursues longer-term management of constraints with contracts to secure production from power

stations required because of network topology (must run contracts). However, neither of these mechanisms is visible to participants of the energy market and does therefore not send direct locational signals, as related dispatch costs are covered by TSOs within transmission tariffs.

The European experience illustrates different approaches that countries have implemented to align the system operation with physical network requirements. Italy has implemented eleven (geographical plus virtual) pricing zones so as to internalize most transmission constraints in market clearing processes.²² Other countries expect that the TSO adjusts generation and load patterns to comply with network constraints. For this TSOs may be equipped with mandates to request redispatch from generation (cost based in Germany and based on pre-defined price in Poland). Without such mandates and therefore exposed to generation with local market power to mark-up bids, regulators have exposed TSOs to incentives to minimize redispatch costs (UK). As a result, systems that often emphasized the role of 'self-dispatch' now may comprise stronger elements of central intervention than system that have defined a common central auction platform to facilitate the integration of system constraints in markets.

Congestion management is inherently linked to the grid topology generation patterns within pricing zones. This needs to be considered in the design of congestion management. The process of moving from market coupling to flow based market coupling illustrated two requirements. First, in the absence of reliable information on generation patterns within pricing zones prior to gate closure generation shift codes that are the basis for flow calculation are not accurate. This reduces transmission capacity that can be made available for commercial use, possibly below previously available levels. Second, market clearing influences generation patterns and thus generation shift keys which in turn impact the market clearing. Thus a sequential instead of integrated congestion and energy clearing results in further inaccuracies. They translate into a combination of increased security margin and thus less efficient transmission use and increased risks linked to extreme events (e.g. wind patterns) that trigger unexpected flow patterns.

Thus information quality and reliability needs to be improved, which ultimately may require incentive compatible pricing regimes with smaller pricing zones. This will also require a shared perspective on the design and allocation of transmission contracts. Currently they are issued by TSOs only for durations up to one year, and do thus not support the duration of energy contracting of 3-4 years that market participants pursue to hedge price risks, stabilize revenue streams, and support (re-) investment choices. If the duration of transmission contracts of physical or more likely financial

²² In addition, the simplified zonal network considers the transmission limits between national zones and the eleven zones representing the foreign countries connected with the Italian market.

nature issued by TSOs are extended, then potential changes to pricing zones need to be anticipated and reflected in the design.

With increasing levels of binding network constraints, it becomes increasingly difficult, costly and risky not to internalize the constraint costs in market results. Many different approaches exist in Europe and shared experiences should lead to a harmonized approach.

3. INTERDEPENDENCIES

The different elements of a power market design discussed in the preceding section are not independent. The following table illustrates a set of dependencies we have identified that need to be considered within the process of further integration of EU power market design.

Changes to the bid format and trading arrangements are possible without adjustments to further elements. Adjustments to the balancing responsibility and pricing do however depend on the bid format and trading arrangements. In particular, uniform pricing based on multi-part bids on an auction clearance platform allows for a more granular definition of balancing responsible parties moving from balancing group to plant level responsibility. With more reliable information on plant level schedules, TSOs can also better anticipate the system requirements, thus avoiding the need for resilient provision of reserves. *In this case it suffices to pool reserves at the system level without additional privately provided reserves.*

A significant increase of the spatial granularity of pricing towards smaller pricing zones exhibits most interactions with other elements. To ensure liquidity, implicit allocation of transmission capacity is required, and this implies auction based trading (similar to market coupling in day-ahead market) to ensure sufficient liquidity. With smaller pricing zones, the inefficiencies of providing reserves at balancing group (company) level increase, hence requiring unit based imbalance responsibility with pooling of reserves at the system level.

		Progress on the each this elements ...				
... requires prior adjustments to these elements.		Bid format	Intraday Trading arrangement	Balancing responsibility and imbalance pricing	Reserve Procurement	Spatial clearance structure
	Bid format		Multi-part bid for full participation in auctions	Marginal, single clearing price for unit responsibility	Unit based bidding to enhance visibility for TSO	Multi-part bids required if all transactions hosted on auction platform
	Intraday trading arrangement	Auctions for multi-part bid clearing		Liquid auction platform required for units	If reserves are acquired with multi-part bids, auction platform required	Auction platform necessary for market coupling
	Balancing responsibility and imbalance pricing				Unit based imbalance responsibility to enhance visibility for TSO	Balancing group level reserve provision not possible within small zones
	Reserve procurement					Pooled reserve procurement necessary with small pricing zones
	Spatial clearance structure					

Table: Interdependencies of progress on common power market design

4. CONCLUSION

We find a set of common elements that may provide national benefits as well as additional synergies at the European level.

A common bid format based on multi-part bids and common auction platforms unlocks additional flexibility of all assets and realizes efficiency improvements in the system operation both within and across countries.

The pooling of reserves at national level, as well as integration of various categories of reserves under common trading and dispatching mechanism (e.g. in the balancing market), and ultimately through closer alignments of reserve procurement and use at the European scale allows for the realization of synergies at national and European level and increases system security.

The efficient use of the network within and across EU countries allows for lower cost system operation, reduces transmission expansion needs and enhances system security at risk due to lack of reliable information on generation patterns and increasing scales of short-term redispatch measures.

To realize the benefits of moving to a common market design, it will be important that every step of market improvement is compatible with the above identified system requirements of each member states. Otherwise the implementation will either result in increased system operation risks or (more likely) the efforts to pursue further integration will be blocked. If in such instances regional initiatives aim achieve further progress, then a regional solution that does not respect the system requirements faced by countries outside of the region will not be transferable. Hence all regional solutions will have to be tested for their compatibility with system requirements of other regions, if the regional initiatives are to advance European power market integration rather than segmentation.

National and regional initiatives have been in the past – and will remain in the future – an important for gathering of new experiences, and for providing blue prints for subsequent replication. The important European subsidiarity principle furthermore limits the scope of harmonized European approaches to activities that do cannot be left to member state discretion. Thus it is important to identify the elements that require common structure to realize significant European synergies.

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