TradeRES

New Markets Design & Models for 100% Renewable Power Systems

D3.3 Design of ancillary service markets and products

Challenges and recommendations for EU renewable power systems

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Executive Summary

The overall objective of the current study is to analyse the implications of the transition towards a renewable, climate-neutral power system in the EU for the demand and supply of ancillary services (AS) of this system in general and for the market design and related EU regulation of these services in particular. The study focuses predominantly on electricity balancing services ('frequency control'). However, other ancillary services – notably reactive power services ('voltage control') and system restoration services ('black start') – are, to some extent, considered as well. More specifically, the study analyses in particular (i) the current situation ('base case') of ancillary (electricity balancing) services in the EU, (ii) the future situation ('towards a 100% renewable EU power system') of these services, and (iii) the major challenges and recommendations for the main ancillary services markets in the EU in order to improve the performance of these markets in the coming years, i.e. up to 2030 and beyond.

Chapter 2 of the present report outlines the current situation ('base case') regarding ancillary services of the power system in EU countries, including a definition, classification and description of the main ancillary services and products in the EU as well as a discussion of the current market design and EU regulation regarding the provision of (one of) the most relevant ancillary services of the power system, i.e. electricity balancing services.

A major finding of Chapter 2 is that, besides similarities across EU countries, the current national electricity balancing markets are characterised by a variety of design variables with major differences regarding these variables across EU countries which may hinder to enhance the further integration and efficiency of these markets across the EU.

Subsequently, Chapter 3 analyses the major implications of the transition towards a renewable, climate-neutral electricity system in the EU for the demand and supply of electricity balancing services in the EU, including the need for the provision of new balancing services by new providers and/or new products.

More specially, Chapter 3 analyses the challenges to maintaining the system energy balance due to the phase-out of synchronous generation and the higher variability and uncertainty of VRE generation. To face these challenges, new frequency-related AS products are emerging, which complement the existing ones, such as frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR). The new emerging AS products described in this study are synchronous inertia, fast frequency response (FFR), fast post-fault active power recovery (FFAR), and ramping reserves.

The main findings of Chapter 3 are:

- The design of energy markets has a direct impact on the requirements for balancing reserves. For example, by clearing energy markets nearer to real-time and reducing their programme time unit (PTU), the market design naturally decreases the uncertainty left that needs to be faced by reserves even when the VRE share increases.

- Although current VRE inverters could lower the need for inertia through synthetic inertia and/or fast frequency response, they cannot replace real physical inertia, which is crucial for a reliable and stable operation of power systems. However, grid-forming inverters (GFC) are emerging as a future class of converters with the potential to completely replace synchronous generation.

Finally, Chapter 4 analyses the major market design challenges related to electricity balancing of current and future (more renewable) power systems in the EU, including (regulation) measures already taken and being implemented in the EU, as well as recommendations for further actions addressing the identified challenges in order to improve the performance of the (future) provision of the balancing services concerned. The major findings of this chapter are summarized in the table below.

Table ES1: Summary table of market design challenges for balancing and other ancillary services (AS), measures already taken and being implemented at EU-level, and recommendations for further action

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
1	Reserve sizing and procurement of balancing capacity are performed nationally (especially FRR, given existing FCR cooperation in Continental Europe), implying each Member State can face all imbalances independently, but increasing the required procurement of reserves and therefore lowering overall cost efficiency.	Regional sizing of reserve capacity, i.e. per system operation region, is one of the tasks of regional coordination centres (RCCs), Art. 6(7) and Art. 37 (1) j&k of Regulation (EU) No 2019/943.	Apply EU-wide sizing and procurement of balancing capacity in RCCs or EU-wide ISO. This will reduce the overall need for balancing capacity and thus lower costs, while it allows countries to face the same level of risk with less capacity since more imbalances tend to statistically cancel out over a larger area.
2	Shortage of cross-zonal network capacity in intraday and real-time timeframes limits possibilities for cross-border balancing capacity procurement/sharing. This is caused by the requirement to nominate cross zonal network capacity at the latest on a day-ahead basis. As a result, the available network capacity for the exchange of energy for intraday and balancing markets in the same direction as the day-ahead trading is largely limited to the network capacity that remains after day-ahead trading.	Reservation of cross-zonal capacity for exchange of balancing capacity on a day-ahead basis is allowed; three different methods are foreseen, amongst others the co-optimization approach (EB GL, Art. 40-42). ACER decision No 12-2020 elaborates upon the co-optimization method, i.e. comparing the actual market value of cross-zonal capacity for trading of energy in day-ahead market and exchange of balancing capacity respectively. This means simultaneous allocation of cross-zonal capacity for trading of energy in day-ahead market and exchange of balancing capacity. However, exchange of balancing capacity is a voluntary initiative between two or more TSOs (EB GL, Art. 33 (1) and 38 (1)), although TSOs need to justify if they do not exchange reserves (EB GL, Art. 60 (2.e-f)).	Require the exchange of balancing capacity among TSOs whenever this may increase economic efficiency while maintaining security of supply. Additionally, allowing for nomination of cross-zonal network capacity at a later moment than day-ahead, e.g. intraday, may further increase efficiency of co-optimization. Study whether it is possible to shift operational network security assessments to a later moment in time or repeat them in intraday and to allocate (part of) the (recalculated) cross-zonal capacity at that moment, e.g. by implementation of a rolling time horizon.
3	Separate day-ahead energy and balancing capacity markets lead to inefficient deployment of flexible resources.	Gate closure times (GCTs) of balancing capacity markets have been shortened to day-ahead, allowing for wider substitution options between provision of energy and balancing capacity by flexibility providers.	NEMOs (i.e. power exchanges) and TSOs should co-optimize energy trading and balancing capacity markets for more efficient pricing and procurement of energy and balancing capacity, and achieving higher social welfare.

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
			Co-optimization should be preferably pursued with simultaneous clearing of energy and balancing reserves markets (day-ahead, hour-ahead). The possibility of linking bids for both markets should be further analysed.
4	Possibly insufficient supply of inertia to meet demand, given the decrease of rotational conventional synchronous generators with increasing shares of variable renewables.	No approach exists yet at EU level to deal with the decline of synchronous inertia, i.e. there are no incentives in place for provision of synchronous inertia by mothballed generators as well as new inertia providers. Concerning synthetic inertia, TSOs have the right to specify in network codes that non-synchronously connected power park modules of types C and D (Nordic countries at least above 10 MW, Continental Europe at least above 50 MW) are capable of providing synthetic inertia during very fast frequency deviations, RfG NC, Art. 21 (2.a). Likewise, also an HVDC system shall be capable of providing synthetic inertia in response to frequency change, based upon results of studies undertaken by TSOs to identify if there is a need to set out minimum inertia, NC HVDC, Art. 14.	In order to enable TSOs to procure sufficient synchronous inertia, incentives can be provided to existing synchronous generators to repurpose their mothballed generators to provide inertia, but also to new inertia providers to ensure investment in grid forming converters (GFC). Once sufficient providers of synchronous inertia (GFC) are available and potential revenues are significant, TSOs could implement a market-based procurement scheme. For synthetic inertia or fast frequency response (FFR), TSOs can also opt for a market-based approach. TSOs can procure FFR jointly with other FCR products if the products are sufficiently harmonized and a similar approach to FCR sharing keys can be used (ENTSO-E, 2019b). Besides, current network code requirements (NC RfG and NC DC) may contribute to adequate levels of supply of synthetic inertia to meet demand in 2030 and beyond.
5	Lower flex provision by system participants and higher need for flex procurement in balancing energy markets using proactive TSO activation strategy.	Mixed picture. Although balancing GCT is short for aFRR and mFRR energy bids (25 minutes before real-time) and RR energy (55 minutes before real-time) bids of BSPs, the GCT for RR energy is long enough for proactive TSO activation.	Apply reactive TSO activation strategy in Continental Europe and Nordics in order to allow new Balancing Service Providers (BSPs), i.e. small generation facilities, demand response, and storages to provide balancing services at a wider scale. This includes harmonization of imbalance settlement procedures, i.e. helping the system to restore its balance should be possible for

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
		Also preconditions for reactive TSO strategy are met (EB GL, Art. 12; Regulation (EU) 2019/943, Art. 6 (13)); single imbalance price, well-functioning intraday markets, legal ability for Balancing Responsible Parties (BRPs) to respond to the price signal, and a timely publication of the system imbalance and its price (Hirth and Ziegenhagen, 2015; FSR, 2020). Art. 44 (1)(c) of the EB GL explicitly allows for non-harmonisation of other aspects, such as the incentives to BRPs to restore the system balance. Both proactive and reactive TSO activation strategies are thus allowed by EB & SO GLs.	BRPs in all Member States, decreasing the need for TSO activation of balancing resources and thus allowing for more efficient balancing energy markets subject to operational security limits.
6	Insufficient possibilities for supply of balancing energy (and capacity) by new BSPs (small generation facilities, demand response, storages) with constraints such as fixed energy constraints and/or load recovery effects.	In light of coupled heat- or process-driven production or demand, some BSPs are not willing to bind themselves contractually ahead of gate opening of balancing energy markets. Therefore, not requiring BSPs to close a contract for balancing capacity with a TSO before participating in balancing energy markets makes available a larger part of flexibility potential to the electricity system. This is already accounted for in legislation; Art. 16 (5) of EB GL provides the right to any BSP to provide balancing energy bids after passing the prequalification process. This is also known as the possibility of free bids. Art 16 (6) prohibits the predetermination of the price of balancing energy bids in a contract for balancing capacity. Free bids are already in place in some EU Member States for aFRR and many EU member states for mFRR. All EU Member States are required to allow for free bids of standard balancing products.	Once sufficient balancing energy providers are available this could potentially decrease the need for balancing capacity procurement well ahead of real-time by TSOs while maintaining the same level of operational security. Possibilities for flex provision by new BSPs could be further increased by procurement of aFRR and mFRR balancing capacity for shorter periods than days e.g. per block of 4 hours (cf. FCR) or even shorter time periods (1 hour).

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
7	High opportunity cost for VRE to participate in ancillary services markets due to production subsidies.	No RES production subsidies are allowed if prices are negative (EC (2014), point 124)), but Member States seem to have some discretion to limit applicability of this legislative measure to a consecutive number of hours.	In order to prevent that production subsidies for RES distort efficient system operation in general and participation in ancillary services markets in particular, several policy options can be pursued: 1) Strengthen requirement to one single hour rather than allowing for subsidies for consecutive hours with negative prices. 2) Changing production subsidies from energy to capacity-based. 3) Phasing out subsidies for new wind and PV installations given decreasing technology costs and sufficient revenue perspectives. Potential effects of these options on ramping, deterministic frequency deviations and voltage issues seem limited and manageable but should be monitored by TSOs.
8	Need for provision of downward balancing services by VRE given higher opportunity costs of thermal plants to provide downward balancing services during hours with high renewable energy production.	Asymmetric provision of FRR and RR obliged by EB GL, Art. 32 (3). Symmetric procurement of FCR is not yet addressed.	Study existing approaches for asymmetric provision of FCR in Belgium, Denmark, Greece and Norway, and consider to roll-out such an approach across whole EU.
9	Need for smaller bid sizes i.e. minimum bid volumes to allow for the effective participation of demand-side response, energy storage and small-scale renewables (DER) in balancing markets	For aFRR and mFRR, a minimum quantity of 1 MW for a standard balancing energy product is prescribed in Art. 7 of the implementation frameworks for both platforms (see ACER Decisions 02-2020 and 03-2020), based upon Articles 21 and 20 of GL EB, respectively. This requirement has to be fulfilled by 1 January 2022. For day-ahead and intraday markets minimum bid sizes of 500 kW or less are prescribed in Regulation (EU) 2019/943, Art. 8 (3).	It is questionable whether reduction of minimum bid sizes of balancing energy products to 500 kW has added value, since at some point the benefits from provision of balancing services will no longer outweigh the transaction costs involved (e.g. prequalification, data communication and trading costs). Therefore, in practice, further lowering bid sizes may not increase participation of DER in balancing markets. Rather, aggregation of resources until 1 MW may be preferred and sufficient.

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
10	Need for stronger coordination between TSOs and DSOs to allow all potential system users to provide ancillary services, including DER, without endangering network operational security.	Current EU rules for TSO-DSO coordination seem limited to generic provisions about TSO-DSO information exchange and cooperation in delivery of active power reserves. Furthermore, the DSO has the right to limit the provision of balancing services by DER for technical reasons such as its geographical location.	Additional rules are needed to secure that distribution networks are managed in an intelligent way such that the use of DER resources for solving distribution problems is optimized and the capability of DER to provide balancing services to TSOs is not unduly restricted.

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List of Abbreviations

AC	Alternating Current
ACE	Area Control Error
ACER	Agency for Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserves
AS	Ancillary Services
AVR	Automatic Voltage Regulator
BC	Balancing Capacity
BE	Balancing Energy
BM	Balancing Market
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CCR	Capacity Calculation Region
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
DAM	Day-ahead Market
DC	Direct Current
DER	Distributed Energy Resources
DSO	Distributed System Operator
DSR	Demand Side Response
EB GL	Electricity Balancing Guideline
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ERCOT	Electric Reliability Council of Texas
EU	European Union
EV	Electric Vehicle
EXPLORE	European X-Border Project for Long Term Real-Time Balancing Electricity Market Design
FACTS	Flexible AC Transmission Systems
FAT	Full Activation Time
FCR	Frequency Containment Reserve
FFAR	Fast Post-Fault Active Power Recovery
FFR	Fast Frequency Response
FRR	Frequency Restoration Reserve
GCT	Gate Closure Time
GFC	Grid Forming Converter

HVDC	High Voltage Direct Current
IBVRE	Inverter-Based VRE
IDM	Intraday Market
ISO	Independent System Operator
ISP	Imbalance Settlement Period
IT	Information Technology
LFDD	Low Frequency Demand Disconnection
mFRR	manual Frequency Restoration Reserves
MW	Mega Watt
NC DC	Network Code Demand Connection
NC RfG	Network Code Requirements for Generators
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operators
PGM	Power Generating Modules
PICASSO	Platform for The International Coordination of Automated Frequency Restoration and Stable System Operation
PPM	Power Park Modules
PTU	Programme Time Unit
PV	Photovoltaic
RCC	Regional Calculation Centre
RES	Renewable Energy Sources
RoCoF	Rate of Change of System Frequency
RR	Restoration Reserves
SEE	South East Europe
SIR	Synchronous Inertial Response
SIRF	Synchronous Inertial Response Factor
SO	System Operator
SO GL	System Operation Guideline
SOR	System Operation Regions
STATCOM	Static VAR Compensator
SVC	Static VAR Compensator
TERRE	Trans European Replacement Reserves Exchange
TOR	Tertiary Operation Reserves
TSO	Transmission System Operator
VPP	Virtual Power Plant
VRE	Variable Renewable Energy

1. Introduction

Background

The transition toward a renewable, climate-neutral electricity system in the EU has most likely significant implications for the demand and supply of ancillary services of this system, notably for vital ancillary services to ensure the security and stability of the EU power system such as electricity balancing ('frequency control') services or reactive power ('voltage control') services.

More specifically, this transition implies both a (nearly) full decarbonisation of the EU power system – including a shift from fossil-based generation to electricity production based on variable renewable energy (VRE) such as sun and wind – as well as a (further) decentralisation of this system, i.e. a shift from centralised power generation units such as coal or gas plants to distributed energy sources (DERs), including local, small-scale electricity generation, storage and demand response.

In addition, the transition towards an EU, climate-neutral energy system as a whole implies, in general, a higher level of electrification of this system, including a higher level of (more variable) electricity demand and, hence, a need for a higher level of electricity supply, largely from (distributed) VRE sources.

All these transition-related changes do not only affect the level (or volume) of demand and supply of ancillary services of the EU power system, notably of electricity balancing services, but also the structure of this demand and supply, including the need to meet the demand for these services by new (distributed) providers and/or new products.

In the EU, certain ancillary services – particularly electricity balancing – are, to some extent, traded on markets for these services, subject to national and, particularly, EU regulation. This raises the question whether the current design of these markets – including the related EU regulation in particular – is still adequate to match the (future) demand and supply of these services in a cost-effective or social optimal way, or whether certain adjustments in market design and EU regulation are desired, or even needed, in order to improve the performance of the ancillary services markets concerned.

Objective (scope/focus)

Against the background outlined above, the overall objective of the current study is to analyse the implications of the transition towards a renewable, climate-neutral power system in the EU for the demand and supply of ancillary services of this system in general and for the market design and related EU regulation of these services in particular. The study focuses on electricity balancing services ('frequency control'), although other ancillary services – notably reactive power services ('voltage control') and system restoration services ('black start') – are, to some extent, considered as well. More specifically, the study analyses in particular (i) the current situation ('base case') of ancillary (electricity balancing) services in the EU, (ii) the future situation ('towards a 100% renewable EU power system') of these services, and (iii) the major challenges and recommendations for the main ancillary services markets in the EU in order to improve the performance of these markets in the coming years, i.e. up to 2030 and beyond.

Structure

The current report is structured as follows. Chapter 2 outlines the current situation ('base case') regarding ancillary services of the power system in EU countries, including a definition, classification and description of the main ancillary services and products in the EU as well as a discussion of the current market design and EU regulation regarding the provision of (one of) the most relevant ancillary services of the power system, i.e. electricity balancing services.

Subsequently, Chapter 3 analyses the major implications of the transition towards a renewable, climate-neutral electricity system in the EU for the demand and supply of electricity balancing services in the EU, including the need for the provision of new balancing services by new providers and/or new products.

Next, Chapter 4 analyses the major market design challenges related to electricity balancing of current and future (more renewable) power systems in the EU, including (regulation) measures already taken and being implemented in the EU, as well as recommendations for further actions addressing the identified challenges in order to improve the performance of the (future) provision of the balancing services concerned.

Finally, Chapter 5 provides a summary of the major findings of the current study.

2. Current situation ('base case')

This chapter outlines the current situation ('base case') regarding ancillary services in EU power systems, focussing in particular on electricity balancing services ('frequency control'). First, Section 2.1 considers some definitions and classifications of ancillary services. Subsequently, Section 2.2 provides a brief description of the main ancillary services and products considered in this study. Finally, Section 2.3 discusses the current market design and related EU regulation regarding electricity balancing.

2.1 Definition and classification of ancillary services

In the literature (including EU regulation), there is a variety of definitions, classifications and terminology used regarding ancillary services in (EU) power systems. For instance, in Kaushal and Van Hertem (2019), ancillary services are defined as "*The functions or services needed by a TSO to guarantee power system security (reliable and secure power system operation)*". Subsequently, they categorise and discuss ancillary services according to the following six capabilities: (i) loss compensation, (ii) frequency control, (iii) black start, (iv) voltage or reactive power control, (v) oscillation damping, and (vi) congestion management.

In EU Directive 2019/944, Art. 2 (48), an 'ancillary service' refers to "*a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management*".[1] In addition, in Art. 2 (49), a 'non-frequency ancillary service' refers to "*a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability*" (EC, 2019b).

More recently, EnergyNautics (2021) – following Wikipedia (2021) – has defined ancillary services as "*the services necessary to support the transmission of electric power from generators to consumers given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system*". Divergent from Wikipedia (2021), however, EnergyNautics (2021) classifies and discusses ancillary services by means of three main categories, i.e. (i) frequency control, (ii) voltage control, and (iii) system restoration ('black start').

In this report, we define ancillary services simply as 'those services required to ensure the reliable and secure operation of the power system' (so, in line with EU Directive 2019/944, including both the transmission and distribution power system). Following EnergyNautics

[1] In practice, there is often a strong interaction between congestion management and ancillary services, notably between redispatching and electricity balancing (Poplavskaya et al., 2020). In this study, however, we do not consider congestion management in general or the link between redispatching and electricity balancing in particular as we see these topics outside the scope and focus of this study.

(2021), we distinguish between three main categories of ancillary services, as mentioned above, i.e. (i) frequency control, (ii) voltage control, and (iii) black start (explained and discussed further in Section 2.2 below). In general, however, this report focuses largely on frequency control ('energy balancing') services, notably at the transmission level, as these services seem to be the most relevant in terms of market volumes and ensuring security of supply and, therefore, most interesting from the TradeRES project perspective, i.e., from the perspective of analysing market design options at the EU power system level [2]

2.2 Main ancillary services and products

This section provides a brief description of the main ancillary services and products in EU power systems. As indicated in the previous section, these services include in particular:

- Energy balancing services ('frequency control');
- Reactive power services ('voltage control');
- System restoration services ('black start').

2.2.1. Frequency control: balancing reserves

In order to ensure a safe and secure operation of the power system, the frequency of the system needs to be controlled and maintained at a stable nominal operating level (i.e., in Europe at 50 Hertz). System imbalances between power demand and supply may result in small but serious frequency deviations, thereby threatening the stability and security of the power system. Therefore, besides inertia response inherent to the system (see Section 3.2), TSOs use active power reserves to continuously control and maintain the system balance and, hence, the frequency and security of the system. These reserves are supplied by so-called 'Balancing System Providers' (BSPs) – including electricity generation, storage and demand response – and can be traded as balancing services or products on balancing markets.

Following the vocabulary of the EU guideline on system operation (SO GL; EC, 2017b), the main balancing reserves or 'standard products' used by European TSOs to maintain continuously the electricity system balance include in particular (with products differentiated by activation method, activation speed and activation response time):[3]

[2] For related and other definitions and classifications of ancillary services in (EU) power systems, see – among others – Easy-RES (2018) and Oureilidis et al. (2020). In addition to the three 'main' ancillary services, both SmartNet (2016) and Easy-RES (2018) discuss a variety of other ('minor') ancillary services such as inertial response, power ramp rate capability, interruptible load service, compensation, resolution of technical restrictions, etc.

[3] For a further discussion of these electricity balancing services/products see, among others, SmartNet (2016), Easy-RES (2018) Algarvio et al. (2019a and 2019b), Crossbow (2019) and Oureilidis et al. (2020).

- *Frequency Containment Reserves (FCR):* FCR are the fastest, primary control reserves that are activated after a system imbalance (that causes a frequency deviation). They are activated automatically, i.e. in a decentralised manner, via frequency measurement. Normally, they should be activated within 15 seconds while a disturbance needs to be controlled within 30 seconds;
- *Frequency Restoration Reserves (FRR):* in case a frequency deviation lasts longer than 30 seconds, FRR are activated to replace FCR. They are divided into two subcategories, depending on the activation method:
  - *automatic Frequency Restoration Reserves (aFRR):* aFRR are activated automatically by means of an Information Technology (IT) signal through the Automatic Generation Control (AGC) system that is managed by the TSO. They are considered as secondary control reserves (to replace FCR) with activation times between 30 seconds and 15 minutes;
  - *manual Frequency Restoration Reserves (mFRR):* mFRR are activated manually (or semi-automatically) by the TSO, either by phone or an IT signal. They are considered as tertiary control reserves (to replace either FCR or aFRR) with activation times within a few minutes (5-15) up to one or a few hours;
- *Replacement Reserves (RR):* RR are activated manually (or semi-automatically) by the TSO to replace and restore FRR (aFRR/mFRR) with activation times within 15-60 minutes up to several hours. It should be noted, however, that not all TSOs in the EU use RR as, in contrast to FCR and FRR, they are not obliged by EU regulation.

Table 1 provides a summary overview of the standard reserve products discussed above.

Table 1: Major characteristics of standard electricity balancing reserves

	Frequency containment process	**Frequency restoration process**		**Reserve replacement process**
Operational reserves defined by SO GL	**Frequency Containment Reserves (FCR)**	**automatic Frequency Restoration Reserves (aFRR)**	**manual Frequency Restoration Reserves (mFRR)**	**Replacement Reserves (RR)**
Control order	Primary control	Secondary control	Tertiary control	Tertiary control
Activation method	Automatically, i.e., decentralized via frequency measurement	Automatically, i.e., centralized (TSO) via IT signal (Automatic Gain Control)	Manually (or semi-automatically), i.e., centralized (TSO) via either phone or IT signal	Manually (or semi-automatically), i.e., centralized (TSO) via either phone or IT signal
Activation speed	15 seconds	30 seconds	15 minutes	15-60 minutes
Activation response time	30 seconds	15 minutes	Hours	Hours

Sources: Algarvio et al. (2019a), Crossbow (2019) and Schittekatte et al. (2020).

2.2.2. Reactive power services ('voltage control')

In addition to frequency control, TSOs are enforced to maintain the required voltage profile across the system to ensure its stability and to avoid possible damage of the connected equipment or disconnection of power generating modules. To achieve this required voltage profile, reactive power needs to be injected at specific locations of the network through controllable devices such as generating units that are equipped with Automatic Voltage Regulators (AVRs) or through Static VAR Compensators (SVCs). These actions need to take place relatively close to the voltage deviation point by providing the required reactive power locally. Generally, in European power systems, the voltage control actions are divided into a three-level hierarchy, based on their activation time (Easy-RES, 2018; Oureilidis et al., 2020):

- *Primary voltage control*: local automatic control which is activated within milliseconds and can last up to one minute;
- *Secondary voltage control*: centralized automatic control action one minute after the voltage deviation and can be maintained for several minutes;
- *Tertiary voltage control*: 10–30 min after the voltage deviation occurrence, optimization of network losses considering the reactive power reserves.

2.2.3. System restoration services ('black start')

System restoration services are ancillary services provided by generating units (black-start units), which are able to inject energy into the system, without any form of electrical energy supply external to the power generating facility. Following a general or partial system operation interruption (black-down), these units can provide energy to the network and thereby facilitate the start-up of other generators. In addition, in order to restore and control system voltage, these units should also be able to consume and produce reactive power. Technologies used include pumped storage, hydro plants, gas and nuclear units, either connected to the transmission or the distribution network (Easy-RES, 2018; Oureilidis et al., 2020).

2.3 Current market design and EU regulation regarding electricity balancing

2.3.1. Introduction

The provision of electricity balancing services in the EU is organised by means of a set of balancing markets distinguished by the type of balancing services and specific products traded in each market. A key distinction is between balancing *capacity* market versus balancing *energy* market, with each market further subdivided by the specific balancing products traded, notably the FCR, aFRR, mFRR and, in some countries, RR (see Section 2.2.1).

Each balancing market is organised and operated by the TSO(s) of the country or frequency control area concerned. Generally, the TSO is also the single buyer of the balancing products traded in each respective market. At the same time, there are usually multiple sellers, called ‘Balancing Service Providers’ (BSPs), including prequalified generators and, in some cases, storage operators and demand response providers (involving large electricity consumers and aggregators of medium and small-scale demand response).

In turn, each balancing market is characterised by a variety of design variables (‘parameters’) such as procurement approach, product resolution, price settlement, etc. (as further discussed below). Besides similarities, there are major differences in these design variables between both specific balancing markets and individual EU countries, as shown in the annual survey on balancing and other ancillary services by the European Network of Transmission System Operators for Electricity (see, for instance, ENTSO-E, 2021c). These differences in balancing market design between EU countries originate from differences in their historical developments, generation mixes or other country-specific characteristics (Poplavskaya and De Vries, 2019).

EU regulation

In order to enhance the performance and integration of balancing markets across EU Member States – for instance, by harmonising major market design variables across these countries – balancing markets and cross-border exchanges of balancing products have increasingly become subject to EU regulation, in particular since the third European Energy Package of 2009 and the resulting EU electricity network codes and guidelines in the years thereafter (Schittekatte et al., 2020). More specifically, regarding electricity system balancing the most relevant EU regulation refers in particular to the two following guidelines:

- *The electricity balancing guideline (EB GL),* published on 23 November 2017 – in the Official Journal of the European Union as European Commission (EC) implementing Regulations – and entered into force on 20 December 2017 (EC, 2017a). The EB GL provides detailed rules on electricity balancing, including common principles and harmonising market arrangements related to procurement, activation and cross-border exchanges of balancing capacity and energy (EC, 2017a; Crossbow, 2019; Schittekatte et al., 2020);
- *The electricity transmission system operation guideline (SO GL),* published on 25 August 2017 and entered into force on 14 September 2017 (EC, 2017b). The SO GL defines actions of TSOs when managing and operating their power system, including requirements and principles regarding operational system security as well as rules and responsibilities for the coordination and data exchange between TSOs, DSOs and others. Related to electricity balancing, the SO GL addresses primarily the harmonisation of reserve categories, the sizing of balancing reserves and the activation strategy for balancing energy in real-time (EC, 2017b; Crossbow, 2019; Schittekatte et al., 2020).

In addition, related to electricity balancing, two grid connection network codes are particularly important, i.e. the *Requirements for Generators Network Code* (RfG NC) and the *Demand Connection Network Code* (DC NC). These codes set the requirements for the grid connection of different (categories of) generation technologies and electricity users, including requirements regarding the provision of electricity balancing and other ancillary services (EC, 2016a and 2016b; Schittekatte et al., 2020).

Finally, the more recent fourth European Package of 2019 ('Clean Energy Package') also includes some additional, updated EU regulation regarding electricity balancing, in particular (i) Regulation (EU) 2019/943 on the internal market for electricity (EC, 2019a), which foresees a second generation of network codes and guidelines, and (ii) Directive (EU) 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/EU (EC, 2019b).

In the next two subsections (2.3.2 and 2.3.3), some characteristic design variables are discussed regarding the balancing capacity market and the balancing energy market, respectively, including EU regulation and differences across EU countries regarding these variables.[4] Although the balancing capacity market and the balancing energy market are treated separately in the subsections below, it should be noted that there is a significant coherence between these markets. For instance, in the balancing capacity market enough balancing capacity is reserved in order to activate enough balancing energy in real-time.

2.3.2. The balancing capacity market: some characteristic design variables

Balancing capacity is defined as "*a volume of reserve capacity that a BSP has agreed to bid in the balancing energy market for the duration of the contract*" (Schittekatte et al., 2020). In the respective balancing capacity markets (FCR, aFRR, mFRR, RR), BSPs offer upward or downward balancing capacity with certain product characteristics to the TSO.[5]

The amount of balancing capacity needed and procured by the TSO depends on a variety of factors, including (Schittekatte et al., 2020; see also Section 3.2):

- The expected system imbalances in real-time;
- The amount of non-contracted flexibility available in real-time ('free bids'), i.e. the more non-contracted, flexible generation/demand is expected to be available in response to high balancing energy prices, the less need for capacity reservation;
- The activation strategy of the TSO, i.e. the more a TSO makes use of proactive balancing actions, the higher the volume of activated energy and the greater the need for reserved capacity (see also subsection 2.3.3).

As noted, there are usually different balancing capacity markets for the different reserve products. In addition, there is a large variety of market design parameters which can differ

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4 For the most recent status of these balancing market design variables across EU countries, see the latest annual survey on electricity balancing and other ancillary services conducted by ENTSO-E. For instance, for the status of these parameters in 2020, see ENTSO-E (2021c). For an assessment framework of 22 balancing market design variables affecting the role of distributed energy resources (DERs) in the organised balancing market, see Poplavskaya and De Vries (2019).

5 Upward balancing capacity means that a BSP will reserve a margin to be able to produce more or consume less electricity when activated. Upward balancing energy is needed when there is less electricity supply than demand (energy deficit). Vice-versa for downward balancing capacity (Schittekatte et al., 2020).

from one balancing capacity market to another, as well as from one EU country to another, and which may change gradually over time from one year to the next one.

In this subsection, we discuss briefly some characteristic design variables related to the balancing capacity market, including:

- The procurement of reserve products on the respective balancing capacity markets;
- The contract length and timing of these products;
- The major design characteristics of the standard reserve products;
- The price settlement rule of the respective balancing capacity products.

Procurement approach

According to Art. 32 of the EB GL (EC, 2017a), the procurement method of the balancing products aFRR, mFRR and RR capacity shall be market-based. Due to regulatory exemptions, derogations or other (historical) reasons, however, in 2019 some EU countries still applied either a 'mandatory' approach (i.e. parties are obliged to offer balancing capacity, usually at regulated prices) or a 'hybrid' approach (i.e. a combination of mandatory and market-based methods) for procuring one or more of these products, as illustrated by the 2019 survey on ancillary services by ENTSO-E (2020a).

The EB GL does not specify whether FCR capacity should be procured market-based or whether parties can be obliged to offer it at regulated prices. Figure 1 shows, however that in 2020 most Central-Western European continental countries applied a market-based method, most Mediterranean and Baltic countries used a mandatory approach, while three countries (Norway, Poland and the UK) applied a hybrid approach to procure FCR capacity.

Contract period and timing of balancing capacity markets

Two related design variables of balancing capacity markets are the timing of these markets and the length of the contract period for offering certain balancing products. The timing of the balancing capacity market refers to the time-lag between the balancing capacity market and the real-time balancing energy market. This time-lag can vary from one year to a day and may differ per country and per balancing capacity product. The time-lag has an impact on how well a TSO can estimate its reserve needs and how easy it is for BSPs to estimate their opportunity costs of participating in the balancing capacity market, compared to the day-ahead or intraday market (Schittekatte et al., 2020).

The length of the contract period refers to the period for which the BSP is obliged to offer (a certain volume of) balancing energy when awarded a balancing capacity contract. This period can vary from one year to several hours. Variations are also possible such as, for instance, a contract that states that the BSP should offer balancing capacity at peak hours for a particular week or month. The length of the contract period has an impact on the extent to which sources such as VRE, storage or demand response may be able to participate in the balancing capacity market (Schittekatte et al., 2020).

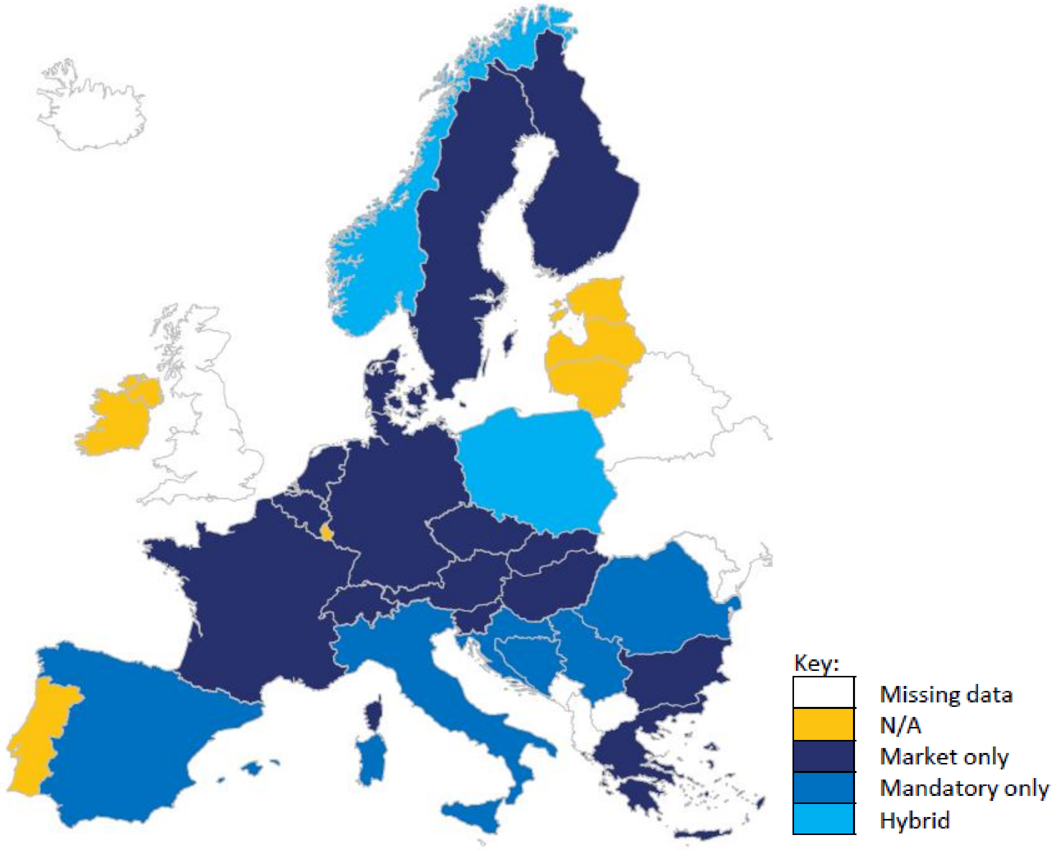

Figure 1: Procurement of FCR capacity in Europa, status in 2020

Note: '*Missing data*' refers to the TSO who did not respond to the questionnaire, while '*N/A*' refers to the TSO who responded the questionnaire but doesn't have the answer to the specific question concerned.

Source: ENTSO-E (2021c).

Regarding these two design variables, the EB GL sets out some high-level principles in Art. 32, stating that (i) "*the procurement process shall be performed on a short-term basis to the extent possible and where economically efficient*;" (Art. 32, 2b), and (ii) "*the contracted volume may be divided into several contracting periods.*" (Art. 32, 2c; EC, 2017a). In this regard, the more recent Regulation (EU) 2019/943 is stricter in the sense that Art. 6 (9) of this regulation states that "*Contracts for balancing capacity shall not be concluded more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day,…".* The same Article, however, continues with the following exemption: *"…unless and to the extent that the regulatory authority has approved the earlier contracting or longer contracting periods to ensure the security of supply or to improve economic efficiency*" (EC, 2019a).[6]

[6] More explanation about the use of this type of exemptions and derogations is provided in Art. 6 (9-11) of Regulation (EU) 2019/943 (EC, 2019a).

Characteristics of standard balancing products

Art. 25 (4) of the EB GL provides a list of characteristics for standard products (aFRR, mFRR and RR) in the balancing capacity (and energy) markets. Standard products allow for an easier cross-border integration of balancing markets, thereby enhancing economic efficiency. The major characteristics ('design variables') of these standard products include (Crossbow, 2019; see also Figure 2):

- *Preparation period:* The period between the activation request by the TSO and start of the ramping period;
- *Ramping period:* The time required for the active power output to increase or decrease from the current set point;
- *Full Activation Time (FAT):* The period between the activation request by the TSO and full delivery of requested MW power. It is the sum of preparation period and ramping period;
- *Minimum and maximum quantity:* Represents the change of power output in MW, offered to the platform by the BSPs. It is necessary that the offered power change can be reached until the end of the activation time. For the mFRR product, the minimum quantity is 1 MW and the maximum quantity is 9999 MW;
- *Minimum and maximum duration of delivery period:* The time period when the BSP delivers full the requested change of power to the system;
- *Deactivation period*: The time required from full delivery to the previous setpoint;
- *Validity period:* Represents the time in which the submitted bid can be activated by the provider;
- *Mode of activation:* Can be either automatic or manual and represents the way the system operator can activate the relevant bid.

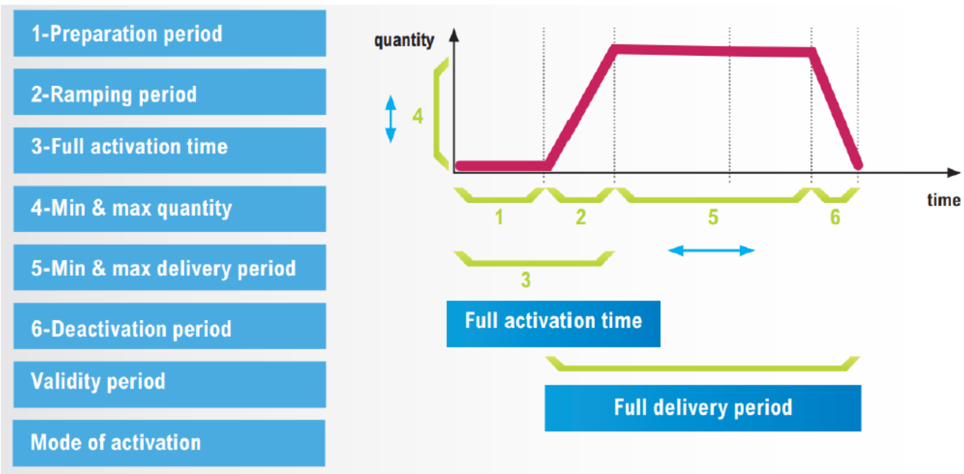

Figure 2: Structure and characteristics of standard balancing products

Source: Crossbow (2019).

One of the (non-trivial) design characteristics mentioned above is the minimum bid volume of a balancing product. In day-ahead and intraday markets, this parameter is usually not considered as restrictive, since it is generally set low enough. In balancing capacity (and energy) markets, however, minimum limits are – or used to be – often a lot higher and, therefore, more restrictive. For instance, for aFRR, the minimum bid size for the balancing capacity market varied from 1 MW (or less) in countries such as France or Poland to more than 10 MW in countries such as Portugal or Spain (ENTSO-E, 2020a). A smaller bid size lowers the entry barriers for new (small-scale) providers in the balancing market, such as bids from distributed energy sources (DERs), including storage and demand response. For aFRR and mFRR, a minimum quantity of 1 MW for a standard balancing energy product is prescribed in Art. 7 of the implementation frameworks for both platforms (see ACER, 2020c and 2020d), based upon Articles 21 and 20 of EB GL, respectively. This requirement has to be fulfilled by 1 January 2022. Furthermore, aggregation of smaller resources is allowed.

Symmetry of balancing capacity products

A major design issue is whether upward and downward balancing capacity shall be procured jointly ('symmetric bids') or separately ('asymmetric bids'). Linking upward and downward reserve requirements may reduce – or even exclude – the participation of (new, small-scale) Balancing Services Providers (BSPs), such as VRE or demand response, because they are not able to provide balancing services in both directions in a similar, cost-effective way (i.e., at the lowest social costs. Delinking of these requirements, however, may enable and stimulate the participation of these providers in the balancing markets, notably in case they are able to provide balancing services cost-effectively only in one direction (either upward or downward). Therefore, it is important that Art. 32 (3) of the EB GL requires that the procurement of upward and downward balancing capacity for at least FRR and RR shall be carried out separately. However, each TSO may submit a proposal (including an economic justification) to the regulatory authority for a temporary exemption to this rule. The same provision is recapitulated in Art. 6 (9) of Regulation (EU) 2019/943 (EC, 2017a; EC, 2019a; Schittekatte et al., 2020).

Price settlement rule

Last, but not least, another major design variable of the balancing capacity market is the price settlement rule. There are two basic options: (i) '*pay-as-bid pricing'*, i.e. a differentiated payment according to the bid price of each individually accepted bid, and (ii) '*marginal (uniform) pricing*', i.e. a uniform payment to all accepted bids according to the highest awarded (marginal) bid in the merit order. These pricing rules affect the bidding strategies of the BSPs, the clearing of the balancing capacity market and, therefore, the overall (efficiency) performance of this market.[7]

[7] For a further discussion of the price settlement rules, their pros and cons as well as their effects and implications for the performance of the balancing markets, see Van der Welle (2016) and Schittekatte et al. (2020), including references cited there.

No specific settlement rule is specified for balancing capacity markets in the EB GL, although regulated prices for FRR and RR are not permitted anymore according to Art. 32 (2) of this guideline (EC, 2017a). In practice, however, the settlement rule applied in most EU countries is pay-as-bid over uniform pricing as illustrated by Figure 3 for the mFRR capacity market in 2019 (ENTSO-E, 2020a; Schittekatte et al., 2020).

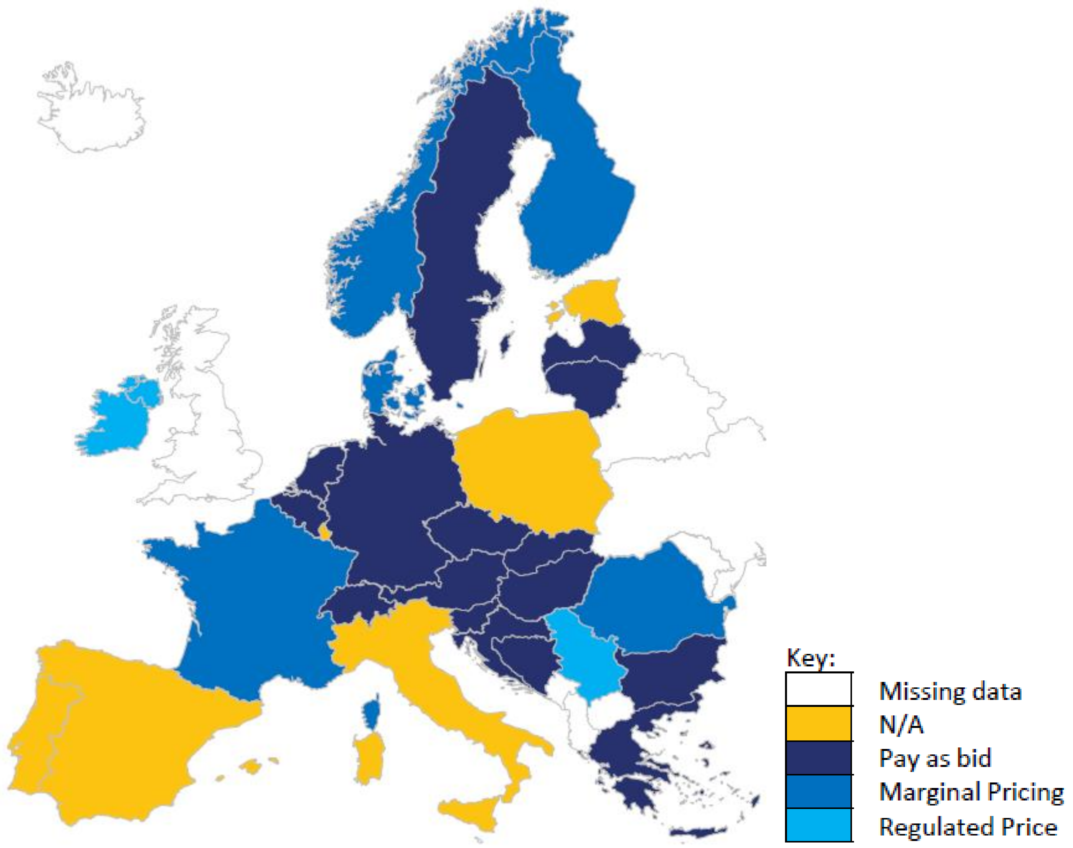

Figure 3: Price settlement rule of mFRR capacity in Europa, status in 2020

Source: ENTSO-E (2021c).

2.3.3. The balancing energy market: some additional design variables

The balancing energy market refers to the demand and supply of actually activated balancing energy. The amount of balancing energy that is activated depends primarily on (the incidence and size of) system imbalances, although it is influenced by some extent by the balancing energy activation strategy (see below). In most cases, balancing energy markets are cleared near to or in real-time. The real-time system imbalance is determined by the aggregated imbalances of all BRPs (no network congestion assumed). If the system imbalance is negative, meaning a deficit of electricity in the system, upward balancing energy is activated by the TSO to restore the balance. Conversely, if the system imbalance is positive, meaning a surplus of electricity in the system, downward balancing energy is activated by the TSO (Schittekatte et al., 2020).

Similar to the balancing capacity markets, there are different markets for the different types of energy reserve products (notably aFRR, mFRR and, if procured – in some countries, RR). The balancing energy markets are characterised by more or less the same set of design variables as for the balancing capacity markets discussed above. The outcomes ('parameter values') of these variables on the specific balancing energy markets usually show major differences across European countries (similar to the balancing capacity markets), although the outcome per variable and per country may be either the same on both the balancing capacity market and the (similar) balancing energy market for a specific reserve product or different on both markets. For instance, Figure 4 shows the price settlement rule of mFRR energy in Europe in 2020. Comparing this figure with Figure 3 (presenting the settlement rule of mFRR capacity in the same year) shows that, for instance, the UK has the same pricing rule (pay-as-bid) in both mFRR markets, whereas France applies marginal pricing for mFRR capacity and pay-as-bid pricing for mFRR energy (and vice-versa in the Netherlands).[8]

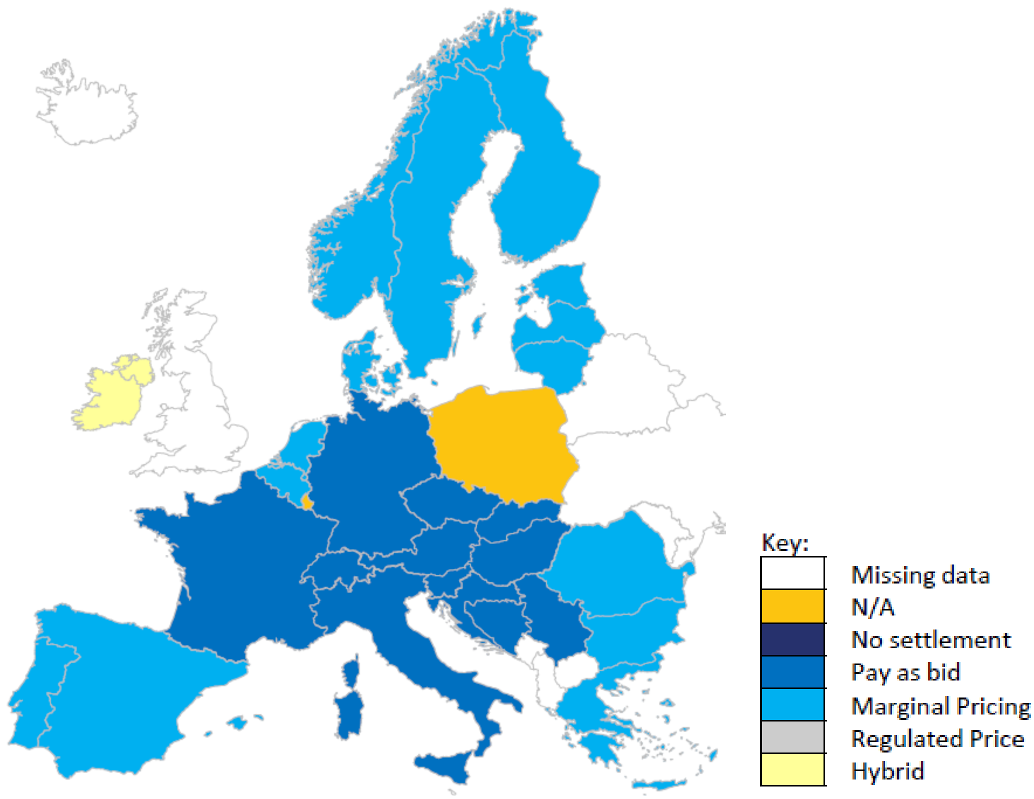

Figure 4: Price settlement rule of mFRR energy in Europa, status in 2020

Source: ENTSO-E (2021c).

8 Note that the EB GL states that the balancing energy price should not be predetermined in the balancing capacity contract for standardized products (but rather be set by the specific energy markets).

Compared to the balancing capacity markets, however, the balancing energy markets are further characterised by some additional, specific design variables, including in particular:

- The activation strategy;
- The activation rule;
- The balancing energy gate closure time;
- The opportunity to make free bids.

These variables are discussed briefly below.

The activation strategy

Regarding the activation *strategy* on balancing energy markets, there are two approaches identified in the EU, i.e. *reactive* balancing and *proactive* balancing. The key difference between the two approaches is that with reactive balancing the TSO activates balancing energy to counteract imbalances in real-time, while with proactive balancing the TSO activates balancing energy before real-time based on forecasts of imbalances. The objective of the reactive approach is to minimize the overall balancing costs by reducing the volume of balancing energy, whereas in the proactive approach, the objective is to minimize the overall balancing cost by reducing the average of balancing energy price.[9]

The activation rule

Considering the activation *rule* applied on the balancing energy markets, there are two methods defined in the EU: *merit-order activation* versus *pro-rata activation*. The merit-order approach refers to the ranking of available sources of balancing energy in ascending order of their short-run marginal costs, so that those with the lowest marginal costs are the first to be activated to meet balancing energy demand. The pro-rata method implies that all available (contracted) bids are always activated in parallel, i.e. in proportion to their size (and the balancing energy need) without distinguishing between the delivery costs of the balancing energy (ENTSO-E, 2021c; Meeus, 2020). In general, the merit-order activation approach is the preferred option as it is more cost-efficient from a social point of view than the pro-rata activation rule.

In 2020, almost all EU countries applied the merit-order rule for activating the mFRR energy reserve (ENTSO-E, 2021c). In the aFRR energy market in 2019, however, only seven EU countries applied the merit-order activation rule while all other countries used the pro-rata method, as illustrated by Figure 5.

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9 For a further clarification and discussion of these two approaches, see Schittekatte et al (2020), notably Section 6.5, and references cited there, as well as Meeus (2020). See also Section 4.3 of the current report, notably issue #5, which further discusses the two activation strategies, including a key recommendation regarding this issue.

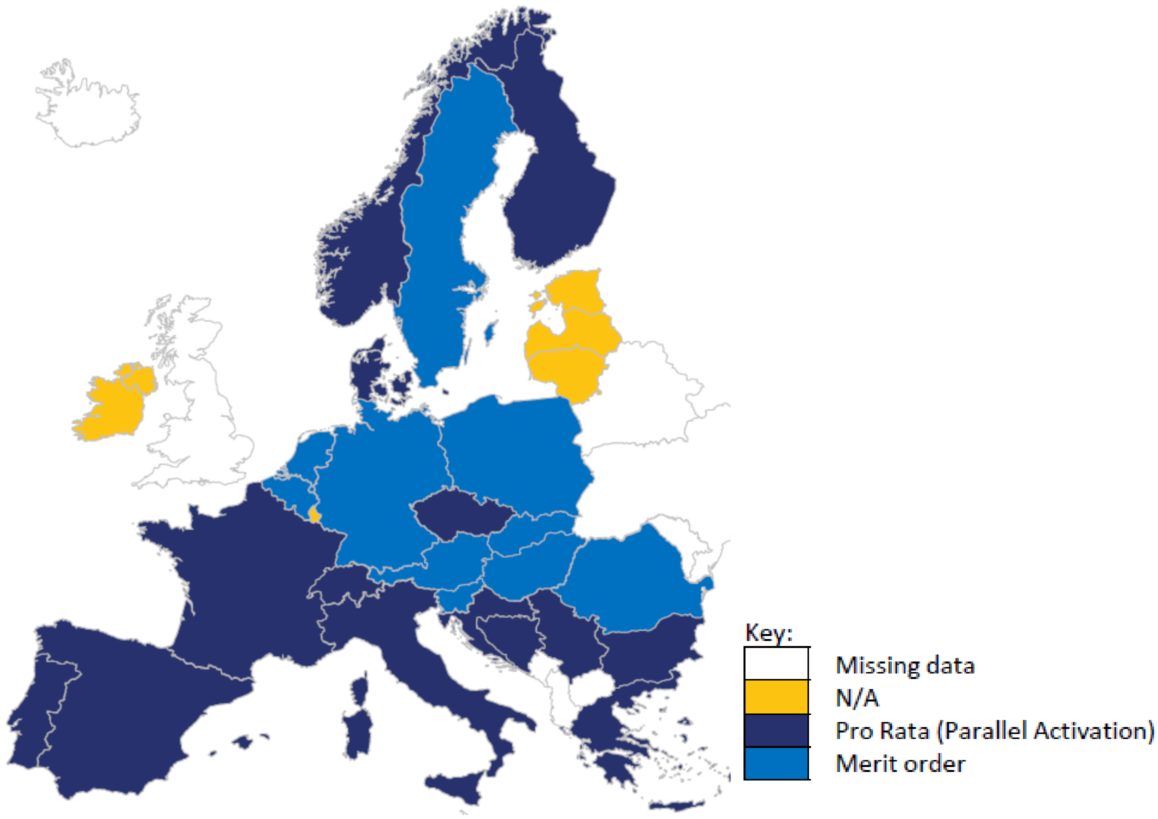


Figure 5: Activation rule on the aFRR energy market in Europa, status in 2020

Source: ENTSO-E (2021c).

Gate closure time

All balancing bids for aFRR, mFRR and RR have to be submitted before the balancing energy gate closure time (BE GCT). According to Art. 24 (1) of the EB GL, the BE GCT per standard product should be harmonized at the Union level (EB GL, Art. 24(1)). In terms of timing, the BE GCT for all standard products should not be before the intraday cross-zonal GCT and as close as possible to real-time (EB GL, Art. 24). The approved implementation frameworks of aFRR, mFRR and RR have set the BE GCTs after GCT of the intraday market at respectively 25 minutes, 25 minutes and 55 minutes before delivery (ACER, 2020c and 2020d; RR, 2018).

Free bids

The final specific design variable regarding the balancing energy market to be discussed in this subsection concerns the opportunity to make a so-called '*free bid'*. In some European countries/balancing energy markets, BSPs are only allowed to make balancing energy bids if they have already closed a balancing capacity contract, including specific conditions regarding these bids (called 'joint procurement'), whereas in other European countries/balancing energy markets they can make balancing energy bids without such a capacity contract (called 'free bids'). This issue is further discussed in Chapter 4 (notably Section 4.3, challenge and recommendation no. 6).

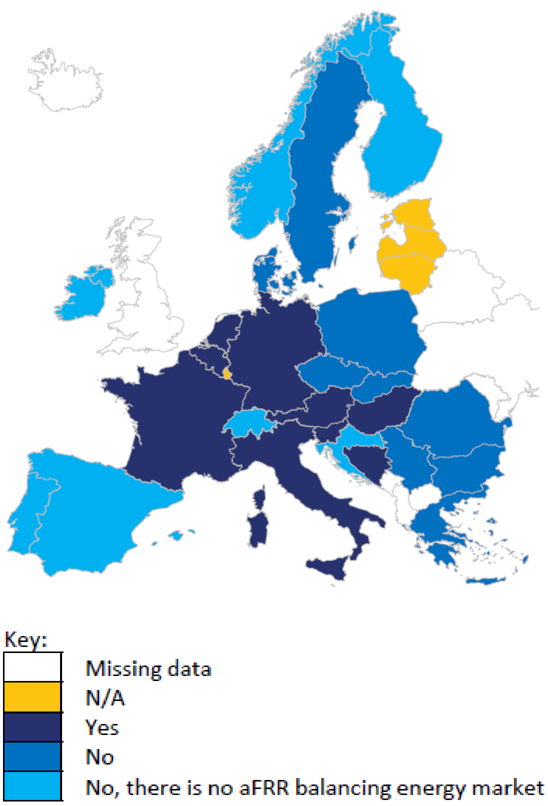


Figure 6: Free bids aFRR energy market in Europe, status in 2020

Figure 7: Free bids mFRR energy market in Europe, status in 2020

Source: ENTSO-E (2021c).

3. Future situation ('100% renewable EU power system')

3.1 Towards a 100% renewable EU power system

In order to substantially reduce CO_2 emissions, electric systems worldwide are facing a sustained growth of VRE production. Figure 8 shows the EU-wide generation mix for 2020 (Eurelectric, 2018) three different scenarios for 2040 (ENTSO-E, 202b) with a share of renewables between 73% and 77%, and a projection for 2045 (Eurelectric, 2018) for a 95% GHG emission reduction, compared to 1990 levels, with a share of renewables of 82% and a much higher expected level of electrification compared to ENTSO-E scenarios.

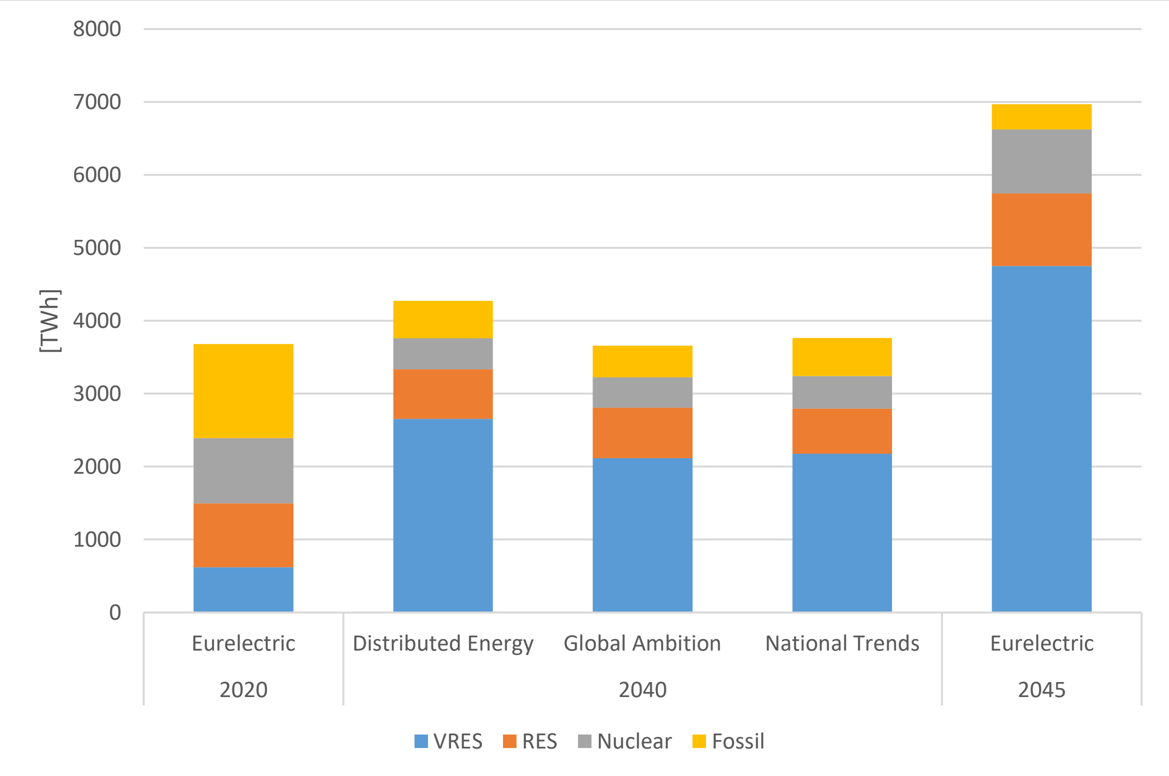


Figure 8: EU-wide generation mix by technology,

Source: ENTSO-E (2020b), Eurelectric (2018).

The figure clearly shows that the VRE production in EU member states will increase considerably in the coming two to three decades. This means that VRE will replace conventional generators, which are usually synchronous, thus changing the system from the currently synchronous-dominated system to an inverted-based dominated system.[10] Figure 9 shows the share of inverted-based technologies and conventional generation for the sce-

[10] VRE technologies are connected to the grid through inverters, which are power electronic devices that convert the native electricity production power (e.g., DC) into grid-compatible AC power.

narios shown previously. On average, throughout the year, inverter-based technologies provide less than 20% of the energy. This percentage is expected to grow near to 70% between 2040 and 2045. The instantaneous share production of inverter-based technologies could reach near to 100% temporally in the future across Europe, which would involve significant challenges for the secure and reliable operation of power systems.

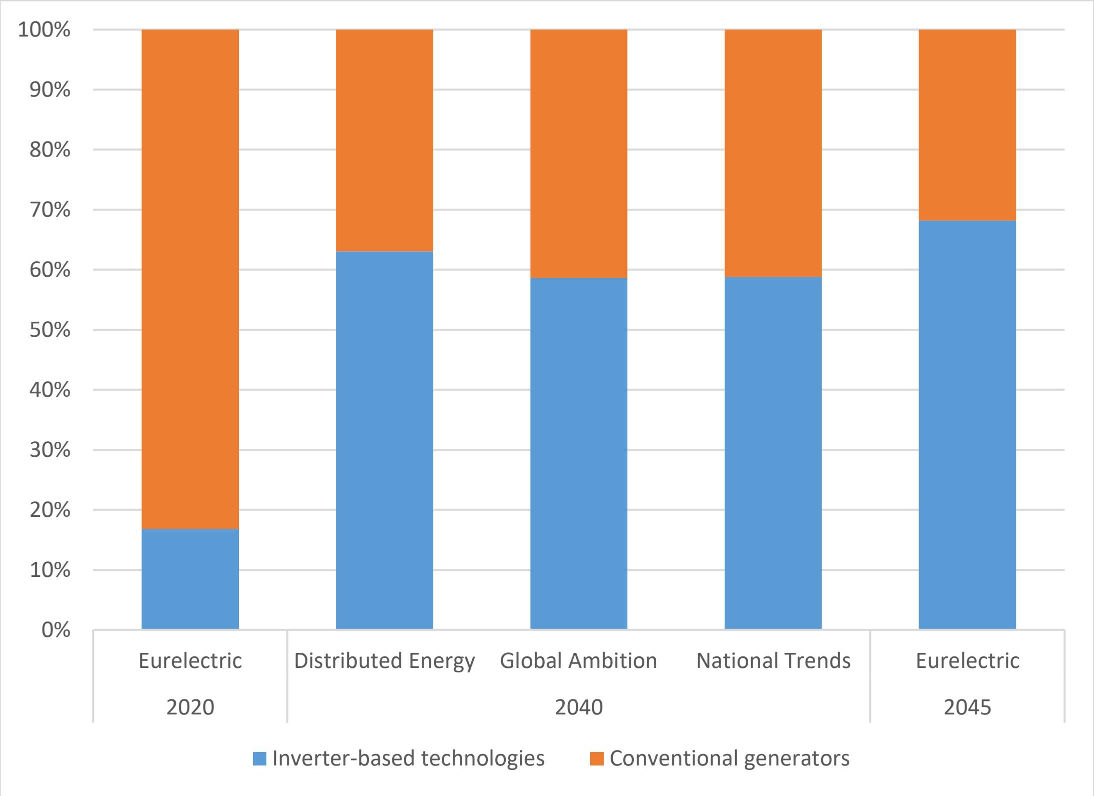


Figure 9: Share of inverted-based vs. conventional technologies

Source: ENTSO-E (2020b), Eurelectric (2018).

The implications of the transition of the EU power system for the demand and supply of ancillary services are explained in the sections below.

3.2 Future changes in the need for ancillary services ('demand')

3.2.1. Phase out of synchronous generation

What are the implications of achieving a 100% renewable power system? There are already some countries with very high shares of renewables. Hydropower has been the renewable source that has been used for decades to provide a relatively inexpensive renewable energy source, helping countries to achieve high percentages of renewables. For example, Canada (62%), Brazil (76%), Costa Rica (93%), Norway (97%), and Iceland (100%), where the latter country achieves 100% renewable power generation by means of geothermal and hydro power. However, these hydropower-dominated systems are limited by natural rainfall and geographic topology, and most of the good potential of hydropower has already been developed worldwide (Kroposki et al., 2017). So, the most promising remaining sources to reach 100% renewables systems worldwide are wind and solar photovoltaic (PV), which are variable renewable energy (VRE) sources.

The fact that some countries have been able to reach a very high share of renewables without major technical difficulties is due to the synchronous nature of their hydropower-dominated generation. In general, current large-scale AC power systems are mainly powered by synchronous generators (e.g., nuclear, hydropower, gas, coal), which are interconnected through extensive transmission and distribution systems, and their intrinsic electromechanical capabilities provide reliable and affordable electricity to customers.

Synchronous generators have a rotating part (rotor) that is moved through a mechanical force and produce a rotating magnetic field inducing a voltage into the windings in the stationary part (stator). Once the generator is synchronized to the rest of the grid, the real power is controlled through the mechanical force, and the voltage and reactive power are controlled through the rotor field current. Thus, synchronous generators have the ability to create AC electricity at a specified frequency (typically 50 or 60 Hz) and are electromagnetically strongly coupled to each other where all their rotors are rotating in synchronism. These unique characteristics have dictated how power systems are planned and operated for more than a century. Synchronous generators allow to ensure a reliable operation of an interconnected system by allowing a tight regulation of the system frequency and voltages.

The rotating components in each machine have mechanical inertia, thus storing kinetic energy in this rotating mass. This inertia makes an interconnected system of machines able to withstand fluctuations in net load and generation, since the energy deficit (or excess) needed to balance the fluctuation can be extracted from (or absorbed into) the kinetic energy from the rotating masses, thus leading to an instantaneous decrease (or increase) of frequency in the system. The ability of the system to absorb variations is proportional to the total amount of inertia in the system, and the magnitude of frequency deviations is inversely proportional to the net inertia of the system. This means that the lower the system inertia the more vulnerable the system is to larger and undesirable frequency deviations for the same system perturbation. In short, abundance of synchronous machines allows to control large active and reactive power imbalances in the system. Current systems rely on synchronous generators to provide a stable and firm voltage and frequency to the rest of the system.

On the other hand, VRE technologies are connected to the grid through inverters, which are power electronic devices that convert the native electricity production power (e.g., DC) into grid-compatible AC power. Inverter-based VRE (IBVRE) is fundamentally different, where the inverter is purely electronic and does not contain any mechanical component or rotating mass. Therefore, inverters are described as having zero inertia because their response depends almost completely on their control strategy. Furthermore, current IBVRE, and inverters in general, operate as current sources and the converters themselves follow the grid voltage (angle) and frequency; i.e., they need a strong voltage source from synchronous machines to function correctly.

The instantaneous penetration of VRE can put at risk the stability of a power system due to the absence of enough synchronous machines. To ensure a secure operation of power systems, some system operators limit the instantaneous penetration of non-synchronous (VRE) generation. For example, Ireland currently limits the instantaneous VRE production to 65% (EirGrid, 2020).

3.2.2. VRE variability and uncertainty

The nature of VRE is both variable and uncertain which poses challenges to balance the power system in different time scales. This problem can be partially tackled with energy markets clearing near to real-time operation (e.g., intraday, or real-time markets) and the remaining uncertainty could then be faced by reserves.

Variability

Figure 10 shows the net load curves evolution experience in California (CAISO, 2016). The “duck curve” clearly illustrates that the system needs to respond to increasing steeper ramps to accommodate higher penetrations of solar power. This is a clear example how increasing VRE penetration leads to increased ramping requirements. Although not pre-sent yet in these magnitudes in EU systems, this ramping requirement is expected to emerge in some countries, for example, Portugal will face this “duck curve” as penetration pf PV capacity increases to accomplish with the national energy and climate plan (NECP) for 2030, see Figure 11.

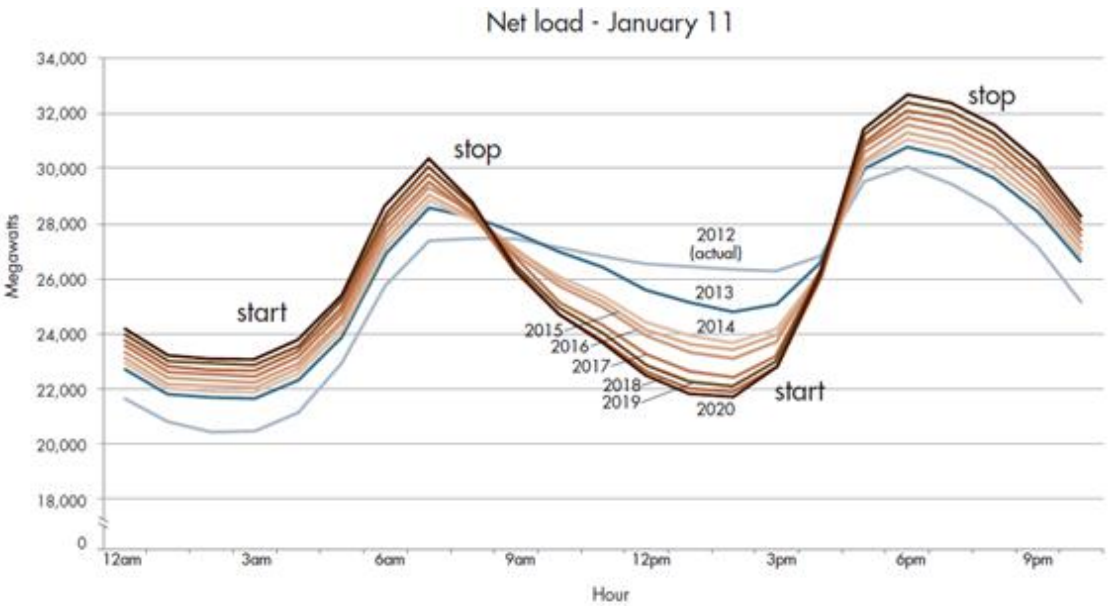


Figure 10: Duck curve: Net load curves evolution experience in California

Source: CAISO (2016).

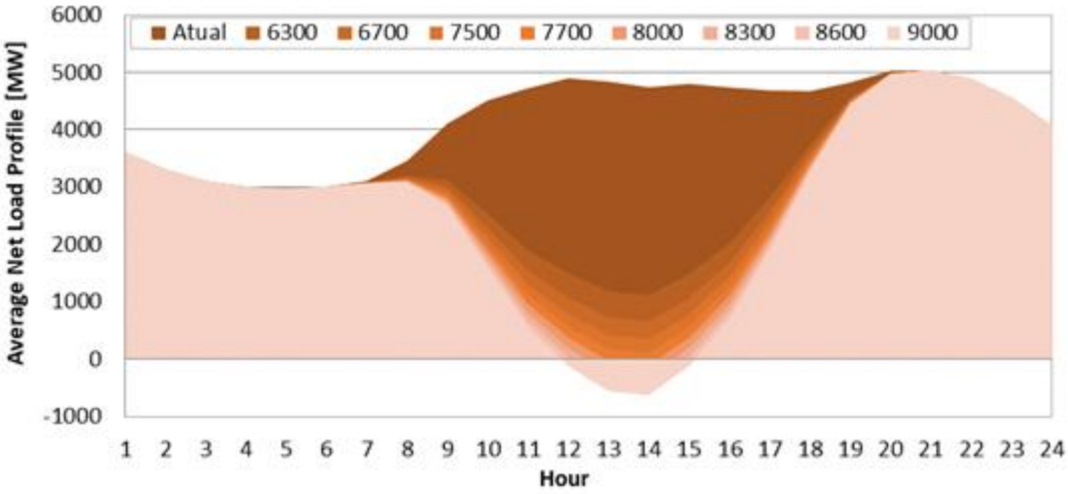


Figure 11: Net load curves evolution for Portugal according different levels of solar PV capacity as foreseen in the national NECP

Source: Couto and Estanqueiro (2020).

Uncertainty

Although the total VRE output can be partially smoothed through sufficient geographical dispersity, the uncertain nature of VRE still represents a significant challenge to balance the system in real-time operation. Indeed, under certain meteorological conditions with a coherent structure that extends over several hundreds of kilometres (e.g., cold fronts) the aggregation of VRE, even when widely dispersed, is not enough to smooth the VRE output (Lacerda et al., 2017). Higher VRE shares generally increase the amounts of reserves needed but policy measures such as energy market clearing closer to real-time and reducing its programme time unit (PTU) may compensate for this since they decrease the uncertainty left that needs to be faced by reserves.

As an example of the benefits of clearing the market closer to real-time, Algarvio et al. (2019c) show, for the Iberian electricity market (MIBEL), that postponing the day-ahead gate closure for only three hours (from 12 a.m. to 2 p.m.) enables wind power producers to benefit from improved meteorological forecasts leading to a reduction in the uncertainty. This reduction allows increasing the wind energy value in the market by nearly 4 €/MWh while reducing the total operating costs in the electricity system by 16%.

Figure 12 illustrates how to reduce the demand for balancing reserves by reducing the PTU size of energy markets, e.g., day-ahead and/or intraday markets. The upper figure shows the 1h and 1/4h schedules for a continuous demand for 12 hours. The bottom figure shows their corresponding balancing reserve requirements, i.e., the instantaneous power needed to perfectly balance the difference between the energy schedules and the continuous demand. Notice that by reducing the PTU from 1h to ¼h the total balancing reserve energy (up and down) needed was reduced by 59%, while also reducing the peak power needed by 77%. This example clearly illustrates how the demand for reserves can be drastically reduced by reducing the PTU size.

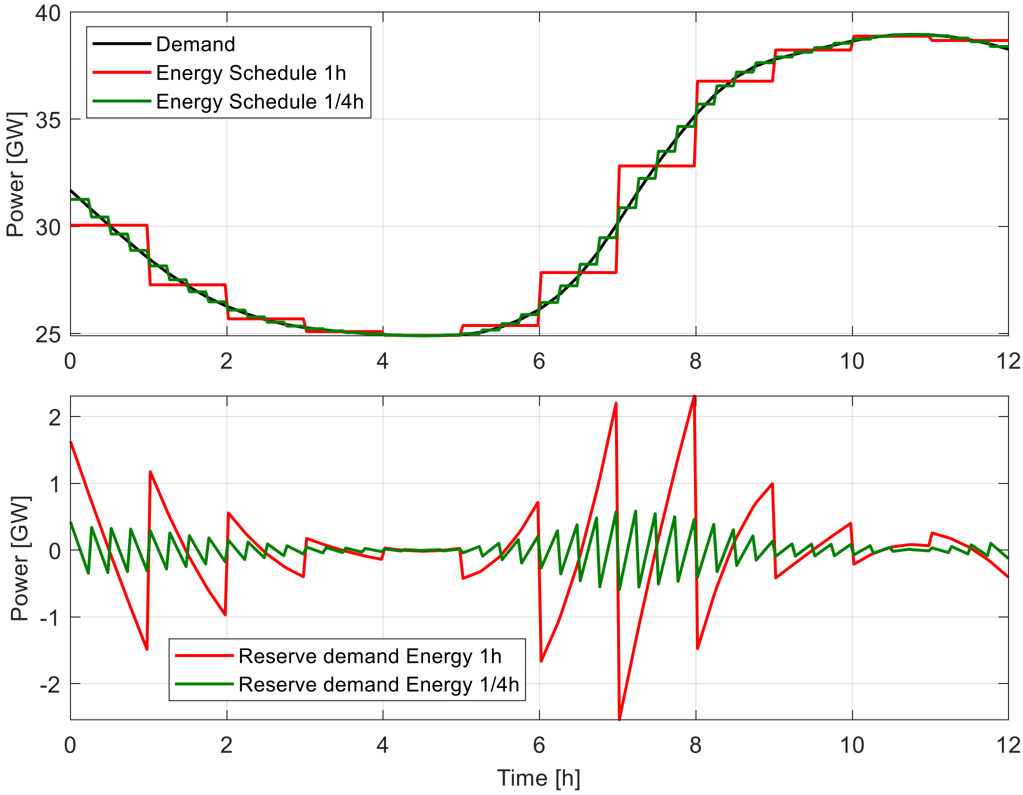


Figure 12: Example of 1h and 1/4h energy schedules (upper figure), and the corresponding demand for balancing reserves (bottom figure)

Another example where the design of energy markets has a direct impact on the reserve requirements of balancing reserves is illustrated in Figure 13, which shows the case of a market design that schedules piece-wise power trajectories instead of the traditional step-wise energy blocks (Morales-Espana et al., 2014; Philipsen et al., 2019). This power-based scheduling process not only schedules energy requirements from the demand, but also naturally follows the ramping requirements of the demand curve. Although this power schedule is hourly, it reduces the total energy needs for reserves by 85% and 64% as well as the peak power needs by 89% and 51% compared with 1h and ¼ hour energy schedules, respectively. Philipsen et al. (2019) show that hourly power-based schedules perform similar to 5-min energy-based market schedules. Furthermore, the power-based schedules better exploit the flexibility of the power system. Morales-España et al. (2017) demonstrate that a deterministic power-based optimal schedule jointly cleared with reserves could better use the procured reserves to face the variability and uncertainty of VRE compared with an "ideal" stochastic energy-based market. See Morales-Espana et al. (2017) for further details.

ERCOT and Germany are two examples where the demand for reserves has been reduced by lowering the PTU size. As shown in Figure 14, ERCOT reduced the regulating reserve requirements to manage imbalances by limiting the dispatch time of the real-time markets from 15 minutes to 5 minutes in 2010.

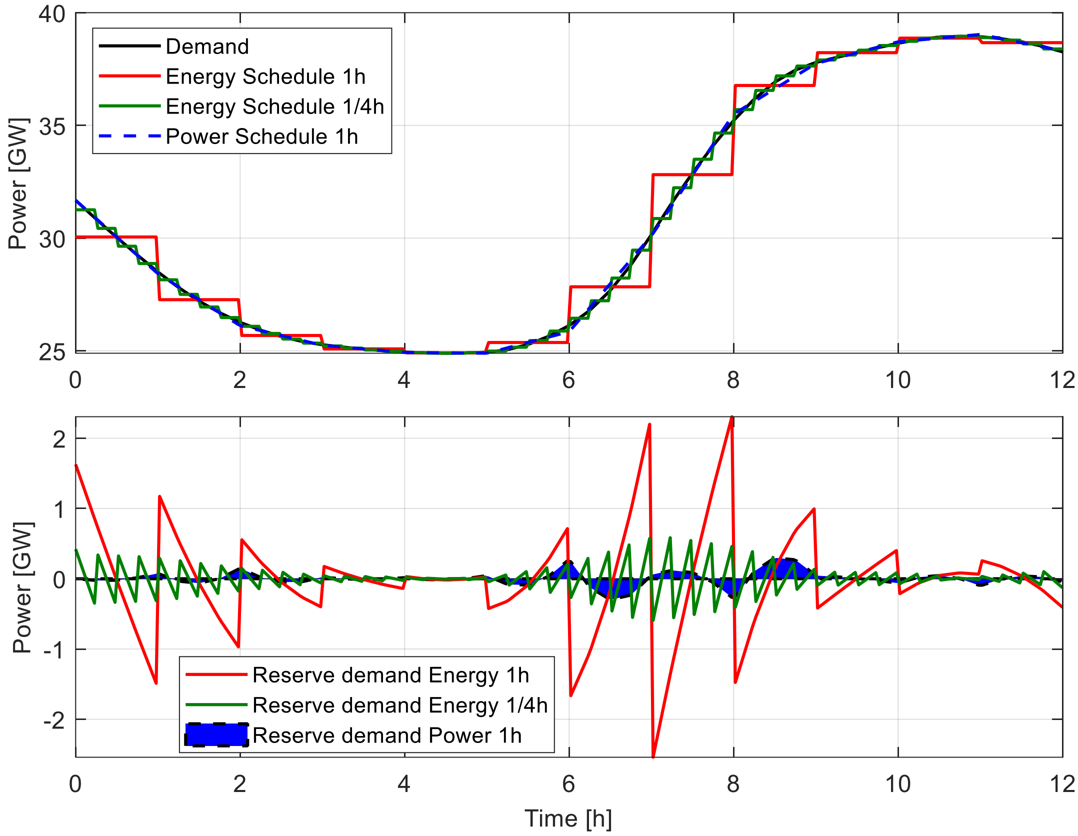


Figure 13: Example of 1h and 1/4h energy schedules vs. 1h power schedule (upper figure), and the corresponding demand for balancing reserves (bottom figure)

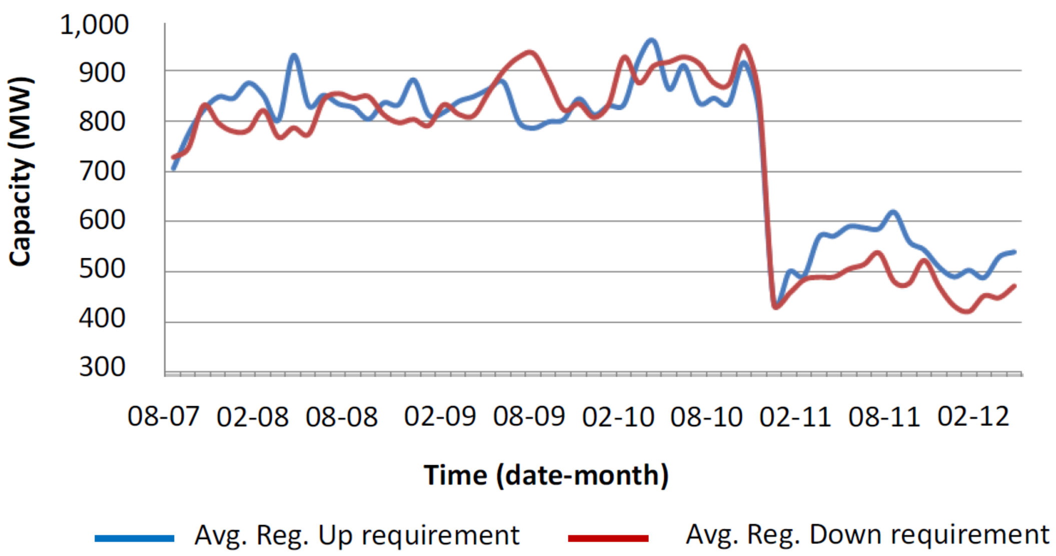


Figure 14: Regulating reserve requirements in ERCOT

Source: EA-RETD (2015).

Germany has also systematically developed its intraday market to facilitate trading closer to real time and shorter PTUs (it went from 1h to 15min) which has decreased the use of balancing reserves through time, even though the shares of VRE have been increasing (Ocker and Ehrhart, 2017), as shown in Figure 15. Furthermore, Germany reduced the need for reserves by imbalance netting between their TSOs (Ocker and Ehrhart, 2017).

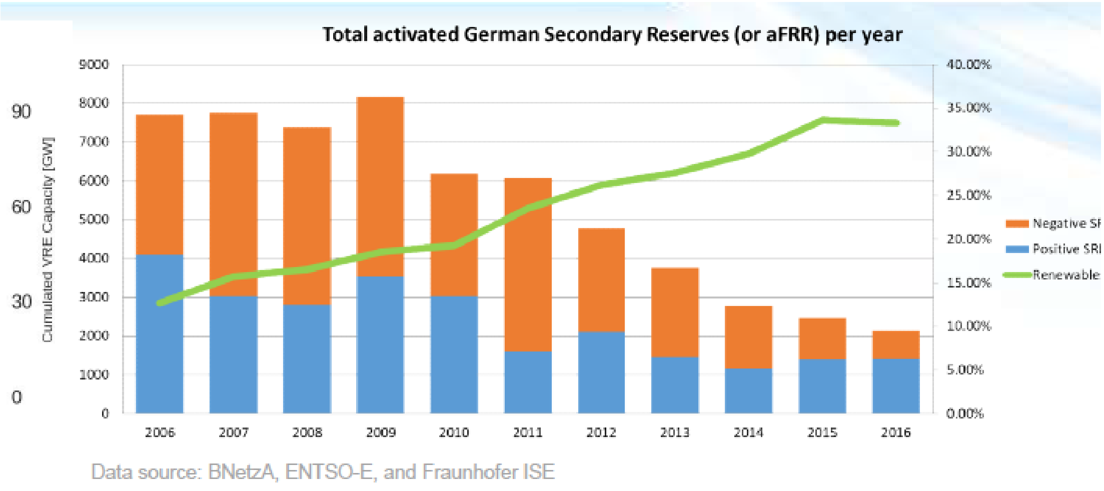


Figure 15: Evolution of activated secondary reserves and renewables share in Germany

Source: EnergyNautics (2021).

Furthermore, allowing the participation of VREs in the current reserve products allows to reduce the reserve demands and at the same time increases the market value of VREs Algarvio et al. (2019d). Design changes to the current reserve products concerning gate-closures as close as possible to real-time, shorter time units and a separate procurement of upward and downward reserves are changes that can allow a more efficient participation of VREs, decreasing the reserve demand.

3.2.3. Distributed energy sources

Small-scale distributed energy resources (DERs) are an emerging reality. DERs include different sources of small-scale generation, e.g., wind and roof solar, and demand, e.g., EVs and heat pumps. A major challenge to balance the system appears when dealing with the variability, uncertainty, unknown reliability, and control of millions of DERs. Distributed resources such as generation, storage and electromobility are changing the customers in prosumers, increasing their potential to deliver valuable services to the system, making DERs potentially part of the solution instead of a problem source. An appropriate aggregation of DERs can deliver advanced services such as balancing services (aFRR, mFRR, RR) and congestion management, which will require special coordination on regional or European level, and better coordination between system management at local and national level (between TSOs and DSOs).

3.3 Options to meet future needs for ancillary services ('supply')

This section focuses on the balancing frequency-related AS products that are emerging to face the growing penetration of VRE in power systems. Current and future power systems need the traditional AS products to continue balancing the system in different time scales, as listed in Chapter 2: FCR, FRR and RR. However, new AS products are emerging in power systems to keep the system in balance at all times under the new challenges outlined before.

Table 2: Balancing frequency-related reserve products and providers

	Traditional products			Emerging products			
	FCR	FRR	RR	Synchro-nous inertia	FFR	FFAR	Ramping reserves
Conventional generation	+	+	+	+	+-	+	+
PV plants - Centralized	+-	+-	+-	-	+	+-	+-
PV plants - Decentralized	+-	+-	+-	-	+	+-	+-
Wind plants	+	+	+	-	+	+-	+
H_2-Fired power plants	+	+	+	+	+-	+	+
DSR - households	+-	+-	+	-	+-	+-	+-
DSR – industry	+-	+	+	+-	+-	+-	+-
Synchronous condensers	+	-	-	+	+-	+	-
Flywheels	+	+	+	-	+	+-	+-
HVDC Interconnectors	+	-	-	-	+	+-	-
Batteries & EVs	+	+	+	-	+	+-	+

Table 2 shows the list of the traditional and new AS products, and different AS providers. The new AS products include: synchronous inertia, fast frequency response (FFR), fast post-fault active power recovery (FFAR), and ramping reserves. Table 2 also lists the main conventional and new technologies that can provide these products. Notice that these technologies can have different hybrid configurations and aggregations to provide AS, e.g., through DERs, prosumers or virtual power plants (VPPs). The capabilities of the different technologies are illustrated in three different colours in Table 2: 1) green stands for the technologies that can intrinsically provide a given reserve product, 2) yellow means that a technology can be designed/adapted and controlled to provide the reserve product, and its performance is expected to be lower than those illustrated as green, and 3) red stands for those technologies that are not capable to provide the product.

The remaining of this section describes all these new AS products and finalizes with a discussion about grid forming inverters, which can potentially replace synchronous machines completely.

3.3.1. Synchronous inertial response

Synchronous inertia is the response that is immediately available from synchronous generators, synchronous condensers and some synchronous loads. This is an inherent physical characteristic of synchronous machines and is key to determining the strength and stability of the system.

As VRE non-synchronous generation shares increases, inertia becomes scare, hence there is a need to incentivise it (see Chapter 4). In particular, synchronous inertial response is crucial when it can be provided at low MW outputs, thus the system can accommodate higher levels of non-synchronous generation.

Although non-synchronous generators, such as wind, solar and batteries, could lower the need for inertia through synthetic inertia and/or fast frequency response, they cannot replace the synchronous inertia, that is why they are not eligible to provide synchronous inertia in current inertia markets (EirGrid and SONI, 2014b).[11]

3.3.2. Fast frequency response (FFR)

Synchronous and non-synchronous generators can provide fast-acting response to changes in frequency with appropriate control systems, thus complementing the inertial response of the system. Fast frequency response (FFR) is the capacity (MW delivered e.g., between 2-10 seconds) that units can deliver faster than FCR (primary operating reserves are usually delivered between 6 and 15 seconds). The FFR purpose is to lessen the extent of the frequency transient.

FFR has also been called synthetic inertia and although it limits the need for synchronous inertia, it is not actual synchronous inertia. FFR needs to first measure a change in frequency (which rate of change is defined by the system inertia) and then through controls

[11] See website: [UK procured 12.5 GVA seconds of inertia worth 328 million pounds over a six-year period | National Grid ESO]

reacts to counteract this change. Although very fast, there is a delay, and it is not instantaneous as synchronous inertia. In short, although FFR can help to lower the inertia requirements of the system, it cannot replace it (ENTSO-E, 2017).

3.3.3. Fast post-fault active power recovery (FFAR)

After a voltage disturbance (including transmission faults), generating units should recover their MW output quickly, otherwise a significant imbalance can occur, leading to a critical frequency transient. Systems with low synchronous generation usually perform poorly in this type of post-fault power recovery. Therefore, some systems might need to introduce a market product that rewards generators that can provide this service, making a positive contribution to the system security (EirGrid and SONI, 2014b).

3.3.4. Ramping products

Traditionally, residual load ramping needs have been supplied by conventional generation, and these ramping needs are usually supplied through energy markets, without needing a separate ancillary service product. However, if the ramping procured through energy markets is not enough to supply the increasing steep and uncertain ramps caused by VRE, new (additional) ramping products are needed to overcome this issue, thus attempting to avoid scarcity ramping events and high energy prices (even when there is capacity available).

The objective of ramping products is to guarantee that there is sufficient ramp available to manage the variability and uncertainty of VRE over different time frames. Therefore, some system operators around the world, e.g. CAISO (2015), MISO (2011) and EirGrid (2014) are complementing their energy and reserves markets with ramping products in order to schedule additional available ramp. These new ramping products ultimately aim at providing incentives for investment in flexible generation, storage and demand.

These ramping products can go from 5-min ramp requirements (CAISO, 2015) to 8-hour ramp requirements (EirGrid and SONI, 2014b). Ramping products differ from other traditional reserves mainly because FCR and FRR are reserved to be used within a PTU, commonly dispatched to balance uncertain events (e.g., VRE uncertainty, or lines/plants outages), and these reserves are not available to be dispatched in the energy markets; on the other hand, the additional available ramping (product) is reserved to meet unexpected net load demand and can be made available and dispatched in the energy markets. For example, it can be dispatched on an economic basis to meet the net load of the next period.

Figure 16 shows the timeline of the different balancing AS products, including FCR, FRR and RR, also known as primary operating reserves (POR), secondary operating reserves (SOR) and tertiary operation reserves (TOR), respectively.

3.3.5. Need for new products to incentivize grid forming capabilities?

Power systems and electricity markets have been designed to work with synchronous generators, which have traditionally provided their inherent capabilities that are critical to guarantee the stable operation of the power system during steady state and severe contingency conditions. However, high renewables penetration means that we need to remove the dependency on synchronous machines.

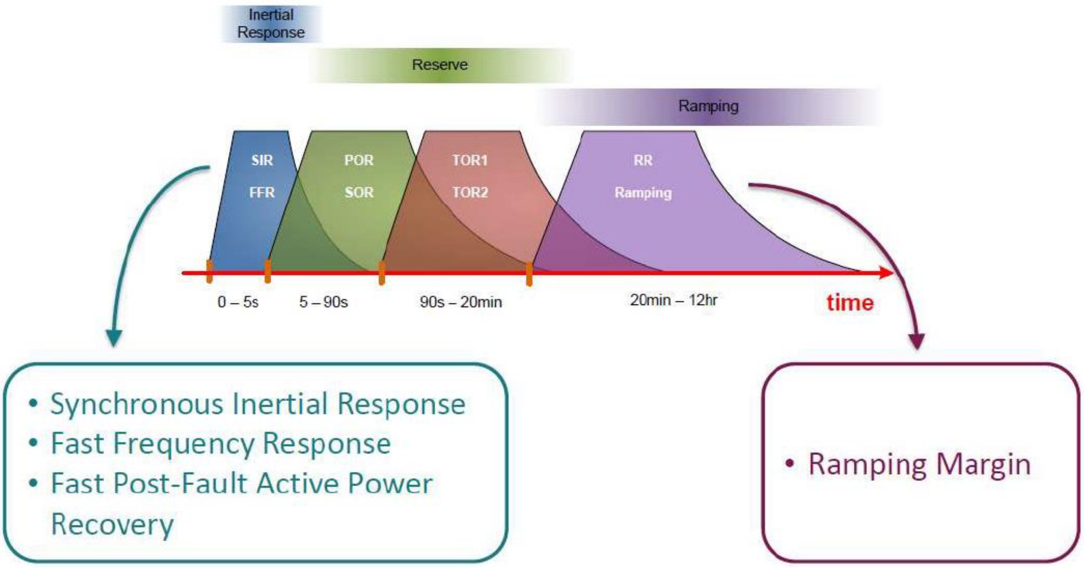


Figure 16: Range of AS balancing products of Ireland

Source: EirGrid (2020).

Traditionally, power electronic interfaced power sources have been designed to operate in steady state with a limited number of dynamic (faster) features, recently including fast frequency response and contributing to fast fault current during system faults (ENTSO_E, 2020c). Furthermore, these power electronic interfaces completely rely on being provided with firm clean voltage, which is supplied by synchronous generators. That is, traditional power electronic interfaced power sources need that synchronous generators form, i.e., provide a strong voltage source to the grid to function correctly. Therefore, high penetrations of power electronics power sources create a non-reliable weak system, known as low system strength (ENTSO-E, 2017).

Grid-forming Converters (GFC) are emerging as a future class of converters with the potential to increase the strength of the system: they must form the grid, e.g., create a strong voltage source, instead of traditionally following the grid, i.e., needing a strong voltage source to function (ENTSO-E, 2017 and 2021b). GFC are power electronics devices designed with specific control and sizing in order to support the operation of an AC power system under normal, alert, and emergency conditions, without having to rely on services from synchronous generators. Future critical capabilities of GFC to allow up to 100% penetration of Power Electronics Power Sources, can be classified as follows (ENTSO, 2017 and 2020c):

1. Creating system voltage;
2. Contributing to fault level;
3. Contributing to total system inertia (limited by energy storage capacity);
4. Supporting system survival to allow effective operation of Low Frequency Demand Disconnection (LFDD) for rare system splits (including brown and black start);
5. Acting as a sink to counter harmonics and inter-harmonics in system voltage;
6. Acting as a sink to counter unbalance in system voltage;
7. Prevent adverse control system interactions.

There is a risk associated with treating these challenges individually, since the positive contribution to one aspect may be detrimental to another. For example, a pure contribution to system inertia may be detrimental to control interactions by making these worse rather than better, and has therefore not been adopted (ENTSO-E, 2017).

The GFC technology is still under development. Research is still ongoing as characteristics are still being shaped according to the changing needs of power systems around the world. Some GFC pilots have shown promising results making VRE virtual synchronous machines able to replace the capabilities of synchronous machines, e.g., by injecting instantaneous inertial power to the system (Matevosyan, 2021).

These critical system needs so far are inherently provided in abundance by synchronous generators without additional significant costs. Therefore, there has been no need to incentivize these requirements. On the other hand, creating GFC with any of the previous characteristics greatly increases investment and operational costs of power electronic devices, e.g., due to over-dimensioning, the need to include battery storage, and to operate always with headroom capacity (opportunity cost) (Matevosyan et al., 2019). Therefore, it should be considered to provide economic incentives for further development and demonstration of GFC technology, in order to be prepared for a sudden large decline of synchronous generators in power systems.

4. Challenges and recommendations for ancillary services markets

With the increasing share of weather-dependent VRE in the generation mix, whose predictability is more accurate in time scales that are shorter than day-ahead, the importance of short-term electricity markets such as the intraday market and notably (real-time) balancing capacity and energy markets for the integration of VRE is rising. This gives rise to three types of challenges for both the adequate functioning of balancing markets and markets for other ancillary services.

First, high volumes of VRE and large-scale cross-border flows increase the demand for balancing reserves and other ancillary services such as reactive power across the EU by TSOs, DSOs and BRPs. At the same time, sizing and procurement of reserves still takes place at the national level, disregarding the efficiency benefits of coordinated sizing and procurement. More VRE also means less synchronous generators and therefore less provision of synchronous inertia. Hence, there arises a need for additional providers of both synchronous and synthetic inertia.

Furthermore, BRPs should have enough possibilities to adjust their positions in balancing energy markets according to the changing circumstances in order to limit both their own balancing costs and the overall system balancing costs.

Besides, the replacement of conventional generation by VRE could be impeded by possibly limited chances for provision of AS by balancing service providers (BSPs) such as small generation facilities, demand response, and storages. Therefore, a level playing field for BSPs, irrespective of their technology, is key.

In the following, these general challenges are discussed and disentangled in 10 specific challenges with associated recommendations for robust AS markets in the future, i.e. the year 2030 and beyond.[12]

4.1 Balancing capacity procurement

1. Reserve sizing and procurement of balancing capacity are performed nationally, implying system costs are higher than necessary

TSOs estimate the required reserves for system balancing ('reserve dimensioning') and subsequently procure balancing capacity for a certain timeframe. National sizing and procurement of balancing capacity or reserves imply that each TSO (or group of TSOs for one Member State) deals with its processes independently, while it increases the required amount of reserves and, therefore, the overall balancing procurement costs.

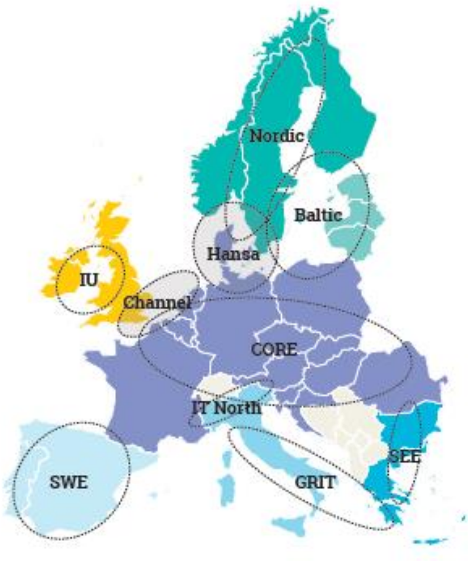
[12] The description of barriers 2, 3 and 5 draws heavily upon (Van der Welle, 2016).

This holds especially for FRR and RR, except for the Nordic countries and the Iberian Peninsula (EC, 2016b). For FCR, joint sizing and procurement of reserves in Continental Europe (Austria, Belgium, Switzerland, Germany, Denmark, France and the Netherlands are participating countries in the cooperation) is already in place and has led to significant cost savings (ACER/CEER, 2018). Since balancing capacity costs constitute the major part of overall balancing costs (see Figure 30 of ACER (2020a)), further optimizing reserve sizing and procurement, notably for FRR, may result in significant cost savings. At the same time, potential revenues are reduced since the exchange of FRR requires cross-zonal network capacity, which is scarce and hence cannot be allocated to day-ahead and intraday markets and thus reduces revenues of cross-border trading in these markets (see challenge 2 below for discussion of developed EU approaches to address this issue). Doorman and Van der Veen (2013) suggested that one entity procuring all reserve capacity could be advantageous. According to (Artelys & FrontierEconomics, 2016) regional as well as EU-wide sizing and procurement of balancing reserves deliver substantial cost savings with a net present value in the range of 27-36 billion euro for the whole EU, compared to the baseline. Since the baseline assumes that imbalances are not netted, cross-zonal exchange of balancing energy is absent, and regional initiatives for balancing services cooperation will not be further developed, the net benefits are to some extent overestimated. But still significant cost savings can be obtained since balancing capacity sharing allows to build less “back-up capacity” and provides access to cheaper balancing capacity in neighbouring countries (EU-SysFlex, 2020).[13]

Regional sizing of balancing capacity and facilitating regional procurement of balancing capacity (regional means here for system operation region i.e. SOR) is already foreseen as one of the tasks of regional coordination centres (RCCs), Art. 6(7) & art. 37 (1)j&k of Regulation (EU) No 943/2019 (EC, 2019a). The RCCs were created with the geographical scope of system operation regions (SORs), a new concept introduced in the CEP. A SOR covers at least one capacity calculation region (CCR), and the TSOs in a SOR are required to participate in that region’s RCC. A CCR is a geographic area in which coordinated capacity calculation is applied. Each CCR comprises a set of bidding zone borders. Figure 17 provides an overview of the CCRs.

Given a proposal of ENTSO-E, based upon art. 36 of Regulation (EU) No 943/2019 ACER decided that the SORs are equal to the synchronous areas in the EU, except for the Continental Europe area which given different operational and organisational requirements is split in two SORs with a separate SOR for the South East European (SEE) region (ACER, 2020b). Figure 18 provides an overview of the synchronous areas.

[13] Besides, a higher temporal granularity of markets for balancing capacity i.e. more frequent reserve sizing and procurement as well as shorter resolution of reserve sizing and procurement blocks can deliver significant operational cost savings as quantitatively illustrated by EU-Sys-Flex (2020). Our focus is here limited to the spatial dimension.



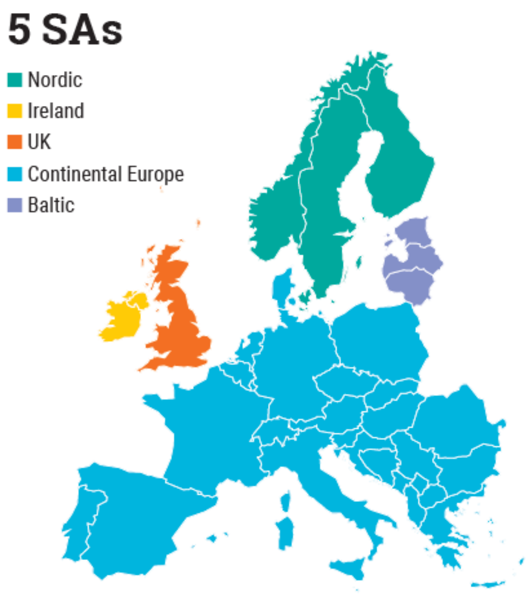


Figure 17: Overview of CCRs

Figure 18: Overview of synchronous areas

Source: ENTSO-E (2019a).

Recommendation

Apply EU-wide sizing and procurement of balancing capacity in RCCs or EU-wide ISO. This will lower costs, while it allows countries to face the same level of risk with less capacity since more imbalances tend to statistically cancel out over a larger area.

2. Shortage of cross-zonal network capacity on intra-day and real-time bases limits possibilities for cross-border balancing capacity sharing

In Europe, only the residual network capacity after day-ahead trading is available for cross-border intraday trading and balancing actions, and no cross-border network capacity for intra-day and balancing is reserved in advance (except for FCR for which the reliability margin of critical network elements is to be used).[14] Therefore, network capacity must also be nominated on a day-ahead basis and is considered firm, or definitive, after nomination.[15] In other words, the utilisation of the network capacity is fixed after the closure of day-ahead

[14] This holds for CCRs where the flow-based approach should be applied (Continental Europe and Nordics), for areas where the coordinated net transmission capacity approach is applied the reliability margin holds per interconnection. See Art. 22 (5) of Regulation (EU) 2015/1222.

[15] With the exception of situations of force majeure.

trading. As a result, the available network capacity for the exchange of energy for intra-day and balancing markets in the same direction as the day-ahead trading is limited to the network capacity that remains after day-ahead trading.[16] In addition to this, network capacity may become available as a result of updates to network capacity calculations due to the decrease in network planning uncertainty faced by TSOs over time. However, after day-ahead calculations are made, TSOs rarely perform updates to capacity calculations for their networks (ACER/CEER, 2015).

Therefore, following articles 40-42 of EB GL three different methods have been defined to reserve cross-zonal network capacity for balancing capacity sharing (FRR and RR) across zones or borders: (i) economic efficiency analysis, (ii) market-based approach, and (iii) co-optimisation approach. Each method compares the market value of cross-zonal capacity for exchange of energy in the day-ahead market with the market value of cross-zonal capacity for the exchange of balancing capacity. The approaches differ concerning the calculation of market values based on forecasts or actual values, the timing of both markets (sequential or simultaneous) and the contracting period of balancing capacity (Schittekatte et al., 2020). Only for the co-optimisation approach the development of a harmonised methodology is obliged by EB GL (Art. 40 (1)), for the other approaches the development of a method is voluntary. The co-optimisation methodology compares the actual market value for cross-zonal capacity for exchange of energy in the day-ahead market and for the exchange of balancing capacity respectively. The allocation of the cross-zonal capacity for both markets is performed simultaneously and the contracting period of balancing capacity is maximum one day. The method is described in detail in Annex I of ACER (2020e).

Note that the exchange of balancing capacity across countries is not obliged yet, but a voluntary initiative between two or more TSOs (EB GL, Art. 33 (1) and 38 (1)). At the same time, TSOs need to justify if they do not exchange reserves (EB GL, Art. 60 (2.e-f)), (Schittekatte et al., 2020).

Additionally, allowing for nomination of cross-zonal network capacity at a later moment than day-ahead, e.g. intraday may further increase efficiency of co-optimization of cross-zonal capacity for different markets and lower the demand for balancing reserves.[17] However, TSOs stated that they need to perform operational network security assessments on day-ahead basis; this implies that co-optimization closer to real-time is infeasible.

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[16] Market participants can trade without any problems in the direction opposite the flow direction which emerges from the DA trade.

[17] Also other policy measures that allow for trading closer to real-time and which are discussed in Section 3.2.2 such, as piece-wise power trajectories and ISP harmonization, can lower the demand for balancing reserves. For an elaborated discussion about trading closer to real time, including the role of intraday markets, see Van der Welle (2016).

Recommendation

Require the exchange of balancing capacity across TSOs whenever this may increase eco-nomic efficiency while maintaining security of supply. Additionally, allowing for nomination of cross-zonal network capacity at a later moment than day-ahead, e.g. intraday may further increase efficiency of simultaneous allocation of cross-zonal capacity. At the same time, TSOs stated that they need to perform operational network security assessments on a day-ahead basis. Study whether it is possible either to shift the assessments to a later moment in time or to repeat them in intraday and to allocate (part of) the (recalculated) cross-zonal capacity at that moment, e.g. by implementation of a rolling time horizon.

3. Separate and sequential day-ahead energy and balancing capacity markets lead to inefficient deployment of flexible resources

In Europe, there are separate markets for aFRR capacity (often daily), mFRR capacity (often daily), day-ahead energy and intraday energy markets. Usually the balancing capacity markets close before the day-ahead energy market. Consequently, producers must commit themselves for the provision of energy to one of these markets and are unsure beforehand whether they selected the market with the highest revenues, i.e. price arbitrage between both types of markets is suboptimal. This market design with separate and sequential markets also limits the number of potential providers of FRR capacity (Van der Welle, 2016) and, therefore, market liquidity. It also increases the risk of splitting capacity between different markets and products (ENTSO-E, 2021a). This results in inefficient utilization of the flexibility of production, demand and storage, lowering overall system efficiency. Furthermore, it is probable that premature setting of balancing capacity leads to higher capacity prices, given that bids will be based on opportunity costs and that the uncertainty regarding fuel costs and the resultant day-ahead and intra-day prices is high. This uncertainty is probably factored into the opportunity costs and, along with them, into the capacity bids (ACER/CEER, 2015).

In order to be able to take the greatest advantage of the available flexible capacity, decisions related to the utilisation of flexible capacity (including demand response) for day-ahead and intra-day energy trading, on the one hand, and for the reservation of capacity for real-time balancing, on the other hand, must be coordinated as optimally as possible. In the past, this was less important, because the demand for balancing capacity and, hence, its procurement was predictable on a weekly (weekdays versus weekend days) and on a daily (peak and off-peak hours) basis. However, in the (near) future, with large shares of weather-dependent electricity production in the mix, the residual demand profile (demand minus wind and solar production) and, with it, the demand for flexible balancing capacity will vary much more at the aforementioned time scales and on an hourly basis. This makes it necessary to implement a market design that stimulates coordinated decisions regarding the provision of energy and balancing capacity by flexibility providers as well as more efficient procurement by TSOs, leading to more social welfare. Once substitution options between provision of energy and balancing capacity are taken into account this also will prevent market power issues and reversed pricing. Market power plays a role once the number of service providers in the balancing capacity market is very limited due to the energy market design, or vice versa, while in principle a wider set of providers is able to provide the balancing capacity service concerned. Reversed pricing occurs when, for example, the power plants with the greatest flexibility receive lower compensation than power plants with lower flexibility.

In order to coordinate the provision of energy with the provision of reserve capacity, the optimisation of energy and reserve capacity can thus occur either sequentially or simultaneously (Helman et al, 2008; Van der Welle, 2016; EU-SysFlex, 2020). In the case of sequential optimisation, markets for reserve capacity and energy are priced one after the next. In the case of simultaneous optimisation, bids for both energy and reserve capacity are made at the same moment, and therefore decisions regarding the utilisation of generation units for the provision of energy and the provision of reserve capacity are taken at the same moment. As outlined above, simultaneous optimisation is clearly preferred.

A comparison of the performance of a sequential and simultaneous or joint clearing of energy and reserve markets for a large-scale case study of the Central Western European electricity system for multiple scenarios with different levels of VRE has been made by EU-SysFlex (2020). They analysed the total operational system costs for a full year and considered both the cost of reserve allocation and activation. To this aim, they deployed a unit commitment model that simulated the day-ahead scheduling of energy and reserves, followed by real-time activation of reserves. The operational system costs are 2.0-2.5% higher for sequential clearing compared to joint clearing of energy and reserve markets in the case of 30-35% wind and solar PV. Furthermore, they illustrate that the cost difference more than linearly increases with higher penetrations of wind and solar PV in the electricity system.

An important market design choice is which party decides which power plants are made available for utilisation in markets. In a power pool-like system with central unit commitment and dispatch, like that in the US, an ISO optimises the utilisation of power plants for the provision of energy and the provision of reserve capacity jointly. Initially, sequential optimisation was used for this, however, virtually all of the ISOs that utilise auctions currently use simultaneous optimisation. In doing so, substitution options are expressed in terms of optimisation restrictions, and the ISO sets the total purchase cost in one optimisation action (Helman et al., 2008).

In a system with self-commitment and dispatching, as is the European target model (ACER, 2015)[18], market participants must decide for themselves which power plants are reserved for the provision of energy and which for the provision of reserve capacity and are responsible for dispatch. To do this, they must weigh the costs of provision in one of the markets against the opportunity costs of provision in the other market. Producers are guided in this

[18] See Annex I, p. 8.

consideration by market incentives, such as the gate closure times of sub-markets and potential revenues from the various sub-markets on which trading occurs bilaterally or via power exchanges (in the EU called nominated electricity market operators or NEMOs) and those on which TSOs are active. The possibility of linking bids of BSPs to separate and simultaneous day-ahead energy markets and balancing capacity markets is currently under discussion at European level (ACER, 2020e). This discussion is conducted in the context of the co-optimization approach for the reservation of cross-zonal capacity for FRR balancing capacity sharing that is covered by challenge 2 above.

Recommendation

NEMOs (i.e. power exchanges) and TSOs should co-optimize energy trading and balancing capacity markets for more efficient pricing and procurement of energy and balancing capacity, and achieving higher social welfare. Co-optimization should be preferably pursued with simultaneous clearing of energy and balancing reserves markets (day-ahead, hour-ahead). The possibility of linking bids for both markets should be further analysed.

4.2 Procurement of inertia

4. Possibly insufficient supply of inertia to meet demand, given the decrease of rotational conventional synchronous generators with increasing shares of variable renewables

The decrease of conventional synchronous generators means that synchronous inertia will decrease, implying that a sudden small difference between load and generation causes a higher frequency deviation and vice-versa. Synchronous inertia is available immediately and is typically provided by Power-Generating Modules (PGMs) and more recently by synchronous condensers. The volume of inertial response present in the system is proportional to the total rotating mass of the synchronous machines and their rotational speed.

As described in Sections 3.3.1 and 3.3.2, synchronous inertia can be provided by synchronous machines or grid forming converters, while synthetic inertia and/or fast-frequency response (FFR, part of FCR) can complement the inertial response of the system.

Synchronous inertia

With the decreasing number of conventional synchronous generators, other market participants should be stimulated to provide synchronous inertia, thus enabling TSOs to procure sufficient synchronous inertia. Incentives can be provided to existing market participants to repurpose their mothballed synchronous generators to provide inertia, but also to new inertia providers to ensure investment in grid forming converters, such as those described in Section 3.3.5.

Although the technical characteristics of inertia have been studied extensively, there is still limited experience in designing an inertial response product and its procurement. One solution applied by UKs TSO National Grid was to award long term (6 years) contracts to different parties for providing inertia. The companies awarded with these contracts will either build new assets or modify existing ones. Under this approach, inertia providers will deliver this service without providing energy. The delivery of synchronous inertia response (SIR) is defined by the kinetic energy of the inertia source (synchronous condenser, demand) multiplied by a SIR Factor (SIRF). This factor, as defined by EirGrid and SONI (2014a) is the ratio of the kinetic energy (at the nominal frequency) to the unit's minimum generation level at which it can operate while providing reactive power. The SIRF stimulates the provision of kinetic energy at low output levels. This approach provides an incentive for conventional generators to operate at minimum stable generation and rewards other technologies such as synchronous condensers. As a result, more renewable generation can be integrated, and the provision of inertia – traditionally from coal and gas-fired power plants – can be carried out with less CO_2 emissions.

Although market-based procurement by TSOs is the trend for other ancillary services products, regulated approaches such as grid code requirements are also allowed if market-based procurement is found not economically efficient by the regulation authority (Art. 40 (5) of Regulation (EU) 2019/943). The extent to which market-based procurement of synchronous inertia could be beneficial is still open.

Synthetic inertia or fast-frequency response

Currently, there are different approaches to determine the required synthetic inertia or FFR, which are based on the systems inertia and the size of a reference incident. This reference incident is dimensioned assuming that the loss of a production unit or an HVDC link should not cause a frequency deviation larger than -1 Hz. The frequency change depends on the imbalance magnitude, the system inertia (which is time dependent), and the speed at which reserves are activated.

Market-based procurement of FFR has already been implemented in different European countries e.g. Ireland, UK, Finland and Denmark. Generation units must complete a prequalification process in which requirements such as maximum activation times after a frequency drop below a specific value are tested. The procurement of this product is done on an hourly basis one day before delivery. The procurement of FFR by TSOs can also be done jointly with other products if the products are harmonized and a similar approach to FCR sharing keys can be used (ENTSO-E, 2019b). Alternatively, a provider which can provide both FFR and maintain response out to other product timescales can contribute significantly to the management of system stability (EirGrid, 2018). Fingrid has proposed the joint procurement of FFR and FCR to enable flexible bidding for reserve capacity suitable for both reserve products.

Furthermore, the need for synthetic inertia is also to some extent addressed by grid connection requirements for different types of VRE generators and demand facilities (Schittekatte et al., 2020):

- TSOs have the right to specify that non-synchronously connected power park modules (PPMs) of type C and D are capable of providing synthetic inertia during very fast frequency deviations to replace the effect of inertia traditionally provided by synchronised PGMs [RfG NC, Art. 21(2.a)].
- The level of inertia influences the frequency gradient or the rate of change of system frequency (RoCoF). All power generators and demand units offering demand response should be able to withstand a certain RoCoF [RfG NC, Art. 13 (1.b); DC NC, Art. 28(2.k)].
- Requirements for PGMs of type C and D to contain or compensate for the frequency drop or rise by regulating the active power output or input, i.e. FCR. If a PGM actively provides FCR, it operates in Frequency Sensitive Mode [RfG NC, Art. 15 (2.d)].

Likewise, also an HVDC system shall be capable of providing synthetic inertia in response to a frequency change, based upon results of studies undertaken by TSOs to identify if there is a need to set out requirements for minimum inertia (NC HVDC, Art. 14).

Recommendations

A power system with fewer synchronous machines needs products or minimum requirements for synchronous and synthetic inertia, which have different technical requirements and functions.

It is essential that the procurement of inertia from new providers is aligned with the decommissioning of synchronous generators.

In order to enable TSOs to procure sufficient synchronous inertia, incentives can be provided to existing market participants to repurpose their mothballed generators to provide inertia, but also to new inertia providers to ensure investment in grid forming converters (GFC). The extent to which market-based procurement of synchronous inertia could be beneficial is still open and deserves further research. Once sufficient providers of synchronous inertia (GFC) are available and potential revenues are significant, TSOs could implement a market-based procurement scheme.

For synthetic inertia or fast frequency response (FFR), TSOs can also opt for a market-based approach. TSOs can procure FFR jointly with other FCR products if the products are sufficiently harmonized and a similar approach to FCR sharing keys can be used (ENTSO-E, 2019b).

Besides, current network code requirements (NC RfG and NC DC) may contribute to adequate levels of supply of synthetic inertia to meet demand in 2030 and beyond.

4.3 Participation of VRE in balancing capacity and energy markets

5. Lower flex provision by system participants and higher need for flex procurement in balancing energy markets using proactive TSO activation strategy

Within many European countries, the opportunities for adjusting previously held energy positions in balancing energy markets are limited. Market participants must often follow their energy programmes strictly and passive balancing is not allowed (e.g. reduce system imbalance by taking opposite position). In this respect, the distinction between proactive and reactive TSO activation strategies is important (TenneT, 2013; EcoGrid, 2013). With a proactive activation strategy, the TSO attempts to prevent imbalance as much as possible ('preventive'); hence RR energy markets close about 1 hour before provision. The TSO activates bids before real time based on the anticipated system imbalance (Van der Veen, 2012). In doing this, the TSO usually uses a relatively large proportion of slow RR and mFRR with a longer activation time. Imbalance is settled with dual imbalance prices, in other words, prices that depend on the direction of the imbalance. This results in prices for positive imbalance being lower than prices for negative imbalance and BRPs running a great financial risk in the event of a faulty action (EcoGrid, 2013). In this scenario, the TSO prevents network users from resolving part of their imbalance in real time, and (intraday) market incentives are eliminated. Examples of balancing markets with this activation strategy can be found in France, Switzerland, the United Kingdom (Haberg and Doorman, 2016), Spain and Portugal (Schittekatte et al., 2020), and to a lesser extent, in the Scandinavian countries.

Instead, with a reactive activation strategy, the TSO only activates bids in reaction to the momentary system imbalance ('curative'). With this strategy, the TSO gives market participants a great deal of flexibility to adjust energy programmes right up until close to real time in order to limit, as much as possible, the need for the TSOs to activate balancing. Some TSOs publish information about the system balance on a real-time basis in order to stimulate market participants to also react in real time to reduce the system imbalance. Market participants may deviate from their portfolios on the condition that they reduce the system imbalance and thus provide support to the TSO. TSOs with a reactive activation strategy use a relatively large proportion of fast reserves (mainly automatic FRR) with a shorter activation time of about 30 minutes before provision. Imbalance is usually settled with single imbalance prices which are independent of the direction of the imbalance. This means that negative imbalance (less production or greater consumption than planned) is not penalised more than a positive imbalance. Balancing markets with this activation strategy can be found in Belgium, the Netherlands and to a lesser extent in Austria and Germany.

There are important differences between balancing markets with a proactive and those with a reactive TSO activation strategy. With a proactive activation strategy, part of the available flexibility supply is not considered by TSOs, and opportunities for adjustments of previous energy positions by market participants are more limited than with a reactive activation strategy. In the former case, adjustments are also often discouraged by means of preventive

TSO actions and (implicit) penalties for imbalance, for example by dual imbalance prices, which results in imbalance prices not accurately reflecting costs.

On the other hand, the utilisation of a proactive activation strategy by TSOs can also lead to more stable activation pathways (Van der Veen, 2012) and increase system security in isolated systems that do not dispose of a high level of interconnection or other flexibility resources. This is not the case for continental Europe which is one of the largest interconnected areas. Besides, a proactive TSO activation strategy entails the use of cheaper RR and, therefore, prevents part of the use of more expensive aFRR. However, in the case of a reactive TSO activation strategy balancing costs are controlled by reducing the system imbalance by market participants, decreasing the demand for balancing energy and associated costs by TSOs. Hence, overall costs of both TSO activation strategies are comparable. Besides, in a future with close to 100% RES power system, current RR providers might not be part of such a system and thus not provide these reserves.

Recommendation

Apply reactive TSO activation strategy in Continental Europe and Nordics in order to allow new BSPs, i.e. small generation facilities, demand response, and storages, to provide balancing services at a wider scale. This includes harmonization of imbalance settlement procedures, i.e. helping the system to restore its balance, should be possible for BRPs in all Member States, decreasing the need for TSO activation of balancing resources and thus allowing for more efficient balancing energy markets subject to operational security limits.

6. Insufficient possibilities for supply of balancing energy (and capacity) by BSPs with constraints such as fixed energy constraints and/or load recovery effects

In some countries, balancing capacity and balancing energy are jointly procured by TSOs, e.g., Denmark, Sweden, and Spain for aFRR (ENTSO-E, 2021c). This approach presents some shortcomings, only generators that can offer balancing capacity are allowed to offer their energy in real-time. This procurement approach restricts the participation of VRE and DER since it is not possible for them to commit capacity earlier than in real-time due to forecast uncertainty. In light of coupled heat- or process-driven production or demand, some BSPs are not willing to bind themselves contractually ahead of gate opening of balancing energy markets (TenneT and DTe, 2004).

Furthermore, joint procurement of balancing capacity and energy implies that the energy price is set for the period of procurement. This can lead to a poor reflection of the value of energy at the time of activation. Another problem is that bids are selected based on the capacity price only, leading to strategic bidding behaviour, e.g. low-capacity bids with high energy bids. With a low-capacity bid, balancing capacity providers are sure that they will be activated for balancing energy and earn high profits in balancing energy markets.

Not requiring BSPs to close a contract for balancing capacity with a TSO before participating in balancing energy markets prevents these problems. Most important, it makes available a larger part of flexibility potential to the electricity system. This is already accounted for in legislation; Art. 16 (5) of EB GL provides the right to any BSP to provide balancing energy bids after passing the prequalification process. This is also known as the possibility for free bids. Art. 16 (6) prohibits the predetermination of price of balancing energy bids in a contract for balancing capacity. An exemption to this rule is possible, but only for specific balancing products (Art. 18(7)(b) and Art. 26(3)(b)) and it should be accompanied with a justification demonstrating higher economic efficiency. Hence, the prohibition holds for all standard balancing products in all EU member states.

It also aligns well with Art. 32 (1)(c) of EB GL about the TSO analysis of the optimal provision of reserve capacity, which explicitly mentions the volume of non-contracted balancing energy bids which are expected to be available as a relevant option that should be taken into account in the analysis. Furthermore, it is in line with Annex I 8.1(c) of Regulation (EU) No 943/2019 which states that RCCs in the determination of the amount of balancing capacity should consider the volumes of required reserve capacity that are expected to be provided by balancing energy bids.

Free bids are already in place in some EU Member States for aFRR and many EU Member States for mFRR as illustrated in Chapter 2 (notably Figure 6 and Figure 7 in Section 2.3.3).

Recommendation

All EU Member States are already required to allow for free bids of standard balancing products. Once more balancing energy providers are available for the system this decreases the need for balancing capacity procurement well ahead of real-time by TSOs while maintaining the same level of operational security. Possibilities for flex provision by new BSPs could be further increased by procurement of aFRR and mFRR balancing capacity for shorter periods than days, e.g. per block of 4 hours (cf. FCR) or even shorter time periods (1 hour).

7. High opportunity cost for VRE sources to participate in balancing markets due to production subsidies

In case VRE sources curtail their production for obtaining headroom between their production and maximum possible production level in order to provide upward balancing services, associated revenues will be outweighed by significant losses due to missed feed-in market premiums from selling energy in, e.g., day-ahead and intraday markets. According to EU state aid guidelines Member States are obliged to implement measures to ensure that generators have no incentive to produce electricity when electricity prices are negative (EC, 2014).[19] In some Member States (Germany, the Netherlands) this rule only holds for six consecutive hours with negative day-ahead prices, and thus induces only marginal, if any,

[19] See point 124 of EC (2014). The guidelines are also applicable for 2021 and are currently under review for the period after 2021.

participation of VRE in balancing markets.[20] In Denmark and France support is not paid during any hours of negative prices, although in France schemes can include a compensation for producers if a large number of negatively priced hours occur within a given calendar year (EC, 2020).

A more stringent requirement for limiting RES subsidies during one or more hours with negative prices will decrease the number of hours with negative day-ahead prices. At the same time, this could result in a ramping issue if a large number of VRE generators disconnects in a short period of time. This could contribute to significant deterministic frequency deviations and local/zonal voltage issues (ENTSO-E, 2021a).

In practice, ramping issues and related possible effects on deterministic frequency deviations and voltage issues seem limited and manageable for several reasons. First, a requirement to limit subsidies during hours with negative prices most probably will hold only for future RES, while existing RES is subject to the current rules and thus will either not react or with a delay.

Moreover, for the activation of balancing energy not the day-ahead prices but the real-time imbalance is key. Market participants will take action in intraday and balancing markets to prevent too frequent ramping of generators in order to limit the associated wear-and-tear costs of both conventional and RES generation, e.g. wind turbines. Since day-ahead prices are already established 12-36 hours before real-time, TSOs have ample time to monitor and to take coordinated (remedial) actions in order to prevent ramping, deterministic frequency deviations and voltage issues. Amongst others they could contract more balancing capacity on an intraday basis such as emergency power (mFRR product) and apply European wide imbalance netting through the existing IGCC covering Continental Europe (except for Baltic countries and South Eastern Europe). They can also propose changes to ramping characteristics of standard and specific balancing products that are defined according to Articles 25 and 26 of EB GL.

In addition, TSOs dispose of access to different technologies that deal with voltage issues, such as synchronous condensers and flexible AC transmission systems (FACTS) including static var compensators (SVC) and static compensators (STATCOMs). In the future power system, these ancillary components can ensure voltage stability. Furthermore, VRE power plants should comply with grid codes, i.e., providing low-voltage ride-through and participating in the centralized voltage control system under normal operational conditions (Nan, 2016).

[20] In Germany, the rule recently has been adapted towards 4 consecutive hours in the framework of the EEG 2021, while the subsidy period for operators is prolonged for the number of time blocks with at least 4 consecutive hours of negative prices. According to EC (2020), countries which experienced the most negative day-ahead prices are Germany and Denmark which had 720 and 679 hours with negative prices respectively, in the period 2014 up to and including 4 September 2019.

Recommendation

In order to prevent that production subsidies for RES distort efficient system operation in general and participation in ancillary services markets in particular, several policy options can be pursued:

1) Strengthen requirement to one single hour rather than allowing for subsidies for consecutive hours with negative prices.

2) Changing production subsidies from energy to capacity-based (Hu, et al., 2018) (Huntington, et al., 2017).

3) Phasing out subsidies for new wind and solar-PV installations given sustained cost price reductions and sufficient revenue perspectives through electricity market prices and possibly guarantees of origin. Hence, these installations may no longer need production subsidies after 2025 or 2030. [21]

Potential effects of these options on ramping, deterministic frequency deviations and voltage issues seem limited and manageable but should be monitored by TSOs.

8. Need for provision of downward balancing services by VRE given higher opportunity costs of thermal plants to provide downward balancing services during hours with high renewable energy production

During hours with high VRE production, electricity prices decrease, which increases the opportunity costs of thermal plants to regulate downwards. To regulate downwards, these plants have to run at minimum load plus downward balancing capacity and bid these in the day-ahead market (DAM) or intraday market (IDM). With low DAM/IDM prices, thermal plants will be making losses and thus have higher opportunity costs to offer downward balancing. Consequently, from a system perspective, it would be efficient to deploy VRE for downward balancing (Hirth and Ziegenhagen, 2015).

Since symmetric bidding requirements were preventing the provision of downward balancing by VRE, European policy makers have set new requirements in the EB guideline as well as in the CEP legislation. These include provisions for asymmetric procurement of FRR and RR (EB GL, Art. 32 (3)). As a result, the barrier has been decreased significantly.

[21] In the Netherlands, the government intends to stop subsidies for wind and solar-PV after 2025. Since 2019, in Portugal the solar-PV capacity is being licensed under a subsidy-free scheme.

The remaining specific barrier is the symmetric provision of FCR. According to TSOs, asymmetric bids could have significant technical and operational implications, like specific upward and downward K-factors[22] per country in their Load Frequency Controllers and the risk related to system splits if positive and negative FCR is not evenly distributed. Also, asymmetric bids raise the question of FCR energy remuneration and BRP imbalance adjustment. Furthermore, they state that BSPs still have the opportunity to use aggregation or pooling of asymmetric technologies in order to create symmetric bids (50Hertz et al., 2018). Given that in some countries, FCR asymmetric provision is already allowed, i.e. in Belgium, Denmark, Greece and Norway (ENTSO-E, 2021c), it seems possible to overcome the issues raised.

Recommendation

Study existing approaches for asymmetric provision of FCR and consider to roll-out such an approach across the whole EU. One option that can serve as a transition to asymmetric procurement of FCR is to allow local asymmetric procurement of FCR. TSO Elia in Belgium has opted for this approach (Elia, 2018). Elia has developed three specific FCR service types to increase competition and market liquidity in the local procurement. There are several benefits of using a combination of symmetrical and asymmetrical products. It is possible to source enough FCR while limiting the dependence of CCGT plants to provide these reserves. Furthermore, upwards and downwards products for FCR enable the participation of other participants such as industrial loads and VRE.

9. Need for smaller bid sizes, i.e. minimum bid volumes to allow for the effective participation of demand-side response, energy storage and small-scale renewables in balancing markets

Bid sizes can be restrictive for DER willing to act as BSP. Smaller minimum bid sizes could lower the entry barriers for a specific set of technologies such as DER. Following the EB GL, minimum bid sizes are already being reduced and harmonised throughout national balancing markets. Nevertheless, bid sizes smaller than 1 MW present other shortcomings.

[22] Definition in Art. 3 (45) of EC (2017c): 'K-factor of an LFC area or LFC block' means a value expressed in megawatts per hertz ('MW/Hz'), which is as close as practical to, or greater than the sum of the auto-control of generation, self-regulation of load and of the contribution of frequency containment reserve relative to the maximum steady-state frequency deviation.' The K-factor plays a role in the calculation of the area control error (ACE) which is defined in Art. 3 (19): 'area control error' or 'ACE' means the sum of the power control error ('ΔP'), that is the real-time difference between the measured actual real time power interchange value ('P') and the control program ('P0') of a specific LFC area or LFC block and the frequency control error ('K*Δf'), that is the product of the K-factor and the frequency deviation of that specific LFC area or LFC block, where the area control error equals ΔP+K*Δf.'

For aFRR and mFRR, a minimum quantity of 1 MW for a standard balancing energy product is prescribed in Art. 7 of the implementation frameworks for both platforms (see ACER, 2020c and 2020d), based upon Articles 21 and 20 of EB GL, respectively. This requirement has to be fulfilled by 1 January 2022. For day-ahead and intraday markets, minimum bid sizes of 500 kW or less are prescribed in Regulation (EU) 2019/943, Art. 8 (3).

Recommendation

One could imagine that the minimum bid size for balancing products is also reduced to 500 kW or less. However, it is questionable whether further reduction of minimum bid sizes of balancing products has added value since, at some point, the benefits from the provision of balancing services will no longer outweigh the transaction costs involved (e.g. prequalification, data communication and costs for accessing trading platforms).

In practice, further lowering bid sizes may not increase participation of small generation, DSR, and energy storage facilities in balancing markets. Instead, these facilities may prefer aggregation of resources until 1 MW to limit transaction costs involved. Hence, currently pursued bid sizes are sufficient.

4.4 Coordination between TSOs and DSOs

10. Need for stronger coordination between TSOs and DSOs to allow all potential system users to provide ancillary services, including DER, without endangering network operational security

Increasing volumes of DER may boost competition across BSPs, decrease balancing costs and enable the efficient integration of VRE (Poplavskaya and De Vries, 2019). Hence, EU research projects have outlined the importance of efficient market design and possibilities for DERs to participate in ancillary services markets (EASY-RES) and the importance of TSO/DSO coordination in this respect (EU-SysFlex). Articles 31 and 40 of Directive (EU) 2019/944 state that DSOs shall exchange all necessary information and shall coordinate with TSOs in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development. This requirement results in a need for both DSOs and TSOs to change their current work practices and their coordination measures.

Barriers for DER at the distribution level to provide ancillary services include, amongst others, specific prequalification rules or disproportionate IT requirements (ENTSO-E, 2021a). Prequalification rules for reserve providing units or groups differ for FCR, FRR and RR and its main characteristics are described in Articles 155, 159 and 162 of the EU SO Regulation (EC, 2017b), respectively. In case of reserve providing units or groups connected to the distribution grid, Article 182 (1) obliges TSOs and DSOs to cooperate “*in order to facilitate and enable the delivery of active power reserves by reserve providing groups or reserve providing units located in the distribution systems*”. Art. 182 (2) specifies that each TSO shall develop in agreement with DSOs the terms for information exchange and for the delivery of active power reserves for this purpose. A recent report from (Prettico et al., 2021) shows that TSO-DSO data exchange is not yet taking place in all EU Member States. Article 182 (4) provides the right to DSOs "*to set limits to or exclude the delivery of active power reserves located in its distribution system, based on technical reasons such as the geographical location of the reserve providing units and reserve providing groups*." This gives DSOs discretion about the actual limits to the provision of balancing services by DER to TSOs. Additional rules are needed to secure that distribution networks are managed in a smart way such that the use of DER for solving distribution problems is optimized (see EU-Sys-Flex, 2020) and the capability of DER to provide balancing services to TSOs is not unduly restricted.

More generally, current rules allow TSOs to issue complementary rules concerning data exchange, e.g. process qualification and data connection of reserve providing units with the TSO for control and verification which could be more burdensome for smaller units connected to distribution grids than for larger units connected to transmission grids.[23] At the same time, reserve providing groups, i.e. aggregation of resources of reserve providing units is allowed.

Furthermore, there are other more general issues concerning, amongst others, resource allocation and real-time TSO-DSO coordination (Schittekatte and Meeus, 2020) which deserve further research and may result in more harmonization efforts in the medium term. These are not discussed here since they have a broader scope than the procurement and provision of ancillary services.

Recommendations

Additional rules are needed to secure that distribution networks are managed in an intelligent way such that the use of DER resources for solving distribution problems is optimised and the capability of DER to provide balancing services to TSOs is not unduly restricted.

[23] See for example TenneT (2019), Section 5.1.12.

5. Summary of main findings

The overall objective of the current study is to analyse the implications of the transition towards a renewable, climate-neutral power system in the EU for the demand and supply of ancillary services (AS) of this system in general and for the market design and related EU regulation of these services in particular. The study focuses predominantly on electricity balancing services ('frequency control'). However, other ancillary services – notably reactive power services ('voltage control') and system restoration services ('black start') – are, to some extent, considered as well. More specifically, the study analyses in particular (i) the current situation ('base case') of ancillary (electricity balancing) services in the EU, (ii) the future situation ('towards a 100% renewable EU power system') of these services, and (iii) the major challenges and recommendations for the main ancillary services markets in the EU in order to improve the performance of these markets in the coming years, i.e. up to 2030 and beyond.

Chapter 2 of the present report outlines the current situation ('base case') regarding ancillary services of the power system in EU countries, including a definition, classification and description of the main ancillary services and products in the EU as well as a discussion of the current market design and EU regulation regarding the provision of (one of) the most relevant ancillary services of the power system, i.e. electricity balancing services.

A major finding of Chapter 2 is that, besides similarities across EU countries, the current national electricity balancing markets are characterised by a variety of design variables with major differences regarding these variables across EU countries which may hinder to enhance the further integration and efficiency of these markets across the EU.

Subsequently, Chapter 3 analyses the major implications of the transition towards a renewable, climate-neutral electricity system in the EU for the demand and supply of electricity balancing services in the EU, including the need for the provision of new balancing services by new providers and/or new products.

More specially, Chapter 3 analyses the challenges to maintaining the system energy balance due to the phase-out of synchronous generation and the higher variability and uncertainty of VRE generation. To face these challenges, new frequency-related AS products are emerging, which complement the existing ones, such as frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR). The new emerging AS products described in this study are synchronous inertia, fast frequency response (FFR), fast post-fault active power recovery (FFAR), and ramping reserves.

The main findings of Chapter 3 are:

- The design of energy markets has a direct impact on the requirements for balancing reserves. For example, by clearing energy markets nearer to real-time and reducing their programme time unit (PTU), the market design naturally decreases the uncertainty left that needs to be faced by reserves even when the VRE share increases.

- Although current VRE inverters could lower the need for inertia through synthetic inertia and/or fast frequency response, they cannot replace real physical inertia, which is crucial for a reliable and stable operation of power systems. However, grid-forming inverters (GFC) are emerging as a future class of converters with the potential to completely replace synchronous generation.

Finally, Chapter 4 analyses the major market design challenges related to electricity balancing of current and future (more renewable) power systems in the EU, including (regulation) measures already taken and being implemented in the EU, as well as recommendations for further actions addressing the identified challenges in order to improve the performance of the (future) provision of the balancing services concerned. The major findings of this chapter are summarized in the table below.

Table 3: Summary table of market design challenges for balancing and other ancillary services (AS), measures already taken and being implemented at EU-level, and recommendations for further action

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
1	Reserve sizing and procurement of balancing capacity are performed nationally (especially FRR, given existing FCR cooperation in Continental Europe), implying each Member State can face all imbalances independently, but increasing the required procurement of reserves and therefore lowering overall cost efficiency.	Regional sizing of reserve capacity, i.e. per system operation region, is one of the tasks of regional coordination centres (RCCs), Art. 6(7) and Art. 37 (1) j&k of Regulation (EU) No 2019/943.	Apply EU-wide sizing and procurement of balancing capacity in RCCs or EU-wide ISO. This will reduce the overall need for balancing capacity and thus lower costs, while it allows countries to face the same level of risk with less capacity since more imbalances tend to statistically cancel out over a larger area.
2	Shortage of cross-zonal network capacity in intraday and real-time timeframes limits possibilities for cross-border balancing capacity procurement/sharing. This is caused by the requirement to nominate cross zonal network capacity at the latest on a day-ahead basis. As a result, the available network capacity for the exchange of energy for intraday and balancing markets in the same direction as the day-ahead trading is largely limited to the network capacity that remains after day-ahead trading.	Reservation of cross-zonal capacity for exchange of balancing capacity on a day-ahead basis is allowed; three different methods are foreseen, amongst others the co-optimization approach (EB GL, Art. 40-42). ACER decision No 12-2020 elaborates upon the co-optimization method, i.e. comparing the actual market value of cross-zonal capacity for trading of energy in day-ahead market and exchange of balancing capacity respectively. This means simultaneous allocation of cross-zonal capacity for trading of energy in day-ahead market and exchange of balancing capacity. However, exchange of balancing capacity is a voluntary initiative between two or more TSOs (EB GL, Art. 33 (1) and 38 (1)), although TSOs need to justify if they do not exchange reserves (EB GL, Art. 60 (2.e-f)).	Require the exchange of balancing capacity among TSOs whenever this may increase economic efficiency while maintaining security of supply. Additionally, allowing for nomination of cross-zonal network capacity at a later moment than day-ahead, e.g. intraday, may further increase efficiency of co-optimization. Study whether it is possible to shift operational network security assessments to a later moment in time or repeat them in intraday and to allocate (part of) the (recalculated) cross-zonal capacity at that moment, e.g. by implementation of a rolling time horizon.
3	Separate day-ahead energy and balancing capacity markets lead to inefficient deployment of flexible resources.	Gate closure times (GCTs) of balancing capacity markets have been shortened to day-ahead, allowing for wider substitution options between provision of energy and balancing capacity by flexibility providers.	NEMOs (i.e. power exchanges) and TSOs should co-optimize energy trading and balancing capacity markets for more efficient pricing and procurement of energy and balancing capacity, and achieving higher social welfare. Co-optimization should be preferably pursued with simultaneous clearing of energy and balancing reserves markets (day-ahead,

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
			hour-ahead). The possibility of linking bids for both markets should be further analysed.
4	Possibly insufficient supply of inertia to meet demand, given the decrease of rotational conventional synchronous generators with increasing shares of variable renewables.	No approach exists yet at EU level to deal with the decline of synchronous inertia, i.e. there are no incentives in place for provision of synchronous inertia by mothballed generators as well as new inertia providers. Concerning synthetic inertia, TSOs have the right to specify in network codes that non-synchronously connected power park modules of types C and D (Nordic countries at least above 10 MW, Continental Europe at least above 50 MW) are capable of providing synthetic inertia during very fast frequency deviations, RfG NC, Art. 21 (2.a). Likewise, also an HVDC system shall be capable of providing synthetic inertia in response to frequency change, based upon results of studies undertaken by TSOs to identify if there is a need to set out minimum inertia, NC HVDC, Art. 14.	In order to enable TSOs to procure sufficient synchronous inertia, incentives can be provided to existing synchronous generators to repurpose their mothballed generators to provide inertia, but also to new inertia providers to ensure investment in grid forming converters (GFC). Once sufficient providers of synchronous inertia (GFC) are available and potential revenues are significant, TSOs could implement a market-based procurement scheme. For synthetic inertia or fast frequency response (FFR), TSOs can also opt for a market-based approach. TSOs can procure FFR jointly with other FCR products if the products are sufficiently harmonized and a similar approach to FCR sharing keys can be used (ENTSO-E, 2019b). Besides, current network code requirements (NC RfG and NC DC) may contribute to adequate levels of supply of synthetic inertia to meet demand in 2030 and beyond.
5	Lower flex provision by system participants and higher need for flex procurement in balancing energy markets using proactive TSO activation strategy.	Mixed picture. Although balancing GCT is short for aFRR and mFRR energy bids (25 minutes before real-time) and RR energy (55 minutes before real-time) bids of BSPs, the GCT for RR energy is long enough for proactive TSO activation. Also preconditions for reactive TSO strategy are met (EB GL, Art. 12; Regulation (EU) 2019/943, Art. 6 (13)); single imbalance price, well-functioning intraday markets, legal ability for Balancing Responsible Parties (BRPs) to respond to the price signal, and a timely publication of	Apply reactive TSO activation strategy in Continental Europe and Nordics in order to allow new Balancing Service Providers (BSPs), i.e. small generation facilities, demand response, and storages to provide balancing services at a wider scale. This includes harmonization of imbalance settlement procedures, i.e. helping the system to restore its balance should be possible for BRPs in all Member States, decreasing the need for TSO activation of balancing resources and thus allowing for more efficient balancing energy markets subject to operational security limits.

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
		the system imbalance and its price (Hirth and Ziegenhagen, 2015; FSR, 2020). Art. 44 (1)(c) of the EB GL explicitly allows for non-harmonisation of other aspects, such as the incentives to BRPs to restore the system balance. Both proactive and reactive TSO activation strategies are thus allowed by EB & SO GLs.	
6	Insufficient possibilities for supply of balancing energy (and capacity) by new BSPs (small generation facilities, demand response, storages) with constraints such as fixed energy constraints and/or load recovery effects.	In light of coupled heat- or process-driven production or demand, some BSPs are not willing to bind themselves contractually ahead of gate opening of balancing energy markets. Therefore, not requiring BSPs to close a contract for balancing capacity with a TSO before participating in balancing energy markets makes available a larger part of flexibility potential to the electricity system. This is already accounted for in legislation; Art. 16 (5) of EB GL provides the right to any BSP to provide balancing energy bids after passing the prequalification process. This is also known as the possibility of free bids. Art 16 (6) prohibits the predetermination of the price of balancing energy bids in a contract for balancing capacity. Free bids are already in place in some EU Member States for aFRR and many EU member states for mFRR. All EU Member States are required to allow for free bids of standard balancing products.	Once sufficient balancing energy providers are available this could potentially decrease the need for balancing capacity procurement well ahead of real-time by TSOs while maintaining the same level of operational security. Possibilities for flex provision by new BSPs could be further increased by procurement of aFRR and mFRR balancing capacity for shorter periods than days e.g. per block of 4 hours (cf. FCR) or even shorter time periods (1 hour).
7	High opportunity cost for VRE to participate in ancillary services markets due to production subsidies.	No RES production subsidies are allowed if prices are negative (EC (2014), point 124)), but Member States seem to have some discretion to limit applicability of this legislative measure to a consecutive number of hours.	In order to prevent that production subsidies for RES distort efficient system operation in general and participation in ancillary services markets in particular, several policy options can be pursued: 1) Strengthen requirement to one single hour rather than allowing for subsidies for consecutive hours with negative prices.

No	AS market design challenge	Measures already taken and being implemented at EU level	Recommendation for further action
			2) Changing production subsidies from energy to capacity-based. 3) Phasing out subsidies for new wind and PV installations given decreasing technology costs and sufficient revenue perspectives. Potential effects of these options on ramping, deterministic frequency deviations and voltage issues seem limited and manageable but should be monitored by TSOs.
8	Need for provision of downward balancing services by VRE given higher opportunity costs of thermal plants to provide downward balancing services during hours with high renewable energy production.	Asymmetric provision of FRR and RR obliged by EB GL, Art. 32 (3). Symmetric procurement of FCR is not yet addressed.	Study existing approaches for asymmetric provision of FCR in Belgium, Denmark, Greece and Norway, and consider to roll-out such an approach across whole EU.
9	Need for smaller bid sizes i.e. minimum bid volumes to allow for the effective participation of demand-side response, energy storage and small-scale renewables (DER) in balancing markets	For aFRR and mFRR, a minimum quantity of 1 MW for a standard balancing energy product is prescribed in Art. 7 of the implementation frameworks for both platforms (see ACER Decisions 02-2020 and 03-2020), based upon Articles 21 and 20 of GL EB, respectively. This requirement has to be fulfilled by 1 January 2022. For day-ahead and intraday markets minimum bid sizes of 500 kW or less are prescribed in Regulation (EU) 2019/943, Art. 8 (3).	It is questionable whether reduction of minimum bid sizes of balancing energy products to 500 kW has added value, since at some point the benefits from provision of balancing services will no longer outweigh the transaction costs involved (e.g. prequalification, data communication and trading costs). Therefore, in practice, further lowering bid sizes may not increase participation of DER in balancing markets. Rather, aggregation of resources until 1 MW may be preferred and sufficient.
10	Need for stronger coordination between TSOs and DSOs to allow all potential system users to provide ancillary services, including DER, without endangering network operational security.	Current EU rules for TSO-DSO coordination seem limited to generic provisions about TSO-DSO information exchange and cooperation in delivery of active power reserves. Furthermore, the DSO has the right to limit the provision of balancing services by DER for technical reasons such as its geographical location.	Additional rules are needed to secure that distribution networks are managed in an intelligent way such that the use of DER resources for solving distribution problems is optimized and the capability of DER to provide balancing services to TSOs is not unduly restricted.

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