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The EU Electricity Network Codes

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Abstract

The EU network codes and guidelines are a detailed set of rules pushing for the harmonisation of national electricity markets and regulations. A total of eight network codes and guidelines entered into force by the end of 2017: three grid connection codes (RfG NC, DC NC and HVDC NC), three market codes (FCA GL, CACM GL and EB GL), and two operation codes (SO GL and ER NC). The major part of this text covers the market codes. The reader is guided through the sequence of electricity markets in place in the EU: forward markets, the day-ahead market, the intraday market and finally the balancing markets. The establishment of these different markets in a national context is discussed and their integration. Additionally, also two connection codes (RfG NC and DC NC) are discussed; the scope of theses codes is described and technical requirements are clarified. Where relevant, the link between the system operation guideline (SO GL) and the market or connection codes is made. In each section, basic market design or more technical concepts are explained, we highlight what is in the codes, and we also refer to some of the relevant academic literature.

Keywords: *National electricity wholesale markets, Integration of national electricity wholesale markets, National electricity balancing markets, Integration of national electricity balancing markets, European regulation, Market design, Grid connection codes, requirements for generators, requirements for demand and distribution facilities*

Note: This report is an updated version of ''*Meeus, L., & Schittekatte, T. (2018). The EU electricity network codes. FSR Technical report. February 2018.''*

This version of the report includes:

- An additional chapter on Grid Connection Codes (CNCs)
- The incorporation of the extensive feedback from the 2nd wave of participants of the FSR EU Electricity Network Codes online training (Autumn 2018)
- Updated descriptions, statistics, figures and the inclusion of a selection of recently published methodologies

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Abbreviations

4MMC: 4M Market Coupling

AC: Alternating Current

ACER: Agency for the Cooperation of Energy Regulators

aFRR: Automatic Frequency Restoration Reserve

ATC: Available Transfer Capacity

AM: Availability Margin

BM: Balancing Market

BEPP: Balancing Energy Pricing Period

BRP: Balance Responsible Party

BSP: Balancing Service Provider

CACM GL: Capacity Allocation and Congestion Management Guideline

CBA: Cost-Benefit Analysis

CCC: Coordinated Capacity Calculator

CDSO: Closed Distribution System Operator

CE: Central Europe

CEP: Clean Energy Package for all Europeans

CEE: Central-East Europe

CEER: Council of European Energy Regulators

CCR: Capacity Calculation Region

CMOL: Common Merit Order List

CNCs: Grid Connection Codes

CNE: Critical Network Element

CNTC: Coordinated Net Transfer Capacity

CoBA: Coordinated Balancing Area

CWE: Central-West Europe

DA(M): Day-ahead (market)

DC: Direct Current

DC NC: Demand Connection Network Code

DER: Distributed Energy Resources

DG: Distributed Generation

DR: Demand Response

DR SFC: Demand Response System Frequency Control

DSO: Distribution System Operator

EB GL: Electricity Balancing Guideline

EB GCT: Energy Balancing Gate Closure Time

EC: European Commission

ENTSO-E: European Network of Transmission System Operators for Electricity

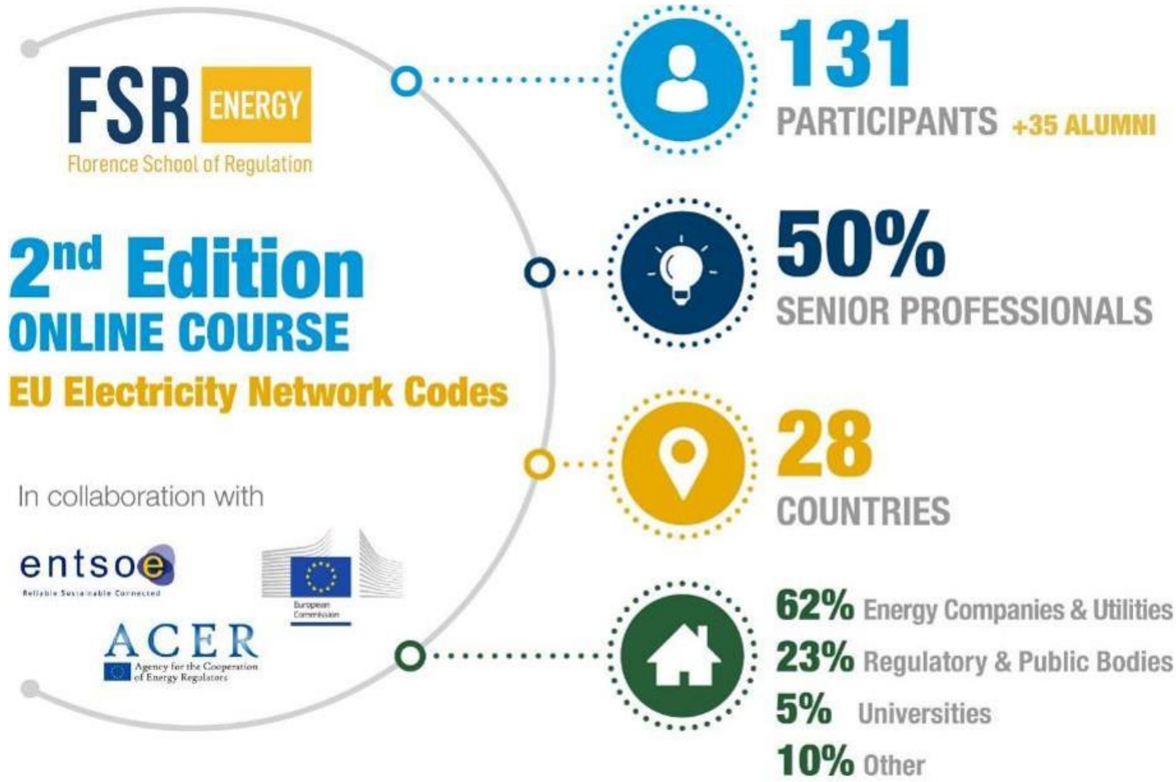
ERCOT: Electric Reliability Council Of Texas

ERGEG: European Regulators' Group for Electricity and Gas
EU: European Union
EUPHEMIA: EU Pan-European Hybrid Electricity Market Integration Algorithm
FRCE: Frequency Restoration Control Error
FB(MC): Flow-Based (Market Coupling)
FCA GL: Forward Capacity Allocation Guideline
FCP: Frequency Containment Process
FCR: Frequency Containment Reserve
FRP: Frequency Restoration Process
FRR: Frequency Restoration Reserve
FRT: Fault-Ride Through
FSM: Frequency Sensitive Mode
FTR: Financial Transmission Right
GCC: Grid Control Cooperation
GCT: Gate Closure Time
HMMCP: Harmonised Minimum and Maximum Clearing Prices
HVAC: High Voltage Alternating Current
HVDC: High Voltage Direct Current
HVDC NC: Requirements for the grid connection of HVDC systems and DC-connected power park modules to the interconnected system Network Code
Hz: Hertz
IDA: Intraday (Capacity Pricing) Auction
ID(M): Intraday (market)
IGD: Implementation Guidance Document
IN: Imbalance netting
INC: Imbalance Netting Cooperation
ISP: Imbalance Settlement Period
IEM: Internal Energy Market
IGCC: International Grid Control Cooperation
JAO: Joint Allocation Office
kVAr: kilo Volt-Amps-Reactive
LFC: Load-Frequency Control
LIPs: Local Implementation Projects
LOLP: Loss of Load Probability
MCO: Market Coupling Operator
mFRR: Manual Frequency Restoration Reserve
MO: Market Operator
MRC: Multi-Regional Coupling
MS: Member State of the EU
MTU: Market Time unit

MVAr: mega Volt-Amps-Reactive
MW: Mega Watt
MWh: Mega Watt Hour
NEMO: Nominated Electricity Market Operator
NRA: National Regulatory Authority
NRV: Net Regulated Volume
NTC: Net Transmission Capacity
OPPM: Offshore Power Park Modules
ORDC: Operating Reserve Demand Curves
OTC: Over-The-Counter
PCR: Price Coupling of Regions
PGM: Power-Generating Module
PPM: Power Park Module
PTDF: Zonal Power Transfer Distribution Factor
PTR: Physical Transmission Right
RfG NC: Requirement for Generators Network Code
RoCoF: Rate of Change of Frequency
RR: Replacement Reserve
RRP: Replacement Reserve Process
RSC: Regional Security Coordinators
RSCI: Regional Security Coordination Initiative
RSO: Relevant System Operator
SDAC: Single Day-ahead Coupling
SEE: South-East Europe
SGUs: Significant Grid Users
SIDC: Single Intraday Coupling
SO GL: System Operations Guideline
SPGM: Synchronous PGM
TSO: Transmission System Operator
UF: Unscheduled Flow
US: United States
VoLL: Value of Lost Load
vRES: variable Renewable Energy Sources (e.g. wind and solar)
XBID: Cross-Border Intraday Market Project

Acknowledgements

Participants from the first two editions of the course were invited to contribute to the text, and many of them did so very actively. Both previous edition of this course welcomed over 130 participants from many different countries, most of them senior professionals from the private and public sector. Below the infographic of the latest edition of the course is shown.



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1. Introduction

The development of network codes and guidelines has been identified as a crucial element to spur the ongoing completion of the internal energy market in the Third Energy Package. More specifically, Regulation (EC) 714/2009 sets out the areas in which network codes will be developed and a process for developing them. These codes are a detailed set of rules pushing for the harmonisation of previously more nationally oriented electricity markets and regulations. In 2017, after a 4-year-long co-creation process by ENTSO-E, ACER, the EC and many involved stakeholders from across the electricity sector, eight network codes and guidelines have been developed and entered into force. After the development of the network codes, the implementation phase started.

In its Clean Energy Package (CEP), issued in November 2016 and approved in late 2018, the European Commission proposed a recast of Regulation (EC) 714/2009. This recast includes provisions that would modify the operation of a number of the network codes and guidelines, in some cases quite significantly. For example, CEP provisions attempt to alter the amendment process for existing network codes/guidelines, and the drafting process for newly introduced network codes.[1] Also, additional areas for a ''second generation of network codes and guidelines'' were identified. Examples are rules on demand response, including aggregation, energy storage, and demand curtailment and rules for non-discriminatory, transparent provision of non-frequency ancillary services. These proposals are not covered in detail in this text.

1.1 **Three groups of network codes**

Eight network codes and guidelines came out of the co-creating process. At the time of writing, all eight have been published in the Official Journal of the European Union as European Commission implementing Regulations. Commission Regulations usually enter into force twenty days after publication, unless explicitly stated otherwise. These eight Regulations can be subdivided into three groups:

- The market codes:
    - The capacity allocation and congestion management guideline (CACM GL) – published on 25 July 2015
    - The forward capacity allocation guidelines (FCA GL) – published on 27 September 2016
    - The electricity balancing guideline (EB GL) – published on 23 November 2017
- The connection codes:
    - The network code on requirements for grid connection of generators (RfG NC) – published on 14 April 2016
    - The demand connection network code (DC NC) – published on 18 August 2016
    - The requirements for grid connection of high voltage direct current systems and direct current-connected power park modules network code (HVDC NC) – published on 8 September 2016
- The operation codes:
    - The electricity transmission system operation guideline (SO GL) – published on 25 August 2017

[1] For more details on the development and amendment process of network codes as proposed in the CEP, please consult a recording of the FSR online debate on this topic: https://www.youtube.com/watch?v=rjtX0RXc83Y&t=2533s or the FSR course text on the CEP by Meeus and Nouicer (2018).

- The electricity emergency and restoration network code (ER NC) – published on 24 November 2017

1.2 Network codes vs guidelines

The eight Commission Regulations in which common rules for the electricity system and market are described, often referred to as 'The network codes', are actually not all network codes by definition. Four out of eight are guidelines (CACM GL, FCA GL, EB GL and SO GL) and the other four are network codes (ER NC, RfG NC, DC NC and HVDC NC). All texts were initially planned to be network codes, and some became guidelines in the development process. Below similarities and differences between network codes and guidelines are listed.

Similarities:

- Both carry the same legal weight (both are Commission Regulations and are legally binding)
- Both are directly applicable – i.e. there is no requirement to transpose them into national law, although some countries still do where they impact a wide range of stakeholders
- Both are subject to the same adoption procedure (Comitology procedure)

Differences:

- Legal basis (Art. 6 for network codes & Art. 18 for guidelines of Regulation (EC) 714/2009)
- Amendment process (Art. 7 for network codes & Art. 18(5) for guidelines of Regulation (EC) 714/2009)
- Topics[2]
- Work to be done in the implementation phase

A significant difference is that guidelines include processes whereby Transmission System Operators (TSOs) or Nominated Electricity Market Operators (NEMOs)[3] must develop methodologies. In most cases, these methodologies have to be jointly developed by all TSOs or all NEMOs at the Pan-European level or by the relevant TSOs/NEMOs at regional level.[4] Besides TSOs and NEMOs developing methodologies, ENTSO-E, ACER and the EC also have several tasks. These tasks are mostly related to monitoring, stakeholder involvement and reporting.

In Box 1 an example of the development of a methodology is described. Network codes do not have such processes – the implementation process can proceed locally or regionally without further methodological development. The implementation process for Grid Connection Network Codes (CNC) is described in more detail in Chapter 8, Section 8.3.1.

[2] Guidelines and network codes can cover the same topics (Art. 18, Reg. (EC) 714/2009), however from practice it is observed that some topics lend themselves better to guidelines than to network codes and vice-versa.

[3] In short, NEMOs can be seen as power exchanges certified to organise cross-zonal electricity trade. Their functions are described in more detail in Section 4.1.

[4] ENTSO-E and ACER provide more information on the implementation status on their websites. For ENTSO-E please see: https://www.entsoe.eu/network_codes/ . For ACER, please see: https://acer.europa.eu/en/Electricity/Pages/default.aspx. ACER also published an implementation table for the CACM GL at https://acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/Pub_Docs/CACM%20implementation%20table.pdf.

Box 1: An example of the development of a methodology in the CACM GL: harmonised minimum and maximum clearing prices (HMMCP) in the Single Day-Ahead Coupling (SDAC).

In the CACM GL in Art. 41(1) it is described that by 18 months after the entry into force of the CACM GL (February 2017), all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single day-ahead coupling. All NEMOs shall submit the proposal to the regulatory authorities for approval (CACM GL, Art. 41 (2)).

Before submitting the all NEMOs proposal to all National Regulatory Authorities (NRAs), first, in order to allow for stakeholder involvement, a public consultation and stakeholder workshop was held. During the public consultation held between 3 November 2016 and 2 December 2016, all relevant stakeholders had one month to provide their comments on a draft proposal. Such step is common practice for the development of most methodologies (CACM GL, Art. 12(1)). After, NEMOs took stock of the comments of the stakeholders, the methodology was submitted to all NRAs on the 14 February 2017. For more information on how stakeholder comments should be addressed see CACM GL, Art. 12(3). After submission, the NRAs can approve the methodology, ask to amend it or fail to reach an internal agreement. The NRAs have 6 months to make a decision (CACM GL, Art. 9 (10)). In this case, the NRAs did not reach an internal agreement regarding the approval of the methodology. More precisely, on 24 July 2017, all NRAs agreed to request the Agency for the Cooperation of Energy Regulators (ACER) to adopt a decision on the harmonised minimum and maximum clearing prices for SDAC, pursuant to Article 9(11) of the CACM GL.[5] Before ACER took the final decision, it launched a public consultation. This public consultation lasted from 24 August 2017 until 15 September 2017. Finally, on 14 November 2017 ACER published its final decision.

It does not mean that because a methodology is adopted that it is implemented immediately. In the final decision by ACER the timeline for the implementation is specified. It is stated that the NEMOs shall implement the harmonised minimum and maximum clearing prices for SDAC in all bidding zones participating in the SDAC immediately after the MCO function has been implemented in accordance with Article 7(3) of the CACM GL.

In general, network codes are more detailed than guidelines. Nonetheless, still many choices have to be made when implementing the network codes nationally. The choices to be made when implementing for example the connection network codes relate mainly to deciding upon thresholds for categories used for classification purposes or to the determination of the value of a specific parameter for a certain technical requirement. In contrast, guidelines shift a larger share of the further development to the implementation phase by requesting the development of methodologies. Shifting tasks to the implementation phase can allow for more flexibility but might also slow down or complicate the overall process. There is also a risk that with guidelines, due to the requirement to develop methodologies, overlaps between different deadlines are generated. More precisely, there are local and regional compliance requirements (e.g. regional outage coordination (SO GL, Article 98(3) and Article 100(4.b)) with predetermined deadlines which rely on methodologies (e.g. methods for calculating the influence of an asset on the system (SO GL, Art. 75(1.a)) of which the date of finalisation is uncertain. The implementation processes of these local and regional requirements can be challenging in case they need to commence before the finalisation of the methodologies on which their implementation depends.

[5] For a deeper discussion on ACER's decision powers regarding the approval of methodologies please see 'Exploring ACER's decision-making powers' by P. Willis posted on 24/08/17, link: https://www.twobirds.com/en/news/articles/2017/global/exploring-acers-decision-making-powers

1.3 Focus of this report

This report focuses on electricity markets in the EU, their integration and the harmonisation of grid connection requirements.

Chapter 2 to 7 of this report focus on electricity markets in the EU and their integration. There is no single electricity market in place, but rather a sequence of markets as explained in the next section. The network codes and guidelines aim at harmonising these different markets to allow for integration. As described in Jamasb and Pollitt (2005), efficiency gains can be realised through market integration and trade as by integrating markets better use can be made of the resource diversity in the EU and across national markets. Also, by integrating markets more competition in the generation of electricity is introduced. The fundamentals of the electricity markets are described in this report and interactions with network codes and guidelines are highlighted.[6] The most relevant network codes when talking about electricity markets are the market codes (CACM GL, FCA GL and EB GL).

The last chapter focuses on the grid connection network codes (CNCs), more specifically on the network code on Requirements for Generators (RfG NC) and the Demand Connection Network Code (DC NC). The idea behind the CNCs is that in order to allow for a secure operation of the interconnected system, the electricity network and the grid users (being it generation or demand), are interdependent and should be seen as one entity from a system engineering point of view. Therefore, relevant technical requirements for the grid users when connecting to the network should be specified to guarantee secure system operation. These requirements intend to respect the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved. The CNCs aim at the harmonisation of these requirements across Europe to an extent that will facilitate the internal electricity market and foster the large-scale integration of renewable generation and demand response. The CNCs also acknowledge that local characteristics shall be taken into account.

Lastly, also the SO GL is of importance in this respect as electricity markets and secure grid connections cannot be decoupled from system operation.

[6] This report treats mainly the text of the guidelines. The technical details of the methodologies, described in the guidelines and for which in most cases the development is ongoing, are generally out of scope.

2. Introduction to electricity markets and links with the grid

This chapter consists of three parts. First, we explain why Europe has not one but multiple electricity markets. After, we describe in more detail this sequence of markets. Lastly, key concepts relevant to how electricity markets and physical grids are interlinked in the EU context are illustrated.

2.1 Why do we have so many electricity markets?

Electricity can be considered as a commodity, just as copper, oil and grain are.[7] However, electricity markets do differ substantially from markets for copper, oil and grain. The underlying reason for these differences are the physical characteristics of electricity:[8]

- *Time*: large volumes of electricity cannot be stored economically (yet). Therefore, electricity has a different cost and value over time.

- *Location*: electricity flows cannot be controlled easily and efficiently, and transmission components must be operated under safe flow limits.[9] If not, there is a risk of cascading failures and black-outs. Therefore, electricity has a different cost and value over space.

- *Flexibility*: demand can vary sharply over time, while some power stations can only change output slowly and can take many hours to start up. Also, power stations can fail suddenly. Demand and generation must match each other continuously, if not, there is a risk of black-out. Therefore, the ability to change the generation/consumption of electricity at short notice has a value.

These three unique physical characteristics can explain why there is not just one electricity market. Electricity is not only energy in MWh. Transmission capacity and flexibility are scarce resources and should be priced accordingly.[10] Therefore, electricity (energy, transmission capacity, flexibility) is exchanged in several markets until the delivery in real-time.

2.2 Electricity market sequence

Different markets allow the pricing of the 'invisible' components of electricity and function as a sequence. In Figure 1 the successive markets along the three electricity components are shown. Additionally, the relevant guidelines are displayed per market. It should be noted that next to trading through organised electricity markets (power exchanges), energy can also be traded bilaterally over-

[7] Two characteristics distinguish commodities from other goods such as watches, phones and clothes. First, it is a good that is usually produced and/or sold by many companies. Second, it is uniform in quality between companies that produce and sell it.

[8] Electricity is not only unique due to its physical characteristics. It can be considered an essential good with relatively (at least until very recently) inelastic end-consumers. This is one of the reasons why, even after the liberalisation of the electricity sector, national regulatory authorities specifically mandated for electricity were established. For a more complete overview of why and how to apply electricity regulation please consult e.g. Chapter 3 in Pérez-Arriaga (2013).

[9] This is true for alternative current (AC) power lines. Today, the meshed onshore grid in continental Europe consists mainly of AC lines. Direct Current (DC) power lines are more controllable. For a technical discussion on AC and DC lines, please consult Van Hertem and Ghandhari (2010).

[10] In this text, we focus on transmission capacity when describing the workings of EU wholesale electricity markets. At the time of writing, wholesale electricity markets interact mainly with the transmission system. The interaction between EU wholesale electricity markets and distribution systems is limited. However, it is expected that in the near future the focus will be enlarged with more resources connected to the distribution system participating in the wholesale electricity markets.

the-counter (OTC) – whereby market participants (electricity generators, retailers, large consumers, and other financial intermediaries) agree on a trade contract by directly interacting with each other. In this text, electricity exchanges are the focus. Unlike bilateral contracts, products on exchanges are tradable, implying transparent prices.

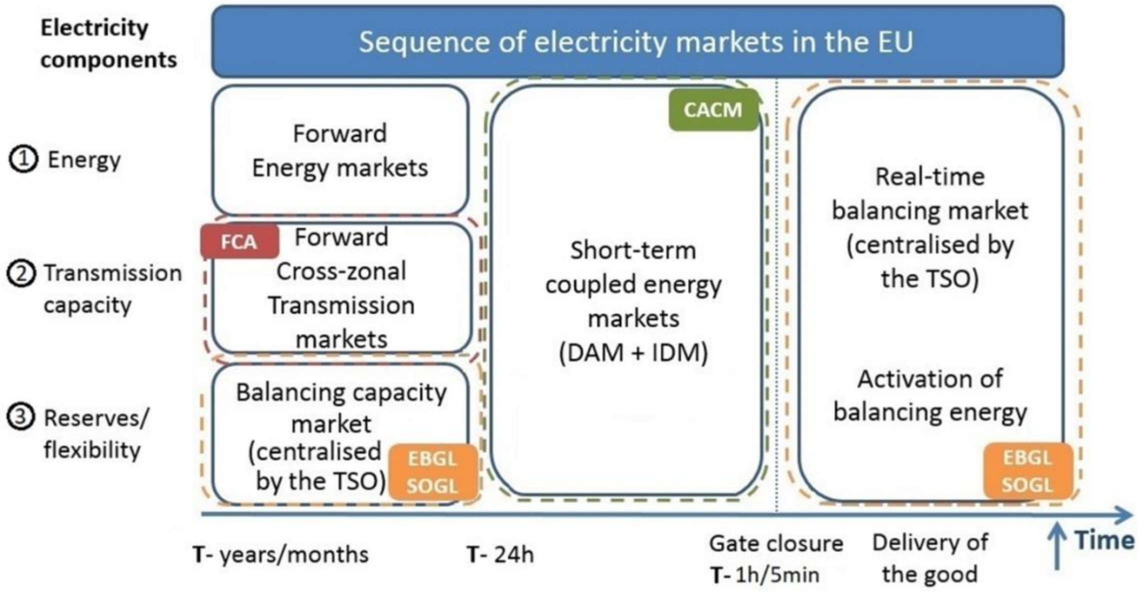


Figure 1: The sequence of electricity markets in the EU and related network codes and guidelines (Adapted from FSR (2014)).

Trading of electricity, with physical delivery or purely financially, can start many years ahead in forward markets.[11] These markets can continue until one day before delivery. The primary purpose of these long-term markets is to allow hedging for producers and consumers. Long-term cross-zonal transmission rights are traded separately from long-term contracts for energy through auctions. Transmission rights allow for hedging of price differences between bidding zones.[12] Long-term cross-zonal transmission capacity markets are the focus of the FCA GL and are described in more detail in Chapter 3 of this report. Both physical and financial long-term transmission rights are discussed.

Closer to delivery, electricity is traded in short-term markets. Generally, it is accepted that short-term markets are comprised of the day-ahead market, intraday markets and the (near) real-time balancing market. The day-ahead market, as the name indicates, is an auction held the day before the delivery of electricity. Market participants that have not yet committed their electricity supply or demand through bilateral contracts submit their bids to the market operator (MO). The MO, described in more detail in Section 4.1, clears the auction and obtains the preliminary schedule results for the following day. The working and main characteristics of day-ahead markets are described in Section 4.2. At the time of writing, in most cases in the EU, transmission capacity is allocated jointly (implicitly) with energy in the day-ahead market. This process is called market coupling. The integration of the day-ahead market is the focus of Section 5.1.

[11] In the financial literature, long-term markets with standardised products are called 'futures markets', while long-term markets with unstandardised products are called 'forward markets'. In this report, we use the term 'forward markets', however a distinction is made between trading in exchanges (standardised) and trading over-the-counter (unstandardised). The focus in this text is on trading through exchanges.

[12] Bidding zones are explained in the Section 2.3.1. A bidding zones is defined as the largest geographical area within which market participants can exchange energy without capacity allocation.

After the day-ahead market, producers and consumers have the possibility to adjust their positions through intraday markets. Intraday markets are organised as continuous markets, with possible complementary auctions. Intraday markets and their integration are described in detail in Section 4.3 and Section 5.2, respectively. The design rules and the ways to integrate day-ahead markets and intraday markets are outlined in the CACM GL. Intraday trading is possible until a moment in time called the intraday gate closure time (GCT). After the GCT, the final production schedule is determined for all participants and only the TSO can act to adjust any deviation. The mechanism used to ensure that supply equals demand in real-time is called the balancing mechanism.

The balancing mechanism is supported by two balancing markets. The first is a balancing market for capacity. This market takes place from one year up to one day before real-time, the exact timing is not harmonised in the EU at present. Generators or demand are contracted to be available to deliver balancing energy in real-time. Second, there is a balancing market for energy. In this market the participating generators or demand indicate the price they want to receive to increase or decrease their energy injection or withdrawal in real-time. These bids/offers are supposed to have been submitted before the balancing energy gate closure. Generators/demand contracted in the balancing capacity market are obliged to participate in the balancing energy market.[13] In real-time, the TSO activates the least-cost resources with the requested technical capabilities to fix imbalances between generation and consumption. The balancing mechanism is the focus of the EB GL. Also, the SO GL is important for this market segment as more details on the types of reserves, their sizing and the roles and responsibilities for ensuring real-time balance are described in that guideline. The balancing mechanism and its integration are the topics of Chapters 6 and 7, respectively. In some cases, the balancing mechanism is also used as the means of procuring some non-frequency ancillary services, such as reactive power.[14] This aspect of the balancing mechanism is not discussed further here.

2.3 The link between markets and grids in the EU: key concepts

As mentioned in the beginning of this chapter, electricity transmission capacity is scarce. An important market design question that needs to be answered is how to deal with the complex physical reality of the grid when trading electrical energy. To tackle this question, this chapter is split into three sections.

- The first subsection focuses on the important concept of bidding zones. In the same section, zonal pricing and the difference between bidding zones and control areas is explained.

- The second subsection introduces the concept of capacity calculation regions. It describes the way interdependent cross-zonal transmission capacity calculation is organised. The focus is on the governance framework; the (more technical) methodologies for calculating the transmission capacities are explained in Subsection 5.1.2. Furthermore, the link between capacity calculation regions and regional security coordinators is explained.

[13] It is not necessary, in some Member States at least, to participate in the balancing market for capacity in order to participate in the balancing market for energy.

[14] For example: Ireland and Northern Ireland, for more information see chapter 8.3 of https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-026%20I-SEM%20ETA%20Markets%20Consultation%20Paper_0.pdf

- The third subsection introduces denotations of geographical areas relevant for balancing and system operation and links these areas back to bidding zones and control areas described in the first section of this chapter.

2.3.1 Local: Bidding Zones (market) and Control Areas (grid)

How can electrical energy trading and physical network flows be matched? The chosen approach to this problem applied in the EU today is called zonal pricing. Zonal pricing means that wholesale electricity prices can differ between zones in Europe, so-called bidding zones, but are homogeneous within a particular zone. From the market perspective, the network within a bidding zone is considered to be a copper plate – physical capacity is treated as infinite.

Different bidding zones are electrically connected by cross-zonal interconnectors. If a cross-zonal connector between two bidding zones is not fully utilised (no congestion) during a certain period of time, the wholesale electricity prices of the two zones converge for that period. The markets are fully coupled. However, when the cross-zonal interconnectors are congested, the prices between the two bidding zones can diverge for that period. The markets of the two bidding zones are in that case split. The price differential between the two bidding zones is called the congestion rent, and this is a revenue for the TSOs owning the interconnection.[15]

It can happen that the outcome of the market, also called the 'nominations' of producers and consumers, results in unfeasible network flows within a bidding zone. In that case, the TSO, operating the part of the network within the bidding zone where the problem occurs will have to take remedial actions. According to the terminology applied by ACER and the Council of European Energy Regulators (CEER), there are different types of remedial actions. Changing grid topology is a preventive remedial measure that does not result in significant costs for the TSO. Conversely, redispatching, counter-trading and the curtailment of already allocated capacity are curative and costly measures (ACER and CEER, 2016). These concepts are further developed in Section 4.4.

Bidding zone configurations are reviewed periodically and, once defined for a certain period, are constant throughout all market time frames (long-term, day-ahead, intraday and real-time). The criteria for reviewing bidding zones are outlined in Art. 33 of the CACM GL: (a) network security; (b) overall market efficiency; (c) stability and robustness of bidding zones. Because of historical reasons, bidding zones in Europe are very similar to country borders. In Figure 2 (left) the bidding zone configuration as it is in 2017 is shown.[16]

[15] For example, imagine that during a certain hour the interconnectors between two bidding zones are congested. The price in one bidding zone equals 30 €/MWh and 40 €/MWh in the other. The interconnection capacity between the two bidding zones is 500 MW. This means that the congestion rent equals 5,000 € in this hour. Please note that in some cases a transmission line can also be owned by a private party other than a TSO. For more information on 'market-driven' merchant transmission investment please consult e.g. Joskow and Tirole (2005). Please also note that the way that TSOs spend this congestion revenue is strictly regulated, for more info see for example ECN et al. (2017).

[16] A bidding zone review study has been carried out by ENTSO-E in March 2018: https://www.entsoe.eu/news/2018/04/05/first-edition-of-the-bidding-zone-review-published/

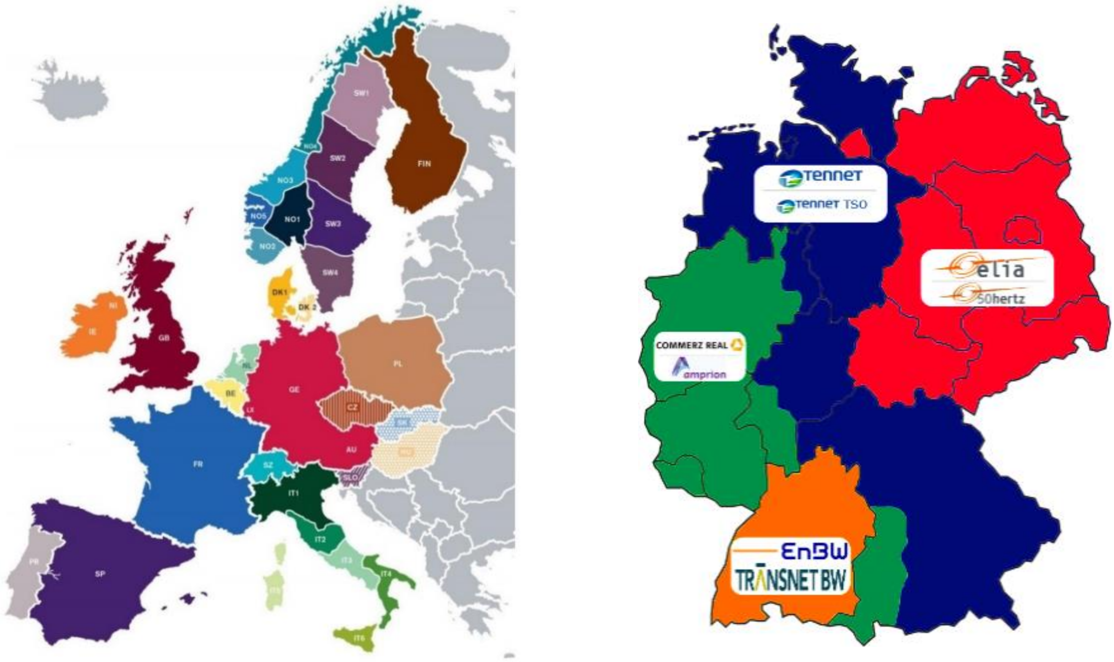


Figure 2: Left – Bidding zones in 2017 before the German-Austrian bidding zone split (Ofgem, 2014). Right – Control areas in Germany (group/TSO) (Wikiwand, 2017).

Two concepts which can be easily confused are bidding zones and control areas. A control area is defined as a coherent part of the interconnected system, operated by a single system operator. The system operator is responsible for maintaining the operational security of its control area. In Europe, the TSO is the entity which operates the transmission system and manages and owns the transmission assets.[17]

In most cases, though not all, the control area matches the bidding area. For example, the Belgian territory is covered by one control area and one bidding zone. The transmission network is owned and operated by one TSO, Elia. There are also countries with more control areas than bidding zones. An example is Germany. The German territory is divided into four control areas, as shown in Figure 2 (right). The country is covered by one bidding zone (together with Luxemburg).[18] Lastly, there are also countries with more bidding zones than control areas. Sweden is an example of a country in which the boundaries of the control area correspond to the national borders. There is one Swedish TSO, Svenska Kraftnät, and the country is split up into four bidding zones.

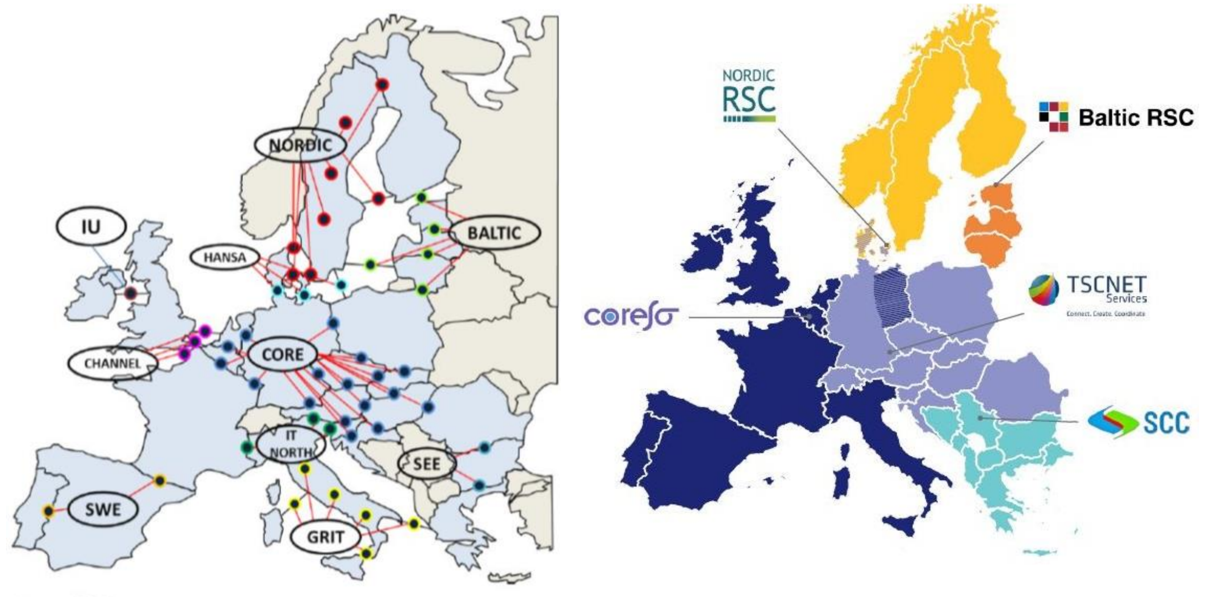
[17] This is true for most European countries with exceptions e.g. in Great Britain and Cyprus, where the 'Transmission System Operator and 'Transmission System Owner' are different entities. Also, in the Americas the transmission system is not necessarily operated by the same entity that manages and owns the transmission assets. For a discussion on this matter please see e.g. Chawla and Pollitt (2013).

[18] Until 30 September 2018, Germany, Austria and Luxemburg constituted one bidding zone. In September 2015, ACER issued a legally non-binding opinion to split the German(DE)/Luxembourg(LU)-Austrian(AT) bidding zone (ACER, 2015d). After, in November 2016, ACER decided to include the introduction of a new bidding zone border between DE and AT in its Capacity Calculation Regions (CCRs). Later, in early September 2018 the implementation of congestion management scheme on the DE-AT border was approved by the competent regulatory authorities of the Central Western Europe (CWE) region. As of 1 October 2018, the DE/LU-AT bidding zone was split into the DE/LU and the AT zones and a congestion management scheme was implemented on the border. Source: http://www.jao.eu/news/messageboard/view?parameters=%7B%22NewsId%22%3A%226ad4b0fc-3273-4300-ac07-a9570095b5da%22%7D

2.3.2 Regional: Capacity Calculation Regions (market) and Regional Security Coordinators (grid & market)

To ensure that the cross-zonal transmission capacity calculation is reliable and that the optimal level of capacity is made available to the market, regional coordination between the TSOs operating the bidding zone borders is required. This is true as electricity flows in a meshed network are highly interdependent due to their physical nature.

In order to facilitate coordination, Art. 15 of the CACM GL requires Capacity Calculation Regions (CCRs) to be determined. A CCR is a geographic area in which coordinated capacity calculation is applied. Each CCR comprises a set of bidding zone borders. In October 2015, ENTSO-E submitted a first proposal for CCRs to all regulatory authorities for approval (ENTSO-E, 2015a). The regulatory authorities failed to reach an agreement regarding this proposal within a predefined six-month period (CACM GL, Art. 9(11)). Therefore, ACER had to decide. Finally, ACER approved the proposal, under the condition of merging Central West Europe (CWE) and Central Eastern Europe (CEE) into one CORE region (ACER, 2016a). Figure 3 (left) shows a map of the CCRs as they are delineated on the 1st of January of 2019 .In the long-term, the idea is to merge more and more CCRs, if feasible.



Source: ACER.

Figure 3: Left – The Capacity Calculation Regions (CCRs), status as on the 1st of January 2019 (ACER, 2019a) Right – Map of the Regional Security Coordinators in Europe as established by the end of 2016 (ENTSO-E, 2019).

CCRs are of importance in all market codes (FCA GL, CACM GL and EB GL) and in the SO GL. In short, for all time frames the capacity calculation should be done with a harmonised methodology per CCR.[19] In the CACM GL it is also outlined that all the TSOs in each CCR shall jointly set up the coordinated capacity calculators and establish rules governing their operation. Coordinated capacity calculators have the task of calculating transmission capacity, at regional level or above. The coordinated capacity

[19] The 'all time frames' being: long-term (FCA GL, Art. 21(2)), day-ahead (CACM GL, Art. 29 and 46(1)), intraday (CACM GL, Art. 29 and 58(1)) and the balancing time frame for the exchange of balancing energy for operating the imbalance netting process (EB GL, Art. 37(3)) and for the allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves (EB GL, Art. 38(2)).

calculator should receive the necessary inputs from all concerned TSOs to perform the computation of available capacity (for long-term, day-ahead, intraday and balancing markets) on all bidding zone borders within its CCR. A crucial tool that is created for this purpose is the common grid model, of which the principles are described in a methodology following FCA GL (Art. 18) and CACM GL (Art. 17).[20]

Entities strongly tied with CCR are Regional Security Coordinators (RSC) whose role was established in EU law with the adoption of the SO GL. In the SO GL it is stated that each control area shall be covered by at least one RSC. RSCs are owned or controlled by TSOs and perform tasks related to TSO regional coordination (SO GL, Art. 3(89)). The predecessors of RSCs were set up as voluntary initiatives (RSCIs) by TSOs in 2008, with CORESCO (based in Brussels) and TSCNET services (based in Munich) as pioneers in Continental Europe. In 2015, one RSCI was created in South East Europe (SEE) in Belgrade. (Voluntary) RSCIs evolved into (mandatory) RSCs. Finally, in 2016, also Nordic and Baltic RSC were established (ENTSO-E, 2019). An overview of the geographical coverage of the five established RSCs is shown in Figure 3 (right).

RSCs are active in one or more CCRs and have five core tasks (ENTSO-E, 2017a). These tasks are mostly related to grid security (for more details, see e.g. FTI-Compass Lexecon (2016)).[21,22] A RSC issues recommendations to the TSOs of the capacity calculation region(s) for which it is appointed. TSOs should then, individually, decide whether or not to follow the recommendations of the RSC. The TSO has the final responsibility for maintaining the operational security of its control area. One of the tasks of the RSCs is also coordinated capacity calculation. The link between the coordinated capacity calculators (FCA GL and CACM GL) and RSCIs (later RSCs in SO GL) is described by ENTSO-E (2014a, p.4): '*For one Capacity Calculation Region with more than one established RSCIs, at a given point in time, one RSCI will be responsible for assuming the function of the Coordinated Capacity Calculator. Other RSCIs having responsibilities within this Coordinated Capacity Calculation Region can assume this function at any time, as a back-up option. This scheme ensures consistency between coordinated capacity calculation and coordinated security assessment.*'

2.3.3 Balancing Areas: in between markets and grids

In order to fully grasp the way balancing is conducted in the EU, as described in Chapter 6, some additional concepts related to geographical areas of importance for the balancing mechanism need to be introduced. Also, links between the new balancing concepts and previously introduced bidding zones and control areas are made in this section.

In Figure 4, the terminology used to indicate geographical areas in the FCA GL/CACM GL (markets), EB GL (balancing) and the SO GL (system operation) are summarised. Balancing is done by means of a market-based process in the EU. However, it cannot be fully decoupled from system operation as this

[20] According to CACM GL (Art. 2(2)), a common grid model is defined as a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.

[21] Additionally, in the Emergency and Restoration Network Code (ER NC) it is described that RSCs will be consulted to assess the consistency of measures described in a system defence and restoration plan of a TSO with the corresponding measures in the plans of TSOs within its synchronous area and in the plans of neighbouring TSOs belonging to another synchronous area (ER NC, Art. 6(3)).

[22] In the recently adopted Clean Energy Package, RSCs are relabelled as Regional Coordination Centres (RCCs) and additional tasks are added on top of the five described in the network codes and guidelines.

process takes place very close to or in real-time. Therefore, geographical concepts in the EB GL can be more market-related or more system operation-related, depending on which part of the balancing code is considered. The largest geographical area in the EU is the Internal Energy Market (IEM) and the smallest building block is a scheduling area.

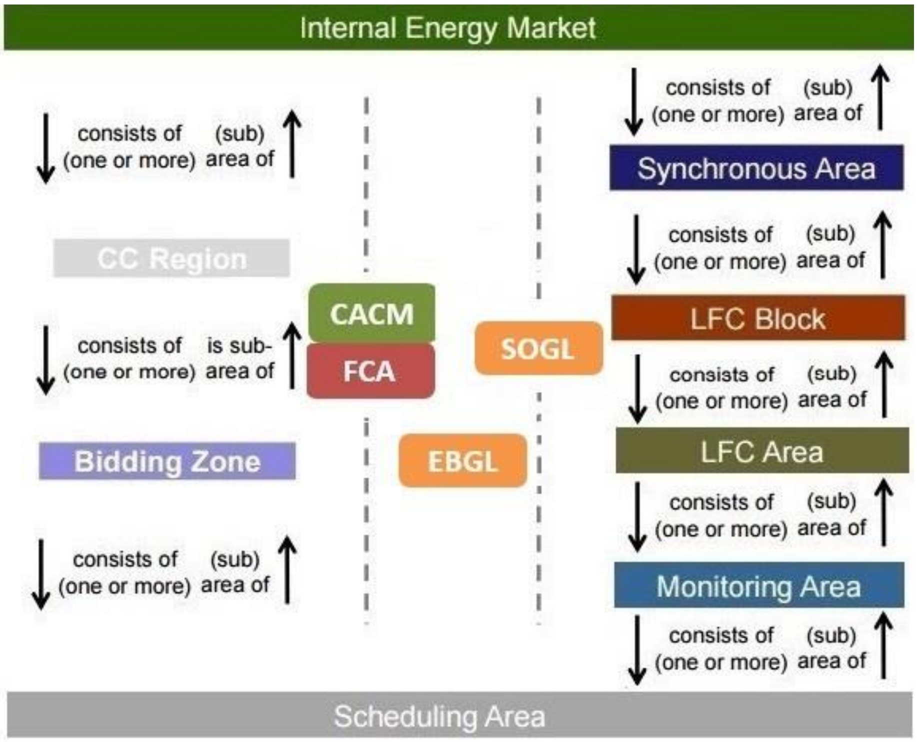


Figure 4: FCA GL/CACM GL (markets) vs EB GL (balancing) vs SO GL (system operation) terminology to denote geographical areas (adapted from ENTSO-E, 2014b).

The IEM is split up into different synchronous areas, as shown in Figure 5 (left), which are defined as '*areas covered by synchronously interconnected TSOs, such as the synchronous areas of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as 'Baltic' which are part of a wider synchronous area*' (RfG NC, Art. 2(2)). Synchronous areas are mainly important for the fastest types of reserves called Frequency Containment Reserves (FCR) which are dimensioned and operated at this scale.[23] The different types of reserves, their dimensioning and functioning are described in Chapter 6.

Also, the notion of a Load-Frequency Control (LFC) Block is important as this is the geographical area over which reserves (other than the fastest type) ought to be dimensioned by the SO GL. The SO GL (Art. 3(18)) defines an LFC Block as '*a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC blocks, consisting of one or more LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control.*'. Article 141(2) of the SO GL requires all TSOs of a synchronous area to jointly develop proposals regarding the determination of the LFC blocks. Figure 5 (right) shows how the LFC Blocks are organised. In the GB synchronous area, the TSO proposal was approved by the NRA in July 2018. The NRAs of the Continental Europe synchronous area approved the TSOs' proposal after amendment requests in August 2018, the Nordic NRAs followed in September 2018 for their synchronous area. At

[23] The main task of the FCR is to dampen/stop a sudden drop or rise in system frequency.

the time of writing, the amended TSOs’ proposal for Ireland and Northern Ireland was forwarded to the relevant NRAs.

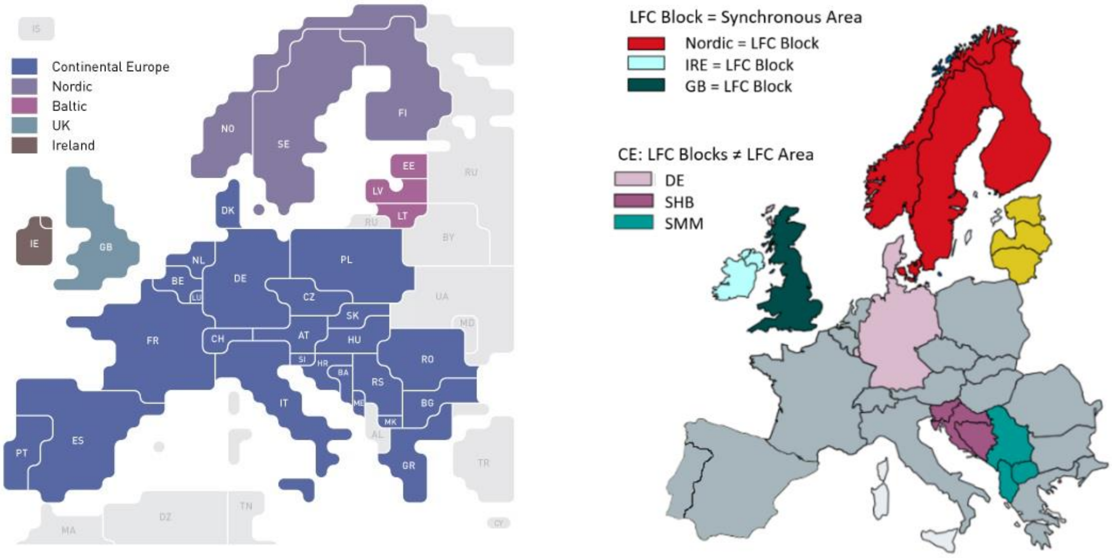


Figure 5: Left – the different synchronous areas in Europe as in 2018 (ENTSO-E, 2014c). Right – the different LFC blocks and LFC areas as in 2018 – For the areas in grey the LFC block equals the LFC area which equals the control area (adapted from ENTSO-E, 2018a).

The frequency restoration process is (jointly) operated by the TSO(s) of a Load-Frequency Control (LFC) Area (SO GL, Art. 141(4b)).[24] In the SO GL (Art. 3(12)) a LFC Area is defined as ‘*a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC Areas, operated by one or more TSOs fulfilling the obligations of load-frequency control.*’ A Monitoring Area is defined in SO GL (Art. 3(145)) as ‘*a part of the synchronous area or the entire synchronous area, physically demarcated by points of measurement at interconnectors to other monitoring areas, operated by one or more TSOs fulfilling the obligations of a monitoring area’*. The real-time active power interchange of the monitoring area is constantly tracked by all TSOs in each monitoring area (SO GL, Art. 141(3)). In most cases, the LFC Area is equal to the Monitoring Area and to the TSOs' control area (ENTSO-E, 2014b).

Finally, a Scheduling Area is considered the smallest building block for system operation. It is equal to one or more control areas, but can never be bigger than a bidding zone. More precisely (SO GL, Art. 110(2)):

- Where a bidding zone covers only one control area (e.g. Belgium), the geographical scope of the scheduling area is equal to the bidding zone.
- Where a control area covers several bidding zones (e.g. Sweden), the geographical scope of the scheduling area is equal to the bidding zone.

[24] This process is operated at LFC area scale but is well-coordinated with the synchronous area. The frequency restoration process can be described as the process in which reserves are activated to release FCR activated at synchronous area scale and to restore the frequency back to the nominal value if imbalances between generation and consumption occur in real time. In more technical terms, the frequency restoration control error (FRCE) is regulated towards zero.

- Finally, where a bidding zone covers several control areas (e.g. Germany), TSOs within that bidding zone may jointly decide to operate a common scheduling process. Otherwise (i.e. if the TSOs do not decide to operate a common scheduling process), each control area within that bidding zone is considered a separate scheduling area.

The notion of scheduling area is important because important actions related to the balancing mechanism are done at the level of the scheduling area, i.e.:

- Contractual positions by Balance Responsible Parties (BRPs) are communicated to the TSO of the scheduling area (SO GL, Art. 111(1))
- The imbalance measurement is done per scheduling area. In other words, the imbalance area equals the scheduling area.[25] The only exception to this rule is the case of a central dispatching model where imbalance area may constitute a part of scheduling area (EB GL, Art. 54(2)).
- The Balancing Service Providers (BSPs) participating in the balancing capacity or balancing energy market and the associated BRPs belong to the same scheduling area (EB GL, Art. 16(8)).[26,27]

[25] EB GL (Art. 2(8)) defines an imbalance as the energy volume calculated for a BRP and representing the difference between the allocated volume attributed to that BRP and the final position of that BRP, including any imbalance adjustment applied to that BRP, within a given imbalance settlement period. The imbalance area is defined as the area in which an imbalance is calculated (EB GL, Art. 2(11)).

[26] EB GL (Art. 18(4.d) requires that each balancing energy bid from a BSP is assigned to one or more BRPs to enable the calculation of an imbalance adjustment. The adjustment is used for calculating the imbalance of these BRPs.

[27] The integration of balancing capacity and energy markets between scheduling areas is the focus of Chapter 7.

3. Forward markets

Trading of electricity, either with physical delivery or purely financially, can start many years ahead of real-time in forward markets. Trading in these markets can continue until one day before delivery. Competitive and liquid forward markets are essential for market participants to hedge their short-term price risks. Prices in shorter-term electricity markets can fluctuate, e.g. due to high/low renewable energy infeed or changing demand patterns. Also, well-functioning short-term markets can deliver sharp scarcity prices. These scarcity prices are crucial to signal the need for flexibility at a particular time and place and to incentivise new investment (adequacy) in the longer run. However, not all producers want their business case to be dependent on hard-to-forecast fluctuating prices and occasional price spikes. Also, large consumers or retailers might want to stabilise their expenditure. Therefore, there is a demand for forward markets with long-term contracts for electricity supply. Newbery (2016) states that '*a lack of forward markets and long-term contracts might not be so critical if the future were reasonably predictable and stable, but that this is far from the case at present*.' Also Genoese et al. (2016) and Neuhoff et al. (2016c) argue that the provision of long-term price signals will become (even) more important in the future, one important argument is that long-term contracts can reduce the cost of capital of renewables and flexible generation, characterised by high upfront investment costs.

The integration of forward energy markets is crucial to allow a more efficient functioning and higher degrees of the necessary liquidity. Therefore, long-term cross-zonal transmission rights are auctioned. By acquiring these rights, market participants can trade cross-zonal in forward markets. Without these rights, the risk related to price differentials between different bidding zones can significantly reduce the appeal of such cross-zonal trades. Also, cross-zonal transmission rights are of importance to be able to hedge risk across different time frames within a certain bidding zone. This would be the case when there is limited variation in the duration of long-term electricity contracts in a given bidding zone, while in another bidding zone (a so-called hub) a greater range of contracts with different durations are offered.

First, forward energy markets are introduced in this chapter. After, the integration of forward markets is discussed and the implications of the FCA GL are highlighted.

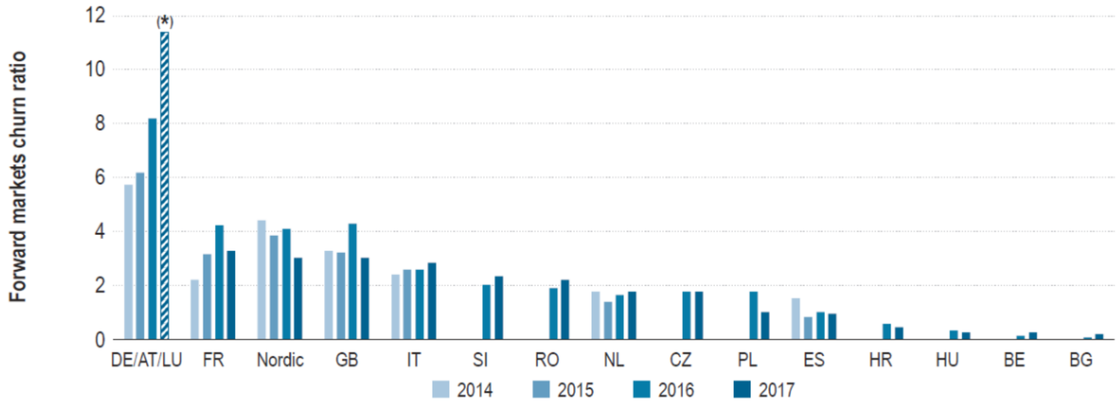
3.1 **Forward energy markets**

Long-term electricity contracts can be traded on unstandardised forward and standardised future markets. The design of the (national) forward electricity markets is not covered by the network codes. Instead, the allocation of long-term cross-zonal transmission rights are the focus of the FCA GL.

The analysis in ACER and CEER (2018) shows that the liquidity of forward markets in Europe remained modest or low in 2017, except in Germany/Austria/Luxemburg, France, the Nordics and Great Britain.[28] Figure 6 shows the churn ratio for the largest European forward markets. The churn ratio is a way to measure liquidity and is defined as the ratio of the volumes traded in forward markets over the final

[28] In their market monitoring report ACER and CEER (2018) note that no direct correlation between the size of the bidding zone and the liquidity of the forward market can be established. Large bidding zones (e.g. Spain or Portugal) record low liquidity in forward markets, while liquidity is among the highest in Europe in some geographical areas with relatively small bidding zones, such as the Nordic area.

physical consumption. A churn factor of three could be considered to be a minimum value (ACER and CEER, 2016). Yet, few countries reach that threshold. It is also important to note that liquidity decreases with increasing forward periods (Genoese et al., 2016).



Source: European Power Trading 2018 report, © Prospex Research Ltd and NRAs (2018).
Note: The figure shows estimates of total volumes traded as a multiple of consumption from Eurostat (see footnote 107).

Figure 6: Ratio of traded volume in forward markets over consumption (ACER and CEER, 2018).

3.2 Integration of forward markets: long-term (cross-zonal) transmission (capacity) rights

Long-term cross-zonal transmission rights are a necessary tool to allow for a further integration of electricity markets. In the recent past, the rules regulating long-term cross-zonal transmission capacity could differ from one bidding zone border over another. On some border, there were simply no cross-zonal hedging tools offered to market parties. As a result, high absolute values of assessed risk premia in the valuation of transmission rights persisted or hedging needs were not met, as for example pointed out in the market monitoring report of ACER and CEER (2016).[29]

The goal of the FCA GL guideline is to foster the trade in long-term cross-zonal transmission capacity rights. With FCA GL in force, TSOs are obliged to issue long-term transmission rights on a bidding zone border unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border. When adopting their decisions, the competent regulatory authorities of the bidding zone border are required to consult the regulatory authorities of the relevant capacity calculation region and take due account of their opinions (FCA GL, Article 30(1)). Additionally, an assessment needs to be done which shall identify whether there are unmet hedging needs for the market participants (FCA GL, Article 30(3.a)); it needs to be shown that there are long-term cross-zonal hedging products other than long-term transmission rights made available which provide sufficient hedging opportunities in the concerned bidding zones (FCA GL, Article 30(3.b-4)). An example of other long-term cross-zonal hedging products beside long-term transmission rights are 'electricity area price differentials' (EPADs) which are applied in the Nordics. EPADS are described in more depth in Box 3 in Section 3.2.3.

[29] For instance, transmission right prices reflect inefficiencies such as lack of market coupling, the presence of curtailments in combination with weak firmness regimes, and periods of maintenance reducing the offered capacity, which dampen the value of transmission rights (ACER and CEER, 2016).

All TSOs issuing long-term transmission rights shall offer long-term cross-zonal capacity to market participants for at least annual and monthly time frames (FCA GL, Article 31(2)). The allocation of long-term cross-zonal transmission capacity is conducted through explicit auctions. Explicit auctions mean that transmission capacity and electricity trading are auctioned separately.

This section is split up into four subsections describing key components of the market in long-term cross-zonal transmission capacity rights: calculation of cross-zonal capacity, allocation, products and pricing and firmness. Please note that this description is not necessarily exhaustive.

3.2.1 Calculation of future cross-zonal transmission capacity

As stated in the FCA GL: '*Long-term capacity calculation for the year- and month-ahead market time frames should be coordinated by the TSOs at least at regional level to ensure that capacity calculation is reliable and that optimal capacity is made available to the market.'*

What 'coordination on regional level' aims at is that calculations are being done at the level of Capacity Calculation Regions (CCR). CCRs are described in Section 2.3.2. For this purpose, TSOs should establish a common grid model gathering all the necessary data for the long-term capacity calculation and taking into account the uncertainties inherent to the long-term time-frames.

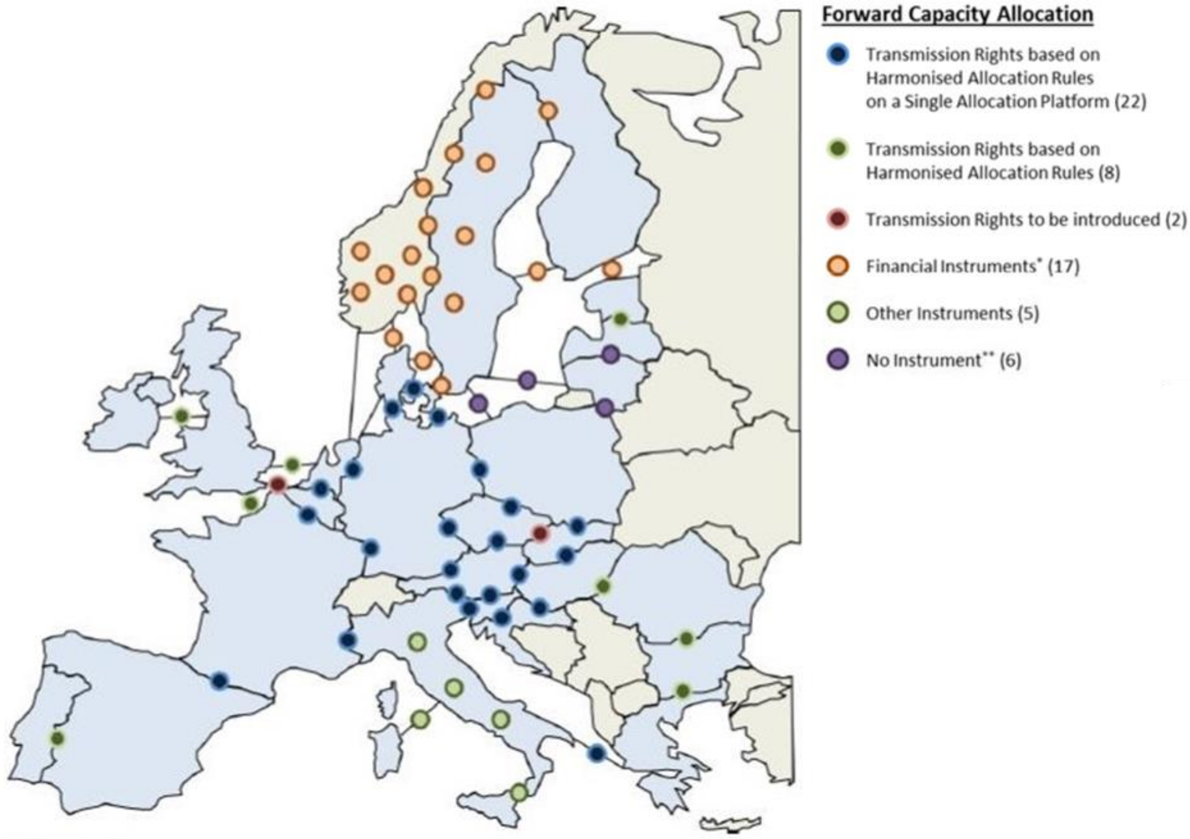
Long-term capacity calculation can follow two approaches: the flow-based approach and the coordinated net transmission capacity (NTC) approach. These calculation methods are explained in more detail in Section 5.1.2. The FCA GL leaves it open as to which approach should be applied. All TSOs per CCR need to submit a proposal to the relevant NRAs for approval (FCA GL, Art. 10). However, it is mentioned that the flow-based approach might be justified where cross-zonal capacities between bidding zones are highly interdependent.

3.2.2 Allocation: Harmonised rules and a single European platform

Different rules for different borders did not allow for efficient cross-zonal trade of long-term electricity supply. The objective of the FCA GL guideline is to harmonise the existing multiple allocation rules at the European level.

A first step in that direction is to introduce harmonised allocation rules (HAR) for long-term transmission rights. According to the FCA GL, all TSOs had to submit a proposal for these rules 6 months after the entry into force of the Regulation (FCA GL, Art. 51(1)) covering several aspects in the forward capacity allocation (FCA GL, Art. 52), e.g. the conditions for transfers and returns of transmission rights, as well as firmness and curtailment compensation rules. Other practical examples are the timing and length of different cross-zonal transmission rights. If long-term transmission rights are not allocated simultaneously, market participants who need to 'cross' several borders cannot efficiently hedge their cross-zonal short-term price risk. In addition to these harmonised allocation rules, specific regional requirements or requirements for individual borders where long-term transmission rights are allocated can be proposed (FCA GL, Art. 51(1)). Given the importance of this task, TSOs had proposed harmonised allocation rules already before the entry into force of the FCA GL as part of the early implementation of the guideline. In the framework of the official implementation of the FCA GL, all TSOs submitted the updated proposal of the harmonised allocation rules and the specific border/regional requirements in April 2017 (ENTSO-E, 2017b). All NRAs did not reach an agreement and the decision was handed over to ACER. ACER finally adopted the proposal after minor modifications in October 2017.

Moreover, a key instrument towards the integration of cross-zonal long-term markets is the setup of a single European platform for the allocation of long-term cross-zonal transmission rights. Some steps have already been taken in this direction. On 24 June 2015, the two regional allocation offices for cross-zonal electricity transmission capacities in place at that time approved the merger agreement to create the Joint Allocation Office (JAO). The JAO is a joint service company of twenty TSOs from seventeen countries. It performs mainly the yearly, monthly and daily auctions of transmission rights. In their proposal for the Single Allocation Platform submitted in April 2017, all TSOs proposed JAO to be named as the Single Allocation Platform (ENTSO-E, 2017c). In September 2017, all NRAs approved this proposal. Figure 7 shows the status of the forward capacity allocation implementation as of 1 November 2018. Since 1 January 2019, forward capacity allocation on all EU borders where LTTRs are issued takes place on JAO.



Source: ACER.

Notes:

**Financial instruments which effectively provide cross-zonal hedging opportunities, but are not necessarily related specifically to that border. For DK1-SE3, DK2-SE4 borders the financial instruments may not provide efficient cross-zonal hedging opportunities.*

*** Relevant regulatory authorities deemed no instrument necessary at those borders pursuant to Article 30(2) of the FCA Regulation.*

Figure 7: Forward Capacity Allocation - Status as of 1 November 2018 (ACER, 2019a).

In Figure 7, the so-called ''other instruments'' between the bidding different zones in Italy are FTR obligations referred to the national Uniform Purchase Price (PUN) or to an adjacent bidding zone. The different instruments and the different types of long-term cross-zonal transmission right are further explained in the next subsection.

3.2.3 Products and pricing

Two products for long-term cross-zonal transmission capacity rights are described in the FCA GL; definitions are taken from Batlle et al. (2014):

- Physical transmission rights (PTR): *'A PTR entitles the buyer to the right to transmit a specific amount of power between two electricity network nodes during a given period of time. In Europe, PTR holders must declare whether they intend to exercise their physical right ('nomination') before a pre-established deadline, often the day ahead. Where they fail to do so, the system operator automatically re-sells the right on the short-term market on behalf of the holder, who receives the resale price. This is known as the use-it-or-sell-it (UIOSI) condition.'*

- Financial transmission rights (FTR): *'An FTR hedges the buyer against the market price difference between two or more bidding zones. These contracts do not have an impact on the economic dispatch or on the actual use of the line. Financial transmission rights can be obligations or options. Obligations imply that the rights holder receives the value of the entitlement when it is positive but must pay the counterparty to the contract if it is less. With options, the holder is not obligated to pay the counterparty if the value of the entitlement is negative.'* The difference between obligations and options is further illustrated in Box 2.

According to the FCA GL, both FTRs and PTRs can be applied.[30] However, the allocation of PTR and FTRs in parallel at the same bidding zone border is not allowed (FCA GL, Art. 31(6)). It is also important to note that PTRs are directly linked to the physical capacity of the line and the only selling counterparty can be the TSO.[31] In principle, FTRs can be issued by any market participant (Batlle et al., 2014). However, in the European context FTRs are generally also issued by the TSO and linked to congestion rents. This implies that the overall amount of PTRs or FTRs is limited to the physical transmission capacity (Spodniak et al., 2017).[32]

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[30] At the time of writing, the large majority of LTTR issued on bidding zone borders are PTRs. On the new bidding zone border between Austria and Germany, 4.9 GW of long-term capacity is nominated in the form of FTRs options. ACER (2019a) explains in its monitoring report of the implementation of the FCA guideline that the choice for FTR options can be partly explained by the fact that 4.9 GW is an exceptionally high volume of offered long-term cross-zonal capacity on this border and of the fact that the calculation of this capacity is not coordinated with other TSOs in a CCR. If PTRs were introduced and all the PTRs were physically nominated in the day-ahead timeframe, this would create high physical flows in the wider region which would imply very low capacity left to be offered in the day ahead timeframe in the wider region. In case of FTR Options, the volume of offered long-term cross-zonal capacity has no impact on physical flows on other borders in the region and thereby does not reduce the day-ahead cross-zonal capacity on those borders. For a full overview for the chosen types of long-term transmission capacity rights in March 2018, please consult https://www.acer.europa.eu/en/Electricity/MARKET-CODES/FORWARD-CAPACITY-ALLOCATION/Pub_Docs/Crosszonal%20hedging%20status.pdf

[31] This means that the TSO (as counterparty) needs to be notified when market participants purchase or transfer long-term transmission rights that were already allocated.

[32] Additionally, the 'netting' of FTR obligations is also possible by selling contracts bi-directionally. Because of counter-flows, a higher volume than the actual transmission capacity may be issued. FTR obligations provide netting, but FTR options do not (Spodniak et al., 2017).

Box 2: Financial Transmission Rights (FTR): obligations vs options, illustrative exercise.

Imagine the following two situations under a certain energy delivery scenario. Which statement is wrong?

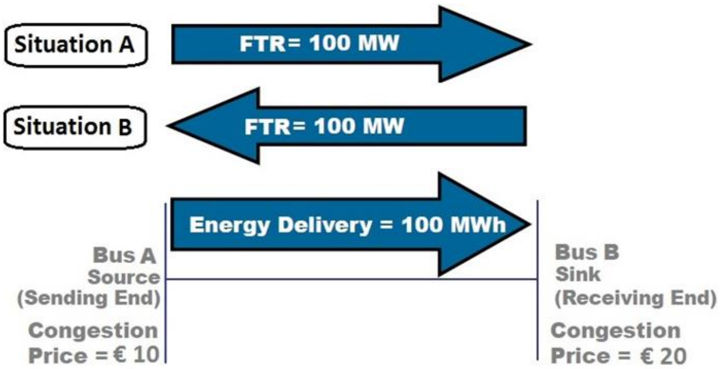

Figure 8: Energy delivery scenarios to illustrate the difference between obligations and options, based on PJM (2011).

a.) If I hold an FTR-option in situation A, I gain €1000
b.) If I hold an FTR-obligation in situation A, I gain €1000
c.) If I hold an FTR-option in situation B, I lose €1000
d.) If I hold an FTR-obligation in situation B, I lose €1000

The wrong statement: c
Justification: In situation A, the outcome for an option and an obligation are the same. The holder of both FTRs gain (20 €/MWh-10 €/MWh)*100 MWh= €1000. In situation B only the holder of an FTR-obligation has to pay (20 €/MWh-10 €/MWh)*-100 MWh= -€1000. A holder of an option will not exercise the option in this case and would not lose any money (except the price paid beforehand for acquiring the option). In other words, in situation A both FTR-obligations and options are a benefit. In situation B, an FTR-obligation is a liability, while an FTR-option is neither a liability nor benefit.

Batlle et al. (2014) describe in detail the pros and cons of PTRs and FTRs. They split their analysis into two parts. Firstly, an ideal market operation and structure is assumed.[33] In that situation, PTRs and FTRs are equivalent. Secondly, an analysis is done under the conditions prevailing in real electricity markets, paying particular attention to situations where market power can be exercised. In that case, there are material differences between both products. The authors conclude that if there is sufficient inter-market coordination and liquidity, FTRs should be the preferred product. However, until these conditions are not attained, PTRs are the most suitable transitory solution. The advantages of FTRs over PTRs are found to be greater transparency, simplification of regulatory supervision and provision of a more valuable hedge for minority market share participants. With PTRs market participants with physical generation assets are clearly in a better position to engage in trading. This is not the case for FTRs, and therefore FTRs would broaden the demand base, enhance competition and increase market liquidity. PTRs vs FTRs has been a strongly debated topic in the academic literature for a long time. Overall, many arguments are found in favour of FTRs, examples of relevant work are Benjamin (2010), Chao and Peck (1996), Hogan (1992) and Joskow and Tirole (2000).

[33] According to Batlle et al. (2014), an ideal market would imply: the absence of technical conditioning (physical flows equal commercial transactions), no regulatory design inefficiencies, unlimited liquidity, no transactions costs, no market power and fully rational market participants.

Box 3: The Nordic approach to long-term transmission rights (based on Spodniak et al. (2017)).

Since 2000, the Nordic electricity market has its own standard product in use for hedging bidding area price differences, called the 'electricity area price differential' (EPAD). EPAD contracts are used to build a hedge for a bidding area price in relation to the Nordic system price (a sort of benchmark price, there is no similar system price in the rest of Europe), while an FTR contract hedges the price difference directly between two adjacent bidding areas.

To hedge the price difference between two adjacent bidding areas with EPADs as an FTR would do, a combination of two EPAD contracts (a so-called EPAD Combo) needs to be acquired by a market player. Two EPAD Combos are required to cover the hedge 'both ways' for each interconnector between two bidding zones. Spodniak et al. (2017) note '*this replication implies that it is theoretically and even practically possible to continue with the EPAD-based system by using EPAD Combos in the Nordic countries, even if FTR contracts would prevail elsewhere in the EU.*' Additionally, the authors do an empirical analysis and show that in practice the pricing of bi-directional EPAD contracts is more complex and may not always be very efficient.

A significant difference between FTRs and EPADs is that EPADs are purely financial contracts traded on a securities exchange, without a direct link to the transmission capacity of the interconnectors. As such, there is also no volume cap in terms of offered transmission rights.

Also in the work of Batlle et al. (2014), FTR-obligations vs FTR-options are discussed. A major difference between both is that obligations are allocated simultaneously in both directions (one product, one auction), while an option only covers the price risk in one direction (two products, two auctions). Although possible higher implementation costs and decreased liquidity can be expected with options, it is argued that these are favoured by market participants as in most cases market participants are interested in hedging the price risk in solely one direction.

Regarding pricing, the FCA GL states in Article 28 that marginal pricing should be applied for each bidding zone border, direction and market time unit. Marginal pricing implies that all successful bidders pay the price of the marginally accepted bid (in this case the lowest accepted bid). The price will equal zero if the demand for transmission rights is lower than the offered long-term cross zonal capacity.

3.2.4 Firmness

Trust in firmness, defined in the CACM GL as *'a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed'*, is a necessary condition for the successful integration of electricity markets. The potential interruption of exports during emergency or scarcity conditions can be a major barrier to the development of (long-term) cross-zonal trade (Mastropietro et al., 2015).

In the FCA GL, three causes for curtailment of long-term transmission rights are distinguished. First, the curtailment of transmission rights in the event of force majeure.[34] In that case, the holder of long-

[34] A force majeure event is defined in the CACM GL as any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively

term transmission rights will receive a compensation by the TSO which invoked the force majeure. This compensation will be equal to the amount initially paid for long-term transmission rights (FCA GL, Art. 56(3)). The national regulatory authority of the TSO invoking the force majeure event shall assess whether an event qualifies as force majeure (FCA GL, Art. 56(5)). Second, long-term transmission rights can also be curtailed prior to the day-ahead firmness deadline to ensure that operation remains within operational security limits.[35] The concerned TSOs on the bidding zone border where long-term transmission rights have been curtailed shall compensate the holder of these rights with the market spread (FCA GL, Art. 53(2)).[36] Further, the concerned TSOs on a bidding zone border may propose a cap on the total compensation to be paid to all holders of curtailed long-term transmission rights (FCA GL, Art. 54(1)).[37] Lastly, a special case would be situation in which bidding zone borders cease to exist. This could happen when two bidding zones are merged or bidding zone borders are redrawn. In that case, the transmission right holders shall be entitled to reimbursement by the concerned TSOs based on the initial price paid for the long-term transmission rights. (FCA GL, Art. 27(2)).

Mastropietro et al. (2015) argue that congestion is not the only source of price-differentials between bidding zones. They state that price-differentials may also originated from a direct regulatory intervention with the aim to prioritise national over regional interests. This would be the case if a TSO (possibly prompted by a regulator) blocks exports through interconnectors when its system is under scarcity conditions. By doing so, a price-differential with no hedge is (artificially) created, and the execution of cross-zonal contracts is impeded. Mastropietro et al. (2015) add that, whenever the physical delivery is not possible because of an intervention from the TSO, the latter should pay not only the financial settlement related to the price differentials but additionally possibly some compensation. This compensation would constitute a penalty for non-compliance which a generator located in one bidding zone should pay to a demand located in another bidding zone when these two parties have signed a contract for the physical delivery of electricity, and the demand is not served.[38] The TSO (representing the regulator and, eventually, the government) should also be required to deposit warranties guaranteeing such payments.

It is of great importance that the risks are properly allocated. Otherwise there is a risk of the TSO becoming more risk-averse and offering less long-term capacity than might be efficient or market participants might be discouraged to engage in long-term cross-zonal trade.

verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation (CACM GL).

[35] 'Operational security limits' are defined as the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits (CACM GL, Art. 2(7)).

[36] Market spread refers to the difference between the hourly day-ahead prices of the two concerned bidding zones for the respective market time unit in a specific direction.

[37] The cap holds for the accumulated compensations over the relevant calendar year and cannot be lower than the total congestion income collected during that same period (FCA GL, Art. 54(1,2)).

[38] The compensation is related to the difference between the utility value that the demand attributes to its supply and the price cap active in the market (Mastropietro et al., 2015).

4. Establishing national day-ahead and intraday markets

The CACM GL is the key regulation outlining the design and integration of the day-ahead (DAM) and intraday market (IDM). In this chapter, we focus on the establishment of the national DAM and IDMs.[39] After, their integration is discussed in Chapter 5. The 'Target Model' pursued by the European Commission (Third Energy Package, Directive 2009/72/EC) is centred around day-ahead auctions operated by power exchanges that implicitly allocate transmission capacity between bidding zones (Neuhoff et al., 2016c). Prices obtained in the DAM auction serve as a reference for forward markets (Meeus, 2011). In recent years, a strong increase in trading in intraday markets was observed, as is illustrated in Figure 9 (below). In that same figure, the trading volumes in the DAM as a share of the hourly consumption for France and Germany for a period from 2012 to 2015 are shown. It can be seen that large differences in proportional volumes exist between both countries. What is common between both is that the centre of gravity of electricity trading is slowly moving closer to real-time.

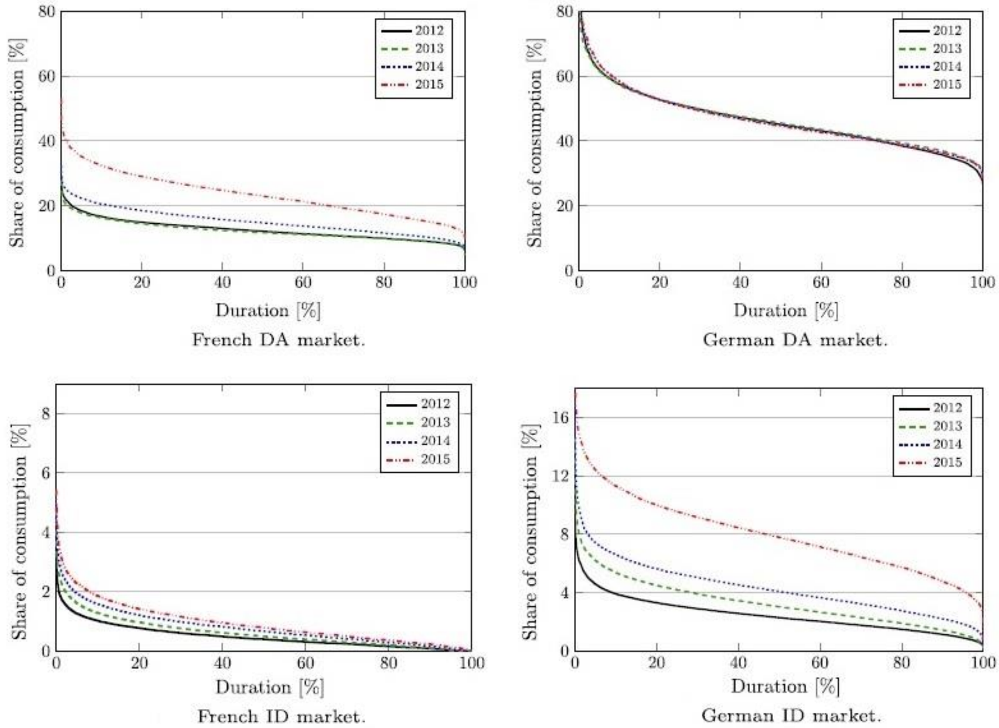

Figure 9: The hourly DA and ID market trading volume as share of the hourly consumption for France and Germany (Brijs et al., 2017).

Short-term electricity market design needs to evolve with its context. Originally, these markets were designed for large, rather slow ramping, and mostly fossil fuel based generators and inflexible demand. The same conditions do not exist now with the penetration of variable renewable energy sources (vRES) at all voltage levels and more options for consumers to manage their demand. How to adjust market design to this new context is a topic of extensive debate (for e.g. AGORA, 2016; Brijs et al., 2017; Henriot and Glachant, 2013; Neuhoff et al., 2015b). In general, it is agreed that flexibility is required to allow for efficient operation of the system with higher penetrations of vRES. Short-term

[39] Besides the products traded in the single European (coupled) DA and IDM, which are the focus of this text, national DA and IDMs can have for instance additional products (e.g. with a finer time granularity). These products are traded after the cross-zonal DA/ID gate closure time and are only national, bilateral or regional but not EU wide.

electricity market design should encourage investment in the right technologies (capacity) and incentivise them to offer their full flexibility (capability). A combination of complementary actions is needed to achieve this goal. Integration of electricity markets at all market time frames is key to make better use of the resource diversity in the EU. Also, the day-ahead market design needs to be adapted, for example by introducing better-adapted bidding products. Furthermore, the functioning of markets closer to real-time needs to be enhanced, both intraday and balancing markets (treated in Chapter 6).

This chapter consists of four sections. In the first section, a key institution, namely the Nominated Electricity Market Operator (NEMO) and its functions are described. The DAM and IDM are both managed by power exchanges, which are labelled as NEMOs in the EU, a concept introduced by the CACM GL. In the second section, the main characteristics of the day-ahead market are discussed. Thirdly, several important elements of intraday market design are discussed. In the last section, it is explained how congestion within a bidding zone is dealt with. The capacities of transmission lines within a bidding zone are not allocated to the market, i.e. the bidding zone is regarded as a copper plate, but in reality internal congestion does occur.

4.1 Nominated Electricity Market Operators (NEMOs)

Power exchanges traditionally collected and matched bids and offers within different time-frames for a certain bidding zone. Recently, power exchanges have been increasingly organising trade between bidding zones in Europe, which was previously mainly the territory of the Over-The-Counter (OTC) electricity trading business (Meeus et al., 2005; Meeus, 2011). To facilitate smooth electricity trading across borders, an institutional framework for power exchanges is required. The CACM GL provides such a framework, outlining common requirements for the designation of NEMOs and for their tasks. In short, NEMOs can be seen as power exchanges certified to organise cross-zonal electricity trade.

4.1.1 NEMO landscape: cost-of-service regulated (monopoly) and merchant (competitive) power exchanges.

Article 2(23) of the CACM GL formally defines 'NEMO' as an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling. A NEMO can be designated for trading services in the day-ahead market, the intraday market or both. Two types of power exchanges can be distinguished in Europe: cost-of-service regulated (monopoly) and merchant (competitive) power exchanges. Namely, in the CACM (Art. 4(1-2)) it is stated that each Member State (MS) shall ensure that at least one NEMO is designated in its territory.[40] However, if in a MS a national legal monopoly already exists by the time the CACM GL enters into force, that MS may refuse the designation of more than one NEMO per bidding zone (CACM GL, Art. 5(1)). In other words, the default option is that a MS allows for merchant (competitive) NEMOs (one or more NEMO designated in the MS) but also the continuation of a cost-of-service (regulated monopoly) NEMO in a MS is allowed (one NEMO designated in the MS).

Cost-of-service regulated are not-for-profit or regulated-profit institutions, which receive an income from regulated fees. They can be established by a public initiative (e.g. OMEL in Spain) or by a TSO initiative (e.g. HUPX in Hungary). Typically, they also perform several tasks that go beyond trading

[40] NEMO(s) designated in a MS have the right to offer trading services with delivery in another MS without the need for designation as a NEMO in that Member State, albeit with exceptions. These exceptions are summarised in Art. 4(6) of the CACM GL.

services. On the other hand, merchant power exchanges are for-profit market institutions whose core business is to provide trading services. Their income depends on various user fees and is linked to the volume of trades executed by the power exchange for its users. Examples are EPEX Spot SE (covering Germany, France, GB, the Netherlands, Belgium, Austria, Switzerland and Luxembourg) and Nord Pool AS (one of the NEMO(s) or single NEMO in 14 MS of the EU and Norway). Historically, merchants were set up by market parties, financial market institutions, TSOs or a combination of private actors. Figure 10 gives an overview of the designated NEMOs per MS, their competitive status and the designating institutions. In the vast majority of countries, either one or two NEMOs are designated, and in most cases, the regulator is in charge of their designation.[41] All designated NEMOs are both designated for the day-ahead and the intraday market. A complete overview per country can be found in ACER (2018).

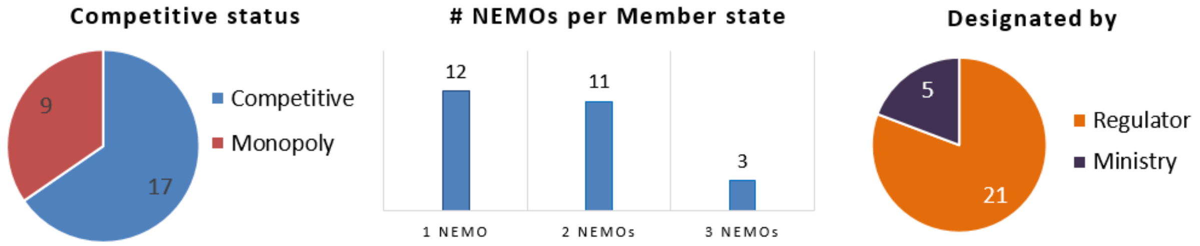

Figure 10: Facts and figures of NEMOs in the EU (excl. Cyprus and Malta). Based on ACER (2018).

In Figure 11 (left) the competitive status per country is visualised. In Figure 11 (right) the NEMOs designated in MS which is open to competition for NEMOs is shown.[42] Pursuant to Article 4(10) of CACM GL, the designating authorities shall inform ACER of the designation and revocation of NEMOs. ACER shall maintain a list of designated NEMOs, their status and where they operate on its website.

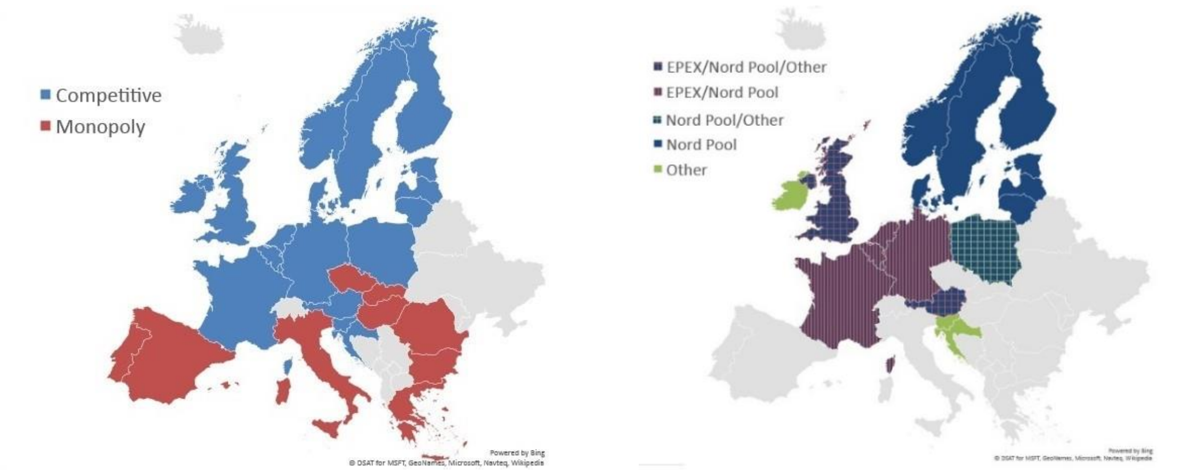

Figure 11: Left – Competitive status of NEMOs in the EU+NO. Right – State of play in MS open to competition in NEMOs (the landscape for the DA and ID market is identical). Based on ACER (2018).

[41] Between 2015 and 2017, the NEMO landscape showed some change. There was no change in numbers with regard to the competitive status of the NEMOs nor concerning the designating authorities. However, the number of NEMOs within a competitive setting increased in 6 countries. In 2015, 18 MS had designated only one NEMO, 6 MS had designated 2 NEMOs and 2 MS had designated 3 NEMOs on their territory.

[42] ACER (2019a) notes that in early 2019 some NEMOs are designated, but are not operating yet, pending the implementation of multi-NEMO arrangements (i.e. the arrangements allowing several NEMOs to operate in one bidding zone).

The CACM GL does not prescribe whether NEMOs should be a monopoly or competitive activity. However, a preference for NEMOs as a competitive activity can be detected in the code. Namely, it is stated that '*a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services'* (CACM GL, Art. 5(2)). However, '*if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another MS, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States*' (CACM GL, Art. 5(3)). In July 2018 the Commission published a first report concerning the development of competition between NEMOs (EC, 2018). The Commission states in that report that it does not take a conclusive view at this stage on whether it is justified to abolish the possibility for Member States to provide for a legal monopoly.

In brief, a trade-off exists. On the one hand, cost-of-service regulated power exchanges have fewer incentives to abuse market power and act anti-competitively than merchant power exchanges. Also, exchanges have natural monopoly characteristics. Firstly, trading systems can benefit from positive network externalities (liquidity attracts more liquidity). Secondly, significant economies of scale are present. On the other hand, cost-of-service regulated power exchanges have fewer incentives to provide an efficient trading service or to innovate in trading systems.

In the light of European electricity market integration, Meeus (2011) argues that it does make sense to have merchant power exchanges. While in principle, facilitating cross-border trade and cooperating with other power exchanges could be just one additional task for cost-of-service regulated power exchanges, in reality a 'regulatory gap' could be created. The reason is that national regulatory authorities frequently do not have effective and independent powers to define and enforce the necessary regulation at EU level, when dealing with problems related to cross-zonal trade. In other words, the function of achieving and operating the European internal energy market is not assigned to a European-wide regulatory entity but to many national regulatory agencies. A merchant power exchange, as opposed to their cost-of service regulated counterpart, has a clear incentive to cooperate in the implementation of market coupling as it can generate significant additional trade volumes, and thus income for the power exchange. However, the market power of power exchanges should be tempered. This could be done by enhancing transparency requirements and introducing governance rules to prevent that cooperation among power exchanges would lead to closed cartels.

4.1.2 NEMO tasks

The tasks of the NEMOs are outlined in Article 7(1) of the CACM GL as follows: '*Their [NEMOs] tasks shall include receiving orders from market participants, having overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices and settling and clearing the contracts resulting from the trades according to relevant participant agreements and regulations.*'

Besides collecting orders and settling contracts, a very important task for NEMOs is the market coupling operator (MCO) function. The market coupling operator (MCO) function is defined as the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities (CACM GL, Art. 2(30)). This task is done jointly by all

NEMOs, and a close collaboration with Coordinated Capacity Calculators (CCCs) is required. In this regard, the development and maintenance of the algorithms, systems and procedures for single day-ahead and intraday coupling are vital. The costs of establishing, amending and operating single day-ahead (and intraday coupling) are borne by all NEMOs (CACM GL, Art. 76(1)). TSOs may contribute to the costs subject to approval by the relevant regulatory authorities (CACM GL, Art. 76(2)). ACER (2019a) describes that, in practice, most of the development and operation costs are borne by TSOs.

4.2 The day-ahead market (DAM)

In Europe, the day-ahead market is organised as a double-side blind auction. By noon of the day before delivery, market parties submit their offers and bids for each hour of the following day to the NEMO to adjust their positions held in forward markets. In the simplest form, orders are hourly price-quantity pairs. In Figure 12 an example of the clearing of an aggregated demand (blue) and supply curve (red) for one hour in a DAM session is given. For each (daily) DAM session 24 such clearings are performed. The supply offers (red) with a price lower than the clearing price, thus offers below the green line, are accepted. The accepted supply offers want to supply energy for a price lower than or equal to the clearing price. The demand bids (blue) above the clearing price, thus offers above the green line, are accepted. The accepted demand bids are willing to pay at least the actual clearing price for energy. Uniform (marginal) pricing applies in the DAM auction, which means that all accepted supply offers and all accepted demand bids receive/pay the same (uniform) price, namely the clearing price.[43]

Figure 12: Example of the clearing of an aggregated demand (blue) and supply curve (red) for one hour of the DAM in Romania on 24/01/2011 (Pérez-Arriaga, 2013).

In this section, three design dimensions of the day-ahead market are discussed in more depth. Namely, the bid formats accepted in the DAM auction, the temporal resolution of the products and the maximum and minimum clearing prices. Integration of the DAMs over different bidding zones is the topic of Section 5.1.

4.2.1 Bid formats: simple, block and multi-part bids

In an auction with marginal pricing, as is the case in the DAM, the optimal bidding strategy for market participants (both for buyers and sellers) is to bid their marginal cost.[44] Namely, if market participants

[43] Marginal pricing is often also called 'uniform pricing' or 'pay-as-cleared'. All three are synonyms.

[44] It should be added that this statement only holds in the absence of market power (i.e. in the absence of ability to affect prices). Also, it should be added that the most expensive units might place bids above their marginal costs in order to recover part of their fixed costs during these so-called scarcity periods.

bid higher than their marginal cost and their bid is not accepted, there will be instances where they could have made a profit, while if they bid lower there is a probability that they would lose money if they are called to generate. It can be argued that simple hourly price-quantity bids and an optimal bidding strategy are not compatible. The reason for this is that a generator cannot include non-convex costs, e.g. start-up cost and minimum run levels. These non-convex costs are becoming more prominent as the share of renewables increases in the generation mix.
One remedy which is used today in the DAM is to allow for block bids. Different formats of block bids exist, for more details see e.g. Meeus et al. (2009). In short, a block bid can be defined as an all-or-nothing order of a given amount of electric energy in multiple consecutive hours.[45] A minimum revenue needs to be obtained for the period of the block bid before acceptance. But, again for block bids, non-convex costs cannot be explicitly represented, and a mark-up needs to be included.[46] Also, (computational) time needed to find a solution for the clearing algorithm increases with the introduction of block bids.

In Art. 40(1) and Art. 53(1), the CACM GL states that NEMOs shall submit a joint proposal concerning products that shall be accommodated by the matching algorithms in the SDAC and the SIDC, respectively. For both market time frames, the orders resulting from these products should be expressed in euros and make reference to one or multiple market time units (Art. 40(2)) In February 2018, all NRAs approved the amended proposals for SDAC and SIDC products by all NEMOs. The CACM GL states in that the products covering one market time unit (an hour) and multiple market time units (multiple hours) should be of the NEMOs. This implies simple and block bids to be within the boundaries of the regulation. Besides simple and block bids, also other types of bid formats are accommodated by the SDAC and the SIDC the matching algorithm. A full comprehensive overview for the SDAC is provided in PCR (2018a).

An alternative to the products accommodated by the SDAC and SIDC today are so-called multi-part bids, wherein non-convex costs are explicitly presented. Neuhoff et al. (2015a, 2015b) and Neuhoff and Schwenen (2013) provide five arguments in favour of multi-part bids over simple and block bids. Firstly, less informed (smaller) participants have greater difficulty determining the optimal mark-up to incorporate in their block bids. If mark-ups are not set at an appropriate level, which is probable, the efficiency of the market outcome decreases, while transaction costs and the uncertainty for market participants increase. Second, market monitoring for block bids is almost impossible as the underlying costs structure is not defined. In contrast, multi-part bids with energy bids and ramping and start-up costs nominations follow auditable cost structures. Third, simple and block-bidding do not lend themselves easily to the provision of early and reliable unit specific generation patterns. By using energy-only bids the flexibility of thermal generation assets cannot be made fully available to the market, generation is often optimised within the portfolio of utilities or aggregators with the implication that system operators have limited information on the ultimate generation pattern to be considered for flow calculations. Also, it is argued that in contrast to block bids, the reflection of technical characteristics in multi-part bids – instead of combinatorial questions – is more suitable for computation of market clearing. Lastly, with block bids, the liquidity in standardised auctions might be

[45] It is important to mention that block bids can have different meanings. For example, in the US a 'block bid' can simply imply a one-hour bid of which also a part of the total quantity offered can be cleared.
[46] The mark-up is the difference between the bid price and the marginal cost of delivering the electricity.

undermined as bids only are valid conditional on being accepted for longer time durations. Today, multi-part bids are present mostly in the US electricity markets (Brijs et al., 2017; Neuhoff et al., 2016c).

A commonly used argument against multi-part bids made by generators is that they would need to reveal commercially sensitive information in their bids. Neuhoff et al. (2015b) state that it is expected that the level of information sharing will not be extended beyond the level of sharing that is already necessary with TSOs. Meeus and Belmans (2007) state that with block-bids the pricing approach in dealing with non-convexities is simpler than with multi-part bids. Arguably, it can be harder to couple markets allowing for multi-part bids because they can apply a different implementation of non-linear pricing internally.[47] The reason is that it is politically difficult to harmonise the treatment of non-convexities and especially if the treatment is already fine-tuned, which is less the case with easier-to-harmonise block bids.

4.2.2 Temporal granularity

Today, in the European DAM the market time unit of traded products is one hour. This granularity in the DAM is not directly seen as problematic in the academic literature, under the condition that products with finer resolution are offered in intraday markets and/or locally. However, it is clear that the finer the granularity, the more volatile the prices. These prices can better reflect and reward the value of flexibility in the system. Units can take advantage of price volatility when they can ramp up or ramp down faster. Flexible resources need clear signals to encourage investment and to deliver energy when needed. A shorter market time-unit can deliver these incentives.

Also, some issues might occur as the settlement period over which market participants are financially responsible for having a balanced portfolio is 15 minutes or 30 minutes.[48] Therefore, shorter market time-units allow for a better alignment of trading in the DAM and imbalances in real-time (Brijs et al., 2017). If demand and supply schedules are scheduled on a shorter time interval, reserve requirements might be reduced (Neuhoff et al., 2015a).[49] Shorter time-units also help in shifting the risks from TSOs to market parties responsible for balancing their demand and supply (Frunt, 2011).[50] Less intervention from the TSO should be required, and thus fewer costs would be socialised (Henriot and Glachant, 2013). In other words, by having more granular products the deterministic imbalances, meaning imbalances introduced due to scheduling and not due to unpredictability in generation/demand or unforeseen events, are expected to be more limited (Hirth and Ziegenhagen, 2015).

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[47] Without going into too much technical detail, when allowing for block bids and/or multi-part bids, it is not always feasible to find a clearing price for which all accepted offers are in-the-money (not making losses), or for which all rejected offers are out-of-the-money (could be making money). Broadly speaking, in the US, with multi-part bids, some accepted offers are making losses when considering solely the clearing price. This problem is solved with uplift payments. In Europe, with block bids, some rejected block offers could be making money considering the clearing price, these are so called 'paradoxically rejected blocks' (Meeus et al., 2009). See also, section 2.2.2. in Papavasiliou and Smeers (2017).

[48] This might become a concern of the past as in the Clean Energy Package, it was agreed that NEMOs shall provide market participants with the opportunity to trade in energy in time intervals at least as short as the imbalance settlement period in both day-ahead and intraday markets (Art. 7(2) in the Regulation on the internal market for electricity). The length of the imbalance settlement period is further discussed in Section 6.4.1 of this text.

[49] Shorter market time-units alone are not a sufficient condition for reducing reserves. E.g. shorter intraday gate closure times, discussed in Section 4.3.3, seem also to be key to reduce reserves.

[50] So-called 'Balance Responsible Party (BRP)', explained in the introduction to Chapter 6.

Counter-arguments are that non-convexities are even harder to include in simple bids with finer temporal granularity and that the computational time to clear the market might increase significantly as more combinations are possible (Henriot and Glachant, 2013). Neuhoff et al. (2016c) explain that the finer the granularity of the bids, the greater the need for multi-part bids.

4.2.3 Maximum and minimum clearing prices

A general remark made in the literature is that price caps and floors should be removed as they distort the price signal and limit the ability of peaking units or more flexible resources to recover their capital costs, contributing to the 'missing-money' problem. There is no theoretical rationale for price floors (Henriot and Glachant, 2013) and with more participation of the demand side, increasing storage possibilities and a weaker presence of market power there are fewer reasons to hold on to price caps as well. Removing price caps will give market participants a high degree of planning security. Additionally, Hogan (2013) argues that higher price caps are a necessary, but not sufficient condition, to be consistent with a reasonable market for addressing scarcity conditions. However, in times of scarcity, it is difficult or even impossible to distinguish real scarcity in supply from the exercise of market power.

In the CACM GL, it is outlined that NEMOs, in cooperation with TSOS, shall develop a proposal on harmonised maximum and minimum prices (HMMCP) to be applied in all bidding zones which participate in single day-ahead coupling (SDAC) (CACM GL, Art. 41) and single intraday coupling (SIDC) (CACM GL, Art. 54). The CACM GL provides that the proposals must take into account an estimate of the value of lost load, intending to provide for an element of scarcity. In February 2017, all NEMOs sent their proposals on HMMCPs for SDAC and SIDC to all NRAs, who could not reach an agreement and therefore requested ACER to adopt a decision. In November 2017, ACER approved that the harmonised maximum clearing price for SDAC shall be +3,000 EUR/MWh and the harmonised minimum clearing price for SDAC shall be -500 EUR/MWh (ACER, 2017a).[51] However, the harmonised maximum clearing price will not be static, namely, the harmonised maximum clearing price for SDAC shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 % of the harmonised maximum clearing price for SDAC in at least one market time unit in a day in an individual bidding zone or in multiple bidding zones. Therefore, the harmonised maximum clearing price cannot really be seen as a 'true price cap' blocking scarcity prices from occurring.

4.3 **The intraday market (IDM)**

Higher shares of wind and solar generation result in increasing volumes of intraday trading.[52] Closer to real-time, wind- and solar (but also demand) forecasts are more accurate and in intraday markets production schedules can be adjusted accordingly. While the day-ahead market design is quite harmonised in the EU, the same cannot be said about intraday market design. In some countries, e.g. Belgium, France and the Netherlands, shortly after the DAM auction, continuous trading with hourly

[51] A proposal was also approved regarding the harmonised maximum and minimum prices of the single intraday coupling (SIDC). The harmonised maximum clearing price for SIDC shall be +9.999 EUR/MWh and the harmonised minimum clearing price for SIDC shall be -9.999 EUR/MWh (ACER, 2017b). The harmonised maximum clearing price for the SIDC will be set equal to the SDAC harmonised maximum clearing price if that price would exceed +9.999 EUR/MWh after adjustments.

[52] Please see also the two graphs on the bottom of Figure 9 above, which show the hourly ID market trading volume as share of the hourly consumption for France and Germany.

products is possible (Brijs et al., 2017). In other countries, e.g. Spain, multiple intraday auctions are held (Hagemann and Weber, 2015). In Germany, a combination of continuous trade and auctions is in place (Neuhoff et al., 2016b). As an illustration, in Figure 13 the EPEX trading process in Germany as it was in 2016 is shown in more detail.

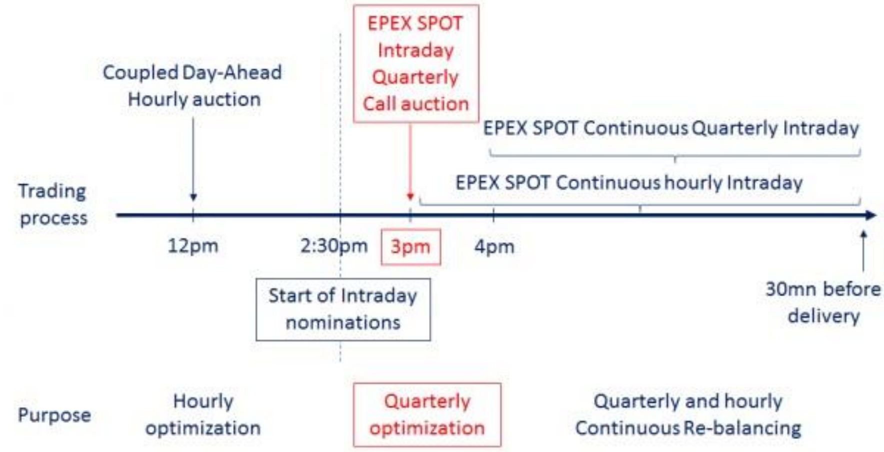


Figure 13: Trading process from the DAM to the IDM gate closure in Germany by EPEX in 2016 (from Neuhoff et al., 2016b).[53,54]

In Germany, 3 hours after the day-ahead auction an intraday auction with 15-minute products (thus 24*4=96 intervals) takes place. It can be argued that not much new information is available for market participants between the gate closure of the DAM and this IDM auction. Instead, this auction is primarily held to allow for adjustments after the outcome of the DAM and to schedule German generation and demand with a finer temporal granularity.[55] Just after, the continuous intraday trading with hourly products starts. Lastly, one hour later, intraday trading with 15-minute products initiates. 30 minutes before real-time delivery the intraday market gate closure takes place and no more trading is possible, except for trading within the respective control areas for which the gate closure is set at 5 minutes before delivery. The goal of continuous intraday trading is different in this context as trading closer to real-time is possible. Its aim is to allow market participants to adjust their positions when better forecasts of renewable production and demand are available, or when unexpected plant outages take place.

A 'hot topic' in the EU is whether continuous trading, auctions or a combination of both is the best trading mechanism to conduct trades in the IDM. This question is discussed in this section. After, the liquidity in intraday markets is described, noting that liquidity cannot be decoupled from the discussion about the best trading mechanism. The last subsection concerns the intraday gate closure time, the moment when trading is no longer possible and the TSO takes over the balance of the system. As already outlined in the previous section, the same logic as for the DAM holds in the IDM regarding maximum and minimum clearing prices.

[53] In March 2017 also 30-minute products were introduced for continuous trading, these products are not displayed in Figure 13 (EPEX SPOT, 2017).

[54] 15-minute products were introduced in 2011 (continuous trading) and 2014 (auction). Märkle-Huß et al. (2018) analyse in their paper the causal impact of 15-minute trading on the EPEX Spot market and find that the introduction of 15-minute products caused a reduction of the prices of existing hourly contracts and incentivizes renewable energy providers to offer additional electricity.

[55] This auction is not open for cross-zonal generation/demand.

4.3.1 Continuous trading vs auctions

Continuous trading has historically been the mechanism in place for intraday trading. In exchange based continuous trading, market participants submit limit orders to the order book at any time during the trading session. [56] All market participants can see the order book. Orders are matched if a new limit order is submitted that is either a buy-order with a higher price than the current best ask or a sell-order with a lower price than the current best bid (Neuhoff et al., 2016b). Of the matched offers, the initially submitted offer sets the price. This implies that buyers/sellers receive the price they bid/offer (pay-as-bid) and that each transaction during the intraday trading session can have a different price. This is one of the key differences with auctions, whereby when uniform pricing is the clearing rule, all buyers/sellers see the same price. In Box 4 the optimal clearing rule is discussed.

The CACM GL states that continuous trading should be in place in the intraday time frame. The matching algorithm should be able to accommodate orders covering one market time unit and multiple market time units (blocks). The market time unit is not specified and shall be defined by a proposal submitted by the NEMOs (CACM GL, Art. 53). Next to continuous trading, complimentary regional intraday auctions may be implemented if approved by the regulatory authorities (CACM GL, Art. 63). The CACM GL also requires the pan-European solution based on continuous trading to be complemented by 'reliable pricing of capacity' (see Section 5.2.2 for more details).

Box 4: The optimal auction clearing rule – Uniform (marginal) pricing vs pay-as-bid.

With continuous trading, pay-as-bid is implicitly the clearing rule used. With an auction, either pay-as-bid or uniform pricing can be opted for. In DAM auctions, marginal pricing is in place and in IDM auctions in Germany, Spain, Italy and Portugal also the marginal pricing rule is implemented. However, in the balancing markets (BM) both marginal and pay-as-bid rules are employed in the EU.

One paper is very frequently cited in the literature regarding this matter, namely 'Uniform pricing or pay-as-bid pricing: a dilemma for California and beyond' by Kahn et al. (2001). The most important idea brought forward in the paper is that the common mistake made by people advocating that pay-as-bid pricing would lead to lower costs compared to uniform pricing is the fact that bidding strategies will be very different according to the clearing rule in place. Under pay-as-bid, the market participants would no longer have an incentive to bid their avoidable costs but, instead, would base their bids anticipating the market price. This would largely remove the hoped-for savings from pay-as-bid (Littlechild, 2007). The main arguments made in favour of uniform pricing over pay-as-bid pricing are (Kahn et al., 2001; Littlechild, 2007; Müsgens et al., 2014):

- Pay-as-bid introduces some inevitable reduction in efficiency as generators depart from bidding their marginal costs. Because if they solely bid their marginal cost and their bid is accepted, they won't receive any compensation for their fixed costs or a contribution to profits. With all bids exceeding the marginal costs, by amounts that depend upon the varying estimates of the bidders of what would be the highest accepted bid, the perfect, total cost-minimizing merit order dispatch is no longer assured.

- Another inefficiency introduced by pay-as-bid is the cost of forecasting market prices that it would impose on all participants. There are significant economies of scale in the efforts to gather the necessary information and make such forecasts on a continuing, hour-by-hour and day-by-day

[56] A limit order is a price-quantity pair and allows you to specify the maximum amount you are willing to pay for electric energy (when you buy) or the minimum amount you are willing to receive for electric energy (when you sell). A market order solely specifies a quantity and is used to buy or sell immediately at the best available price.

basis. The data analytics necessary to forecast market pricing dynamics are complex and costly. Under pay-as-bid, large players are more likely to have the resources available to gather better insight in bidding strategies and thus gain an advantage by forecasting prices. In short, uniform pricing rewards low costs (because all winners get the same price) whereas pay-as-bid rewards good (but costly) guesses (because guesses determine the price).

- There is a greater transparency of bidding under uniform pricing than under pay-as-bid facilitating attempts to detect uncompetitive behaviour. If the market were competitive, all bidders would have the incentive under uniform pricing to bid their marginal costs. Since at least marginal generating costs are relatively easily measured, it should be feasible to ascertain whether bid prices had exceeded those levels.

- Under pay-as-bid no transparent price to serve as a benchmark for contract markets is available. Neuhoff et al. (2016a) argue that a price reference closer to real-time is necessary.

- Under pay-as-bid a supplier with market power can be successful in an auction with a bid increased beyond what would have been the bid in a competitive market. Under uniform pricing the monopolistically leveraged price automatically goes to all competitors alike. However, as discussed below, with uniform pricing there are also concerns when market power is present.

An argument against uniform pricing is:

- Market power is the main concern when uniform pricing is applied. Namely, if there is imperfect competition and uniform pricing in place, suppliers with market power have incentives to reduce supply that could otherwise be profitably operated. The reason is that reducing supply may increase the market clearing price and thus the profitability of the infra-marginal units. An analogous strategy is not possible with pay-as-bid, because bids on one unit cannot directly influence the payments for other units.

Overall, auction theory does not find a unique ranking with respect to the efficiency of the settlement rules (Ausubel and Cramton, 2002). However, considering all arguments summarised in this box, uniform pricing seems to be favoured for auctions in electricity markets.

Next to the arguments in Box 4 summing up the benefits of auctions with uniform pricing, three additional arguments in favour of auctions over continuous trading can be added:

1/ *Allocation of cross-zonal transmission capacity (discussed in more detail in Section 5.1.1):* One of the most important arguments in favour of auctions in the IDM is the fact that auctions would facilitate the coupling of the IDM as the DAM is coupled today. One of the challenges with coupling is the allocation of cross-zonal transmission capacity. The most efficient solution would be to hold intraday auctions which simultaneously allocate transmission capacity (implicit allocation). Combining efficient allocation of transmission capacity with continuous trading is not straightforward (Neuhoff et al., 2016b). With continuous trading in place, valuable transmission capacity would be allocated on a first-come-first-served basis, thus possibly favouring more rapid/experienced traders instead of efficient ones. Extending this point, auctions would prevent robots capturing increasing shares of bid-ask spreads and scarcity value of transmission capacity in the market.

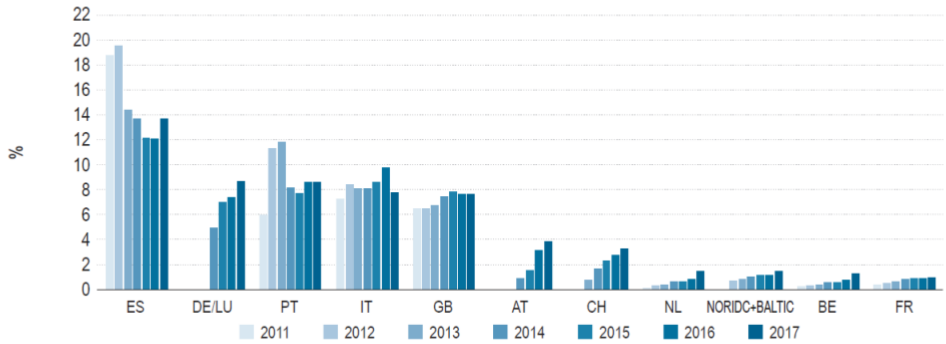
2/ *Operational security:* Auctions are operationally simpler for the exchange and involve lower risk of technical malfunctions of market systems (Neuhoff et al., 2016b). Additionally, Neuhoff et al. (2016a) explain that as generation units will mark-up their bids during continuous intraday trading to reflect opportunity costs, the market outcome may not reflect an efficient generation schedule. In a subsequent real-time balancing auction with uniform pricing, generation units will submit bids reflecting their marginal cost and the auction clearing results in a least-cost generation schedule. This might imply significant adjustments to the output of individual power stations resulting in greater uncertainty regarding flow patterns very close to real time.

3/ *Liquidity (discussed in more detail in the next subsection):* The (single) price obtained from an auction increases price transparency, this is not the case with continuous trading whereby an average or other indices need to be computed. A liquid and transparent intraday price is beneficial especially for hedging and ultimately for providing clear price signals to attract investment in flexibility (Neuhoff et al., 2015b). In contrast, this stretching of liquidity over the whole trading period when continuous trading is in place can make the intraday market price volatile and non-transparent (Hagemann and Weber, 2015). Also, auctions tend to involve significantly lower fees for participants trading in intraday markets (Neuhoff et al., 2015b). Additionally, continuous trading is unlikely to deliver the liquidity for different types of block-bids to support efficient bilateral matching (Neuhoff et al., 2015b).

An argument in favour of continuous trading is made by Henriot (2012). He argues that continuous markets provide participants with a sufficient degree of freedom to express their needs, while discrete auctions may lead to inefficiencies due to lost trading opportunities. In this vein, Hagemann and Weber (2015) mention that continuous markets allow 24/7 trading and thus market participants may trade imbalances as soon as they appear. Hence, new information can be used continuously. Additionally, Bellenbaum et al. (2014) state that the longer time lag for auction-based trading between gate closure and actual delivery tends to lower the informational efficiency.

4.3.2 Liquidity in the IDM

Liquidity is necessary to have a clear price signal in the IDM for market participants to offer their flexibility in this market on the short term and encourage investment in the long term. At the time of writing, liquidity is still a concern in most EU intraday markets. Figure 14 gives an overview of the liquidity across the largest organised European ID markets using data from 2011-2017. Compared to 2016, the highest relative increase in ID liquidity in 2017 was seen in Belgium (+77 %), the Netherlands (+75 %) and the Nordics and Baltics (+31 %). ACER and CEER (2018) state in their market monitoring report that this increase for Belgium and the Netherlands can be partially explained by the introduction of an improved implicit ID cross-zonal capacity allocation platform in October 2016.



Source: NEMOs, Eurostat, CEER National Indicators Database and ACER calculations (2018).
Note: Only markets with data available for at least four years are shown.

Figure 14: Ratio between ID traded volumes and electricity demand in a selection of EU markets – 2011–2017 (%) (ACER and CEER, 2018).

An inference that could be made from Figure 14 is that an auction-based market design in the IDM fosters liquidity. ID auctions in Spain, Italy and Portugal have generally shown a higher liquidity than IDM of other European countries with continuous trading in place. This observation is studied in the paper by Hagemann and Weber (2015) and discussed by Chaves-Ávila and Fernandes (2015). Hagemann and Weber (2015) conclude that the high volumes observed in auction-based intraday markets cannot be explained by the auction-based design but are mainly caused by market peculiarities. They developed an analytical method which considers wind and solar power forecast errors, power plant outages with relevance for intraday trading, market concentration and portfolio internal netting options as the main drivers of trading volume.

Next to these fundamental drivers, one of the most important reasons found for the high liquidity in the Italian, Spanish and Portuguese market was that rescheduling of power plants' generation output within one generation portfolio is only possible via trades in the intraday market. [57] No bilateral trade after the DAM and internal portfolio netting outside of the market are allowed (Rodilla and Batlle, 2015). Additionally, Hagemann and Weber (2015) also argue that renewable support schemes have an influence on IDM liquidity. In countries with low-risk support schemes, such as a feed-in tariff (FIT), the balancing responsibility is typically transferred to the TSO (or DSO). TSOs need to trade the imbalances on the intraday markets, raising the trading volume. On the contrary, in countries with high-risk support schemes, such as feed-in premiums (FIP), the owners of vRES are responsible for their forecast errors. Unlike the TSO, these parties can either use controllable generation for internal self-balancing or do not manage forecast errors actively in the intraday market if they are too small.

ACER and CEER (2018) is less strong in its statements but supports these analyses in saying that the relatively high level of ID-traded volumes in Spanish, Italian and Portuguese markets can be partially explained by three common characteristics of these markets. These are first, a high penetration of vRES generation, second, the fact that no continuous trading and no alternative to the organised market in the form of an ID auction exists, as well as third, obligatory unit bidding (as opposed to portfolio bidding).

In contrast with Hagemann and Weber (2015) and Chaves-Ávila and Fernandes (2015), Neuhoff et al. (2016b) do not attribute the high liquidity levels to market peculiarities, but more clearly argue in favour of intraday auctions over continuous trading in the IDM. More specifically, Neuhoff et al. (2016b) have studied the implementation of the 15-minute intraday auction in Germany (see also Figure 14). They observed that the additional auction increases liquidity, lead to a higher market depth (the revelation of market participant's capacity/flexibility) and to a reduced price volatility.

Not yet mentioned in this discussion but extremely relevant to this matter is the fact that sufficiently high imbalance settlements, paid when a party is found to be unbalanced in real-time, should give an incentive for market participants to balance their output on the IDM. If these price signals are not

[57] Chaves-Ávila and Fernandes (2015) and Rodilla and Batlle (2015) also mention three other reasons explaining the high liquidity in the Spanish market. Firstly, there is an additional upward regulation reserve, which can be called upon, consisting of units which were not dispatched in the DAM. If a unit gets selected in this market, it is forced to bid into the IDM in order to get committed. Also, there is a national coal support mechanism which has given incentives to some units to avoid being committed in the DAM and to bid in the IDM instead. And lastly, price arbitrage opportunities have been identified between DAM and IDM in recent years. These might have been (partly) caused by the regulation around this upward reserve and the national coal support scheme.

strong enough, market participants will not feel the need to trade on the IDM and liquidity will remain low. Additionally, if vRES were held responsible (preferably under the same rules as conventional units) for their imbalances, they would be forced to trade in the IDM. Also, transparent 'near-real-time' information about the system state is of crucial importance. If market participants have this information, they can estimate potential imbalance settlements and they will be strongly incentivised to balance their positions in the IDM, especially when it is highly needed from a system perspective. In brief, a well-functioning liquid IDM depends on well-designed imbalance settlement rules.

4.3.3 IDM gate closure: the gap between trading and real-time operation

As implicitly stated in Article 59 (2) of the CACM GL, the length of the IDM gate closure is a trade-off between:

'*(a) a maximisation of market participants' opportunities for adjusting their balances by trading in the intraday market time-frame as close as possible to real time;*

and (b) providing TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security.'

Further, it is stated in the CACM GL, Art. 59(3) that the intraday cross-zonal gate closure time, the gate closure time for cross-zonal transmission capacity, shall be at most one hour before real-time. Intraday energy trading for a given market time unit for a bidding zone border shall be allowed until the intraday cross-zonal gate closure time (CACM GL, Art. 59(4)).

The closer gate closure is to real-time, the better vRES will be able to update their forecasts and the more they will be trading in the IDM to avoid imbalances (if imbalance settlements give the required incentive to adjust). A gate closure closer to real time will lead to a higher liquidity in the intraday market and a better deployment of flexible resources - the only resources, next to (fast) demand response (DR), that are able to adjust their output close to real time. Because of a more accurate dispatch of flexible peak units, fewer power plants will have to operate (inefficiently) at partial load in order to deliver balancing services (Müsgens and Neuhoff, 2006). Also, less reserve power capacity may need to be contracted, and less real-time action of the SO should be required, which would lead to a lower system cost if borne out.[58]

The main driver of the time lag between gate closure and real-time is the fact that grid operators require sufficient time after market closure to check system stability and take any necessary measures before real-time. It is undeniable that the level of coordination between TSOs and power exchanges will become increasingly important to minimise the gap between gate close and real time.

4.4 **Matching markets with grids within a bidding zone: redispatch and countertrading**

Before discussing the integration of the day-ahead and intraday markets across different bidding zones in the next chapter, in this section, redispatch and countertrading are introduced to explain how markets and grids are matched within a bidding zone. In Europe, zonal pricing is applied as described in Section 2.3.1. In short, this means that electricity is traded in a bidding zone which is linked to other bidding zones through cross-zonal interconnectors. The physical network within a bidding zone is

[58] This claim is related to the discussion around the TSO's balancing energy activation philosophy described in Section 6.5 of this text.

treated as a copper plate (no network constraints), while the limitations of links between bidding zones are taken into account when trading.

Not incorporating grid constraints within bidding zones is a serious simplification. The flows which would result from electricity trading do not always lead to feasible flows over all lines within a bidding zone (internal congestion). Internal congestion is a structural problem in several regions in Europe, aggravated by the rapid increase in renewable generation and more volatile cross-zonal trade (ACER and ENTSO-E, 2012; Dijk and Willems, 2011; Kunz and Zerrahn, 2016; Van den Bergh et al., 2015).

In the short run, network congestion can be relieved by non-costly preventive measures, such as changing grid topology or by costlier curative measures, such as countertrading or redispatch. With countertrading or redispatch, the TSO arranges an increase in generation at one end of the congested grid area, compensated by a decrease at the other end. The costs of these deviations from the spot market dispatch are socialised through network tariffs (Kunz and Zerrahn, 2016). If countertrading or redispatch opportunities are not available, TSOs may curtail previously allocated cross-zonal capacities. In that case, the owners of the transmission rights have to be compensated.

Definitions of countertrading and redispatch are provided in a presentation by ACER and ENTSOE (2012):

- *Redispatch: 'Any measure activated by one or several system operators by altering the generation and/or load pattern in order to change physical flows in the Transmission System and relieve a physical congestion. The precise generation or load pattern alteration is **pre-defined**.'* Redispatching can be:
    - Internal redispatching: the redispatching is performed in the bidding zone where the congestion is.
    - External redispatching: the redispatching is performed in bidding zone A whereas the congestion is on bidding zone B.
    - Cross-zonal redispatching: the redispatching is carried out in different bidding zones
- *Countertrading*: '*Cross zonal energy exchange initiated by system operators between two bidding zones to relieve a physical congestion. The precise generation or load pattern alteration is **not pre-defined**.*'

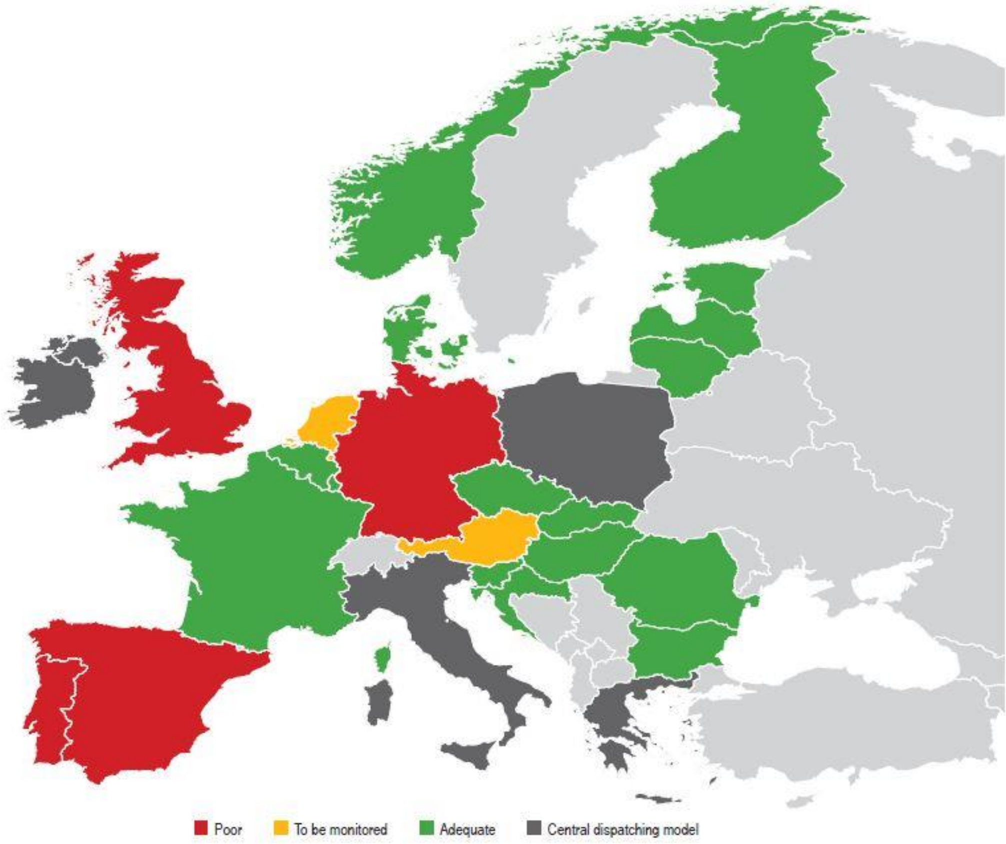
Redispatch can further be distinguished between preventive redispatch that is used to maintain the system in normal state and curative redispatch, which is activated immediately or relatively soon after operational security limits are violated (e.g. Netzstabilitätsanlagen in Germany).

In the CACM GL, Article 35(5) it is stated that the pricing of redispatch and countertrading shall be based on:

'(a) prices in the relevant electricity markets for the relevant time frame; ***or***

(b) costs of redispatching and/or countertrading resources calculated transparently on the basis of incurred costs.'

ACER and CEER (2016) report that the remuneration of activated internal or cross-zonal redispatching differs among Member States. The most common method used is the pay-as-bid pricing followed by the regulated pricing based on either another market price (e.g. DAM price) or a cost-based pricing (e.g. remuneration for the cost of fuel and other costs related to the change in the operating schedule of the plant).[59] Below in Figure 15, the national performances with respect to the use of costly remedial actions averaged over the period 2015–2017 are shown.



Source: NRAs, ENTSO-E and ACER calculations (2018).

Note: Poor performance corresponds to the cost of remedial actions per unit of demand being above 1.0 euro/MWh, performance to be monitored corresponds to the cost of remedial actions per unit demand being between 0.2 and 1.0 euro/MWh, and adequate performance corresponds to the cost of remedial actions per unit demand being below 0.2 euros/MWh. The detailed qualification methodology is described in Annex 4. As the central dispatching model is applied in Greece, Ireland, Italy, Northern Ireland and Poland, costs specifically linked with remedial actions are not available; as a result, these jurisdictions are depicted in dark grey. Sweden is depicted in grey, because the information on costly remedial actions was not made available by the Swedish TSO.

Figure 15: National performances with respect to the use of costly remedial actions (2015–2017) (ACER and CEER, 2018).

Redispatch and countertrading are short-term solutions to solve internal congestion. In the long run, the TSO can build new lines to accommodate the flow patterns. Alternatively, bidding zones can be redrawn or nodal electricity markets can be introduced. Nodal pricing is applied in some regions of the US (e.g. PJM) and can be considered as an extreme form of zonal pricing, namely each node in the transmission network becomes a bidding zone. Dijk and Willems (2011) explain that '*under nodal spot pricing, electricity prices reflect physical constraints, and hence, scarcity of the transmission network. In the short run, nodal spot prices, therefore, ensure optimal usage of the transmission network. Over the long term, they give the optimal incentives for new investments.*'

[59] It can be argued that the best approximation for a fair redispatch price would be the price of the balancing market at the relevant market time unit (and not the DAM price), since redispatch is (or should be) activated close to real time. More precisely, the activated energy for redispatch has not been sold in the DA or IDM, hence, the market price was lower than the production/opportunity costs. Better pricing of redispatch would lead to increased efficiency in the scheduling of available generation/demand units.

None of these three solutions is without downsides. Building new transmission lines costs time and money, just as redrawing bidding zones does. Further, nodal pricing is not considered to be in line with the current European target model for many reasons. In the initial impact assessment for the Framework Guidelines on Capacity Allocation and Congestion Management, the European Regulators' Group for Electricity and Gas (ERGEG) considered the nodal approach as one of the policy options to deliver the objectives of CACM GL (ERGEG, 2010).[60] The implementation of nodal pricing, however, would require numerous substantial (and costly) changes to the current market design and institutional setting, with additional provisions and obligations needing to be defined for TSOs, market participants and regulators. Moreover, there are redistributional concerns with multiple prices within one country which could be politically difficult as also described in Oxera (2013). However, ERGEG (2010) concludes that it is *'important to consider the Nodal Approach as the ultimate goal and (technically and economically) optimal solution for capacity calculation within CACM for the future, but at the same time to pursue the practical development and implementation based on the flow-based calculation.'*[61]

Lastly, it is generally agreed that closer cooperation in congestion management between TSOs has a beneficial impact. More specifically, the sharing of network and dispatch information, cross-zonal counter-trading, and multilateral redispatch can reduce overall system costs and allow for more cross-zonal capacity to be offered to the market (ACER and ENTSO-E, 2012; Kunz and Zerrahn, 2016). For that reason, the CACM GL (Art. 35(1)) requests to all TSOs per CCR to develop a proposal for a common methodology for coordinated redispatching and countertrading. Article 35(2) states that the methodology shall include actions of cross-border relevance and shall enable all TSOs in each capacity calculation region to effectively relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not. Also, Article 74 describes that a redispatch and countertrading cost-sharing methodology will be developed by all TSOs per CCR as coordinated remedial actions can have distributional effects.

[60] The ERGEG is an advisory group to the European Commission on internal energy market issues in Europe. The ERGEG was set up by the European Commission to assist the Commission in consolidating a single EU market for electricity and gas. ERGEG's members are the heads of the national energy regulatory authorities in the EU's 28 Member States.

[61] For a discussion of the zonal (EU) vs the nodal (US) electricity market model, please consult a recording of the FSR online debate on this topic: https://www.youtube.com/watch?v=UerHK6DQH64.

5. Integrating day-ahead and intraday markets

The integrated European electricity market is beneficial due to increased liquidity, transparency, efficiency and social welfare. Glachant and Lévêque (2006) identified the improvement of the congestion management of interconnectors to be the single priority action to be undertaken to foster the internal EU electricity market. After significant progress, ten years later, Glachant (2016) describes the formation of an internal electricity market as follows:

‘The EU opened its many national power markets without a “Target Model” of any kind (and then without a common “Market Design”) and stayed as such for 13 years (1996–2009). A “Target Model” finally emerged, but it had never been defined in any European single regulation or Green Paper. It has been produced by qualified European actors through an institutional process originated in the 3rd European Energy Package. This “Target Model” has at least three key characteristics:

- *1° It brings a large “merit order” at a European scale from a reference pricing mechanism being the one of energy traded in Power Exchanges on Day-Ahead.*
- *2° It simplifies TSO cross-border trading by “zoning” the grids as if each EU TSO grid was some type of “national copper plate”; and, by “coupling” the allocation of grid access between these “zoned area copper plate” grids with the merit order built into the PXs in Day-Ahead trading. This is done only after having chosen a guaranteed inter-zonal capacity calculated ex ante (on the same Day-Ahead horizon) by the grid transmission operators (the TSOs).*
- *3° This “Target Model” has its own “last mile” hard task being to open a similar “zones cross-border” process for the shortest time frames (Intraday & Balancing) as to “Europeanise” the last step to power reserve & energy balancing procurement between the TSO grid zones.’*

The network codes and guidelines are developed specifically to smoothly ‘Europeanise’ electricity markets. In this section, first, the integration of day-ahead markets is discussed. Arguably, day-ahead markets are quite well integrated. Overall, we seem to have almost arrived at the ‘last mile’ of the ‘EU Target Model’. Second, the integration of intraday markets is discussed. The integration of intraday markets can be considered more as work-in-progress, however, recently important steps were taken.

5.1 Day-ahead market integration

At the time of writing in early 2019, the Pan-European single day-ahead coupling (SDAC) serves 27 countries. A single price coupling algorithm, called Price Coupling of Regions (PCR) EUPHEMIA (EU + Pan-European Hybrid Electricity Market Integration Algorithm), is used to calculate electricity prices across Europe from Portugal to Estonia. In 2018, the EUPHEMIA algorithm was jointly operated by the eight NEMOs (PCR, 2018b). Traded electricity and transmission capacity between bidding zones are allocated simultaneously by the algorithm; this process is called implicit allocation of transmission capacity. For more detailed information about the function of EUPHEMIA, please consult the presentation on PCR (2016).

In the SDAC, two coupling projects are in parallel operation, namely the Multi-Regional Coupling (MRC) and 4M Market Coupling (4M MC) project. Figure 16 shows the state-of-play of SDAC as of July 2018. In Figure 16, the MRC market connected 21 countries representing close to 90 % of the European electricity consumption.[62] Since October 2018, also Ireland is coupled after it reformed its electricity market. Further, ACER (2019a) states that also Greece is reforming its electricity market and is expected to be coupled in 2019 through the Greece-Italian interconnector. The 4M MC covers Czech Republic, Slovakia, Hungary, and Romania. Both areas apply very similar technical solutions based on EUPHEMIA which are ultimately to be integrated (ENTSO-E, 2018b; TGE, 2015). Furthermore, two countries out of the SDAC (for now) use the same PCR algorithm for calculating the prices of their day-ahead markets, albeit on an independent basis, namely, Serbia and Switzerland (OMIE, 2015).

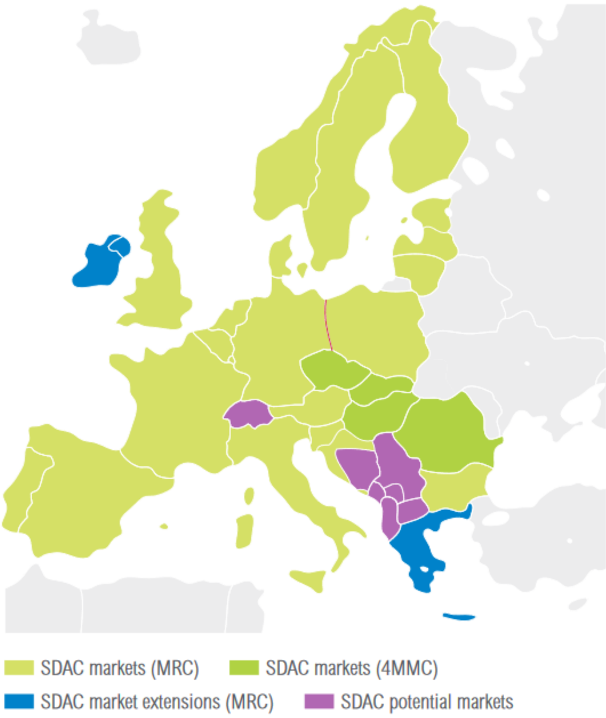


Figure 16: State-of-play in Single Day-Ahead Coupling as of July 2018 (ENTSO-E, 2018b).

The ultimate goal of market coupling is to maximise welfare or economic surplus; this would be achieved through the efficient use of all available resources spread over bidding zones.[63] Gains can be made as different countries have a different energy mix and imperfect correlated demand and renewable production. Key to achieving this goal are interconnectors, connecting different bidding zones. Market coupling implies that if exchange between two bidding zones occurs and not all commercially available cross-zonal capacity between the two bidding zones is utilised, the electricity prices in both bidding zones converge.[64] If the exchange results into full utilisation of the offered cross-zonal capacities between the bidding zones to the market, i.e. the cross-zonal lines is congested, the

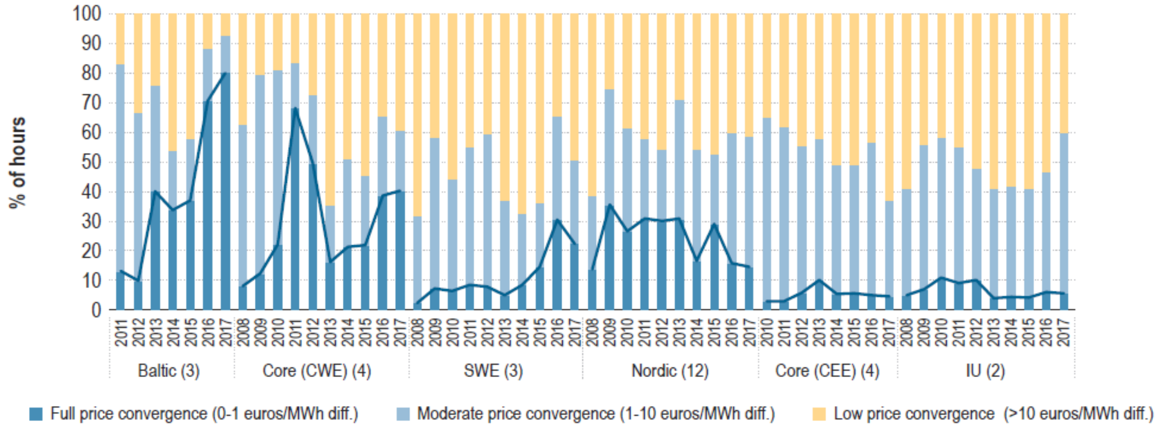
[62] Bulgaria is a member of the MRC, and connected to the MRC calculation via the common PCR EUPHEMIA algorithm, but without interconnection capacities. The red line between Poland and Germany indicates that the two countries are not coupled. Poland is coupled through interconnectors with Sweden and Latvia. Germany through interconnectors with Austria, France, the Netherlands and Denmark.

[63] In the CACM GL (Art. 2(46)) economic surplus is defined as the sum of (i) the supplier surplus for the single day-ahead or intraday coupling for the relevant time period, (ii) the consumer surplus for the single day-ahead or intraday coupling, (iii) the congestion income and (iv) other related costs and benefits where these increase economic efficiency for the relevant time period, supplier and consumer surplus being the difference between the accepted orders and the clearing price per energy unit multiplied by the volume of energy of the orders.

[64] In more technical terms: cross-zonal energy exchange does not result in a binding cross-zonal transmission constraint.

prices between the bidding zones can diverge. In that case, it is said that the respective markets are 'split' and a price differential between the electricity prices in the different bidding zones can occur. Price differentials between bidding zones results in congestion rent for the TSO(s) or independent party operating the interconnector.[65,66]

Figure 17 shows the level of price convergence in different regions in the EU, comprising multiple bidding zones.[67] Different regions show various levels of convergence. For most regions an increase is visible over the last years. Between 2016 and 2017, the highest increases in the frequency of price convergence were observed in the Baltic and CWE regions. These regions also showed the highest shares of hours with full price convergence, respectively, 80 % and 41 % of the hours in 2017.



Source: ENTSO-E and ACER calculations (2018).

Note: The numbers in brackets refer to the number of bidding zones included in the analysis per CCR.

Figure 17: DAM price convergence from 2011-2017 (ACER and CEER, 2018).

'The optimal level of price convergence' is very hard to determine, if not impossible. 100 % convergence would mean over-investment in grid infrastructure, very low convergence could imply underinvestment in grids or inefficient use of existing interconnector capacity. The criterion in theory, under ideal assumptions, is that for an optimally developed grid the total congestion income would recover 100 % of the total grid investment costs (Pérez-Arriaga et al., 1995). In reality, congestion income covers only a fraction of total grid costs. In Box 5 an example of how congestion rent is generated with implicit transmission capacity allocation is given.

Box 5: Numerical example: the generation of congestion rent with implicit capacity allocation from Schittekatte and Meeus (2018).

Suppose that the day-ahead market auction for a certain hour results in a price in zone A of 50 €/MWh and a price in zone B of 60 €/MWh. The satisfied demand in zone A is 100 MW, the satisfied demand in zone B is 150 MW and the interconnector capacity allocated for trade between the two zones was 50 MW. As there is a price differential between the two zones, it implies that the cross-zonal interconnector capacity is fully utilized, i.e. the total electricity flowing through the interconnector is 50 MW. Electricity flows from the low price zone (A) to the high price zone (B).

	Price	*Demand*	*Generation*	*Demand cost*	*Generation cost*
Zone A	50 €/MWh	100 MW	150 MW	€ 5,000	€ 7,500

[65] Congestion rent (€/h) = the price differential (€/MWh) x congested capacity of the interconnector (MW).
[66] For a recent overview of how congestion rent is spent please consult e.g. p.12-14 of ECN et al. (2017).
[67] Here defined as the % of hours the DAM prices were the same for the different bidding zones within a certain region.

			(demand zone A + interconnector)		
Zone B	60 €/MWh	150 MW	100 MW (demand zone B - interconnector)	€ 9,000	€ 6,000
				€ 14,000	€ 13,500

The total amount collected by generation over the two zones is € 13,500 while the total amount spent by demand equals € 14,000. The difference between the two is the congestion rent of € 500 equalling the price differential between the two zones (€ 10/MWh) multiplied by the capacity of the line (50 MW). This congestion rent is transferred to the TSO(s) owning the interconnector.

The following part of this section focuses on the efficient use of cross-zonal transmission capacity. First, explicit and implicit allocation of transmission capacity is described in more detail. Then, methods for the calculation of transmission capacity available for trade are explained. Lastly, unscheduled flows are defined and their origins discussed.

5.1.1 Explicit vs implicit allocation of transmission capacity

There are two market-based arrangements for the (short-term) allocation of cross-zonal transmission capacity: explicit and implicit allocation of transmission capacity.[68] With explicit trading, transmission capacity and energy are traded separately. Market participants wanting to sell power over a bidding zone border need to acquire the transmission capacity to do so and nominate it. With implicit allocation, electricity and transmission capacity are traded simultaneously. Cross-zonal trade is possible for market participants without explicitly acquiring transmission capacity under the condition that interconnectors are not congested (market coupling). In the SDAC, implicit allocation is in place, as established in the CACM GL.

Figure 18 shows how price differentials should be when transmission capacity is efficiently allocated. If the line between country A and B is not congested the price difference between both should be zero (1). However, if the line is congested in the direction of country B (2), then the price in country B should be higher than the price of country A, as electricity should flow from low price areas to high price areas. The exact difference between the price in country A and country B depends on local supply and demand at a certain time. Similarly, if the line is congested in the direction of country A (3), then the price in country A should be higher than the price in country B.

[68] Kristiansen (2007) explains that there are also non-market based cross-zonal congestion arrangements possible, but these are not in use in the EU anymore.

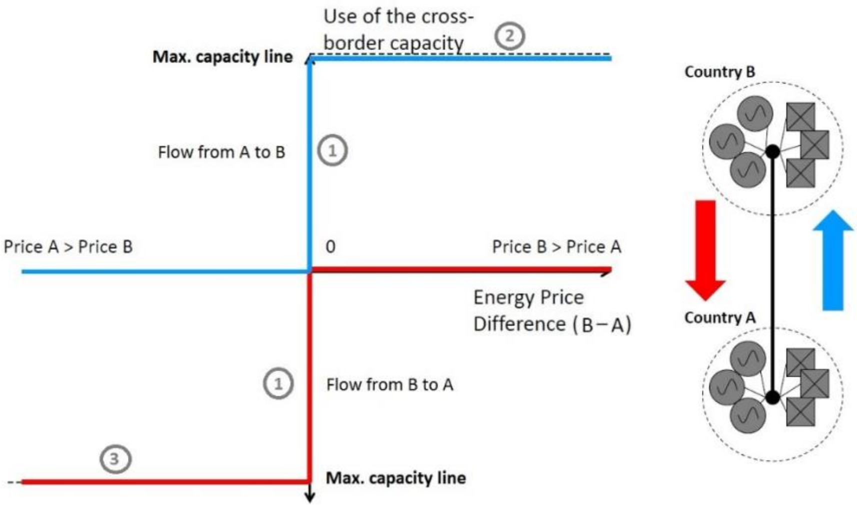


Figure 18: Zonal pricing and optimal cross-zonal allocation (FSR, 2018).

Under ideal assumptions, the outcome for explicit allocation and implicit allocation should be the same and optimal (as shown in Figure 18). In Figure 19, results are shown for the French-Spanish border in 2012. At that time, explicit auctions for cross-zonal transmission were held, MRC was not yet in place. The pattern diverges quite strongly from what we would expect with optimal cross-zonal allocation. In some cases, the prices differ between the countries while the interconnector is not congested. Even more extreme, often the price in France was higher, but the electricity was flowing towards Spain (quadrant 1) or vice-versa versa (quadrant 3). Reasons for the deviation from optimal usage are coordination issues (timing, limited information, imperfect forecast) for market participants or uncompetitive behaviour.[69]

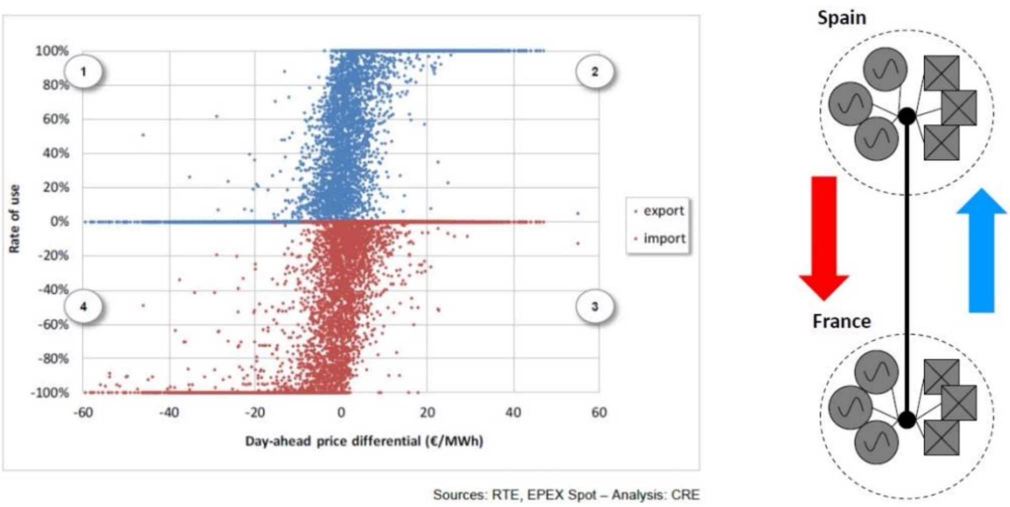


Figure 19: Explicit cross-zonal allocation: use of net daily capacities on the French-Spanish interconnector compared with hourly DAM price differences, data of 2012 (FSR, 2018).

[69] Under Flow-Based Market Coupling (FBMC, see next subsection), it is also possible, even though rather exceptional, that a flow occurs from a higher price area to a lower price area. This happens if such a flow pattern increases the total social welfare of the region. Such 'non-intuitive' local counter flows can relieve congestions in the system by allowing increased exchanges on other borders, which have a larger and positive social welfare impact. The Nordic RSC provides Q&A regarding FB MC at https://nordic-rsc.net/related-projects/questions-answers/. For more information on 'plain' vs. 'intuitive' FB MC, please consult EPEX SPOT (2013)

Figure 20 shows the results for implicit allocation between Belgium and France in 2012. These markets were coupled at the time. It can be seen that with implicit allocation cross-zonal capacity is efficiently used. With implicit allocation, there are no coordination issues.

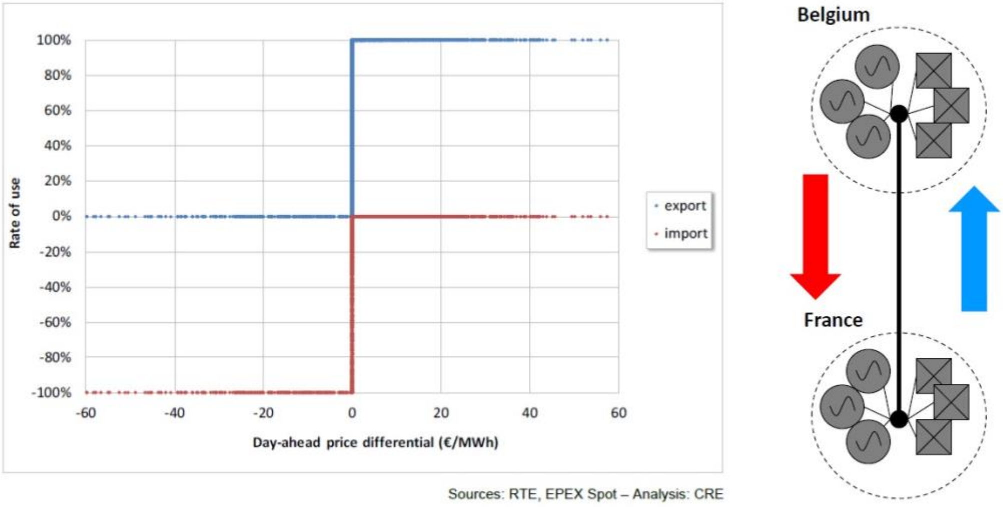


Figure 20: Implicit cross-zonal allocation : use of net daily capacities on the France-Belgium interconnector compared with hourly price differences, data of 2012 (FSR, 2018).

Efficient allocation of available cross-zonal transmission capacity is an important dimension of well-functioning integrated electricity markets. Another crucial dimension is the calculation of the total transmission capacity that should be allocated to market participants. In other words, in this subsection, efficient allocation of cross-zonal capacity was discussed while in the next subsection, the question ''how much cross-zonal capacity can be made available for trade without putting the system at risk?'' is tackled. Limited available capacity offered for electricity trade, even when efficiently allocated, does not lead to fully integrated markets.

5.1.2 Cross-zonal capacity calculation: approaches and issues

It is not straightforward to properly calculate the available transmission capacity between bidding zones. The reason for this is that electricity does not flow directly from generators to consumers, but spreads out over a (meshed AC) network according to the laws of physics (Kirchhoff laws). Energy flows across all paths in proportion to their admittance. This implies that one line can be constrained by other lines before reaching its maximal thermal capacity.[70] Several other issues, directly or indirectly related to the physical nature of electricity and zonal pricing, make it impossible to fully offer the thermal capacity of lines for trade (Nabe and Neuhoff (2015), Schavemaker and Beune (2013) and Van den Bergh et al. (2016)):

- *Calculating cross-zonal capacity for trade is a chicken-and-egg-issue*. Namely, the transmission capacity available for commercial transactions between bidding zones depends on the generation and load pattern within a bidding zone. However, the generation and load pattern within a bidding zone is a function of the market outcome and as such is influenced by the volume of transmission capacity made available by TSOs for cross-zonal trade. This implies that safety margins need to be introduced to compensate for the approximations and simplifications made.

[70] For an illustrative example please see Pérez-Arriaga (2013), more precisely section 6.1.3 'The Transmission Grid: Technical Considerations'.

- *Transit flows*: Some cross-zonal capacity of one bidding zone will be used by parallel flows resulting from trade between other bidding zones. For example, trade between Germany and France can flow through Belgium. As such, the cross-zonal transmission capacity available for trade between Belgium and its neighbours will be impacted. Transit flows are unscheduled when the exchange causing the flow is cross-zonal and the capacity calculation is not coordinated with the zone facing the flow. A flow is called an 'unscheduled flow (UF)' when the physical flow in the network differs from commercial exchanges between consumers and producers within a bidding zone or between two different bidding zones (ACER, 2013). If the cross-zonal capacity calculation is coordinated between the zones causing and the zone facing the transit flow, the transit flows can be accounted for in the transmission calculation progress. A transit flow is illustrated in the left of Figure 21.

- *Loop flows:* Transactions within a bidding zone can have an impact on the flows through adjacent bidding zones. For example, if there is a commercial transaction between the North and the South of Germany, it is possible that electricity would flow through Poland to reach its destination. As such, the cross-zonal transmission capacity available for trade between Poland and its neighbours (mostly Germany in this case) will be impacted. Loop flows are by definition always unscheduled as they occur between two nodes within the same bidding zone (Schavemaker and Beune, 2013). A loop flow is illustrated in the right of Figure 21.

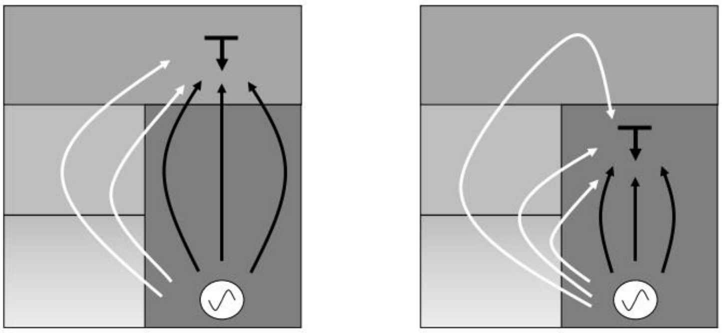


Figure 21: Scheduled flows (black), transit flows (white-left) and loop flows (white-right) (Schavemaker and Beune, 2013).

Today, two methods are in place in Europe to perform the cross-zonal capacity calculation. The conventional Coordinated Net Transfer Capacity (CNTC) approach or the more sophisticated flow-based approach. The calculation is done by a Coordinated Capacity Calculator (CCC) per Capacity Calculation Region (CCR) as explained in Section 2.3.2.[71] The CACM GL says in recital (7) that:

'There are two permissible approaches when calculating cross-zonal capacity: flow-based or based on coordinated net transmission capacity. The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The flow-based approach should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value.'

[71] When they are all in place, RSCs are expected to take over this task.

Furthermore, in Article 20(2) of CACM GL it states that '*no later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region.*' A methodology for both day-ahead and intraday capacity calculation shall be proposed. A delayed submission was permitted with respect to certain CCRs (CACM GL, Art. 20(3-4)). In January 2019, 7 of the 10 CCMs were approved (ACER, 2019a). At a later point it is intended that the capacity calculation of two or more adjacent CCRs in the same synchronous area shall be integrated if all CCRs implement a flow-based capacity calculation methodology (CACM GL, Art. 20(5)).

In the remainder of this subsection, first, the CNTC approach is explained. Then, the flow-based approach is described. Lastly, possible remedies are mapped against issues with cross-zonal capacity calculation.

Coordinated Net Transfer Capacity (CNTC)

Van den Bergh et al. (2016) explain that in the CNTC approach the link between the physical network and commercial transactions is heavily simplified. Bidding zones are represented by one equivalent node, and only cross-zonal links are considered as shown in Figure 22 (left) for three bidding zones.

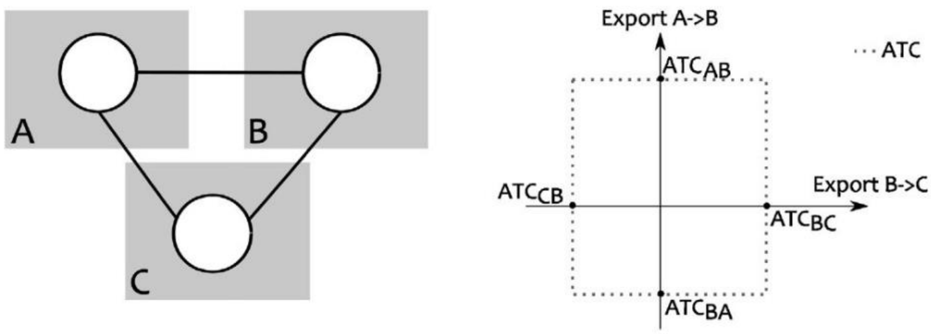


Figure 22: Grid model under the CNTC approach (left) and flow domain (right) (Van den Bergh et al., 2016).

With CNTC, the cross-zonal capacity offered for one link (the so-called Available Transfer Capacity (ATC) value) is independent of the flows on other cross-zonal links as can be seen in Figure 22 (right). TSOs use a heuristic to calculate the cross-zonal capacity available for trade based on assumptions of the market outcome (2-days ahead) and associated physical flows. As such, capacity allocation takes place ex ante, completely separated, from the market clearing.

The CNTC approach is compatible with both explicit and implicit allocation of transmission capacity. At the time of writing in early 2019, the CNTC approach is used in European markets, except for Central-West Europe, where flow-based market coupling was introduced in May 2015 (ACER and CEER, 2016). The CORE CCR, the largest central CCR, and the Nordic CCR intend to implement flow-based market coupling in their respective regions.

Flow-based (FB) approach

In contrast, the FB approach is only compatible with implicit allocation of cross-zonal transmission capacity or market coupling; hence, the method is often also directly called flow-based market coupling (FBMC). In FBMC, although still simplified, more physical transmission constraints are taken into account in the market clearing. It can be said that with FBMC the cross-zonal capacity allocation happens partly ex ante and partly simultaneously with the market clearing as the (simplified) transmission constraints are taken into account in the market clearing. In other words, there is an interaction between cross-zonal capacity allocation and market clearing.

In Figure 23 (left) a simplified representation of a grid model under FBMC is shown. Combining all main inputs from the TSOs and flow equations, a feasible FB trading domain is obtained as shown in Figure 23 (right). With FBMC, the cross-zonal capacity offered to the market on one line is no longer independent from other cross-zonal flows. Actually, in the FB approach, the entire (in most cases larger) flow domain is offered to the market. In contrast to the CNTC approach, with the FB approach the market, driven by bids and offers, decides on the allocation of transmission capacity among market participants.

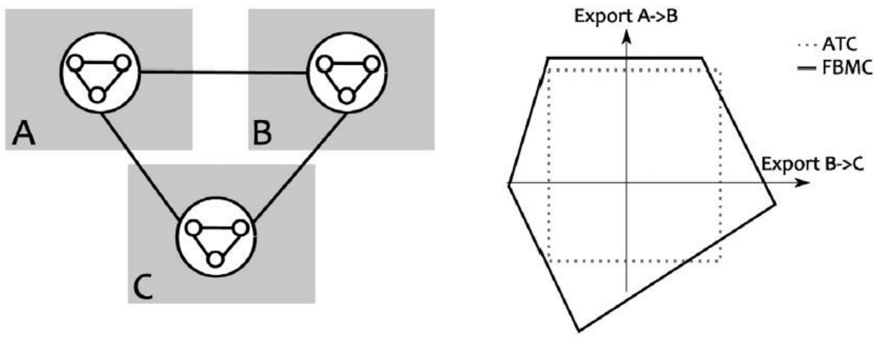


Figure 23: Grid model under FB approach (left) and flow domain (right) (Van den Bergh et al., 2016).

As stated before, with FBMC cross-zonal capacity allocation happens partly ex ante and partly simultaneously with market clearing. In the previous paragraph, the simultaneous part was discussed. The ex-ante part refers to the main inputs from TSOs which are combined on a regional level and needed to determine the flow domain. Plancke et al. (2016) explain that to arrive at the simplified network model without having to consider all individual lines, each TSO defines Critical Network Elements (CNEs) for its control area. CNEs are also called Critical Branches in the literature and include cross-zonal lines, but can also include internal lines or transformers that are significantly impacted by cross-zonal exchanges. In the flow-based capacity calculation, cross-zonal lines are considered together with internal critical network elements.

The FBMC is a process, not a one-step calculation, which starts two days before real-time ('Base Case') and ends the morning one day ahead. At that moment, the coordinated capacity calculators deliver the necessary parameters to the NEMO who is in charge of the day-ahead market clearing algorithm. The FB-parameters incorporated in the market clearing algorithm are challenging to determine (Plancke et al., 2016; Van den Bergh et al., 2016).[72] They consist of:

- *Zonal Power Transfer Distribution Factors (PTDFs)*:
  - **What?** Zonal PTDFs describe the linear relationship between the physical flow in a critical branch and the net exchange position of a specific bidding zone.[73] They are formulated in a (sparse) matrix form with on one dimension all the bidding zones and on the other dimension all the cross-zonal interconnectors.

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[72] For transparency reasons, the way they are determined should be described in detail in the capacity calculation methodology per CCR (CACM GL, Art. 21(1)). This was already the case for the CWE FBMC, this data is published on the website of the JAO (www.jao.eu -> Support-> CWE FBMC).

[73] The net exchange position of a bidding zone is equal to the total production within the zone minus the total consumption within a zone. If the production is higher than the consumption, the zone will be a net exporter. Vice-versa the zone would be a net importer.

- **How are they derived?** With zonal pricing, nodes are grouped per zone. This implies that in order to correctly represent flows between zones, zonal PTDFs need to be approximated from what happens at nodal level within a zone. Generation Shift Keys (GSKs) 'translate' changes in generation/consumption at nodal level to impacts on the net exchange level of a zone. GSKs are not easy to determine as they are based on predictions of the market outcome and subject to forecast errors. Each TSO calculates the GSKs for his control area. Van den Bergh et al. (2016) describe that the way TSOs derived GSKs in the past was not harmonised. The CACM GL establishes in Article 24 that the common capacity calculation methodology (per capacity calculation regions) shall include a proposal for a methodology to determine a common way to derive generation shift keys for each bidding zone. Additionally, the common grid model plays a crucial role in obtaining optimal forecast to increase the accuracy of GSKs.

- *Available Margins (AM) on Critical Network elements (CNE)*:
  - **What?** The AM is the maximal flow (a fraction of the thermal limit) that can be carried by CNEs due to flows induced by day-ahead trade. In the literature, the Available Margin is also referred to as the Remaining Available Margin (RAM).
  - **How are they derived?** The determination of 1.) what the critical network elements are within a control zone and 2.) the contingencies (critical outages) to be considered for system security are key for the determination of this FB-parameter. Van den Bergh et al. (2016) find that the exact method to derive the AM is confusing and inconsistently formulated in consulted FBMC reports. In general, AM are derived as the maximal flow an element can carry minus 3 flows:
    - The Reference Flow on a CNE: the reference flow is caused by transactions between or within bidding zones other than the DA market, such bilateral transactions or transactions in forward markets.
    - A Final Adjustment value: a margin which is TSO specific and depends on, for example, complex remedial actions. To determinate this value it is important to ensure that there is no discrimination between internal and cross-zonal flows (CACM GL, Art. 29(7)(d)).
    - A Flow Reliability Margin: a safety margin compensating for approximations made in the FB-approach

    Also, regarding the calculation of the AM and its components, the CACM GL tends to create transparency and harmonisation with Article 29.

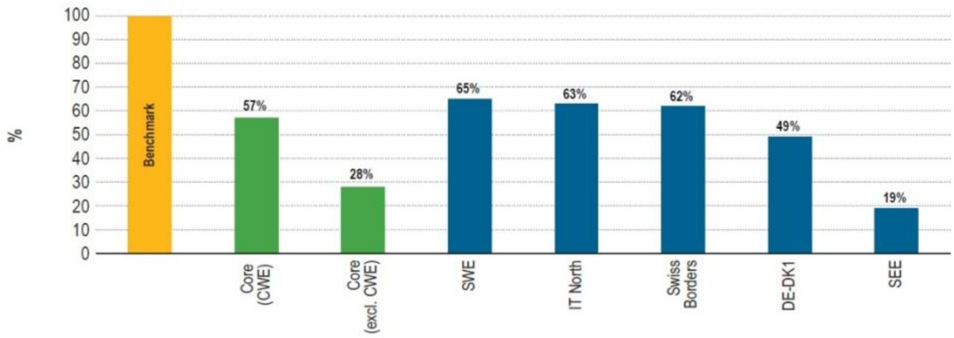
Van den Bergh et al. (2016) state that by better representing the physical characteristics with the FB approach, the cross-zonal capacity offered to the market can be determined in a less conservative way. Plancke et al. (2016) agree that the FB is more sophisticated than the CNTC approach, resulting in (theoretically) higher cross-zonal capacity offered to the market. However, the authors add that operational challenges could arise due to the increased complexity.

Limited commercial cross-zonal capacity: causes and issues

ACER and CEER (2018, 2017, 2016) find in their Market Monitoring Reports (MMR) that, in recent years, the volume of tradable cross-zonal capacities in the EU has remained relatively limited. Improvement was anticipated after investments in transmission networks and progress in capacity calculation methods. Important variation between regions are found but on most EU borders only a small proportion of the physical capacity is offered to the market. For example, in 2015, the MMR analysis shows that on average more than 84% of HVDC and 28% of HVAC interconnector's thermal capacity was used for trading (ACER and CEER, 2016).

However, the thermal capacity of a line is not the best metric to assess whether a reasonable proportion of the capacity is offered to the market. Therefore, a new metric was introduced by ACER and CEER (2017) in their 2017 MMR.[74] This new metric, called 'the benchmark capacity', is the maximum capacity that could be made available to the market on a given border if the recent Agency's Recommendation on capacity calculation were to be followed.[75] This means that i) cross-zonal capacity is only limited by cross-zonal network elements and that ii) the full capacity of these network elements is fully available for cross-zonal exchanges. In other words, it is assumed that no internal flows or loop flows are prioritised over offering cross-zonal capacity for trade; the remaining congestion within bidding zones is assumed to be addressed via remedial actions. Additionally, it is assumed that the thermal capacity of all individual cross-zonal network elements is reduced by 15 % to cope with uncertainty (Reliability Margin (RM)) and with a residual amount of unscheduled flows that would remain in any 'close-to-ideal' configuration of bidding zones. Furthermore, the methodology for calculating benchmark capacity respects the N-1 security criterion. Lastly, the methodology requires that the values of benchmark capacity on different borders must be simultaneously feasible.[76]

The results of the ACER and CEER assessment for 2016 show that an average of 47% of the HVAC benchmark capacity was made available for trading. The share was much higher (over 85% on average) for HVDC interconnectors. In their assessment for 2017, the MMR focused solely on HVAC interconnectors as the performance of those was the most problematic. The average capacity made available for trading increased in 2017 to 49 % of the HVAC benchmark capacity, presenting still considerable room for improvement. Figure 24 shows the results for different regions.



Source: NRAs, Nord Pool Spot, ENTSO-E's CGM (2017) and ACER calculations (2018).

Note: CCRs where FB capacity calculation methodologies (CCMs) are currently applied or envisaged (based on TSOs' proposals) are shown in green, otherwise coordinated net transfer capacity (CNTC) methodologies are assumed and shown in blue.

Figure 24: Ratio between the available cross-border capacity for trade and the benchmark capacity of HVAC interconnectors per region in 2017 (ACER and CEER, 2018).

ACER and CEER (2018) argue that low level of cross-zonal transmission capacity offered to the market is probably the result of congestions not being properly addressed by the current bidding zone configuration in Europe. This conclusion is based on two indications and elaborates on the findings of the previous MMRs.

First, the relatively low level of available cross-zonal capacity compared to the benchmark capacity may be an indication that structural congestion is located within bidding zones rather than on bidding

[74] If 100% of the physical capacity of an HVAC line would be offered to the market, it would mean that: no margin for security is foreseen, the network is perfectly built (no 'bottlenecks' due to Kirchhoff's laws) and bidding zones are perfectly demarcated.

[75] This is the Recommendation of the Agency No 02/2016 of 11 November 2016 (ACER, 2016b).

[76] For a more detailed explanation of the methodology to calculate benchmark capacities for cross-zonal exchange, please consult Annex 2 of ACER and CEER (2017).

zone borders. In other words, congestion most often relates to intra-zonal CNEs rather than to interconnectors.

Second, TSOs need to apply costly remedial actions to address these intra-zonal congestions. However, a controversial claim exists, that due to the lack of correct and adequate incentives for TSOs, the latter prefer to limit ex-ante cross-zonal capacities during the capacity calculation process in order to limit the costs of redispatching and countertrading required to accommodate internal flows. It is hard to prove that TSOs demonstrate such behaviour. Glachant and Pignon (2005) demonstrate, using a theoretical example, that such behaviour could be feasible.

The CACM GL clearly states that internal and cross-zonal flows should be treated equally. More precisely, it states that there should be no undue discrimination between internal and cross-zonal flows. Article 23 of the CACM GL says that: [77]

(1) Each TSO shall respect the operational security limits and contingencies used in operational security analysis.

(2) If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

***(3) If TSOs apply allocation constraints[78], they can only be determined using**:*

> *(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or*
>
> *(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling.*

In their previous MMRs, ACER and CEER (2016, 2017) had also identified a lack of coordination between TSOs concerning the cross-zonal capacity calculation. For 40 out of 48 assessed borders, either a bilateral or partly coordinated capacity calculation method is applied (ACER and CEER, 2016). Additionally, on many borders during certain market time-frames, capacity calculation is simply not applied by at least one of the TSOs. Until a more efficient alternative bidding zone configuration is identified and applied, the capacity calculation process is expected to mitigate the situation (ACER and CEER, 2018). The CACM GL (Art. 15(1)) requires the establishment of capacity calculation regions (CCRs) and a common capacity calculation methodology per CCR (Art. 20(2)). Also, by 31 December 2020, all

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[77] ACER (2016b) repeats point 3 of Article 23 of CACM GL in their recommendation on the common capacity calculation and redispatch and countertrading cost sharing methodologies to not take into account internal congestion when calculating cross-zonal capacity (it should in principle be resolved with remedial actions in the short term and other solutions in the long term), except temporarily, if:

(a) it is needed to ensure operational security; and

(b) it is economically more efficient than other available remedies (taking into account the EU-wide welfare effects of the reduction of cross-zonal capacity) and minimises the negative impacts on the internal market in electricity.

[78] Allocation constraints are defined in the CACM GL, Art. 2(6) as the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and which have not been translated into cross-zonal capacity or are needed to increase the efficiency of capacity allocation.

regions shall use a harmonised capacity calculation methodology, which is described in more detail in Article 21(4) of the CACM GL. By increasing coordination among TSOs (e.g. by applying FB capacity calculation), it is expected that first, unallocated transit flows can be significantly reduced and that second, the extent to which internal exchanges are unduly prioritised over cross-zonal ones can be limited (ACER and CEER, 2018).

5.2 Intraday market integration

The Target Model for the intraday market has been laid down in the CACM GL and is based on continuous trading where cross-zonal transmission capacity is allocated through implicit continuous allocation. Implicit allocation implies that the common IT system will accommodate the continuous matching of bids and orders from market participants in one bidding zone with bids and orders coming from its own bidding zone and from any other bidding zone while cross-zonal capacity is still available. By integrating intraday markets, the opportunities for market parties to trade close to real-time can be significantly increased as they also can benefit from the available liquidity in other zones next to their bidding zone, which increases matching probabilities. An initiative called the Cross-Border Intraday Market Project (XBID) is providing the basis for the Pan-European Single Intraday Coupling (SIDC). At the time of writing, the XBID project is comprised of members from 14 European countries (''the first wave''), as illustrated in Figure 25. The following products are supported: 15-minutes, 30-minutes, 60-minutes and hourly user-defined blocks per market area. The complex XBID project went live in mid-June 2018. A 'second wave' of countries connecting to XBID via dedicated Local Implementation Projects (LIPs) is expected to go ahead in the summer of 2019 (ENTSO-E, 2019). More information regarding the LIPs can be found in ENTSO-E (2018b).

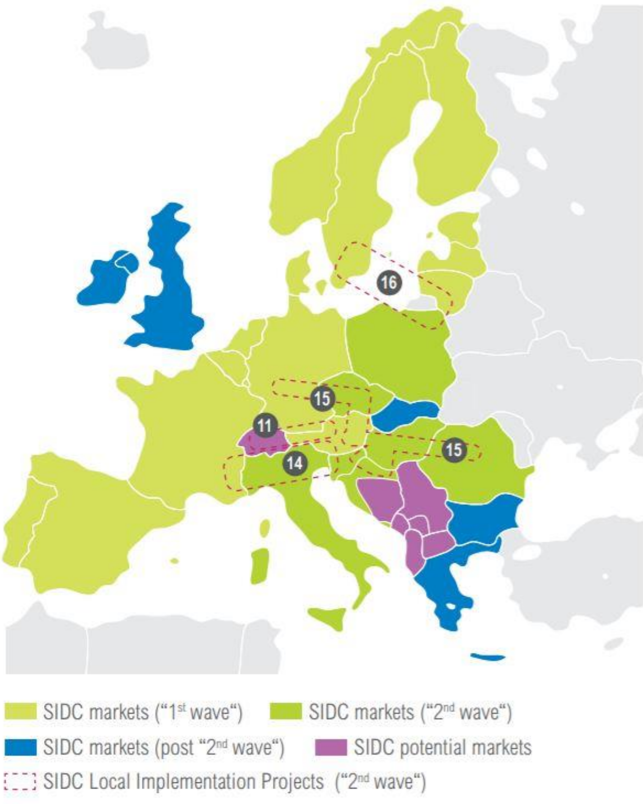


Figure 25: State-of-play of SDIC as of July 2018 (ENTSO-E, 2018b).

XBID does not only support implicit continuous intraday trading but also explicit intraday cross-zonal allocation of transmission capacity. Both are in line with the CACM GL, which says in Article 64: '*Where jointly requested by the regulatory authorities of the Member States of each of the bidding zone borders concerned, the TSOs concerned shall also provide explicit allocation, in addition to implicit allocation, that is to say, capacity allocation separate from the electricity trade, via the capacity management module on bidding zone borders.*'

However, explicit allocation of cross-zonal transmission capacity is only transitional as implied by Article 65, titled 'Removal of explicit allocation'. More precisely: *'The NEMOs concerned shall cooperate closely with the TSOs concerned and shall consult market participants in order to translate the needs of market participants linked to explicit capacity allocation rights into non-standard intraday products.'* [79] At the time of writing, in early 2019, the cross-border capacities are allocated only implicitly on all borders, except for the FR-DE border, where both explicit and implicit options are possible.

A major difference between the DAM integration and IDM integration is the fact that the former is based on 'coupling' auctions of bidding zones (single merit order if no transmission constraints are present), while the latter is based on 'merging' order books for continuous trading. It is generally agreed that it is more straightforward to efficiently allocate cross-zonal capacity with auctions. The pros and cons of auctions vs continuous trading have already been discussed in Section 4.3.1. In this section, the implications for the allocation of cross-zonal capacity of both options are further elaborated on.

5.2.1 Integration with continuous trading

Bellenbaum et al. (2014) describe in their paper six methods to allocate cross-zonal capacity in the intraday market frame. Three methods are based on continuous trading, two on auctions and one represents a hybrid method combining both.

In this subsection we focus only on one method based on continuous trading, namely, <u>continuous cross-zonal trading with implicit allocation of cross-zonal transmission capacity</u>. This method is in place in XBID. Trading is based on an order book and is possible every day around the clock until intraday cross-zonal gate closure, e.g. one hour before delivery. Bids are continuously matched, disregarding the time of order placement, and cross-zonal capacities (calculated using the NTC approach) are automatically updated after each executed trade. Two problems arise with this method:

1.) *No market-based allocation of cross-zonal transmission capacity*: Transmission capacity is allocated on a first-come-first-serve and is not priced. Neuhoff et al. (2016a) explain that the first mover receives the potential scarcity value of transmission capacity. In short, this allocation favours quick trades, rather than efficient ones. Pricing of transmission capacity could be introduced within this method: capacity prices could be administratively set ex ante or ex post or through explicit auctions. Both approaches introduce inefficiencies.

[79] Non-standard intraday products offered through implicit allocation.

2.) *Suboptimal calculation of available cross-zonal transmission capacity*: It is impossible to apply a flow-based capacity calculation approach with continuous trading. This implies that TSOs, not the market, will repartition ex ante available cross-zonal capacity over borders. As a result, less cross-zonal capacity might be offered by the market.

5.2.2 Continuous trading complemented with (regional) intraday auctions

In accordance with Art. 55(3) in the CACM GL, all TSOs had to develop a methodology for pricing intraday cross-zonal capacity which shall reflect market congestion and shall be based on actual orders. In the proposal by all TSOs for a single methodology for pricing intraday cross-zonal capacity submitted for public consultation in April 2017, it is stated that it is not possible to efficiently price intraday cross-zonal capacity solely with continuous trading. With intraday capacity pricing auctions (IDAs), the two problems mentioned with continuous intraday trading could be resolved.[80] The proposal thus foresees a hybrid model, combining continuous trading with two IDAs. One initial IDA on the day before delivery (D-1) and one on the day of delivery. The auction on day D-1 shall contain market time units (MTUs) of the day of delivery. The other auction, held on the day of delivery, contains all MTUs from its first delivery hour until the end of day D.

On 10 August 2017, an updated proposal was submitted by all TSOs to all NRAs and the Agency (ENTSO-E, 2017d). The updated proposal foresees only one IDA; the IDA held at D-1 for all MTUs of day D with a deadline for bid submission at 22:00. The within-day (D) auction was removed. In July 2018, all NRAs jointly agreed to request ACER to adopt a decision on the proposal pursuant to Article 9(12) of the CACM GL. The main reasons why the regulatory authorities were not able to reach a unanimous position on the proposal related to the number of the intraday IDAs, their timings and the necessity to recalculate cross-zonal capacity before each IDA. Finally, in January ACER made a decision (ACER, 2019b). ACER chose to implement a Pan-European IDA at least at three different moments: (i) at the intraday cross-zonal gate-opening time (i.e. 15 :00 D-1) using the cross-zonal capacity remaining from the day-ahead timeframe to take advantage of shared order books and more efficient cross-zonal capacity allocation through an auction; moreover, such intraday capacity would remain unpriced, (ii) at 22:00 D-1, when the first intraday capacity re-calculation is — at least as a first step - expected to be completed and (iii) at 10:00 of the delivery day when the second intraday capacity re-calculation is — at least as a first step - expected to be completed.

It is not so clear-cut how cross-zonal capacity would be optimally divided between continuous trading and the intraday auctions. Avoiding gaming between both trading options remains a concern as during continuous implicit trading there would be no capacity price, while in an implicit auction a capacity price could be determined based on energy price differences. Also, the integration of intraday-auctions requires a cross-zonal consensus on the optimal frequency and exact timing of regional (CACM GL, Art. 63) or national intraday auctions. If those are not aligned, efficient integration is not possible. With respect to (complementary) regional intraday auctions, ACER (2019a) suggests that with three Pan-European IDAs in place, it would not be necessary anymore to still allow these regional auctions. Lastly,

[80] Neuhoff et al. (2016a) describe an additional benefit of intraday auctions in this context. They state that intraday auctions allow TSOs to reduce the capacity made available before by repurchasing cross-zonal transmission capacity. This additional flexibility allows for a less conservative provision of commercial transmission capacity.

there are concerns regarding the impact of complementary auctions on the liquidity in continuous trading. In many countries, intraday markets are only just emerging and it is argued that splitting liquidity between auctions and continuous trading could impede this development. In this regard, Figure 26 shows the volumes of 15-minute products in the intraday continuous market in Germany before and after the introduction of the 3 pm (national) auction. Indeed, it can be seen that it is very plausible that there is a substitution effect to a certain extent. However, the same figure also shows that overall trade volumes significantly increased.

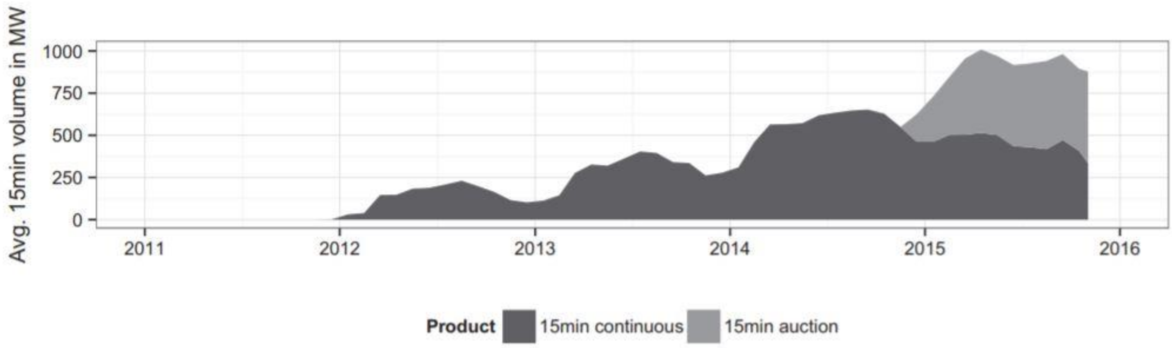


Figure 26: Stacked trading volumes of 15-min intraday continuous and auction products in Germany (Märkle-Huß et al., 2018).

6. Establishing national balancing markets

In a power system, demand should equal supply at all times. In more technical terms, the system frequency must be maintained close to its nominal value (50 Hz in Europe). If the system frequency deviates significantly, generators can trip off (to protect themselves from damage) which in itself causes further frequency deviation, thus a cascade of generation tripping off the system can occur. This is called a ‘system collapse’ and can result in a widespread blackout. Each TSO is responsible for the real-time balance in its control area to avoid such a collapse, and the balancing mechanism is in place to manage this process. At the time of writing, the organisation of the balancing mechanism (incl. balancing markets) is not harmonised in the EU.

Two network codes aim to support the harmonisation of balancing and are of particular importance in this chapter: the EB GL and the SO GL. The EB GL primarily intends to harmonise market arrangements related to balancing: the design of balancing markets and the imbalance settlement mechanism.[81] However, as balancing happens in real-time, balancing market arrangements cannot be fully decoupled from system operation and security. Therefore, the SO GL is also relevant for this chapter. The SO GL primarily addresses three other aspects of balancing: the harmonisation of reserve categories, the sizing of reserves and the activation strategy for balancing energy in real-time.

This chapter consists of five sections. In the first section, the different types of reserves and their processes are introduced. Also, an overview of the balancing mechanism is given. This overview consists of four building blocks. Sections 6.2-6.5 each describe one building block, namely reserve sizing, the balancing markets, the imbalance settlement mechanism and the activation of balancing energy. The last section also contains Box 10 in which the main differences between self-dispatch and central dispatch are explained. Unless explicitly stated otherwise, the functioning of the balancing mechanism described in the following two chapters refers to the self-dispatch model.

6.1 The different types of reserves and their activation processes

The SO GL defines four types of reserve products which can be grouped under three processes. The reserve categories are Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). Previously, different denominations existed. To avoid confusion, frequently used terms are summarised in Table 1.

Table 1: Terminology for reserve products (based on E-Bridge consulting GmbH and IAEW, 2014).

	Frequency containment process	Frequency restoration process		Reserve replacement process
Operational reserves defined by SO GL	**Frequency Containment Reserve (FCR)**	**Automatic Frequency Restoration Reserves (aFRR)**	**Manual Frequency Restoration Reserves (mFRR)**	**Replacement Reserve (RR)**
ENTSO-E CE Operation handbook	Primary Control	Secondary Control	Tertiary Control	Tertiary Control

[81] Balancing services are also often referred to as ancillary services for frequency control. Examples of ancillary services for non-frequency control (grid services) are voltage support and congestion management.

These types of reserves meet different operational needs, in practical terms they differ mainly in response time and maximum duration of delivery. The activation of different reserves after a frequency drop/spike is shown in Figure 27.[82] From the moment the frequency drops/spikes, FCR is almost instantaneously activated to stabilise the drop/spike. FCR are the fastest types of reserves and operated using a joint process involving all TSOs of the synchronous area, as described in Section 2.3.3. Within a couple of minutes, the frequency restoration process (FRP) starts. The FRP is operated per LFC Area. In most cases, the LFC Area is equal to the TSO's control area (ENTSO-E, 2014b). First, aFRR and later mFRR are activated. aFRR are reserves activated automatically by a controller operated by the TSO, mFRR are activated upon a specific manual request from the TSO. FRR aims at restoring the frequency to its nominal value. In more technical terms, the frequency restoration control error (FRCE) is regulated towards zero. Finally, after about 15 minutes or more, RR, the slowest type of reserves, can be activated to support or replace FRR. Not all systems have RR as this process is not made mandatory by the SO GL.[83]

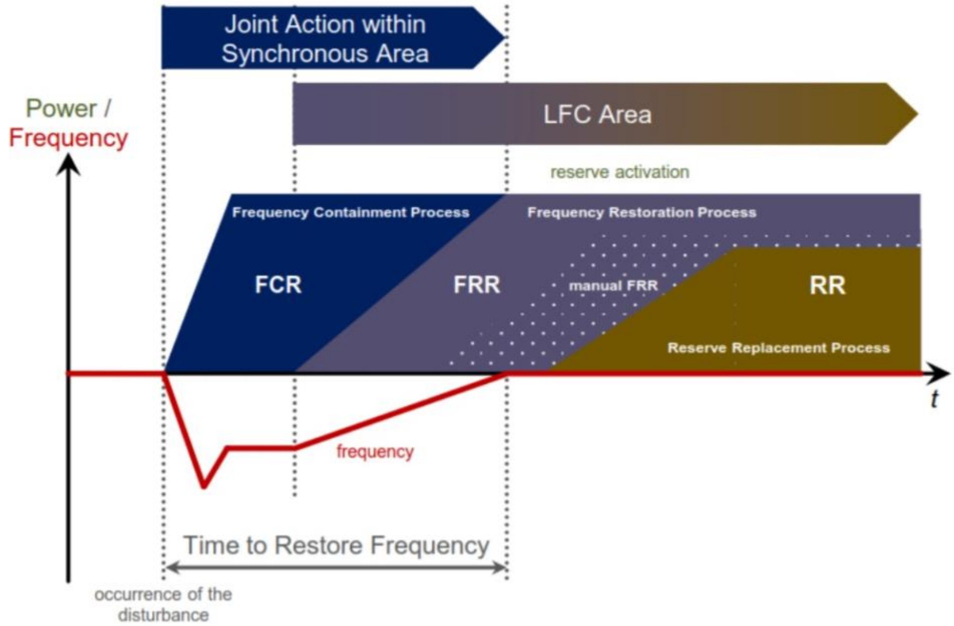


Figure 27: A frequency drop and the reserve activation structure (ENTSO-E, 2018a).[84]

[82] A frequency drop is due to a deficit of energy in the system finding its cause in more consumption or less generation than scheduled in real-time. Vice-versa, frequency would rise. In the EB GL terminology: the aggregate of the (contractual) positions, meaning the declared energy volume of a balance responsible party (BRP) to the TSO at intraday gate closure, is lower than the total allocated volume attributed to the BRPs. The allocated volume means an energy volume physically injected/withdrawn from the system and attributed to a BRP. A BRP is a market party or its representative responsible for imbalances. A BRP can be an individual generator or industrial consumer connected to the transmission grid or a portfolio of generators/consumers (balancing groups).

[83] All balancing processes follow similar functioning principles in terms of general roles, responsibilities and requirements, although slight differences due to product specificities and timing exist for different products.

[84] Three remarks should be added to this figure: (a) the activation process shown is the typical activation process for a TSO with a reactive approach to the activation of balancing energy. This concept is further explained in Section 6.4.; (b) it is assumed that FCR is fully replaced by FRR; (c) inertia as the first source of energy limiting frequency drop is not depicted in the figure. Inertia is an inherent physical property of e.g. turbines. Inertia slows down a frequency drop/spike immediately after a sudden mismatch of supply and demand and does not need any control signal. In other words, with little inertia a small sudden difference in supply and demand can cause a large direct frequency drop/spike. Inertia is further discussed in Section 8.1.1.

Although the same categories of reserve products exist in the EU, the exact product definition and the methodologies used for sizing or activation can still differ strongly from one control area to another. Also, the way balancing resources are procured in balancing markets and the exact working of imbalance settlement mechanism varies. These aspects are discussed in the following sections, which are structured to reflect the four building blocks of the balancing mechanism as displayed in Figure 28.

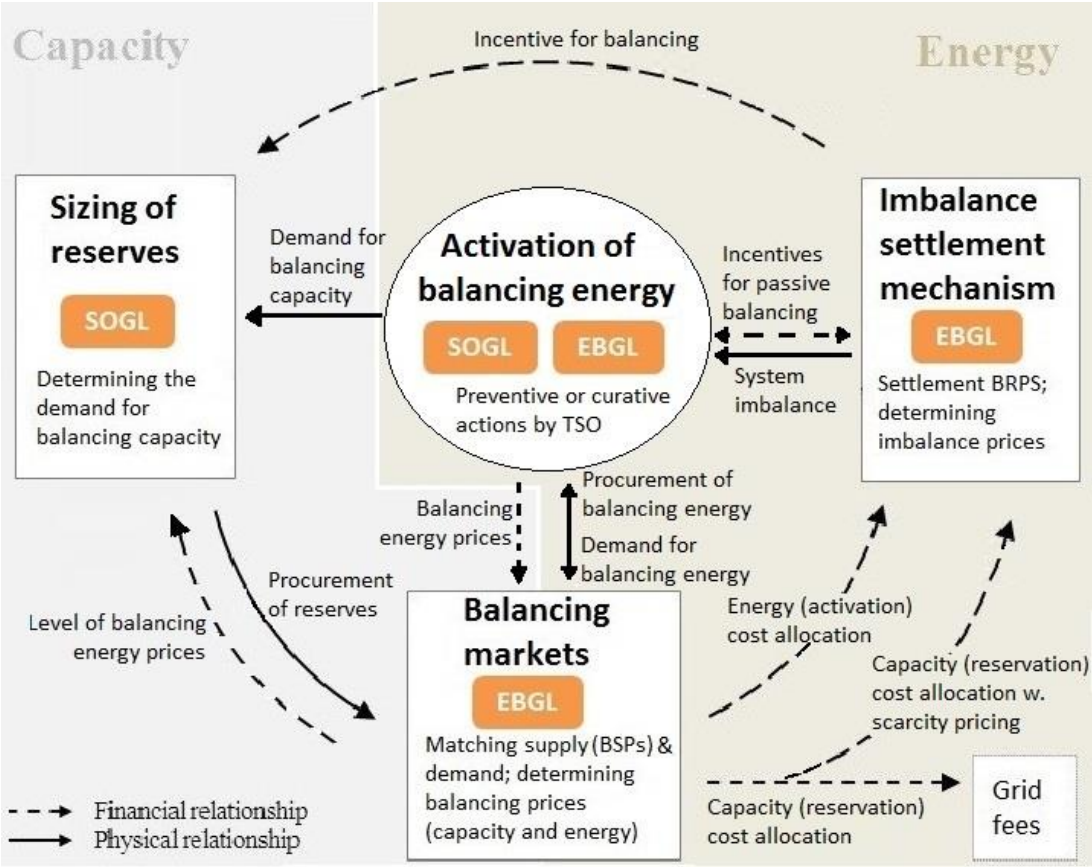


Figure 28: The four building blocks of the balancing mechanism, financial and physical relationships and relevant network codes (adapted from Hirth and Ziegenhagen, 2015).

The different building blocks are financially or physically interlinked. The design of different blocks is covered by network codes EB GL and/or SO GL. It should be noted that the way balancing mechanisms are designed strongly influences trade in other short-term markets, e.g. high imbalance prices encourage rebalancing by trading in the intraday market or high reserve requirements or overlapping of the balancing market and the other short-term markets can reduce the supply in short-term markets. The EB GL and SO GL also outline how to integrate balancing markets; this topic falls out of the scope of this chapter and is picked up in the next chapter. In the next four sections, the different building blocks are covered one by one.

6.2 Sizing of reserves

Sizing of reserves is an exercise done by TSOs. The amount of balancing capacity needed is a function of:

- The expected system imbalances in real-time. The more BRPs are incentivised (high real-time imbalance prices) or able (adequate market design of and liquidity in the intraday and day-ahead market) to balance their positions, the less reserve capacity is required.

- The amount of non-contracted flexibility available in real-time: the more generation/demand is available simply in response to high balancing energy prices, the less need for capacity reservation.
- The activation strategy of the TSO: 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 Section 6.5 for more information).

The way reserve sizing is conducted determines the demand and frequency of balancing capacity markets, which in its turn can create barriers to certain technologies' participation in these markets. Hirth and Ziegenhagen (2015) describe that, broadly, TSOs can apply two methods for reserve sizing: static or dynamic sizing. Static sizing implies that reserves are acquired for long periods, such as a month or a year, while with dynamic sizing the reserve requirements are more frequently updated and have a stronger link with the actual state of the system. In general, static reserves are mostly calculated using a deterministic approach (e.g. 'the worst-case event', N-1 procedure) and dynamic reserves using a probabilistic approach (e.g. probability density functions of events and correlations).

It is argued by Hirth and Ziegenhagen (2015); Just and Weber (2015); Neuhoff et al. (2015a) that countries with high shares of vRES need to allow for short-term procurement of reserves to lower the entry barriers for these generation assets to participate in the balancing capacity market. The same holds true for demand response (DR). Unlike conventional generation, whose bids will vary as a function of their running costs which are relatively stable and predictable over longer periods of time, renewable generators' and demand response resources' bids are primarily based on opportunity costs rather than direct costs. Shorter-term procurement will make it easier for these market parties to correctly estimate their opportunity cost to bid in the balancing capacity market, which should lead to a better allocation of resources across the system as a whole. Brijs et al. (2017) add that there is less uncertainty of vRES or DR resources' availability with shorter time periods. This availability risk can also be (partly) mitigated by splitting the total procured volume into shorter blocks which are procured separately. Finally, by holding more frequent auctions for shorter time periods, the need for balancing capacity could be lowered, leading to efficiency gains. Daily auctions with a contract duration of one hour are proposed by Hirth and Ziegenhagen (2015), similar to day-ahead spot auctions. This setup is already used in the Nordics and some Eastern European countries (ENTSO-E, 2015b).

However, TSOs are reluctant to move to shorter time periods. They are concerned that the risk of failing to contract the required level of reserves increases with a shorter window to source these reserves. TSOs can have some reservations about a dynamic, daily adjusted procurement volume since this requires an additional probabilistic assessment of the forecast errors and ramps of the next day. Nabe and Neuhoff (2015) state that '*TSOs have the incentive to be "on the very safe side" since they do not benefit from lower prices of reserves but would be accounted for insufficient reserve procurement.*'[85] Brijs et al. (2017) note that an argument in favour of longer contract periods might be that they make it easier to finance investments in flexibility.

[85] This statement does not always hold. For example, in GB there is a NRA approved incentive scheme for the TSO that rewards the TSO financially for reducing the costs to consumers – they share in the benefit and conversely share in any over-procurement costs. This aims to align the TSO with the interests of the customer if the incentive is designed correctly. For more details, see e.g. 'System Operator Incentives', link: https://www.ofgem.gov.uk/gas/wholesale-market/market-efficiency-review-and-reform/system-operator-incentives, consulted on 19/12/2018.

Sizing of reserves is mainly covered by the SO GL. The dimensioning rules for FCR, FRR and RR are described in SO GL, Articles 153, 157 and 160, respectively. In summary, it is outlined that:

- FCR
    - Should be dimensioned at least on an annual basis
    - The geographic scale of dimensioning is the synchronous area
    - The dimensioning rule shall take into account a reference incident (3000 MW in positive and negative direction in CE)
    - CE and Nordic synchronous area have the right to (additionally) define a probabilistic approach
    - Each TSO has an FCR requirement proportional to the net generation and consumption in its control area.
- FRR
    - The geographic scale of dimensioning is the LFC Block
    - A probabilistic approach should be applied using historical data
    - Per LFC Block the TSOs will determine the ratio of aFRR over mFRR
    - The FRR procured shall not be less than the dimensioning incident and cover all imbalances (based on the probabilistic assessment) for at least 99 % of the time in its respective direction (positive or negative).[86]
- RR
    - The geographic scale of dimensioning is the LFC Block
    - If procured, the dimensioning process should be done jointly with FRR
    - If procured, in the CE and Nordic synchronous area there should be enough positive/negative RR to restore positive/negative FRR
    - If procured, in the GB and IE/NI synchronous area there should be enough positive/negative RR to restore positive/negative FRR and FCR.

Figure 29 summarises which obligation in terms of activation of reserves, as described in the previous section, and sizing should be done per different area.

Obligation	LFC Area	LFC Block	Synchronous Area
Frequency Restoration Process	MANDATORY	MANDATORY	MANDATORY
FRR Dimensioning	NA	MANDATORY	MANDATORY
RR Dimensioning	NA	MANDATORY	MANDATORY
Frequency Containment Process	NA	NA	MANDATORY
FCR Dimensioning	NA	NA	MANDATORY

Figure 29: Overview of the obligations for the different areas, adapted from: ENTSO-E (2018a).

Additionally, the EB GL sets out high-level principles regarding the procurement of FRR and RR in balancing capacity markets, which cannot be decoupled from reserve sizing. In Article 32(2) it is stated that:

[86] A dimensioning incident is defined in SO GL, Art. 157(2.d) as '*the largest imbalance that may result from an instantaneous change of active power of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line within the LFC Block.'* A dimensioning incident is determined both in the negative (deficit of energy) and positive (excess of energy) direction.

(a) the procurement method [of balancing capacity] shall be market-based for at least the frequency restoration reserves and the replacement reserves;
(b) the procurement process shall be performed on <u>a short-term basis to the extent possible and where economically efficient</u>;
(c) the contracted volume may be divided into several contracting periods.

But procuring reserves closer to real-time and dividing the contracted volume into several contracting periods is not enough to allow vRES and DR to participate in balancing capacity markets. Many other market design parameters matter. In the next section the balancing capacity market and the balancing energy market are discussed in greater detail.

6.3 The balancing markets: capacity and energy

The TSO organises and is the single buyer on the balancing capacity and balancing energy markets. On the supply side, balancing service providers (BSPs), market participants with reserve-providing units or reserve-providing groups offer balancing services to TSOs. The amount of balancing capacity procured is determined by the balancing reserve requirement (sizing, as discussed in the previous section). The amount of balancing energy activated depends on system imbalances. The activation strategy of balancing energy can influence the demand for balancing energy and prices as further discussed in Section 6.5.

To be able to participate in these markets a prequalification process exists. Technical minimum requirements and the prequalification process of FCR, FRR and RR are described in Art. 154 and 155 for FCR, Art. 158 and 159 for FRR and Art. 161 and 162 for RR in the SO GL. Additionally, for FCR details regarding the exact provisions are given in Art. 156 of the SO GL. Technical requirements and the prequalification process for reserve products also impact balancing capacity market entry barriers as described in Box 6.

Box 6: The participation of resources connected to the distribution grid in balancing markets and the power of the DSO.

In recital (8) of the EB GL it is declared that a level-playing field should be in place for all market participants, including demand-response aggregators and assets located at the distribution level, to offer balancing services and ensure adequate competition.

The SO GL specifies in Art. 182(3) that the prequalification process for balancing resources connected to the distribution level shall rely on rules concerning information exchanges and the delivery of active power reserves between the TSO, the reserve-connecting DSO and the intermediate DSOs.[87] Each reserve-connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in the distribution system during the prequalification process. Reasons for limitations or exclusion should be technical, such as the geographical location of the reserve providing units and reserve providing groups (SO GL, Art. 182(4)).

Further, each reserve-connecting DSO and each intermediate DSO can set temporary limits to the delivery of active power reserves before their activation. Procedures need to be agreed upon with the respective TSO (SO GL, Art. 182(5)). It is not decided yet to whom the costs of such an action should be allocated. In Art. 15(3) of the EB GL it is stated that each TSO <u>may</u>, together with the

[87] No formal definition of 'intermediate DSO' was found.

reserve-connecting DSOs within the TSO's control area, jointly elaborate a methodology for allocating costs resulting from the exclusion or curtailment of active reserves connected to the distribution level.

It is not an understatement to say that balancing markets are not harmonised in the EU today (AGORA, 2016; Brijs et al., 2017). The EB GL outlines market design rules to allow for harmonisation. In this section, firstly the balancing capacity market and its key design parameters are described. After, the balancing energy market and its market design parameters are introduced.

6.3.1 The balancing capacity market and its key market design parameters

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. This implies that a BSP cannot commit this capacity in preceding markets. In the balancing capacity market, BSPs offer upward or downward balancing capacity with certain product characteristics to the TSO.[88] In general, there are different markets for the different reserve products procured in a market-based way (possibly FCR, aFRR, mFRR and, if procured, RR). The demand for reserves procured in the balancing capacity market is determined in the reserve sizing process, described previously, and these two building blocks of the balancing mechanism cannot be fully decoupled. There are many market design parameters which can differ from one balancing capacity market to another, for a full and recent overview please consult ENTSO-E (2018c). Two key differentiators touched upon previously are:

- *The time-lag between the balancing capacity auction and the start of the contract period in which the balancing capacity must be offered as balancing energy in the real-time market*: this time-lag can vary from a day to months and may differ by reserve product. The time lag has an effect on how easy it is for market parties to estimate their opportunity cost and how well a TSO can estimate its reserve needs.

- *The (length of) the contract period*: if a BSP's balancing capacity offer is accepted, the BSP is obliged to offer (a certain volume of) balancing energy during a certain period. The contract period can vary from a year to a couple of hours. Variations are also possible such as e.g. a balancing capacity contract that states that the BSP should offer balancing capacity at peak hours for a particular week. The length of the contract period has an influence on the extent to which vRES, storage and DR may be able to participate in the balancing capacity market.

One other important point is whether upward and downward balancing capacity should be procured jointly, in what are called 'symmetric balancing capacity products' (AGORA, 2016). Rodilla and Batlle (2015) argue that by linking the upward and downward reserve requirements vRES and DR are excluded from participation. Hirth and Ziegenhagen (2015) argue that during hours of high renewable production the energy price decreases, which increases the opportunity costs of thermal plants to provide negative balancing power. More precisely, thermal generation offering downward reserves will have to be running at minimal load plus downward reserve power. Therefore, thermal plants will have to bid in the DAM or IDM with this quantity. If the marginal costs of the thermal plant are higher than the DAM or IDM price it will be making losses because of its commitment to provide downward energy. The lower the prices in the DAM or IDM get, the higher its losses, thus the higher its

[88] Upward balancing capacity means that a BSP will reserve a margin to be able to inject balancing energy into the system when activated. Upwards balancing energy is needed when there is less electricity supply than demand (energy deficit). Vice-versa for downward balancing capacity.

opportunity cost to offer downward balancing. In other words, during the hours vRES is able to supply, thermal generators have high costs. Thus, during such hours it would be efficient to use vRES for downward balancing. 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.

Another non-trivial design parameter is the minimum bid volume. In DAM and IDM this parameter is not considered restricting as it is set low enough (AGORA, 2016). However, in balancing capacity markets, limits are often a lot higher, e.g. for aFRR, the minimum bid size ranges from more than 5 MW in Norway to 1 MW in Belgium. A smaller minimum bid size lowers the entry barriers for new players in the balancing market. It should be added that higher minimum volume requirements can be compensated for in the market design if aggregation is allowed. Art. 25(4) of the EB GL provides a list of characteristics for standard products in the balancing capacity (and energy) market.[89] Examples of characteristics listed other than minimum (and maximum) bid size, are e.g. the ramping period, the full activation time and the minimum and maximum duration of the delivery period. All TSOs have to come up with a proposal for parameter values of these characteristics of standard products (EB GL, Art. 25(2)). Standard products will allow an easier integration of balancing markets. The less standard products, the more liquidity. However, a trade-off exists between minimising the number of standard products to increase liquidity and having enough standard products to satisfy the wide range of technical needs of the different TSOs. This trade-off is one of the reasons that besides standard products, each TSO may develop a proposal defining specific products which could be used in parallel with standard products in their control area. These specific products should be demonstrated to be necessary and non-distortive. Every two years an assessment is made about whether these conditions still hold (EB GL, Art. 26).

Last, but not least, the settlement rule for the balancing capacity auctions provides a point of discussion. Two options are possible: pay-as-bid or uniform (marginal) pricing. In Box 4 (in Section 4.3.1) the optimal trading setup in the intraday market is discussed: continuous trading (which implies pay-as-bid) or auctions (can be pay-as-bid or uniform pricing). The more general arguments also apply for balancing capacity markets. Additionally, Müsgens et al. (2014) argue that specific complexities of balancing markets tend to strengthen the case for uniform pricing. They state that: '*More precisely, bidders on the capacity balancing market will take into account their expected revenues from calls on the energy balancing market. This necessitates accurate estimates of the revenues from the energy market. These are difficult to determine under uniform pricing. However, we will argue that they are even harder to predict with pay-as-bid. Let us consider the situation under uniform pricing first. Under uniform pricing, bidders can simply bid their variable cost on the energy market. However, the expected revenues from the energy market are needed when calculating the optimal capacity bid because bidders have to subtract these revenues from their capacity bid. Hence, suppliers have to estimate market prices on the energy market for different levels of calls and the associated probabilities. It is especially challenging to estimate the probability function empirically. Yet these estimations are even*

[89] Next to fixed standard characteristics, there are also variable characteristics of a standard product to be determined by the BSP during the prequalification or when submitting the standard product bid. One of these variable characteristics is of course the price, others are divisibility, location and the minimum duration between the end of the deactivation period and the following activation (EB GL, Art. 25(5)).

more complex under pay-as-bid. Recall that bidders do not reveal their variable costs on the energy market with pay-as-bid. Instead, to simplify, bidders try to guess the most expensive accepted bid. The determination of the most expensive accepted bid requires an estimation of the probability distribution for calls of different energy levels, however. Bids on the capacity market depend on the expected profit on the energy market, which makes an accurate estimation regarding the energy market even more important. These estimates become harder when strategic bidding is an additional part of the equation.'

Box 7: The scoring rule for balancing markets.

Another discussion related to balancing markets is whether the balancing capacity and energy bids should be cleared separately (as was assumed so far) or jointly. In other words, should the bids with the lowest capacity cost be accepted or the bids with the lowest expected total cost (capacity and expected energy costs)? This is called the scoring rule in Müsgens et al. (2014).

In their paper, Müsgens et al. (2014) state that the expected total cost can be gamed, even in competitive markets. They claim that scoring should be based on capacity bids, as in line with the EB GL. It is stated that: '*[capacity] bids will reflect all relevant costs, including the variable costs of delivering balancing power. To be more precise, rational bidders' capacity bids in competitive markets equal the foregone expected profit on the wholesale electricity market minus the expected profit from called energy – this is the reserve price when offering balancing power.*'

Neuhoff et al. (2016c) oppose and state that due to shorter contracting periods of reserves[90] the interaction between energy and reserve markets increases. As such, efficiency improvements can be made by a joint clearing of balancing energy and capacity.

In the EB GL (Art. 16(6)), it is stated that exceptionally the balancing energy price can be predetermined in the balancing capacity contract if proposed by a TSO, however only for specific balancing products and when this approach can be demonstrated to deliver greater economic efficiency. There is a clear trade-off between accommodating specific products with more complex structures and liquidity as markets would be fragmented with fewer BSPs per product category.

No settlement rule is specified for balancing capacity markets in the EB GL. In practice, the settlement rule applied in most EU markets is pay-as-bid over uniform pricing. Also, in some countries prices for balancing capacity of certain reserve products are regulated and not set by an auction, e.g. for aFRR in France (ENTSO-E, 2018c). Regulated prices for FRR and RR are not permitted anymore according to the EB GL (EB GL, Art. 32(2)).

6.3.2 The balancing energy market and its key market design parameters

The balancing energy market is cleared (in most cases) very near to or in real-time.[91] Real-time system imbalances drive the demand for the activation of balancing energy which is selected from a merit order.[92] Balancing energy bids for aFRR, mFRR and RR have to be submitted before the balancing

[90] For the good reasons mentioned in Section 0.

[91] The purpose and timing of the activation of balancing energy is further discussed in Section 6.5.

[92] 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.

energy gate closure time (GCT).[93] The balancing energy GCT for all standard products should be harmonised at the Union level.[94] In terms of timing, the balancing energy 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).

BSPs contracted in the balancing capacity market are obliged to offer balancing energy for their contract duration. It is important to note that the price of the balancing energy bid should not be predetermined in the contract of balancing capacity (EB GL, Art. 16(6)).[95] Brunekreeft (2015) remarks that if a bid is selected on the balancing capacity market and its bidder is thus obliged to bid in the balancing energy market, this balancing energy market bid can be very high in order to avoid commitment. This way the relevant bidder still earns a balancing capacity payment. Such market behaviour is rather unlikely although not impossible in practice.

Next to BSPs contracted in the balancing capacity market, other BSPs without contracted balancing capacity may also bid in the balancing energy market (EB GL, Art. 16(5)). Lastly, it is also relevant that the EB GL specifies that TSOs have the right to compel BSPs to offer their unused generation capacity or other balancing sources as balancing energy when justified (EB GL, Art. 18(7)).

Figure 30 shows the Net Regulated Volume (NRV) over 15 minutes as a share of the consumption over the same 15 minutes for France and Germany. The NRV is calculated as the net of the overall activated downward and upward balancing energy volume. The share of balancing energy activated over consumption is declining in both countries.[96] Lower volumes are observed because of better functioning intraday markets and more efficient TSO cooperation in the activation of balancing energy.

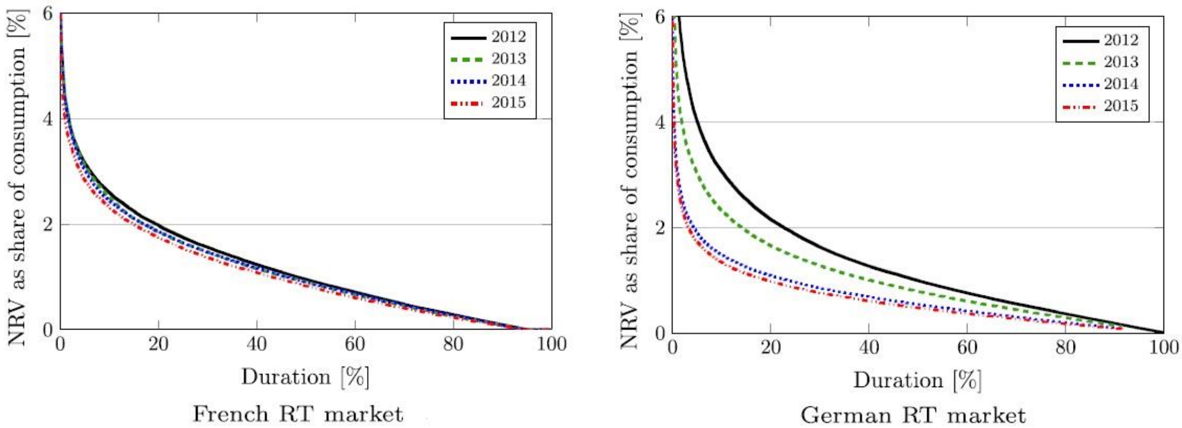


Figure 30: Duration curves of the net regulated volume (NRV) in France and Germany for 2012-2015 (Brijs et al., 2017).

[93] In most cases the activation of FCR is not remunerated, only its reservation is paid. In case the activation of FCR is not remunerated, FCR is symmetric (offering fast upwards and downward energy) and because of (short and fast) activations in both directions payments would eventually be cancelled out (Van den Bergh et al., 2017).
[94] It is unclear whether there can be a different harmonised pan-European balancing energy gate closure per reserve type. This query requires a legal view on EB GL, Art. 24(1).
[95] Exceptionally for specific balancing energy products it can be requested by the TSO that this rule is not applied.
[96] The German case is described in more detail in Box 11 of the following chapter.

Displaying the NRV per 15 minutes is not a random choice. 15 minutes equals the imbalance settlement period (ISP) in some scheduling areas (e.g. Germany, Belgium, the Netherlands).[97] The ISP is the time unit for which BRPs' imbalance is calculated. The determination of the length of the ISP is discussed in Section 6.4.1.

Standard products are envisioned in the balancing energy market (EB GL, Art. 25(1)). In that regard, the same characteristics as for balancing capacity markets hold for balancing energy markets. Specific balancing energy products per TSO are allowed (EB GL, Art. 26). However, they need to be justifiable and are temporary.

The settlement rule in the balancing energy market is another serious point of controversy. A profound discussion concerning the settlement rule for balancing energy markets was found in Littlechild (2007). Littlechild (2007) favours uniform pricing but is aware that some characteristics of the balancing energy market make it more difficult to apply this rule in some situations. In his paper, the author mentioned a paragraph taken from the original proposals for NETA (Review of Electricity Trading Arrangements: Proposals, Offer, July 1998, para 4.49.) wherein an argument in favour of pay-as-bid in the balancing market is given: '*The balancing market will be open for several hours, including real-time operation. During this period, conditions on the system will be continuously changing. Trades may be accepted at particular times at prices that are quite different from the average price of accepted trades over the period as a whole. Consequently, there is no obvious definition for the marginal or market clearing price throughout the period. To pay a uniform accepted price on all increments of generation and decrements of demand, which would presumably have to be the highest price accepted from any one of them, would not obviously be more efficient and could be expensive.*'[98] Littlechild (2007) adds that the weight of this argument depends on the gap between the gate closure time and real-time operation, which has been decreasing since then, and the duration of the settlement period, which has tended to decrease as well.[99]

Box 8: The settlement rule in balancing energy markets – specific technical difficulties and implementations in the Netherlands, Belgium and Spain.

A problem specific to balancing energy markets arises when different products of different reserve types, for example, aFRR and mFRR, are used at the same instance. In the Netherlands, uniform pricing is applied, and the price is set by the highest bid of the two reserve types, even if this most expensive unit has only been activated for a very short fraction of the ISP (E-Brige Consulting, 2014).

[97] For a state of play of the duration of the ISP in the EU in 2014, please consult Exhibit 2 on page 11 of Frontier Economics (2016).

[98] In Littlechild (2015) a similar argument is made, but phrased differently, it is stated that '*in the balancing mechanism near real-time, the system operator does not see a nice stack of energy trades but rather chooses from a plethora of up and down actions each with different dynamic characteristics in the presence of noisy need. Some might be attractive enough to keep for several trading periods. Others will need to be reversed in favour of new opportunities or will come to an end because of self-dispatched movements. In such a context, the concept of marginal cost is a tenuous one. The most expensive 1 MWh bought or sold (even after flagging, tagging and offsetting) is not necessarily representative of the cost of a slight increase or reduction in capacity with respect to the half-hour as a whole.*'

[99] It could be argued that there are almost no significant material changes for the dispatchable supply-side resources, except for contingencies, in e.g. the hour up to real-time. Renewables are obviously different and also the demand side may be a different matter.

Another practical example illustrating why an adequate settlement rule is difficult to define for the balancing market is the aFRR balancing market in Belgium (as it was in 2014). For technical reasons, the aFRR was activated on a pro-rata basis.[100] A monthly tender for balancing capacity was organised to contract aFRR capacity. The selection of the balancing energy bids took place D-1 at 18:00, pre-contracted parties were obliged to offer their contracted bids, other parties could place a bid voluntarily. Elia selected up to 150 MW (upwards and downwards) according to their price starting with the lowest one. Then all bids that had been selected day-ahead were activated according to their participation factors for pro-rata activation and paid their bid price (E-Brige Consulting, 2014). Using the marginal pricing rule in this particular case seems counter-intuitive. Today the selection of FRR bids is done using a merit order (Elia, 2017a), making it more suitable for marginal pricing.

In Spain, aFRR was also deployed on a pro-rata basis and the pricing issue was solved by valuing the net energy usage (positive or negative) at the marginal price of RR that would have been applied in the settlement period to replace the FRR energy delivered (Rodilla and Batlle, 2015).

Article 30(1.a) of the EB GL clearly states that the balancing energy market should be based on (uniform) marginal pricing. However, if all TSOs identify inefficiencies in the application of marginal pricing, they may request an amendment and propose an alternative pricing method if proven more efficient (Art. 30(5)). Art. 30(1.b) adds that the methodology to determine prices for balancing energy shall '*define how the activation of balancing energy bids activated for purposes other than balancing affects the balancing energy price, while also ensuring that at least balancing energy bids activated for internal congestion management shall not set the marginal price of balancing energy.*' This article tackles a concern of Littlechild (2007) who states that '*marginal pricing may lead to erratic prices, especially where the price order 'stack' can be distorted or 'polluted' by system actions taken by the System Operator.*'

An important point in this regard is Art. 30(1.c) in the EB GL stating that there shall be ''*at least one price of balancing energy, for each imbalance settlement period''*. 'At least one' could mean that: (a) multiple balancing energy prices should exist if both upward and downward energy is activated in the same ISP in one scheduling area (that can happen due to a change of the system imbalance within the duration of one ISP or internal congestion); (b) could mean different prices for different types of reserves activated in the same direction; (c) that the granularity of balancing energy prices is finer than the ISP (a possible change of price each <=15 minutes). In that regard, in their pricing proposal for balancing energy and cross-zonal capacity pursuant to EB GL, Art. 30(1,3), all TSOs foresee one marginal price for RR balancing energy bids, two for mFRR (scheduled and direct activation type), and one for aFRR (ENTSO-E, 2018d, 2018e). [101,102]

[100] On a discussion between pro rata activation and merit order selection of balancing energy, please consult E-Bridge and IAEW (2016). EB GL prescribes merit order selection of balancing energy bids.

[101] Direct activation is defined in the proposal by all TSOs as a mFRR-Platform process that can occur at any point in time to resolve large imbalances within the Time-To-Restore Frequency.

[102] The marginal prices for balancing energy are calculated for a time interval called the 'balancing energy pricing period' (BEPP). The pricing proposal by all TSOs (ENTSO-E, 2018d) foresees a BEPP of 15 minutes for RR and mFRR while for aFRR, the BEPP shall equal the optimisation cycle of the activation optimisation function of the respective European balancing platform PICASSO (3-5 seconds). All TSOs argue in their proposal that the pricing methodology shall be consistent with the congestions identified within each process and that this would not have been ensured if the BEPP for aFRR would have been chosen equal to 15 minutes.

Finally, cap and floor prices for balancing energy are optional. If applied, they should be harmonised and take into account the caps and floors applied in the day-ahead and intraday market (EB GL, Art. 30(2)).

6.4 Imbalance settlement mechanism

This section discusses how the imbalance price or charge, the price an unbalanced BRP needs to pay (or receive), should be set.[103] In real-time, the allocated volume (physical real-time energy consumption/generation by a BRP) is not exactly the same as the contractual position for a given imbalance settlement period. Two situations can occur:

- The BRP can have a positive imbalance (long), this implies that:
    - If the BRP is a net buyer, he consumes less electricity than its position.
    - If a BRP is a net seller, he produces more electricity than its position.
- The BRP can have a negative imbalance (short), this implies that:
    - If the BRP is a net buyer, he consumes more electricity than its position.
    - If a BRP is a net seller, he produces less electricity than its position

The EB GL (Art. 55) specifies that each TSO shall set up rules to calculate the imbalance price and that an imbalance price shall be calculated for each imbalance settlement period, each imbalance price area and each imbalance direction. The financial flows between TSOs and BRPs are displayed in Table 2. Individual BRPs receive/pay an imbalance settlement depending on the direction of their imbalance. By convention, if the imbalance is positive the BRP will receive the imbalance price multiplied by the volume of its imbalance. If the imbalance is negative, the BRP will pay the imbalance price multiplied by the volume of its imbalance. The imbalance price is a function of the direction and volume of the overall system imbalance and can be positive, negative or zero. [104]

Table 2: Financial flows between TSOs and BRPs for imbalances (EB GL, Art. 55(1)).

	Imbalance price positive	*Imbalance price negative*
Positive imbalance BRP	Payment from TSO to BRP	Payment from BRP to TSO
Negative imbalance BRP	Payment from BRP to TSO	Payment from TSO to BRP

Also, important to add is that the EB GL states in Art. 18(6.c) that: '*All balance responsible parties shall be financially responsible for their imbalances, and that the imbalances shall be settled with the connecting TSO.*' In the past, it was not unusual that vRES were exempt from being financially responsible for their imbalances as an implicit subsidy for their deployment.

Hirth and Ziegenhagen (2015) remark that TSOs and regulators often view the imbalance settlement primarily from a cost allocation perspective, i.e. as a mechanism to recover balancing cost. However, looking at it from an efficiency perspective, its crucial role is to give an economic incentive to BRPs to

[103] Also called 'cash-out price' in GB.

[104] Negative balancing prices are frequently incurred when the system balance is positive and can be explained as follows. The imbalance price is based (in most cases) on the cost of balancing energy needed to restore the system balance, as discussed in more detail later in this section. In the case the system balance is positive, downward balancing energy will need to be activated. In that case BSPs will bid to be selected to reduce their electricity generation (or increase their demand). In the case they reduce their generation they actually 'win' the avoided fuel cost. Therefore, they would be willing to pay a price equal or lower than their avoided fuel cost to offer downward balancing energy. As such, the imbalance price becomes negative.

avoid (or not avoid) being imbalanced. The imbalance settlement discussion is split up into four parts, each part answering an interrelated question:

1. *Imbalance settlement period (ISP):* What should be the length of the time slot over which an imbalance is measured?

2. *Pricing rule*: Should the imbalance settlement be determined by the average balancing energy costs made to solve the imbalances or should it reflect the marginal cost of the system?

3. *Balancing capacity cost allocation*: How should the costs for the reservation of balancing capacity be allocated? Should imbalance settlement prices rise if balancing capacity utilisation reaches a certain level to reflect scarcity?

4. *Single vs dual imbalance pricing*: Should positive and negative schedule deviations be charged the same price? Related to this, can market parties aggregate their imbalances over their portfolio or should they be held accountable at plant/demand facility level?

6.4.1 The length of the ISP

The ISP is the time unit for which BRPs' imbalance is calculated. The length of the ISP itself is an important parameter. A shorter ISP more correctly allocates the cost of balancing, i.e. it is possible to better reflect the costs of fast-changing flexible balancing actions. Also, shorter ISPs incentivise BRPs to be better balanced and thus TSOs have to deal with less imbalances; this is of particular importance with more volatile generation and consumption. However, the longer the ISP, the more the imbalance volume is limited for the BRP as short-term fluctuations of the BRPs' imbalances are netted out.

In Europe, countries currently apply ISPs of 60, 30 and 15 minutes. Article 53 of the EB GL outlines that the ISP should be harmonised over scheduling areas. More precisely, the article states that by three years after the entry into force (i.e. by January 2021), all TSOs shall apply the imbalance settlement period of 15 minutes. An exemption is possible per synchronous area if the TSOs of that synchronous area can justify an alternative duration and this exemption is approved by the NRAs. Alternatively, also all NRAs of a synchronous area can apply for an exemption at their own initiative. In both cases, every three years the relevant TSOs or NRAs need to show ACER that the benefits of having an unharmonised ISP outweigh the costs.[105]

6.4.2 Pricing rule for imbalance charges

The price signals sent by the imbalance charge should be strong enough to incentivise BRPs to balance their injections and withdrawals. As such, the actions of the TSO to solve imbalances in real-time and the volume of reserves that need to be procured are minimised. Chaves-Ávila et al. (2014); Hirth and Ziegenhagen (2015) and Littlechild (2015, 2007) all argue that efficient resource allocation requires the imbalance price to represent the marginal cost of balancing and that imbalance settlements based on average costs may increase incentives for market parties to intentionally deviate from their schedule.

[105] In the EB GL, Art. 62(9) it is stated that derogations from a 15-minute ISP may only be granted until 1 January 2025.

This discussion of whether the average cost for balancing energy or the marginal balancing energy cost should set the imbalance price cannot be decoupled from the settlement rule for balancing energy. Two cases can be distinguished:

1.) *Pay-as-bid for balancing energy*: In this case, BSPs who are activated receive the price of their bid. This means that the average balancing energy cost (average price paid to all BSPs) will be lower than the cost of the marginal balancing action.[106] A choice can be made whether the imbalance price should equal the average balancing energy cost or the cost of the marginal action. In the former, a zero-sum situation is created. The latter results in a surplus which can be allocated to the TSO or other parties (e.g. divided among BRPs).

2.) *Marginal pricing of balancing energy*: In this case, BSPs who are activated all receive the price of the marginal bid. This means that the average balancing energy cost (price paid to all BSPs) equals the cost of the marginal balancing action. Therefore, in this case the answer is trivial; it does not matter whether the average or marginal cost of balancing energy sets the imbalance price as they are the same. As mentioned previously, marginal pricing of balancing energy is also put forward in the EB GL, Art. 30. If, however, different (marginal) prices exist for different products and the granularity is lower than the ISP, a rule is needed to reduce all these (marginal balancing) prices into one imbalance price. At the time of writing it is still debated whether the imbalance price shall be calculated using a marginal (''the marginal of the marginal'') or an averaging approach. In this regard, it is important to note that the harmonisation of the imbalance price calculation is not foreseen in the EB GL. Instead, in Article 55(1,3) of the EB GL says that each TSO shall set up rules to calculate the imbalance price and shall determine the imbalance price for each ISP, its imbalance price areas and each imbalance direction.

Box 9: The 'Price Average Reference Volume (PAR)' approach in GB (based on ACER and CEER (2016), Littlechild (2015, 2007) and Ofgem (2015)).

In GB, a hybrid methodology is in place: the so-called chunky marginal concept is introduced to come to an imbalance price in between the average and marginal cost. The reasoning goes as follows. As balancing energy may be activated for different purposes, and due to the heterogeneity of balancing energy bids activated (for example in terms of duration), it is not easy to determine the real marginal cost of balancing actions. As a result, some sort of 'representative' figure for the cost of balancing actions needs to be found.

As a solution, the imbalance price is set equal to the average cost of the most expensive X MWh of balancing purchases during a settlement period, defined as the Price Average Reference Volume (PAR)). As such, a sliding scale is obtained between at one end, applying the average cost, and at the other end, applying the marginal cost of balancing actions to set the imbalance price. The setting of PAR determines whether the imbalance price leans more towards the average or marginal cost.

Historically the PAR was set to 500 MWh. It was proposed to gradually reduce the average cost of the most expensive 500 MWh balancing actions to the most expensive 50 MWh (PAR50) in November 2015, before reducing it to 1 MWh (PAR1) in the winter of 2018.

Furthermore, in EB GL, Art. 55 (4,5) it is specified that:

'4. *The imbalance price for negative imbalance shall not be less than, alternatively:*

[106] Or equal in an extreme case.

(a) the weighted average price for positive activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

5. The imbalance price for positive imbalance shall not be greater than, alternatively:
(a) the weighted average price for negative activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.'

6.4.3 Balancing capacity cost allocation

Before starting the discussion about how to allocate the cost of balancing capacity, it is important to have an insight on how significant this cost is relative to the balancing energy cost. In Figure 31 the overall balancing cost and its components over the national electricity consumption for the year 2016 are shown.[107] Additionally, it is also shown what proportion of the balancing costs are covered by imbalance charges.

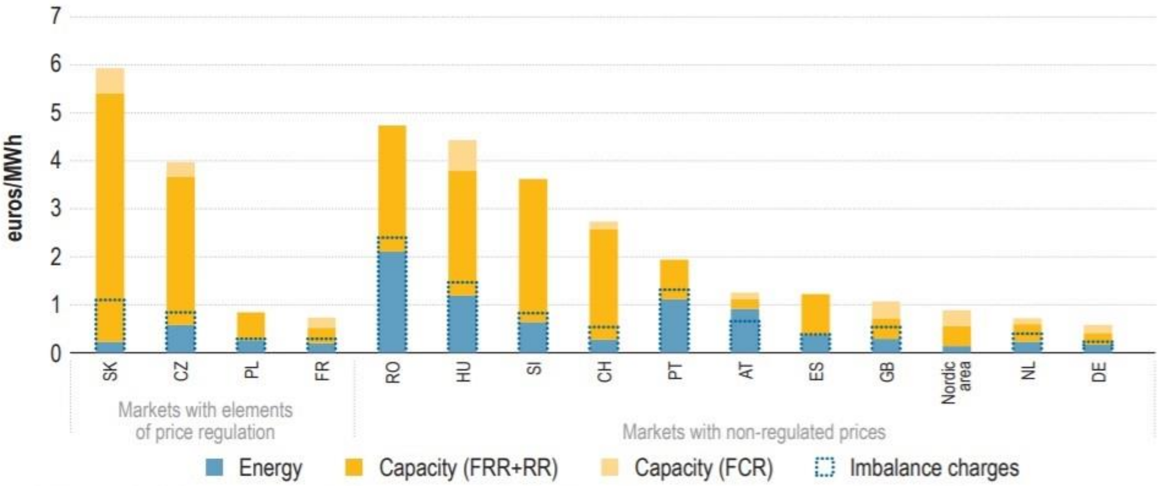


Figure 31: Overall cost of balancing (energy plus capacity) and imbalance charges over the electricity consumption per country in 2016.[108]

Three observations can be made from Figure 31:

- The total balancing costs over national electricity consumption are very heterogeneous.
- For almost all countries the balancing capacity cost is significantly higher than the balancing energy cost.
- Total imbalance charges are in most countries similar to balancing energy cost, but far from enough to cover the total cost of balancing.

[107] In their MMR for the year 2017, ACER and CEER (2018) observe no significant changes in the overall costs of balancing compared to 2016 and state that '[O]verall, the conclusions drawn from equivalent figures in preceding MMRs are still valid.'

[108] For the purpose of this calculation, the unit cost of activating balancing energy is defined as the difference between the balancing energy price of the relevant product and the DA market price. The procurement costs of reserves reported by the Polish TSO comprise only a share of the overall costs of reserves in the Polish electricity system. This is due to the application of central dispatch which makes the calculation more difficult.

In this section, we focus on observations 2 and 3, more precisely on how to allocate the balancing capacity cost which is shown to be a strong driver of overall balancing costs. ACER and CEER (2016) put forward two important solutions to lower the cost of balancing capacity. Firstly, the integration of balancing markets which would allow for the joint procurement and sharing of reserves.[109] Secondly, the maximum participation of all technologies in the provision of balancing capacity, including vRES, storage and DR. The EB GL seeks to support the realisation of both complementary solutions to lower the balancing capacity cost.

Traditionally, and still in place in most EU countries today, the balancing capacity procurement costs are socialised. Network users pay these through network charges, or these costs are allocated to BRPs in proportion to their consumed or produced energy volumes (ACER and CEER, 2016). It can be argued that by socialising the cost of reserving balancing capacity the wrong signals are being sent to market parties.

First, by socialising capacity costs, the large generators (or e.g. a large HVDC interconnector) which actually motivate the scale of the reserves might be insufficiently charged for the costs they cause to the system. Neuhoff et al. (2015a) describe this problem as: '*this [the allocation of the cost of balancing capacity procurement to those that cause the need for these reservations] does not imply that the costs of paying for availability of reserves should be allocated to the imbalance of the specific hour, e.g. by spreading the availability costs for the hour across the parties that are in imbalance in this hour. Otherwise, imbalance prices may be very high at times of low imbalance volumes (example Germany). Most availability costs for reserves are thus born by demand and intermittent generation that creates frequent but small-scale deviations rather than large generators that may cause large imbalances that motivated the scale of reserve provision, but are only infrequent in imbalance.'* Also Vandezande et al. (2010) state that the capacity costs for reserves should not be socialised, but borne by those BRPs that cause the need for reservation.

At the same time, BSPs who could provide flexibility at moments of stress (which are exactly the moments wherefore balancing capacity is procured) are not incentivised if prices are not high enough. The same holds for BRPs not being sufficiently incentivised to be balanced at those particular moments.

A solution, called Operating Reserve Demand Curves (ORDC), is brought forward in the literature (see e.g. Hogan (2013) and Papavasiliou and Smeers (2017)) and already implemented in some parts of the US (e.g. in Texas, see e.g. Levin and Botterud (2015)) and in GB (ACER and CEER, 2016). Please note that the implementation in GB differs from that in Texas (and details matter), but the philosophy behind the approach is similar. The rationale behind ORDC is to introduce an incentive component when balancing reserves are depleted to a certain level, and the probability of the loss of load becomes non-negligible. This makes sense as by being imbalanced at moments of high system stress, there is not only an energy cost related to solving the imbalance itself but also an increased probability of loss of load. To put a price on this incentive component, the Value of Lost Load (VOLL) and the Loss of Load Probability (LOLP) mapped on the volume of available reserves need to be estimated. Determining a

[109] This is further elaborated upon in Section 7.2.2.

‘correct’ VOLL is difficult and necessarily implies an administrative intervention, making this procedure more of a challenge to implement.

By applying ORDC, imbalance prices could rise higher than the marginal cost of delivering balancing energy. If only imbalance prices rise and not balancing energy prices (as in the GB implementation), the balancing capacity procurement costs could be (partly) recuperated. With rising imbalance prices BRPs are strongly incentivised to be balanced at moments of system stress. Yet a decision could be made to let both the imbalance prices and the balancing energy prices rise at moments of system stress by applying ORDC (as in the US implementation). In this case, not only would BRPs be motivated to be balanced, but BSPs would also have a stronger incentive to be available in real-time at moments they are needed the most.[110] In this case, a similar outcome could be achieved by not having balancing energy price caps. However, as stated by Hogan (2013), it would be very difficult if not impossible to distinguish scarcity prices from the exercise of market power. Closing the loop, both implementations, to varying degrees, could lower the need for high volumes of balancing capacity to be procured, leading to lower total balancing capacity costs to be recuperated.

Please note the difference between ORDC and a penalty added to the imbalance price, as also described in Vandezande et al. (2010). First, a penalty is typically applied to the imbalance price in one imbalance direction, not on both imbalance directions. Second, a penalty is in most cases triggered when a certain threshold of balancing energy is activated in real-time. Activation of high volumes of balancing energy does not necessarily imply a situation of system stress as there might be high volumes of reserves available.

Related to the allocation of balancing capacity procurement costs, in Art. 44(3) of the EB GL it is stated that: *‘Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity (pursuant to Chapter 5 of this Title), administrative costs and other costs related to balancing.[111] The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority.’*

6.4.4 Single vs dual imbalance pricing

Imagine an imbalance settlement period wherein the system is short of power. In that case, the imbalance price is expected to be positive as it is related to the activated upward balancing power. In this case, should a BRP which has a negative imbalance (short), thus contributing to the system imbalance, be charged an imbalance price equal to that which a positively imbalanced BRP (long), thus helping the system, receives?

[110] Or even stronger, this approach could (partly) solve the missing money problem by giving an additional incentive for flexible generation to be installed.

[111] Chapter 5 of this title (‘Settlement of balancing capacity’) refers to *EB GL Article 56: Procurement within a scheduling area*

1. Each TSO of a scheduling area using balancing capacity bids shall establish rules for the settlement of at least frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

2. Each TSO of a scheduling area using balancing capacity bids shall settle at least all procured frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

In the case of single imbalance pricing, this is what happens in practice while with dual imbalance pricing, the short BRP would be charged a different imbalance price to that which the long BRP would receive. In EU countries today both single, dual and hybrid pricing is in place (ENTSO-E, 2018c). Single pricing is often favoured over a dual pricing in the academic literature (Chaves-Ávila and Fernandes, 2015; Hiroux and Saguan, 2010; Littlechild, 2007; Neuhoff et al., 2015a; Newbery, 2006). Under dual pricing, the reverse price (individual imbalances in the opposite direction of the system imbalance) is often linked or capped by a reference or day-ahead market price, while the price of imbalances in the direction which aggravates the system imbalance is linked to the cost of balancing energy.

Article 52(2) of the EB GL is relevant to this matter. It states that single pricing should be applied. However, a TSO may propose to the NRA to apply dual pricing under certain conditions and with the necessary justification. More precisely:

'*By one year after entry into force of this Regulation, all TSOs shall develop a proposal to further specify and harmonize at least:*

….

(c) the use of single imbalance pricing for all imbalances pursuant to Article 55, which defines a single price for positive imbalances and negative imbalances for each imbalance price area within an imbalance settlement period; and

(d) the definition of conditions and methodology for applying dual imbalance pricing for all imbalances pursuant to Article 55, which defines one price for positive imbalances and one price for negative imbalances for each imbalance price area within an imbalance settlement period, encompassing:

> *(i) conditions on when a TSO may propose to its relevant regulatory authority in accordance with Article 37 of Directive 2009/72/EC the application of dual pricing and which justification must be provided;*
>
> *(ii) the methodology for applying dual pricing.'*

Many arguments in favour of single pricing are found in the academic literature. An important argument is the fact that dual imbalance pricing discriminates against smaller generation units where companies can aggregate imbalances within a portfolio (Neuhoff et al., 2015a). This is especially the case if there is no liquid intraday market to trade imbalances (Chaves-Ávila et al., 2014). Also, a single imbalance price would constitute a suitable liquid reference price. Further, the dual price imbalance design is reputed to be less cost-reflective than the single price design (Newbery, 2006). Littlechild (2007) explains it as follows: *'[with dual pricing] the reverse price (individual imbalances in the opposite direction of the system imbalance in a dual price system) has been 'deliberately delinked' from the System Operator's costs. It is difficult to see how this is consistent with the stated philosophy of setting imbalance prices to reflect the System Operator's costs. And by linking the imbalance prices with the short-term market prices the risk of distorting the traded market by introducing incentives to influence that market price in order to influence imbalance price is run.'*

Another important argument brought up by Littlechild (2007) in favour of single pricing is that under that mechanism both short and long BRPs participants can contribute to balancing the system, but the dual pricing encourages only one set of market participants to do so.[112] This argument relates to Hirth and Ziegenhagen (2015) who see two types of balancing: active and passive balancing. When TSOs deploy balancing energy, they actively balance the system. However, when the imbalance price provides the right incentive to BRPs, these can 'passively' balance the system by purposely deviating from the schedule. This is also called self-balancing. Three preconditions are needed for effective passive balancing: single pricing, a timely publication of the system imbalance and its price, and the legal ability for BRPs to respond to the price signal (which has not been the case for Germany in the past). [113]

There are also arguments in favour of dual pricing over single pricing. Brijs et al. (2017) and Vandezande (2011) note that speculation of BRPs about the direction of the system imbalance would be avoided with dual pricing. In that same line, if BRPs do not passively balance themselves, it would be easier for the TSO to estimate real-time system imbalances and anticipate power flows. This is of particular importance when internal grid congestion is a frequent issue. An interesting point is made by Chaves-Ávila et al. (2014). In their paper, they mention the fact that a single pricing scheme for a whole country can lead to misleading imbalance prices in the context of internal congestion splitting the scheduling zone into two areas. In that case, market parties can be incentivised to worsen their local imbalance if the imbalance direction is opposite in the different areas. A similar remark is made by Brunekreeft (2015). He states that if the imbalance within one settlement period changes from positive to negative (or the other way around), for one of these imbalances, the imbalance price would be wrong and would set the wrong incentives. In fact, everything would go the other way around, and the system would destabilise. Chaves-Ávila et al. (2014) argue that a nodal or more granular zonal pricing would solve the issue, but that this solution is hard to implement today because of technical and political reasons. A temporary solution would be to use a hybrid pricing rule, more precisely using single pricing when there is a unique direction of regulation and dual pricing when both upward and downward reserves are activated. Chaves-Ávila et al. (2014) conclude that such a scheme can result in a lower efficiency of cost allocation, but that it prevents adverse actions destabilising price signals. This is also the regulation put in place in the Dutch system today (Brunekreeft, 2015).

The last point, directly related to single or dual pricing is whether market parties should be responsible for their imbalances at plant/demand facility level or whether aggregation of their imbalances over their portfolio is allowed, defined as balancing groups by Neuhoff et al. (2016c). Today in Europe, this rule is not harmonised (ENTSO-E, 2018c). Balance responsibility on an individual level is compatible with the single pricing, as mentioned before; the financial outcome when imbalances are accounted for individually or on an aggregated scale will not differ. On the contrary, if dual pricing is implemented aggregation will make a difference in the total cost, favouring large portfolios. Additionally, Neuhoff et al. (2016c) argue that balancing groups have a cost for the system as it lowers the liquidity in the balancing market by encouraging balancing within groups and could have the effect that the TSO over-contracts balancing capacity as it does not have a good oversight of balancing resources available in

[112] Littlechild (2007) states: '*the significant gap between system buy and sell price seems likely to have distorted decisions on how far each participant decides to balance its own position rather than use the facilities of the System Operator. Not surprisingly, many market participants seem to have taken the view that being short is to be avoided at almost all costs. This is unlikely to be efficient.*'

[113] EB GL (Art. 12(3.a)) states that each TSO shall publish: '*Information on the current system imbalance of its scheduling area, as soon as possible but no later than 30 minutes after real-time.*'

the system. The authors argue that the design of the imbalance price can only partially compensate for this effect and that the problem is aggravated if transmission capacity within a scheduling zone is scarce.

In Art. 54(3) of the EB GL it is left to the individual TSOs to decide whether aggregation of imbalances over a portfolio is allowed. More precisely, it is stated that '*each TSO shall calculate the final position of a balance responsible party using one of the following approaches:*

(a) balance responsible party has one single final position equal to the sum of its external commercial trade schedules and internal commercial trade schedules;

(b) balance responsible party has two final positions: the first is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from generation, and the second is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from consumption;'

6.5 The activation of balancing energy: two approaches

Two approaches to the activation of balancing energy are identified in the EU, reactive balancing and proactive balancing (Elia and TenneT, 2014; Haberg and Doorman, 2016; Pentalateral Energy Forum, 2016). 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.[114] The activation strategy of balancing energy cannot be decoupled from the reliance of a TSO on BRPs to self-balance and thus the imbalance settlement mechanism. With a reactive approach, the TSO relies more heavily on the engagement of decentralised (proactive) market players in managing the system imbalance. Therefore, shorter imbalance settlement periods and single imbalance pricing fit well with this approach.

Conversely, the proactive approach relies more strongly on active balancing by the TSO and generally gives weaker incentives to the BRPs. The flexibility of the available generation mix, which is in its turn in most cases a function of the size of the system and its interconnectivity, has an influence on the applied activation strategy. A proactive approach is often believed to increase system security in the case of more isolated systems (with little flexible capacity) possibly combined with a high share of vRES generation resulting in unpredictable electricity flows. An overview of a selection of EU countries and their approach to the activation of balancing energy as assessed by Haberg and Doorman (2016) is shown in Figure 32. Additionally, in the same figure, the relationship between BRP incentives and the activation strategy is displayed. It can be seen that there are also countries (e.g. Denmark) applying an approach in between reactive and proactive balancing.

[114] The Pentalateral Energy Forum (2016) mentions at least one hour before real-time.

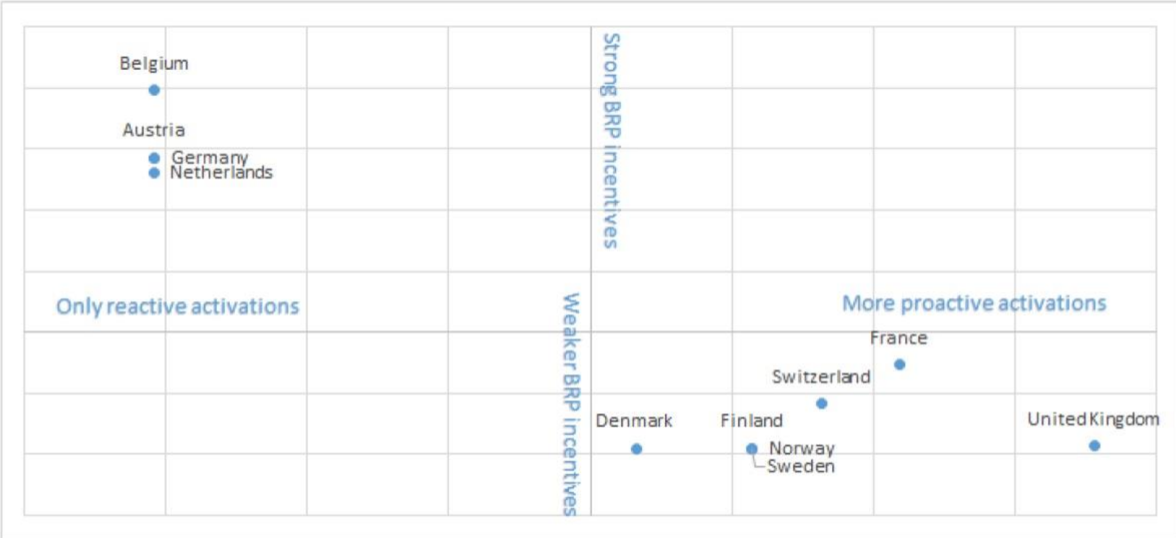


Figure 32: Classification of European balancing markets based on activation strategy in balancing energy and BRP incentives (Haberg and Doorman, 2016). Additionally, Portugal and Spain are identified as proactive by the Pentalateral Energy Forum (2016).

In a document by the Pentalateral Energy Forum (2016) the rationale behind both approaches is summarised as: '*The objective of the proactive approach is to minimize the overall balancing costs by reducing the average balancing energy price, whereas in the reactive approach, the objective is to minimize the overall balancing cost by reducing the volume of balancing energy.'* Another distinction is that TSOs applying the reactive approach generally do not procure RR, while TSOs applying a proactive approach do and can activate manual reserves (mFRR or RR) to intervene before real-time (Elia and TenneT, 2014).

It is important to add that the reactive approach relies on a liquid and well-functioning intraday market and intraday gate closure near real-time, making it possible for BRPs to trade their imbalances. As such, the need for the activation of large volumes of balancing energy in real-time is minimised. In contrast, it can be argued that a proactive approach distorts the functioning of the intraday market. Two issues can be identified. First, the resources that are procured for proactive balancing (RR) are not available anymore to trade in the intraday market, lowering supply in the intraday market. Second, by minimising the real-time imbalance and as a consequence also the balancing prices and imbalance charges, BRPs have less incentive to trade in the intraday market to be balanced, thus reducing demand in that market. Actually, by applying proactive balancing BRPs do not receive price signals indicating system stress. Instead, price signals are dampened by intervention before real-time. The cost of this real-time intervention then needs to be recuperated in other, less cost reflective ways. Advocates of a proactive approach argue that it is hard to send correct signals to BRPs close to real-time; TSOs have better information near real-time and can optimize the whole area (not just their portfolio). Therefore, it is argued that a proactive approach could be more economic.

The EB GL and SO GL do not explicitly favour one approach to the activation of balancing energy over the other. It seems that within these regulations both approaches are allowed, although activation of balancing energy far ahead of real-time seems to be restricted. There are several articles of importance with respect to this matter. Most importantly, in Art. 29(2,3) of the EB GL it is stated that:

'2. TSOs shall not activate balancing energy bids before the corresponding balancing energy gate closure time, except in the alert state or the emergency state when such activations help alleviate the severity of these system states and except when the bids serve purposes other than balancing pursuant to paragraph 3.

3. By one year after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology for classifying the activation purposes of balancing energy bids.[115] *This methodology shall:*

(a) describe all possible purposes for the activation of balancing energy bids;
(b) define classification criteria for each possible activation purpose.'

Article 24(1,2) of the EB G states with, regard to the balancing energy GCT for standard products:

'1. As part of the proposals pursuant to Articles 19, 20 and 21, all TSOs shall harmonise the balancing energy gate closure time for standard products at the Union level, at least for each of the following processes:

(a) replacement reserves;

(b) frequency restoration reserves with manual activation;

(c) frequency restoration reserves with automatic activation.

2. Balancing energy gate closure times shall:

(a) be as close as possible to real time;

(b) <u>not be before the intraday cross-zonal gate closure time;</u>

(c) ensure sufficient time for the necessary balancing processes.'

Furthermore, in the CACM GL (Art. 59(3)), concerning the intraday cross-zonal GCT, it is stated:

'One intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be <u>at most one hour before the start of the relevant market time unit</u> and shall take into account the relevant balancing processes in relation to operational security.'

These articles imply that the balancing GCT will be at most one hour before real-time and would mean that proactively activating balancing energy long (a couple of hours) before real-time will not be allowed unless in an alert on emergency state. However, considering the lead-time for activation of RR 30 minutes (or shorter), one hour can be considered sufficient time for proactive activation by the TSO. In line with this it must be noted that the procurement of RR and having in place a Reserve Replacement Process (RRP), compatible with the proactive balancing approach, is a right described in EB GL (Art. 19) and SO GL (Art. 140(2)). In Art. 144(1) of SO GL it is stated that:

'The control target of the RRP shall be to fulfil at least one of the following goals by activation of RR:

[115] By one year after entry into force of the EB GL, all TSOs are required to develop a methodology for classifying all purposes for the activation of balancing energy (EBGL, Art. 29(3)). In the proposal published by all TSOs in December 2018, the following purposes other than balancing are foreseen: the activation of RR and mFRR balancing energy product bids to solve system constraints, such as maintaining voltage or power-flow limits, system margins or active and reactive power reserves (ENTSO-E, 2018i).

(a) progressively restore the activated FRR;

(b) support FRR activation;

(c) for the GB and IE/NI synchronous areas, to progressively restore the activated FCR and FRR.'

Box 10: Self-dispatch vs central dispatch models.

Several articles in the EB GL and the SO GL mention that (slightly) different provisions hold for self-dispatch or central dispatch systems, the two dispatch models applied in the EU. Self-dispatch models can be reactive or proactive in their activation of balancing energy. If a similar label were to be put on central dispatch models, they could generally be categorised as proactive in their balancing approach, although reactive forms exist as well.[116]

In Europe, the self-dispatch model is the most common and defined *'as a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities*' (EB GL, Art. 2(17)). On the contrary, with a central dispatch model *'the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process*' ((EB GL, Art. 2(17)). An integrated scheduling process means that balancing, reserve procurement and congestion management are done concurrently (Marneris and Biskas, 2015).

In short, under the self-dispatch model different markets are organised for different purposes (balancing energy, balancing capacity)[117] and market parties with their economic incentives are more important, while under central dispatch an integrated process is executed with a much greater role for the TSO. Currently, the central dispatch model is in place in, e.g. Italy, Greece, and Poland (ENTSO-E, 2018c).

The self-dispatch model is more in line with the European Target model (see also ACER (2015b) and Gorecki (2013)) and is seen as 'default' in the EB GL as can be deducted from Art. 14(2):

'*Each TSO shall apply a self-dispatching model for determining generation schedules and consumption schedules. TSOs that apply a central dispatching model at the time of the entry into force of this Regulation shall notify to the relevant regulatory authority in accordance with Article 37 of Directive 2009/72/EC in order to continue to apply a central dispatching model for determining generation schedules and consumption schedules. The relevant regulatory authority shall verify whether the tasks and responsibilities of the TSO are consistent with the definition in Article 2(18).'*

As mentioned in the introduction of this chapter, the working of the balancing mechanism as described in this chapter and the next chapter refers to the self-dispatch model. Otherwise, it is explicitly stated.

[116] E.g. Greece has a central dispatch system with reactive real-time activation of balancing energy bids. The commitment of units and procurement of reserves is done proactively by the TSO. The TSO does not, however, activate balancing energy before real-time based on forecasts, but reacts on the system imbalance in real-time. It should be added that at the time of writing in early 2019, Greece is going through a reform of the power system.

[117] As mentioned above, balancing energy bids can also be activated for purposes other than balancing.

7. Integrating balancing markets

Significant efficiency gains and an increase in security of supply can be achieved by integrating balancing markets. For example, see the report by Mott MacDonald (2013) in which it is estimated that the theoretical benefit of the full integration of balancing markets with hypothetical scenarios of the European system in 2030 is up to 3 billion € per year, or the study by Artelys et al. (2016) in which it is shown that most monetary gains can be made by joint dimensioning and procurement of reserves (open for DR and vRES) at EU level. However, balancing mechanisms are complex and different national approaches have grown organically to fit best local needs. As a result, it is not straightforward to integrate this segment of the electricity market sequence. An important difference between the integration of DA and ID markets and balancing market is highlighted by Neuhoff and Richstein (2016). They state that for DA and ID markets the focus was mainly on a harmonisation of products, timelines and transmission capacity allocation, while with balancing one important challenge is added, namely the harmonisation of operational paradigms. In other words, the alignment of markets in itself is not enough – certain relevant elements of system operation must also be aligned.

The two important network codes in this regard are the EB GL and SO GL. The provisions on Load-Frequency Control (LFC) and reserves in the SO GL provide the technical framework that is necessary for the development of cross-border balancing markets. In more detail, the SO GL addresses the structure and operational rules of LFC, the quality criteria and targets, the dimensioning, exchange, sharing and distribution of reserves as well as monitoring related to LFC. The EB GL sets out the principles, market rules and proposals which need to be followed, implemented or developed to allow balancing markets to integrate.

This chapter is split into three sections. Subsection 7.1 discusses which market design blocks or operational paradigms need to be harmonised to allow the efficient integration of balancing markets. Then, four complementary ways of cross-zonal cooperation in balancing are described. First, in subsection 7.2, imbalance netting and the exchange of balancing energy is discussed. Besides the principles of both forms of cooperation, ongoing implementation projects on the regional and the European level are presented. Second, in Subsection 7.3, the exchange of balancing capacity and sharing of reserves are described. In the same subsection, also cross-zonal transmission capacity allocation for balancing purposes is discussed.

7.1 How far should harmonisation go to allow for integration?

In earlier drafts of the EB GL, e.g. the version 3.0 published on the 30th of August 2014, a concept called Coordinated Balancing Areas (CoBAs) was mentioned.[118] In that version of the EB GL, CoBAs are defined as '*a cooperation with respect to the Exchange of Balancing Services, Sharing of Reserves or operating the Imbalance Netting Process between two or more TSOs.*' The main idea behind CoBAs was a phased approach toward the full integration of balancing markets. First, regional initiatives, allowing for more flexibility in design, would emerge which would then slowly be merged. ACER (2015c) also confirmed that a regional implementation is an unavoidable interim step to single EU-wide integration. However, CoBAs were removed in the final version of the EB GL (approved by the MSs on 16 March 2017). The

[118] Link: https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20EB/140806_NCEB_Resubmission_to_ACER_v.03.PDF consulted on 19/12/2018.

focus was laid more strongly on the (single) European Target Model and meanwhile, some of these regional initiatives have evolved into international cooperation projects, others are on the verge of becoming European platforms for the exchange of balancing energy as set out in the EB GL (see Subsection 7.2.2).

Whatsoever, what to harmonise in order to allow for integration remains an interesting discussion. In that regard, the Pentalateral Energy Forum (2016) remarks in a document that ACER and ENTSO-E held different views on the degree of harmonisation needed across regional initiatives. ACER reasoned that a sufficient degree of harmonisation is needed in order to avoid getting stuck with incompatible regions, while the document stated that ENTSO-E was of the opinion that regional balancing initiatives can start without complete harmonisation. Four main dimensions of balancing markets were identified, namely balancing products, the balancing energy gate closure time, the imbalance settlement period and the pricing rule in balancing energy markets. It can be said that the final version of the EB GL leans more towards ACER's view regarding the choices made for these dimensions.

Standardised balancing products and a **harmonised balancing energy gate closure time (BE GCT)** are the two dimensions whose harmonisation both parties agree is absolutely necessary for integration. The EB GL outlines in Art. 25 that standard balancing products need to be defined. However, as described in the previous chapter, if requested by a TSO and justified, temporarily specific balancing products might be in place in parallel with standard products (EB GL, Art. 26(1)). Balancing energy bids from specific products can be converted into balancing energy bids from standard products or can be activated locally without exchanging them (EB GL, Art 26(3)). The EB GL also states that these standardised balancing energy products for mFRR, aFRR and RR need to be exchanged on European trading platforms (EB GL, Art. 19, 20 and 21). Regarding the balancing energy GCT, Art. 24(1) of the EB GL firmly states the BE GCT for standardised products should be harmonised for at least mFRR, aFRR and RR processes. In their current proposal, as of November 2018, all TSOs proposed a BE GCT on the European platforms of 25 minutes for aFRR and mFRR and a BE GCT of 55 minutes for RR (ENTSO-E, 2018e).

ACER (2015c) also regards the **harmonisation of the imbalance settlement period (ISP)** and the **agreement on the pricing rule in balancing energy markets as** two other no-regret options needed for the integration of balancing markets. This view is supported by Neuhoff and Richstein (2016). Regarding the former and as already mentioned in the previous chapter, the EB GL states clearly that the ISP should be 15 minutes in all control areas (EB GL, Art. 53(1)).[119] Art. 53(2, 3) of the EB GL states that an exemption can be requested by all TSOs of a synchronous area. In that case the relevant NRAs have to approve. Or, the relevant NRAs of the synchronous area can decide to exempt themselves. In both cases the relevant NRAs have to conduct a CBA (at least every 3 years) in cooperation with ACER to show whether it is reasonable not to harmonise the ISP with other synchronous areas and/or within their own synchronous area. Also, the (harmonised) pricing rule in balancing energy markets was already discussed in the previous chapter and is determined in the EB GL. Article 30(1.a) of the EB GL states that marginal pricing should be applied. TSOs might propose an amendment or alternative to this rule if they can identify inefficiencies in the application of this methodology (EB GL, Art. 30(5)).

[119] It is no secret that not all MSs agree with this view. Also, a CBA performed for ENTSO-E by Frontier Economics (2016) is not in favour of such full harmonisation.

In addition to these four mentioned dimensions of balancing markets, ACER also regarded harmonised **principles for (activation) algorithms, activation purposes of balancing energy** and **TSO-TSO settlement rules** as necessary to allow for (efficient) integration of the balancing energy markets (ACER, 2015c; Pentalateral Energy Forum, 2016).[120]

Four complementary forms of coordinated balancing are identified in the EB GL and SO GL. In the following, they are described in pairs. First, imbalance netting and the exchange of balancing energy are bundled as they more directly affect the balancing energy market. Then, the exchange of balancing capacity and sharing of reserves are jointly discussed. These forms of coordinated balancing have a more direct impact on the balancing capacity market. The exchange of balancing capacity and sharing of reserves adds a layer of difficulty as cross-zonal transmission capacity must be reserved or anticipated to serve these purposes. In contrast, for imbalance netting and the exchange of balancing energy, cross-zonal capacity must be available as these processes take place in real-time.

7.2 **Lower volumes of cheaper balancing energy: imbalance netting and the exchange of balancing energy**

The following section is split into two parts. The first part describes the principles and functioning of imbalance netting and the exchange of balancing energy. The second part gives an overview of the existing regional balancing initiatives (or 'balancing pilots') and discusses in detail the four European balancing platforms required to be set up by the EB GL.

7.2.1 Principles of imbalance netting and the exchange of balancing energy

Imbalance netting is defined in Article 3(128) of the SO GL as '*a process agreed between TSOs that allows avoiding the simultaneous activation of FRR in opposite directions, taking into account the respective FRCEs as well as the activated FRR and by correcting the input of the involved FRPs accordingly*.' Put simply, if for example, two neighbouring LFC Areas have an opposite system imbalance at a point in time, the TSOs can agree to exchange the imbalance, and thus avoid the activation of counteracting balancing energy (FRR in this case) in both LFC Areas. This process leads to an overall reduction in the total volume of activated balancing energy and thus a cost reduction.[121] ACER and CEER (2018) report that imbalance netting continued to be a successful tool to exchange balancing services in 2017. In several European markets, imbalance netting across borders covers more than half of the needs of balancing energy, e.g. in Latvia and the Netherlands imbalance netting avoided 83 % and 55 % of the balancing needs for that year, respectively.

Article 22(1) of the EB GL outlines that a proposal for the implementation framework for a European Platform for imbalance netting shall be developed. In Art. 22(5) it is further stated that: '*by one year after the approval of the proposal for the implementation framework for a European platform for the imbalance netting process, all TSOs performing the automatic frequency restoration process pursuant to Part IV of Commission Regulation (EU) 2017/000 [SO] shall implement and make operational the European platform for the imbalance netting process. They shall use the European platform to perform the imbalance netting process, <u>at least for the Continental Europe synchronous area</u>.*' Moreover, EB GL, Art. 50(1.d) requires all TSOs to develop common settlement rules for imbalance netting as well as

[120] TSO-TSO settlement rules are discussed in the next section of the chapter.
[121] There could be (rare) situations where the savings triggered by the activation of downward reserves (fuel cost savings) are larger than the cost of activating upwards reserves.

for the exchange of aFRR, mFRR and RR. The European platforms and the settlement rules will be further discussed in Subsection 7.2.2.

A second way to lower overall balancing cost is by the **exchange of balancing energy** across scheduling areas. The exchange of balancing energy is defined in Article 2(24)) of the EB GL as *'the activation of balancing energy bids for the delivery of balancing energy to a TSO in a different scheduling area than the one in which the activated balancing service provider is connected*.' Two models are possible when exchanging balancing energy: TSO-TSO or the TSO-BSP model. In the TSO-TSO model, the BSP provides balancing services to its connecting TSO, which then provides these balancing services to the TSO requesting the balancing energy. The connecting TSO is defined as *'the TSO that operates the scheduling area in which balancing service providers and balance responsible parties shall be compliant with the terms and conditions related to* balancing' (EB GL, Art. 2(22)). In the TSO-BSP model, the BSP provides balancing services directly to the contracting TSO, which then provides these balancing services to the requesting TSO. The contracting TSO is defined as *'the TSO that has contractual arrangements for balancing services with a BSP in another scheduling area'* (EB GL, Art. 2(44)).

The EB GL clearly states that the TSO-TSO model should be preferred. More precisely, Art. 19(2), 20(2) and 21(2) state that European platforms for RR, mFRR and aFRR need to be developed which shall apply a multi-lateral TSO-TSO model with common merit order lists (CMOL) to exchange all balancing energy bids from all standard products. One temporary exception and one permanent exception from the TSO-TSO model is possible. Namely, two or more TSOs may on their initiative or at the request of their relevant regulatory authorities develop a proposal for the temporary application of the TSO-BSP model until four years after entry into force of the Regulation (EB GL, Art. 35 (1,7)).[122] The permanent exception is that the TSO-BSP model is allowed in cases where the connecting TSO has not implemented a certain product process, for instance, the Reserve Replacement Process, to allow cross-zonal exchange of this product (EB GL Art. 35 (6)). The TSO-TSO model with CMOL can lead to savings in the procurement of balancing energy as resources can be more efficiently allocated. Figure 33 illustrates the workings of a CMOL.

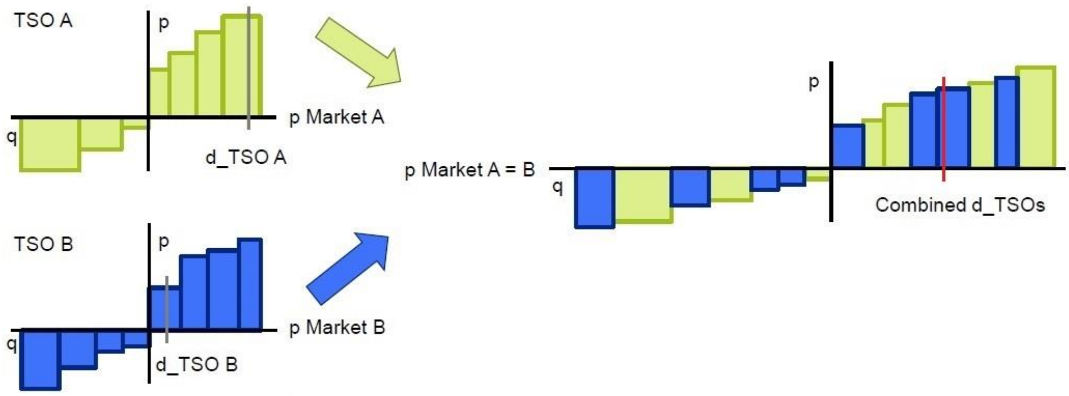


Figure 33: Illustration of the efficiency gains with a common merit order list for the activation of balancing energy under no congestion. 'p': price, 'q': quantity and 'd': demand (Elia et al., 2013).

[122] This implies that by that time all exchanges of balancing energy shall also be based on the TSO-TSO model. Article 35(5-6) of the EB GL states that the TSO-BSP model for the exchange of balancing energy from FRR can only be applied where the TSO-BSP model is also applied for the exchange of balancing capacity for FRR. The same holds true for balancing energy and capacity for RR with the exception mentioned in the text.

Also, the EB GL outlines in Art. 50(1.a-c) that common settlement rules shall be developed by all TSOs in the case of the exchange of balancing energy. Two remarks about the exchange of balancing energy need to be added. First, the total balancing volume a TSO may request for activation from the common merit order list is limited by its own contribution of balancing energy bids to the list (for more details, see EB GL Art. 29(12)). Exceptions to this rule can be proposed by TSOs, provided that all other TSOs are informed (EB GL, Art. 29(13)). Second, a TSO can declare a balancing energy bid submitted to the activation function of the common merit order list unavailable for the activation by other TSOs only in case of internal congestion or due to operational constraints within the connecting TSO's scheduling area (EB GL, Art. 29(14)).

In order to conduct imbalance netting or the exchange of balancing energy, available transmission capacity between scheduling areas or LFC Areas is a prerequisite.[123] In relation to this, Art. 36(1) requires that all TSOs shall use the available cross-zonal capacity after the cross-zonal intraday gate closure for the exchange of balancing energy or for operating the imbalance netting process. Two situations can exist, assuming there is spare capacity in both directions between two LFC Areas:

- *The imbalances in both areas are opposing*: First, imbalance netting will take place. Then, if the imbalance in one of the areas persists and the transmission line is not congested, the exchange of balancing energy can take place.

- *The imbalances in both areas are in the same direction*: No imbalance netting will take place. The exchange of balancing energy can take place.

A methodology per CCR will be developed to calculate the available cross-zonal capacity within the balancing time frame (EB GL, Art 37(3)). It is not mentioned in the EB GL whether cross-zonal capacity can be reserved specifically for imbalance netting or the exchange of balancing energy.[124]

7.2.2 Practical implementation: pilot projects & European platforms

In parallel to the development of rather 'top-down' network codes and regulations, different balancing pilots have been launched since 2013. Balancing pilots are voluntary initiatives which aim to gain bottom-up experience for the implementation of different aspects of the integration of European balancing markets. Figure 34 gives an overview of the different balancing pilots in Europe. Balancing pilots are dynamic projects, their active members can evolve as can be seen from the figure.

[123] An exemption to this statement holds for the exchange and operation of FCR (EB GL, Art. 38(4)). FCR can be exchanged using the reliability margin, calculated as described by CACM GL, Art. 22. This exemption does not hold if the interconnector is a DC line.

[124] However, as discussed in Subsection 7.3, cross-zonal transmission capacity can be reserved for the exchange of balancing capacity or for the sharing of reserves. Thus, indirectly also for balancing energy exchange.

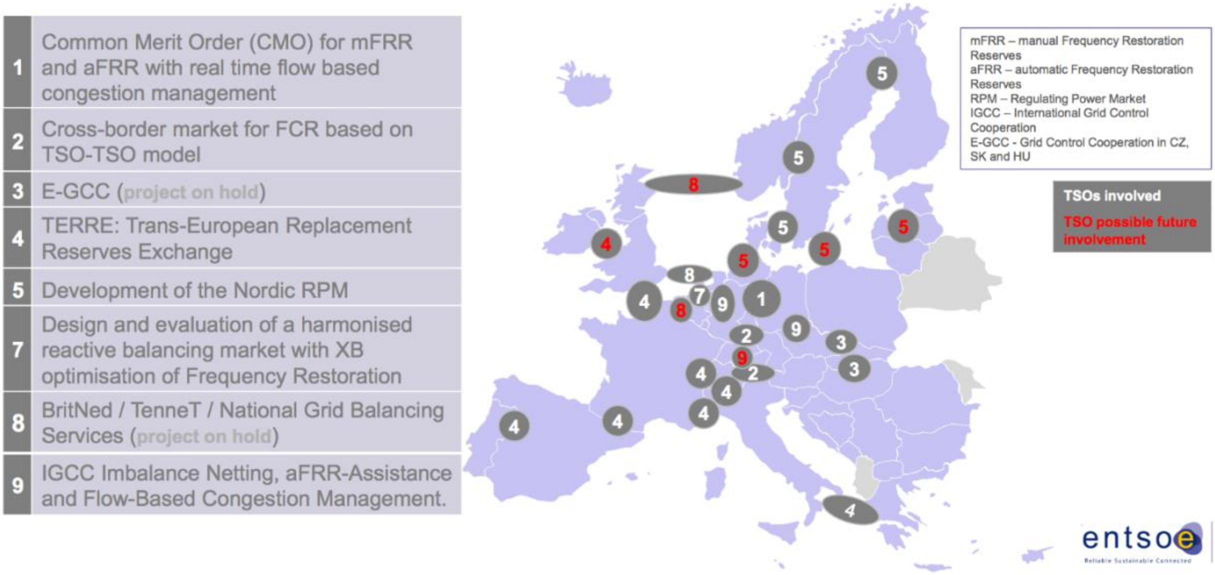


Figure 34: Overview of the balancing pilot projects (ENTSO-E, 2018f).

Articles 19(2), 20(2), 21(2) and 22(2) of the EB GL foresee the implementation of common European platforms for the exchange of balancing energy from RR, mFRR and aFRR as well as for the imbalance netting process, thereby harmonising the European balancing market processes. The four implementation projects established by the European TSOs are displayed in Figure 35: the International Grid Control Cooperation (**IGCC**) for the imbalance netting (IN) process, the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (**PICASSO**) for the aFRR process, the Manually Activated Reserves Initiative (**MARI**) for the mFRR process and the Trans-European Restoration Reserves Exchange (**TERRE**) for the RR process.[125] These implementation projects build partly on existing balancing pilot projects and are described in more detail in the following paragraphs. Box 11 describes a practical example of balancing cooperation and its merits.

Box 11: 'The German Paradox' – more renewables but less and cheaper reserves?

Generally, with an increased share of vRES in the system the reserve requirements would intuitively be expected to increase as well. But this is not necessarily the case. While in Germany the vRES capacity has tripled since 2008, reserve requirements had been reduced by 15%, and costs by 50% by 2014. (Hirth and Ziegenhagen, 2015). This indicates that other factors can be quantitatively more important than vRES in determining the reserve requirement.

Ocker and Ehrhart (2017) investigate this paradox in their paper and attribute the reduction in reserve requirement, next to better forecasting techniques of vRES generation, to two factors:

International and national cooperation: from 2009 to 2010 the four German TSOs introduced a common balancing market.[126] As a result, counteracting activations of balancing energy in different balancing areas could be avoided and fewer reserves needed to be procured, leading to significant

[125] By December 2018, proposals by all TSOs for the implementation frameworks for the IN, aFRR, mFRR and RR platforms have been submitted to the NRAs for approval. At the time of writing, only the proposal for the implementation framework for the RR platform was approved by the relevant NRAs.

[126] The project, called the German Grid Control Cooperation (GCC), consists of 4 modules: 1) Prevent counteracting reserve activation; 2) Common dimensioning of reserves; 3) Common procurement of FRR; 4) Cost-optimised activation of reserves. For more information, please consult Regelleistung.net (2017).

savings (see also Haucap et al. (2014)). Additionally, the International Grid Control Cooperation (IGCC) was founded, and as a consequence significant amounts of balancing energy were saved.

Adaptations to the German energy market design: a strong increase in intraday trading was witnessed from 2006-2014. Intraday trade leads to a reduced need for balancing. Additionally, it is argued that the introduction of the intraday action with 15-minute products in December 2014 helped to allow more precise scheduling of vRES and other generation technologies.

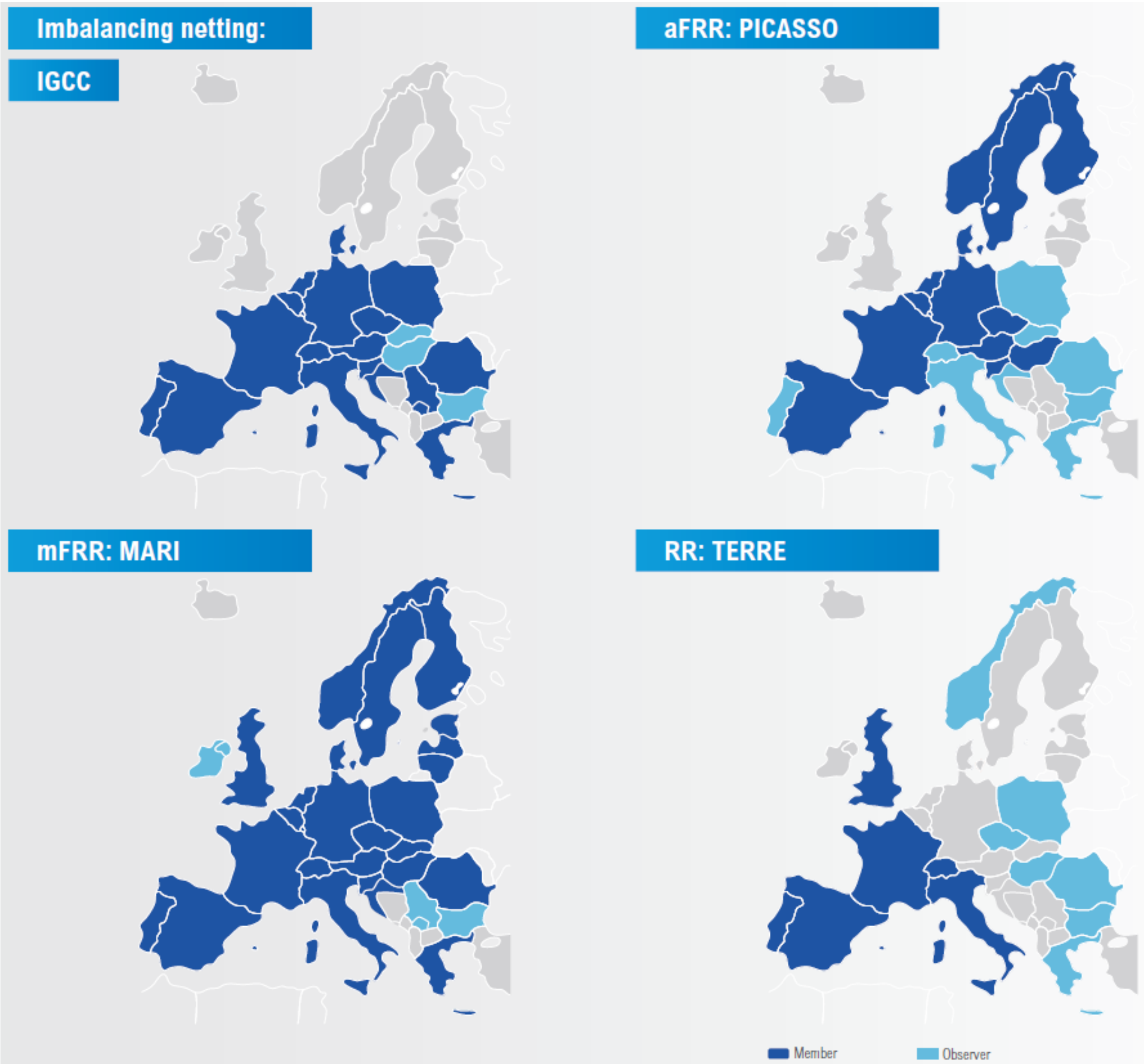


Figure 35: Overview of European balancing implementation projects and their TSO members as of November 2018 (ENTSO-E, 2018e).

ENTSO-E (2017e) describes that TSOs had previously gained experience with imbalance netting through pilot projects including ‘International Grid Control Cooperation’ (IGCC), ‘e-GCC’ and the ‘Imbalance Netting Cooperation’ (INC). It was later agreed the IGCC would be used as the starting point for the implementation of the European platform for imbalance netting. **IGCC** finds its origin in the coordination of balancing services by the four German TSOs. Currently IGCC involves 20 TSOs (+3 observers) from 20 countries.[127] The IGCC deals exclusively with IN. Based upon the principle of proportional distribution, each IGCC Member is assigned an IN potential in each real-time optimisation cycle (IGCC, 2016). It is important to add that the EB GL also requires common settlement rules for imbalance netting to be developed by all TSOs in Art. 50(1.d). For IGCC the volumes of exchange energy of each IGCC member are settled by calculating the opportunity costs, reflecting the value of netted imbalances (see IGCC Settlement Principles in ENTSO-E (2017e) for the rules and Verpoorten et al. (2016) for a case study).

In July 2017, the **PICASSO** project was initiated.[128] The PICASSO project is the implementation project for the European aFRR platform (EB GL, Art. 21). As illustrated in Figure 35, PICASSO currently involves 16 TSOs (+10 observers). The main objectives of PICASSO are to design, implement and operate an aFRR platform based on the TSO-TSO model, thereby enhancing economic and technical efficiency within the limits of system security (ENTSO-E, 2018f). PICASSO builds further on the work done in a regional project called EXPLORE. EXPLORE stands for 'European X-border Project for LOng-term Real-time balancing Electricity market design' and was not an official balancing pilot but a joint initiative of the TSOs of four countries: Austria, Belgium, Germany and the Netherlands. The objective of the EXPLORE study was to investigate how to exchange most optimally Frequency Restoration Reserves (FRR) while taking into account interactions with other balancing processes and the spot market. All countries participating in the EXPLORE project applied a <u>reactive</u> approach to the activation of balancing energy and, in contrast to the TERRE countries, showed more commonalities in their approach to the balancing mechanism as also confirmed by Neuhoff and Richstein (2016).

Further, **MARI** is the European implementation project for the creation of the European mFRR platform. In April 2017, 19 TSOs signed a Memorandum of Understanding outlining the major cornerstones of the cooperation. Since then, MARI has grown to currently involve 28 Members (+5 observers incl. ENTSO-E) (see Figure 35). In December 2018, all TSOs forwarded their proposal for the implementation framework for a European mFRR platform to the relevant NRAs for approval. The implementation framework lays down the design, functional requirements, governance and cost sharing of the mFRR platform.

Finally, **TERRE** was a pilot which is turned into an implementation project for the European platform for the exchange of RR (EB GL, Art. 19). TERRE stands for 'Trans European Replacement Reserves Exchange' and has 9 active partners: the TSOs from France, Great Britain, Spain, Portugal, Italy, Switzerland, Czech Republic, Poland and Romania. The TSOs from Greece, Bulgaria, Hungary and Norway as well as ENTSO-E are observers. ENTSO-E (2017f) described the objective of TERRE as: '*setting up and operating a multi-TSO platform capable of gathering all the offers for Replacement Reserves (RR) and to optimise the allocation of RR across the systems of the different TSOs involved. It is moving towards cross-national exchange of RR.*' It is no coincidence that all TSOs involved in the project apply a rather <u>proactive</u> approach to the activation of balancing energy. Neuhoff and Richstein

[127] These are the TSOs from Austria, Belgium, Switzerland, Czech Republic, Germany, Denmark, Greece, France, Croatia, Italy, the Netherlands, Poland, Portugal, Romania, Serbia, Slovenia and Spain. Hungary, Bulgaria and Slovakia hold an observer status (ENTSO-E, 2018f).

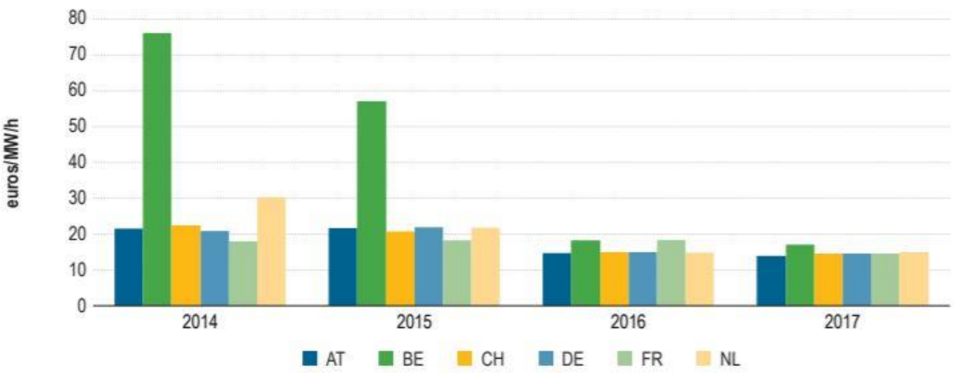
[128] The website of the Picasso project: https://electricity.network-codes.eu/network_codes/eb/picasso/ consulted on 19/12/2018.

(2016) add that the TERRE countries provide room for the continuation of national procedures as the operational paradigms between these countries, although all rather proactive, still significantly differs.

7.3 More efficient procurement and sizing: exchange of reserves and reserves sharing

Next to imbalance netting and the exchange of balancing energy, the exchange of reserves and reserve sharing are also outlined in the EB GL as important to lower overall balancing procurement costs.

The **exchange of balancing capacity** is defined in EB GL, Art. 2(25) as '*the provision of balancing capacity to a TSO in a different scheduling area than the one in which the procured BSP is connected.*' An example is a project for cross-zonal exchange of FCR capacity which started in late 2015 and involved the German, Austrian, Dutch and Swiss TSOs. ACER and CEER (2016) report that the exchange of balancing capacity allowed a reduction of approximately 14 % in the overall balancing capacity procurement costs for FCR in 2015 when comparing with 2014 for these four countries recorded. Later also the French, Belgian and Danish TSOs joined the project. Figure 36 shows in more detail how the prices for FCR balancing capacity decreased and converged over the years in the different participating countries.



Source: NRAs and ACER calculations (2018).

Note: The prices refer to the joint procurement of 1 MW upward and 1 MW downward capacity when the product is symmetric or to the sum of prices to procure 1 MW upward and 1 MW downward capacity when the products are procured separately. Western Denmark is not shown in the figure, as it had not yet joined the project by the end of 2017.

Figure 36: Average prices of balancing capacity (from FCRs) in the markets involved in the FCR cooperation project– 2014–2017 (euros/MW/h) (ACER and CEER, 2018).

The same two models for the exchange of balancing capacity are possible as with the exchange of balancing energy: TSO-TSO and the TSO-BSP model. Also, in this case, the EB GL states that the exchange shall always be performed based on a TSO-TSO model unless the same exceptions as with the exchange of balancing energy hold (EB GL, Art. 33(2)). As all TSOs engaged in exchanging balancing capacity submit all balancing capacity bids from standard products to a common capacity procurement optimisation function (EB GL, Art. 33(3)), a more efficient allocation of resources will result. Overall balancing capacity reservation costs can be lowered, and BSPs can benefit from access to an enlarged market without new pre-qualification procedures or contracts.

However, as remarked by Doorman and Van Der Veen (2013), it might be more difficult to convince TSOs to exchange balancing capacity than to exchange balancing energy. Namely, a TSO with low-cost balancing resources may see an increase in its balancing procurement cost when sharing these resources with areas with higher cost resources. In the case of balancing energy, potential cost increase for a TSO will be passed on to BRPs causing the imbalances. In most cases, this will be a zero sum for the TSO as discussed before. However, in the case of reserve capacity, these costs are often included in the grid tariffs, and increasing them might prove to be more difficult. This reasoning could serve as an additional argument to include balancing capacity cost in imbalance prices.

It can be said that **sharing of reserves** goes one step further than the exchange of balancing capacity. Namely, with reserve sharing more than one TSO takes the same reserve capacity (FCR, FRR or RR) into account to fulfil its respective reserve requirements (SO GL, Article 3(97)).[129] Sharing of reserves can lead to lower overall volumes of balancing capacity, which is not the case with the exchange of balancing capacity in the strict sense. However, to make sharing of reserves feasible, difficult estimates need to be made about the probability that TSOs would need the same balancing resource at the same moment. A very important example of sharing of reserves, which is already in place, is the joint dimensioning of FCR. As also discussed by Van den Bergh et al. (2017), FCR is dimensioned to cover the worst-case event (e.g. tripping of the largest generator unit). However, the probability that a worst-case event happens in several EU countries is very low. Therefore, FCR is dimensioned at the scale of the synchronous area with a key determining how much each control area should contribute. This arrangement obviously leads to significant savings for all countries.

Unlike imbalance netting and the exchange of balancing energy, the exchange of balancing capacity and sharing of reserves are voluntary initiatives between two or more TSOs (EB GL, Art. 33(1) and 38(1)). However, a balancing report shall be published at least every two years by each TSO wherein the opportunities for the exchange of balancing capacity and sharing of reserves should be analysed. Additionally, an explanation and justification for the procurement of balancing capacity without the exchange of balancing capacity or sharing of reserves should be given (EB GL, Art.60(2.e-f)).

In order to exchange balancing capacity or share reserves, the availability of transmission capacity in real-time between scheduling areas needs to be anticipated. Article 36(2.c) and more precisely Article 38(5) of the EB GL describe that cross-zonal capacity for the exchange of balancing capacity or sharing of reserves can be allocated. **Cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves** shall be used exclusively for FRR and for RR (EB GL, Art. 38(4)). The reserved capacity shall be limited depending on the way the reserved capacity is calculated (Article 40 (1.d), 41(2) and 42(2)). It should be added that all TSOs exchanging balancing capacity or sharing of reserves shall regularly assess whether the cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is still needed for that purpose as it means that this capacity is no longer offered to wholesale markets (Article 38(8)).

Capacity allocation for the exchange of balancing capacity or sharing of reserves is a stochastic problem as described by Van den Bergh et al. (2017). In other words, at the time the transmission capacity is allocated, the state of the system and thus the need for the activation of balancing energy in a certain direction is uncertain, as is the remaining interconnection capacity. This renders it difficult to estimate the optimal volume and direction of the transmission capacity to be reserved. In the EB GL three methods to obtain estimates for the optimal cross-zonal capacity for the purpose of the exchange of balancing capacity or sharing of reserves are enumerated: an approach based on economic efficiency analysis, a market-based approach and a co-optimisation approach.

[129] By definition this balancing capacity is cross-zonal for all TSOs involved except for the connecting TSO.

The three approaches can be described as follows:

- *Approach based on economic efficiency analysis*: a method based on a comparison of the forecasted market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, and the forecasted market value of cross-zonal capacity for the exchange of energy (EB GL, Art. 42 (3)).[130] Cross-zonal capacity is reserved before the transmission capacity auction for the exchange of energy takes place. This method, if in place, applies for the exchange of balancing capacity or sharing of reserves with a contracting period of more than one day and where the contracting is done more than one week in advance of the provision of the balancing capacity (EB GL, Art. 42(1)).

- *Market-based approach*: a method based on a comparison of the actual market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves and the forecasted market value of cross-zonal capacity for the exchange of energy, or on a comparison of the forecasted market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, and the actual market value of cross-zonal capacity for the exchange of energy (EB GL, Art. 41(3)).[131] Cross-zonal capacity can be reserved just before or just after allocation for the exchange of energy. This method, if in place, applies for the exchange of balancing capacity or sharing of reserves with a contracting period of not more than one day and where the contracting is done not more than one day in advance of the provision of the balancing capacity (EB GL, Art. 41(1)).

- *Co-optimisation approach*: a method based on a comparison of the actual market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves and the actual market value of cross-zonal capacity for the exchange of energy (EB GL, Art. 40(2)). Allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves is done simultaneously with the capacity allocation for the exchange of energy. This method shall apply for the exchange of balancing capacity or sharing of reserves with a contracting period of not more than one day and where the contracting is done not more than one day in advance of the provision of the balancing capacity (EB GL, Art. 40(1)).

A summary of the three approaches is given in Table 3; it can be seen that the co-optimisation approach is the most advanced method, integrating best cross-zonal transmission capacity allocation for the exchange of balancing capacity and sharing of reserves with the capacity allocation for the exchange of energy.

[130] *'The forecasted market value of cross-zonal capacity for the exchange of energy between bidding zones shall be calculated based on the expected differences in market prices of the day-ahead and, where relevant and possible, intraday markets between bidding zones.'* (EB GL, Art. 39(5))

[131] Art. 39(4) of the EB GL describes that '*the actual market value of cross-zonal capacity for the sharing of reserves shall be calculated based on the avoided costs of procuring balancing capacity.*'

Art. 39(2) of the EB GL describes that *'the actual market value of cross-zonal capacity for the exchange of energy shall be calculated based on the bids of market participants in the day-ahead markets, and take into account, where relevant and possible, expected bids of market participants in the intraday markets.*'

Art. 39(3) of the EB GL describes that '*the actual market value of cross-zonal capacity for the exchange of balancing capacity shall be calculated based on balancing capacity bids submitted to the capacity procurement optimisation function.*'

Table 3: Summary of the three approaches for cross-zonal capacity calculation for the exchange of balancing capacity or sharing of reserves.

	Based on a comparison of		*Timing calculation vs timing of the allocation for the exchange of energy*	*Method shall apply to*	
	Market value of the exchange of energy	*Market value of the exchange of balancing capacity or sharing of reserves*		*Contracting period reserves*	*Time lag between contracting and delivery of reserves*
Economic efficiency analysis	Forecasted	Forecasted	Before	> 1 day	> 1 week
Market-based approach	Forecasted/Actual	Actual/Forecasted	Just before/after	<= 1 day	<= 1 day
Co-optimisation approach	Actual	Actual	Simultaneous	<= 1 day	<= 1 day

It can be derived from the EB GL that the preferred approach is the co-optimised allocation process. Namely, for an approach based on economic efficiency analysis and a market-based approach, a harmonised methodology may be proposed by all TSOs (EB GL, Art. 41(1) and 42(1)); while for a co-optimised approach a harmonised methodology shall be proposed by all TSOs (Art. 40(1)). The latter method is the one best in line with the idea to optimally integrate capacity allocation over time frames and also with the provision to procure balancing capacity on a short-term basis (EB GL, Art. 32(2.b)).

8. The grid connection network codes

There are three grid connection network codes (CNCs), i.e. the Requirements for Generators Network Code (RfG NC), the Demand Connection Network Code (DC NC), and the High Voltage Director Current Network Code (HVDC NC). This chapter only convers the first two. They set the requirements for the connection of different users and technologies. The objectives of the CNCs are threefold. A first objective is to make sure that the system can handle the integration of (decentralised) renewable energy resources and increased demand response. A second objective is to facilitate the internal electricity market by levelling the playing field of grid users in different Member States (MS). A third objective is to increase competition among equipment providers by harmonising the requirements they need to comply with in different markets. It should be added that more stringent requirements result into a more reliable electricity system but also come with a higher cost for those that have to comply with these requirements when connecting to the system. The CNCs intend to strike a balance.

This chapter is split up into three sections. First, we introduce the requirements in the RfG NC and DC NC. Second, we discuss to whom the different types of requirements apply. Third, we highlight the timeline and implementation process of these two network codes, including the derogations that can be introduced at national level.

8.1 Requirements in the RfG NC and DC NC

Most requirements described in the RfG NC and DC NC are non-exhaustive requirements. Non-exhaustive requirements are requirements for which further national specification is needed, e.g. the RfG NC defines a parameter range for a requirement of general application, and at national level a value within this range has to be proposed by the Relevant System Operator (RSO) and approved by the NRA (RfG NC, Art. 7(4) and DC NC, Art. 6(4)).[132] The RSO is the system operator, TSO or DSO, a grid user has a grid connection contract with. Besides non-exhaustive requirements, the CNCs also contain exhaustive requirements which do not need further national specification. Please note that both exhaustive and non-exhaustive requirements can be either mandatory to be implemented in a MS or non-mandatory.

In the RfG NC, the requirements with which different Power-Generating Modules (PGMs) need to comply are listed per category (A to D). This categorisation is a function of the power capacity of the PGM (in MW) and the voltage level the PGM is connected to. The categorisation is described in more depth in Subsection 8.2.1. Generally, all requirements of a lower category (e.g. A) need to be fulfilled by a higher category (e.g. B). Furthermore, specific requirements shall apply to a PGM being a synchronous PGM (SPGM), a non-synchronously connected power park module (PPM) or an AC connected Offshore Power Park Module (OPPM).[133] Lastly, requirements can also differ between

[132] It is also possible that at national level a range of values for a certain parameter within or equal to the range stated in the RfG NC is proposed. As such, slightly more implementation freedom is given to the relevant PGMs.
[133] RfG NC, Art.2(9) defines a SPGM as an indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism. Essentially, a SPGM is a single synchronous generating unit or a single synchronous storage device operating in electricity generating mode or an ensemble of synchronous generation or storage units (ENTSO-E, 2012). A PPM is any unit or ensemble of units generating electricity, which is connected to the network non-synchronously or through power electronics and has a single connection point to

system operators (DSOs or TSOs) when the specific requirement is to be set by the RSO. It is important to add that all requirements are minimum requirements. PGMs can always have more enhanced capabilities if this does not impact the system security negatively.

In the DC NC, the different requirements are split into two groups. Firstly, the requirements for transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems. And secondly, the requirements for demand units used by a demand facility or a closed distribution system to provide demand response services to the system operators. Again, dependent on the voltage level of the connection, the requirements can differ within these two categories.

This document is not intended to cover all requirements exhaustively in detail. Such detailed description is out of scope of this text and would demand a profound background in electrical engineering. Instead, a short overview is given with a main focus on the requirements related to frequency and voltage issues. A full overview of the different non-exhaustive RfG NC and DC NC requirements can be found in ENTSO-E (2016a).

We split the RfG NC and DC NC requirements into five types as introduced in ENTSO-E (2016a): requirements related to frequency issues, voltage issues, robustness, system restoration, and general system management. General system management requirements include for example instrumentation, simulation models and protection. For some requirements, it is not straightforward to classify them into one category as the categorisation is not fully mutually exclusive.[134] Compliance testing/simulation of the different requirements and the operational notification procedure for connection to the grid are also described within the RfG NC and DC NC; these topics are not covered in this document. The following five subsections each cover a different type of requirement.

8.1.1 Requirements related to frequency issues

The requirements related to frequency issues are split up into three parts. First, requirements related to inertia are introduced. The inertia of a system relates to the magnitude of the frequency deviation due to a sudden imbalance between load and generation. After, the requirements related to frequency ranges are discussed. Frequency ranges over which a PGM should be able to withstand frequency disturbances for a certain period of time without disconnecting are very important to avoid a sudden loss of a large group of generators which then could initiate a cascading failure. Lastly, a set of requirements are described which enable PGMs to contain or compensate for the frequency drop or rise by regulating the active power output or input. This last set of requirements is split up into operation under normal and emergency situations and is related to the balancing mechanism (Chapter 6).

Inertia represents the capability of synchronously connected rotating machines to store and inject their kinetic energy to the system. It is important to note that inertia only supports frequency in near instantaneous situations, where an imbalance is caused by a sudden disconnection of large units or a

a transmission, distribution system including closed distribution system or HVDC system (RfG NC, Art. 2(17)). An OPPM is a PPM located offshore with an offshore connection point (RfG NC, Art. 2(18)).

[134] E.g. fault-ride through capabilities for PGMs are classified under 'robustness' in ENTSO-E (2016f) and under 'voltage issues/stability' in ENTSO-E (2016a).

near instantaneous change in production or load. Inertia does not support frequency under 'normal' imbalance conditions, when the imbalance is caused by a prognosis error and resulting differences between production and consumptions plans. Classical synchronous generation (e.g. thermal generators) naturally contributes to system inertia while power-electronic based non-synchronous generation (typically vRES), does not. ENTSO-E (2017g) explains that the system inertia is typically lower for small synchronous areas and that system inertia tends to continuously decrease with increasing shares of vRES displacing synchronous generators. [135] If the system inertia is low, a small sudden difference between load and generation causes a high frequency deviation and vice-versa. Therefore, the RfG NC describes in Art. 21(2.a) that the relevant TSO shall have the right to specify that 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 SPGMs.

If the system inertia decreases strongly, there can be an increasing need for a faster and/or larger response in the future to contain a change in frequency and restore the nominal frequency (Du and Matevosyan, 2018; ENTSO-E, 2017g). The left graph of Figure 37 below shows the correlation between net load and inertia of the power system in Texas (ERCOT). A low net load implies that many synchronous generators are offline for economic reasons. The graph on the right shows the need for fast response services in the same power system. It is clear that the lower the system inertia, the more fast responding reserves (FCR) should be available at all times to contain the deviation in frequency.

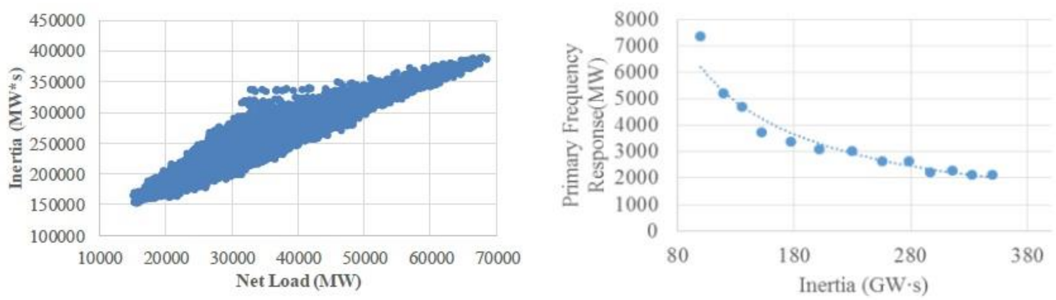


Figure 37: Correlation between net load and inertia (left) and mapping of inertia and the necessary size of the primary frequency response reserve in ERCOT (Du and Matevosyan, 2018).

The level of inertia influences the frequency gradient or **rate of change of system frequency (RoCoF)**. ENTSO-E (2016b) demonstrates that the frequency gradient [Hz/s] is a clear measure of the power system weakness with respect to withstanding sudden system imbalances after forced outages or system separations. The higher the frequency gradient, the less stable the power system. However, the higher the share of non-synchronous generation (replacement of SPGMs by PPMs), the greater the need for the system to resist conditions with greater imbalances and higher RoCoFs.[136] PGMs therefore

[135] However, as smaller units of (renewable) non-synchronously connected generation are replacing larger synchronously connected (thermal) generation, the probability of a sudden loss of a large unit causing a significant frequency deviation also becomes lower. Thus one could say that small non-synchronously connected generation does indeed not contribute to inertia provision but also does not create an additional demand or even lowers the demand for inertia.

[136] A good example is Ireland, where the TSO and the regulator investigate ways to increase the currently employed limit for the share of non-synchronous generation from 50 % of the load to 75 % (IRENA, 2016). One of the measures is a change in requirements for generators to stay connected to the system during certain RoCoFs. Currently, generators are required to remain connected during RoCoFs of up to 0.5 Hz/s. This threshold will be raised to 1 Hz/s in the future (IRENA, 2016). Please note, that present and future challenges with regard to system stability differ strongly across Europe and are closely linked to the level of system interconnectedness.

should be able to withstand a certain RoCoF. The RfG NC states in Art. 13 (1.b) that all PGM types shall be capable of staying connected to the network and operating at rates of change of frequency up to a value specified by the relevant TSO. Also in the DC NC, it is stated that demand units offering demand response shall have the withstand capability to not disconnect from the system due to the rate of change of frequency up to a value specified by the relevant TSO (DC NC, Art. 28(2.k)).

Box 12: Ramping constraints in the RfG NC and the SO GL.

> Ramping limits can be important as steep ramps can induce fast changes in frequency. In the RfG NC it is described that the relevant operator shall specify, in coordination with the relevant TSO, minimum and maximum limits on rates of change of active power output (ramping limits) in both an up and down direction of change of active power output for a PGM of type C and D (RfG NC, 15(6.e)). The determination of the ramping limits shall be done while taking into consideration the specific characteristics of the technology of the PGM. For example, imagine the difficulty of a wind generator to limit the decrease in active power output if the wind speeds are steeply falling (Etxegarai et al., 2015).
>
> Also, in the SO GL in Art. 137(4.a) it is stated that all TSOs of an LFC block shall have the right to determine obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units in the LFC block operational agreement.

Besides inertia and the capability to withstand a certain RoCoF, a very important requirement related to frequency stability are the **frequency ranges** throughout which the different units connected to the system shall remain connected for a certain duration. Figure 38 shows the different requirements per synchronous area graphically. Both under the RfG and the DC NC the RSO may agree with the respective owner of the PGM, demand facility or DSO on wider frequency ranges or longer minimum time for operation (RfG NC, Art. 13(1.a.ii) and DC NC, Art. 12(2)).

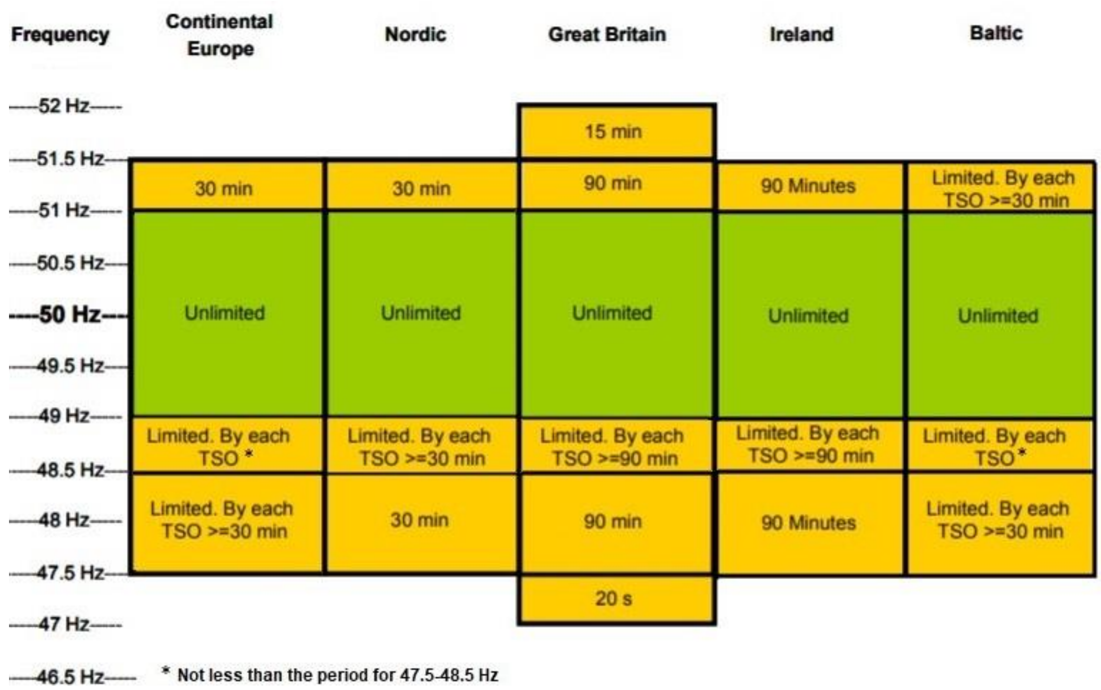


Figure 38: Frequency ranges and duration of connection requirement per synchronous area for PGMs of all types and a transmission-connected demand facility, a transmission-connected distribution facility or a distribution system. Adapted from Rouco et al. (2012).

These ranges and durations are described in both the RfG NC and the DC NC. If PGMs or demand facilities are exposed to over-frequency or under-frequency for too long, their equipment can be damaged. The RfG NC describes in Art. 13 (1.a) that all types of PGMs shall be able to operate within certain frequency ranges and time periods. In the DC NC, exactly the same frequency ranges and durations are required for a transmission-connected demand facility, a transmission-connected distribution facility or a distribution system (DC NC, Art. 12). Demand units providing demand response services to the system operators shall also comply with this requirement individually, or where it is not part of a transmission-connected demand facility, collectively as part of demand aggregation through a third party (DC NC, Art 28(2.a) and Art. 29(2.a)).

So far, static technical requirements related to frequency are described. In the following, a set of requirements is described which enable PGMs to actively contribute to the containment or the compensation of the frequency drop or rise by regulating the active power output or input. We first describe requirements which relate to actions under normal system operation. Second, we go over requirements which relate to actions in emergency situations.

It was already explained in Chapter 6 that under normal operation conditions, the balancing mechanism is designed to deal with system frequency deviations. The fastest type of reserves is the **Frequency Containment Reserve (FCR)**. This type of reserve was historically mostly provided by PGMs. An alternative to adjusting generation output to address load and generation imbalances is to adjust demand in the form of **demand response active power control**. FCR is used to limit variations in frequency quickly. A PGM which actively provides FCR is said to be operating in **Frequency Sensitive Mode (FSM)**. Figure 39 shows the operation in FSM. If the frequency increases, the active power output decreases and vice-versa. There is also a deadband in place to avoid over-reactions to very small frequency disturbances. Besides the requirement of being capable of providing FCR in FSM, type C and D PGMs shall also provide functionalities related to the provision of Frequency Restoration Reserves (FRR) (RfG NC, Art. 15(2.e)). The specific functionalities are determined by the relevant TSO.

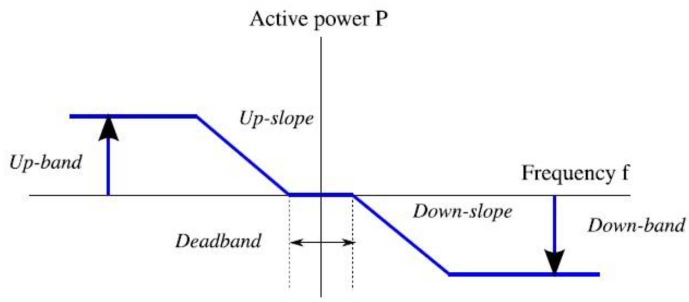


Figure 39: Operation under the Frequency Sensitivity Mode (FSM). From Etxegarai et al. (2015).

According to RfG NC, Art. 15(2.d) and Art. 16(1), type C and D power generating modules shall be capable of **providing of FCR in FSM**, detailed technical parameters are also described in that article. Also, the relevant system operator shall be able to **monitor FSM in real-time** (Art. 15(2.g)). Regarding demand, FCR can be provided by demand response active power control (remotely controlled). The settings for demand response active power control are described in Art. 28(2) of the DC NC. Lastly, in ENTSO-E (2018g) it is described that in principle also **Demand Response System Frequency Control (DR SFC)** can be used for FCR provision, however, that today DR SFC is expected to be more important for other frequency related services than FCR. This service can be provided by every demand unit that has an inherent thermal store, for example, refrigeration, space heating/cooling, water heating/cooling and any other heating/cooling device. The capabilities of DR SFC are described in Art. 29 of DC NC, the final settings are determined at national level.

As discussed above, certain PGMs are required to have FCR capabilities, but that does not necessarily imply that PGMs (and demand response units) shall provide FCR services for free. The procurement method as well as the settlement rule for FCR provision vary between European countries. In some, FCR balancing capacity is remunerated, while in others it is not. In many countries market-based procurement is in place, yet in some regulated prices are (still) applied.[137] Figure 40 gives an overview of how FCR capacity is procured in different countries in Europe.

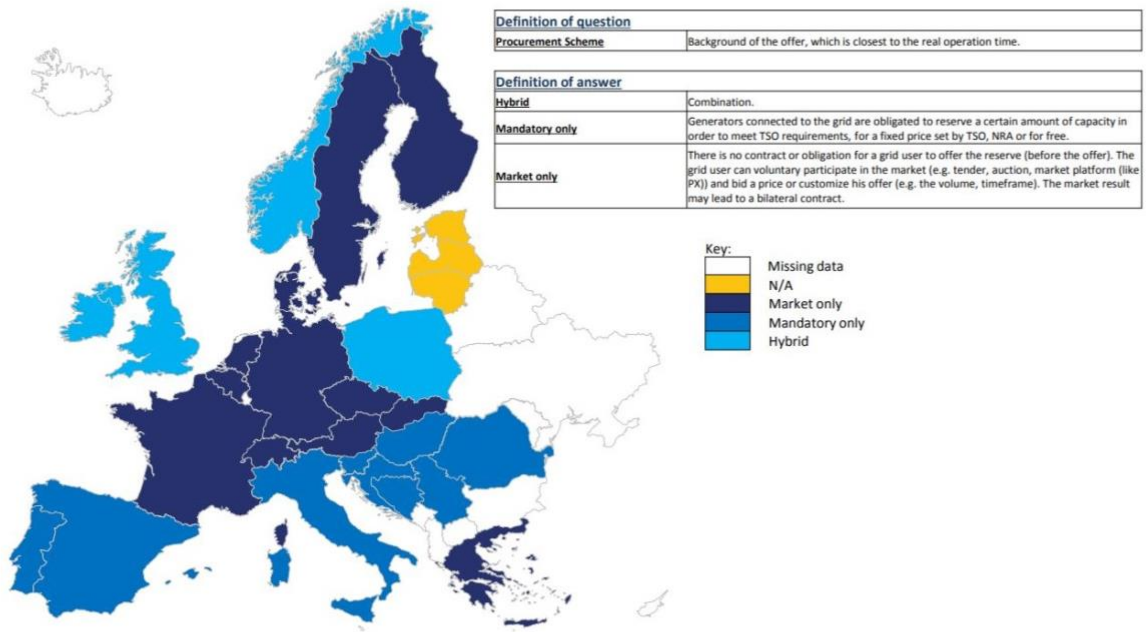


Figure 40: FCR capacity procurement in Europe, status in 2017 (ENTSO-E, 2018c).

No complex system can be perfectly controlled at all times; <u>emergency situations</u> can always occur. More precisely, ENTSO-E (2017g) describes that the relevant design criteria for the Continental Europe (CE) synchronous area is to keep the system frequency within 50.0 Hz +/- 0.2 Hz in case of a load imbalance of +/- 3,000 MW. Nonetheless, more severe disturbances exceeding this FCR reference incident cannot be excluded. An example brought forward by ENTSO-E (2017g) is the case when an interconnected system splits into separate parts each with a high load imbalance due to a high power exchange between these parts before the disturbance. To protect the system against such large shocks in frequency when the deviation cannot be mitigated by the FCR resources only, the RfG NC requires PGMs to be able to run in **Limited Frequency Sensitive Mode (LFSM)** in emergency situations. Also, demand can mimic LFSM, which ENTSO-E (2018g) describes to be the main initial possible contribution of DR SFC to the frequency stability.

When the system is in an emergency state after a severe disturbance, which has resulted in a major generation surplus and all FCR is deployed, **Limited Frequency Sensitive Mode for Over-frequency**

[137] Art. 32 of the EB GL states that the procurement method of mFRR, aFRR and RR capacity shall be market-based. The EB GL does not specify whether FCR capacity should be procured market-based or whether market parties can be obliged to offer FCR at regulated prices.

(LFSM-O) is to be activated to avoid a system collapse and gain time for further operational measures for frequency reduction. In case LFSM-O is activated, PGMs shall decrease the active power towards the **minimum regulating level** according to the selected **droop setting**. The droop setting indicates the percentage of change in frequency to cause a 100 % change in active power output. For example, a 2 % frequency droop setting means that for a 2 % change in frequency, the unit's power output changes by 100 %. This means that if the frequency increases by 1 %, the unit with a 2 % droop setting will decrease its power output by 50 %. **Natural active power frequency response capability of PGMs in LFSM-O** is a capability that is required by PGMs of all types (RfG NC, Art. 13(2)). RfG NC, Art. 13(2.b) adds that for PGMs of type A, the TSO may allow alternatively to disconnect type A PGMs at randomised frequencies if it can be shown that the same level of operational security is maintained.

Oppositely, when the system is in an emergency state after a severe disturbance, which has resulted in a major generation deficit and all FCR is deployed, **Limited Frequency Sensitive Mode for Under-frequency (LFSM-U)** is to be activated. Art. 15(2.c) of the RfG NC specifies that PGMs of type C and D shall be equipped with **active power frequency response capability in LFSM-U**. In case of LFSM-U activation, PGMs shall continuously increase the active power towards the highest achievable output at that moment according to the selected droop. Regarding LFSM-U also demand can play a crucial role. ENTSO-E (2018g) states that the full capability of DR SFC should be activated before the actions of last resort are chosen. The full capability of DR SFC is equivalent to the **selective shedding of non-essential loads** while the actions of last resort are (non-selective) load shedding and finally load disconnection. Art. 19(1) of the DC NC is relevant in this respect, stating that all transmission-connected demand facilities and transmission-connected distribution systems shall fulfil certain requirements related to **low-frequency demand disconnection functional capabilities.** According to RfG NC, Art. 15(2.f), also PGMs of type C and D which are capable of acting as a load (including hydro pump-storage power-generating facilities) shall be capable of **disconnecting their load**.

8.1.2 Requirements related to voltage issues

Next to frequency, another physical parameter of great importance for secure system operation is voltage. ENTSO-E (2016c) states: '*Voltage requirements are critical to secure planning and operation of a power system within a synchronous area. Voltage issues have a cross-border impact as disturbances can propagate widely and, in the worst case, can cause significant disconnection of PGMs, either directly or because of the consequence of a large disturbance on the system frequency*'. This description already reveals an important difference in nature between voltage and frequency, namely, voltage issues are local while frequency has a system-wide character. This subsection consists of four parts. First, reactive power requirements are introduced. Second, voltage ranges are described. After, reactive power capabilities are discussed. In this third part, the section is again split into actions taken in normal system operation and in emergency situations. Lastly, the remuneration of reactive power provision/consumption is also discussed.

Frequency can be controlled by adjusting active power consumption or generation, while voltage is controlled by reactive power consumption or generation.[138] As opposed to active power, reactive

[138] Reactive power is defined in the RfG NC (Art. 2(28)) as the imaginary component of the apparent power at fundamental frequency, usually expressed in kilovar ('kVAr') or megavar ('MVAr'). Reactive power exists in an AC

power cannot be transmitted over long distances. Basically, if there is a lack of reactive power (too much reactive power is consumed by inductive load), voltage decreases. This typically is the case for underground cables regardless their load or for aerial lines at moments of very high loading.[139] Oppositely, if there is an excess of reactive power (too much reactive power is generated by capacitive load), voltage increases. This typically is the case at moments of very low loading of lines/cables. Voltage control is carried out by controlling the generation, consumption and flow of reactive power at all levels in the system. Due to this relationship between reactive power and voltage, the DC NC specifies in Art. 15 **reactive power requirements** for transmission-connected demand facilities and transmission-connected distribution systems.

More specifically, Art 15(a) states that for transmission-connected demand facilities, the actual reactive power range specified by the relevant TSO for importing and exporting reactive power shall not be wider than 48 percent of the larger of the maximum import capacity or maximum export capacity (0.9 power factor import or export of active power), except in situations where either technical or financial system benefits are demonstrated. For transmission-connected distribution systems, the actual reactive power range specified by the relevant TSO for importing and exporting reactive power shall also respect certain boundaries, for more information see Art. 15(1.b) of the DC NC and Box 13 below. Again, except in situations where either technical or financial system benefits are proved by the relevant TSO and the transmission-connected distribution system operator through joint analysis, these boundaries can be different.

Box 13: The rise of distribution-connected generation and reactive power issues.

More recently, voltage issues became a significant technical challenge when integrating Distributed Energy Resources (DER) into the distribution network, see e.g. Mahmudn and Zahedi (2016) for a review of voltage control strategies in smart distribution networks. There are several aspects to be considered; in this box, we selected three.

First, due to the growing numbers of DER in distribution networks, electric power flows are no longer always unidirectional (from high voltage to low voltage) but can be bi-directional. More specifically, when assuming unidirectional flows, the feeder voltage drops with increasing distance from the substation. However, with DER, more specifically Distributed Generation (DG) connected to the end of a line, a long feeder can have significant power generation at the endpoint, where the voltage is normally the lowest. It could even happen that current will flow in the reverse direction (i.e. towards the substation), resulting in a voltage profile that increases with distance from the substation. This inverted voltage profile may create operational issues and confuse conventional controls (Comfort et al., 2001).

Second, a major consequence of the increasing penetration of DER and the gradual replacement of SPGMs by PPMs is the loss of key sources of reactive power. SPGMs have the capability to generate or absorb reactive power depending on their so-called ‘excitation’. They are usually equipped with an automatic voltage regulation continuously adjusting the excitation to control the voltage level. This capability now needs to be provided by DER. PPMs can generally provide reactive power, yet at times with low or zero active power output additional equipment may be required in order for them to meet the requirements. Another dimension is related to small loads. Traditionally, loads

circuit when the current and voltage are not in phase. For a discussion regarding reactive power from an economist’s viewpoint, please consult Berg et al. (1982).

[139] Owing to their high capacitance, underground cables generate reactive power under all operating conditions. Aerial lines absorb or supply reactive power depending on the load current.

absorb reactive power. However, the increasing connection of electronic devices at households is changing the reactive power performance of small consumers. They are changing from being natural consumers of reactive power to being generators of reactive powers due to the capacitors integrated in electronic devices.

Lastly, there can be issues with reactive power exchange between DSOs and TSOs. Namely, a situation can occur when the load of the distribution system is very low or when the total electricity generated by DER is high relative to the load thus resulting in a low net load at the connection point between distribution and transmission. As a result, it is possible that reactive power is exported from the distribution system to the transmission system. Article 15(1.c) of the DC NC requires the relevant TSO and the transmission-connected distribution system operator to determine the optimal solution for reactive power exchange between their systems. More specifically, DC NC Art. 15(2) states that the relevant TSO may require that **transmission-connected distribution systems have the capability at the connection point to not export reactive power (at reference 1 pu voltage) at an active power flow of less than 25 % of the maximum import capability**. This requirement for the transmission-connected distribution systems is discussed in-depth in ENTSO-E (2017h). It is argued that transmission-connected distribution system operators should have the capability not to export reactive power at a low active power flow as reactive power is most efficiently supplied when the distance between production and demand is minimised. In other words, it is proposed that to a certain extent transmission-connected DSOs take care of reactive power balancing within their systems.

It is important to add that distribution and transmission grids perform differently with regard to reactive power. Depending on the generation and transmission configuration as well as the system loading, the transmission system itself either generates reactive power that must be absorbed (light loading) or consumes reactive power that must be replaced (heavy loading). In distribution networks, the impact of reactive power is smaller. Therefore, care must be taken when extrapolating issues from transmission to distribution level.

Second, similarly to frequency ranges, also **voltage ranges** are defined for which PGMs and demand facilities should remain connected to the network for certain time periods. ENTSO-E (2016c) describes that the time period chosen for remaining connected during a voltage deviation shall be long enough for the TSO to take the necessary mitigating actions and short enough to limit the constraints on the grid users' equipment. A major difference is that the compliance with frequency ranges is required for all types of PGMs while for voltage ranges solely type D PGMs are required to comply (RfG, Art. 16 (2)). Additional to the RfG NC, the SO GL states in Art. 28(1) that by 3 months after entry into force of the SO GL, all Significant Grid Users (SGUs)[140] which are transmission-connected power generating modules not subject to Art. 16 of the RfG NC shall inform their TSO about their capabilities compared to the voltage requirements in Art. 16 of the RfG NC, declaring their voltage capabilities and the time they can withstand without disconnection.

[140] Art. 2 of the SO GL defines SGUs as: (a) existing and new power generating modules that are, or would be, classified as type B, C and D in accordance with the criteria set out in Article 5 of the RfG NC; (b) existing and new transmission-connected demand facilities; (c) existing and new transmission-connected closed distribution systems; (d) existing and new demand facilities, closed distribution systems and third parties if they provide demand response directly to the TSO in accordance with the criteria in Article 27 of the DCC; (e) providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Part IV of the SO GL; and (f) existing and new high voltage direct current ('HVDC') systems in accordance with the criteria in Article 3(1) of the HVDC NC.

Regarding demand, in the DC NC is it stated in Art. 13(1-2) that transmission-connected demand facilities, transmission-connected distribution facilities and transmission-connected distribution systems connected above 110 kV shall be capable of remaining connected to the network and of operating at the specified voltage ranges and time periods. Additionally, the same holds for equipment of distribution systems connected at the same voltage as the voltage of the connection point to the transmission system. Art. 28(2.b) and 29(2.b) of the DC NC state that demand units used by a demand facility or a closed distribution system to provide demand response services to system operators shall be capable of operating across the voltage ranges specified in Art. 13 if connected at a voltage level at or above 110 kV. With regard to transmission-connected distribution systems with a voltage below 110 kV at the connection point, the relevant TSO shall specify the voltage range at the connection point that the distribution systems connected to that transmission system shall be designed to withstand (DC NC, Art. 13(7)). Finally, the voltage ranges can differ whether an asset is connected at a voltage level between 110 kV and 300 kV or above, both in the RfG NC and the DC NC. Lastly, for PGMs wider voltage ranges or longer minimum time periods for operation may be agreed upon between the RSO and the PGM owner in coordination with the relevant TSO (RfG NC, Art. 16(2.b)). In the case of demand, the SO GL states in Art. 28(2) that by 3 months after entry into force of the SO GL SGUs, which are transmission-connected demand facilities and which are not subject to Art. 3 of the DC NC, shall inform their TSO about their capabilities in relation to the voltage requirements defined in the DC NC declaring their voltage capabilities and the time they can withstand without disconnection.

Third, again similar as for frequency control, mechanisms need to be designed to contain or compensate for voltage deviations from their reference values. Frequency can be controlled by adjusting active power consumption or generation, while voltage is controlled by reactive power consumption or generation. First, **reactive power capabilities** in <u>normal system operation</u> are described. After, actions taken to deal with voltage issues in <u>emergency situations</u> are briefly introduced. Lastly, the remuneration of reactive power is discussed.

Synchronous PGMs are important in regulating the voltage in <u>normal system operation</u> as they have the ability to both generate and consume reactive power, depending on the needs of the grid. Reactive power is generated or absorbed by varying the strength of magnetic field energy (flux) within the machine, so-called under- or over-excitation. Art. 17(2.a) of the RfG NC describes that the relevant system operator shall have the right to specify capabilities of synchronous PGMs of type B regarding **reactive power capabilities.** Art. 18(2.a-c) and Art. 19(1) add requirements for type C and D synchronous machines with regard to **reactive power capabilities at maximum and below maximum capacity**. Finally, Art. 17(2.b) and Art. 18(1) state the mandatory requirements for synchronous PGMs of type B and C to be equipped with a **voltage control system**.[141] Art. 19(2) adds stricter requirements for the voltage control system of synchronous PGMs of type D. Etxegarai et al. (2015) explain the difference between reactive power control and voltage control. The authors state that '*reactive power control regulates the reactive power independently of the active power, whereas voltage control regulates the voltage at the reference point, normally with a droop like characteristic equivalent to an automatic voltage regulator*'. There is also a third method, namely power factor control. Power factor control regulates the reactive power not independent from but proportional to active power.

[141] Voltage control is defined in Article 3(21) of the SO GL as manual or automatic control actions at the generation node, at the end nodes of the AC lines or HVDC systems, on transformers, or other means, designed to maintain the set voltage level or the set value of reactive power.

Regarding Power Park Modules (PPMs), these are mostly connected via a power electronics interface. (ENTSO-E, 2016d) states that power electronics offer a broad flexibility of control modes and parameters, even after commissioning. It is very crucial that PPMs are capable of providing voltage support in normal system operation as synchronous generators will be displaced at times of high vRES production and this removes a key source of reactive power (ENTSO-E, 2016e). Article 20(2.a) of the RfG NC states that the relevant system operator can specify **requirements for reactive power capabilities** of type B PPM. RfG NC Article 21(3.a-c) and Art. 22 specify the reactive power capabilities for type C and D. The requirements are defined for operation both **at maximum capacity and below maximum capacity**. Finally, RfG NC Art. 21(3.d) and Art. 22 define the **reactive power control modes** of type C and D. The RfG NC requires a reactive power control mode, three possible implementations are accepted: voltage control mode, reactive power control mode and power factor control mode. The relevant system operator in coordination with the relevant TSO and the PPM owner have the right to choose which of the reactive power control mode is to be applied.

Also, demand units can provide reactive power control (DC NC, Art. 28). Art. 2(17) of the DC NC defines **demand response reactive power control** as '*reactive power or reactive power compensation devices in a demand facility or closed distribution system that are available for modulation by the relevant system operator or relevant TSO'*. Lastly, DC NC Art. 15(3-4) state that the relevant TSO may require the **transmission-connected distribution system** to **actively control the exchange of reactive power** at the connection point for the benefit of the entire system. In that case, the transmission-connected distribution system operator may require the relevant TSO to consider its transmission-connected distribution system for reactive power management.

If voltage levels cannot be stabilised by voltage control or reactive power provision, a last-resort solution in emergency situations is the option to disconnect grid users. In the RfG NC, Art. 15(3) it is stated that type C PGMs shall be capable of **automatic disconnection** when the voltage at the connection point reaches levels specified by the relevant system operator in coordination with the relevant TSO. For PGMs of type D, automatic disconnection is not necessarily mandatory; the relevant system operator shall have the right to specify voltages at the connection point at which a PGM is capable of automatic disconnection (RfG NC, Art. 16(2.c)). Further, the requirements related to voltage issues are split up between synchronous PGMs and PPMs due to their difference in nature. Also, in the DC NC automatic disconnection of demand is discussed. DC NC Art. 13(6) specifies that if required by the relevant TSO, a transmission-connected demand facility, a transmission-connected distribution facility, or a transmission-connected distribution system shall be capable of automatic disconnection at specified voltages. The terms and settings for automatic disconnection shall be agreed upon between the relevant TSO and the transmission-connected demand facility owner or the DSO. Further specifications are given under DC NC Art. 19(2). **Voltage control with disconnection and reconnection** is also described for demand units used by demand facilities or closed distribution systems to provide demand response to system operators in Art. 28(3) of the DC NC.

As described above, certain voltage control and reactive power capabilities are required by the RfG NC and DC NC before connection to the network. However, that does not exclude the **remuneration** of the provision of reactive power dispatched to solve voltage issues. This is not an easy task; it is hard to design an adequate equivalent to balancing markets (which deal with frequency issues) for voltage issues. One of the main reasons, as described in Barquin et al. (2000) is the local character of voltage issues. Reactive power cannot be transmitted efficiently over a long distance. This can cause that, in some moments, just one (or a few) generators can provide the necessary reactive power flows, leading to monopolistic behaviour. Since a long time, there has been a debate in academia on whether in the presence of voltage constraints also reactive power prices should be determined in addition to active power prices. For example, Hogan (1993) claimed that reactive power prices complementing active power prices are needed, while Kahn and Baldick (1994) state that 'reactive power is cheap', and that reactive power pricing can be very hard in practice. Barquin et al. (2000) propose a conceptual framework for the remuneration and charging procedures of reactive power. Regarding the more recent challenge of voltage control in distribution networks, for example Rueda-Medina and Padilha-Feltrin (2013) describe in their work a way to design a settlement procedure for a reactive power market for DG in distribution networks.

In this respect also the SO GL is relevant. Namely, Art. 108(2) states:

'*With regard to active power and **reactive power services**, and in coordination with other TSOs where appropriate, each TSO shall:*

(a) design, set up and manage the procurement of ancillary services;

(b) monitor, on the basis of data provided pursuant to Title 2 of Part II, whether the level and location of available ancillary services allows ensuring operational security; and

*(c) use all **available economically efficient and feasible means to procure** the necessary level of ancillary services*.'

Figure 41 below shows the unharmonised landscape of voltage control remuneration in Europe. The left figure shows that not all countries pay for voltage control services and the right figure shows how PGMs or demand is remunerated in the countries which do pay for voltage control services. It is important to note that the provisions with regard to which generators have to provide voltage control services to the TSO as well as the nature of these requirements (mandatory, non-mandatory) vary across countries (ENTSO-E, 2018c), which has effects on the voltage performance across the networks.

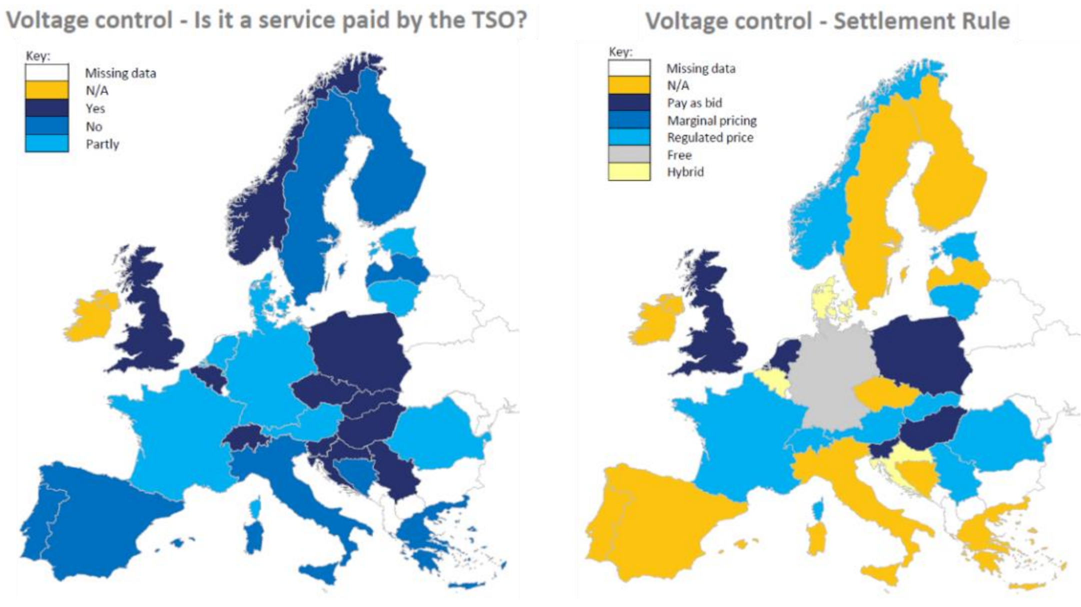


Figure 41: Voltage control remuneration in Europe, status in 2017 (ENTSO-E, 2018c).

8.1.3 Robustness

Robustness or resilience can be defined as the ability to cope with disturbances without loss of proper functioning, i.e. remain connected to the grid after a voltage dip to help to prevent any major disruption or to facilitate restoration of the system after a collapse. Voltage dips in high voltage transmission grids are caused by switching activities which result in a redistribution of energy flows, happening as a result of a short circuit or a planned disconnection. [142]

In the RfG NC one of the most important requirements described with regard to robustness is the **Fault-Ride Through (FRT) capability**. RfG NC Art. 2(29) defines FRT as the capability to remain connected to the network and operate through periods of low voltage at the connection point.[143] FRT is important to prevent a disconnection of a large amount of generation capacity which could finally result in a blackout. Art. 14(3), Art. 15(1) and Art. 16(1,3) of the RfG NC specify that all types of PGMs, except type A, should have FRT capabilities. The exact requirements differ per PGM type and whether the PGM is synchronous or a PPM. Many parameter settings of the FRT capability are non-exhaustive. In this respect, also the **short-circuit requirements** for transmission-connected demand facilities and transmission-connected distribution systems are relevant. Namely, in Art. 14(1) of the DC NC it is stated that 'based on the rated short-circuit withstand capability of its transmission network elements, the relevant TSO shall specify the maximum short-circuit current at the connection point that the transmission-connected demand facility or the transmission-connected distribution system shall be capable of withstanding.' Again, not being able to withstand high short-circuit currents could lead to a cascade of disconnection of grid users which could eventually lead to a blackout.

PGMs are also required to help to minimise the spread of the voltage dip by recovering their active power output quickly following a voltage disturbance. This capability is called **post-fault active power recovery**. All synchronous PGM of types B, C and D shall be capable of providing post-fault active power recovery. The relevant TSO shall specify the magnitude and time for active power recovery (RfG NC, Art. 17(3)). Similar specifications for PPMs of type B, C and D regarding post-fault active power recovery are described in Art. 20(3) of the RfG NC.

8.1.4 System restoration

Even when a power system is extremely secure, a blackout can never be excluded. In that case, the system needs to be restored.[144] However, most PGMs cannot restart without external power after a blackout. Therefore, PGMs having **black start capability** are valuable. Black start capability is defined as the capability of recovery of a power-generating module from a total shutdown through a dedicated

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[142] A short circuit is an electrical circuit that allows a current to be transmitted along an unintended path with no or a very low electrical impedance. Therefore, a short circuit fault current implies sudden current increases within milliseconds that are many times larger than the normal operating current of the system. In order to avoid damaging other electrical assets due to the over-currents and to isolate the fault, switches in substations must open as fast as possible, generally within 50 – 100 milliseconds. Main causes of short circuits are damaged insulation of wires, improper designing, mechanical damage and contact with water.

[143] More precisely, FRT is a voltage versus time profile. The PGM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile (Elia, 2018).

[144] The Network Code on Electricity Emergency and Restoration (ER NC) lays down harmonised procedures to efficiently and rapidly restore system operation and the normal system state after the spread of a disturbance or after a blackout. Each TSO is required to establish a system defence as well as a restoration plan in coordination with relevant DSOs, SGUs, NRAs, neighbouring TSOs and the other TSOs in the respective synchronous area.

auxiliary power source without any electrical energy supply external to the power-generating facility (RfG NC, Art. 2(45)). For example, some PGMs can have small diesel generators which can be used to start larger generators, which in turn can be used to start the main generators.

Art. 15(5.a.i) and Art. 16(1) of the RfG NC state that for PGMs of type C and D, black start capability is not mandatory without prejudice to the Member State's right to introduce obligatory rules in order to ensure system security. Further, the relevant TSO may request the PGM owner to equip its PGM with a black start capability if the TSO considers system security to be at risk due to a lack of black start capability in its control area. In that case, the PGM owner shall provide a quotation for providing black start capability. Figure 42 shows whether black start service is paid and which settlement rule is used. Again it can be seen that the way of remunerating this ancillary service varies widely over Europe. It is interesting to note that black start is a service that might be very suitable to be provided by (large) energy storage systems in the future (Etxegarai et al., 2015).

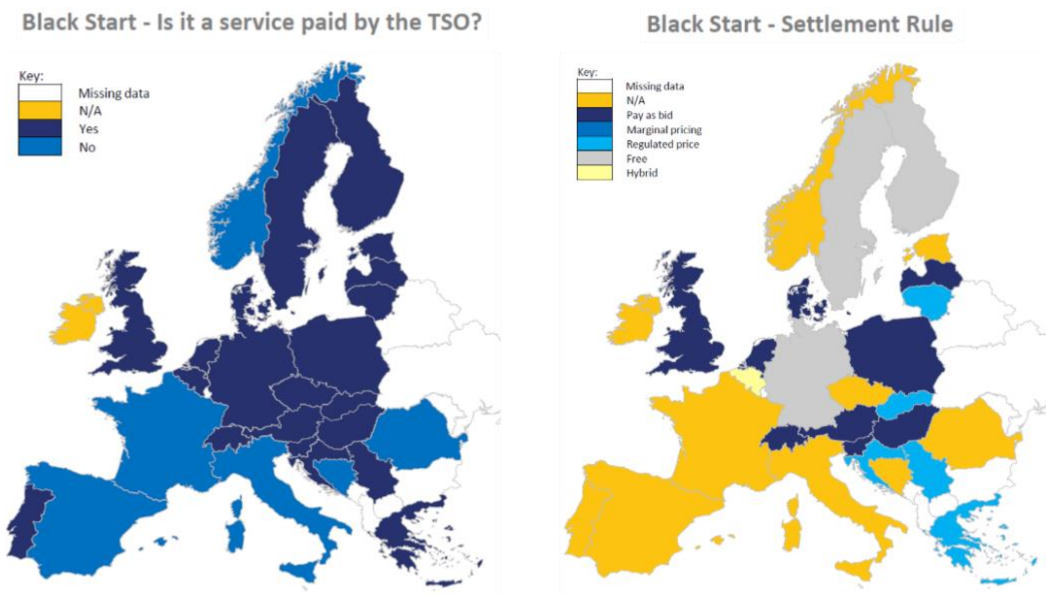

Figure 42: Black Start remuneration in Europe, status in 2017 (ENTSO-E, 2018c).

Another example of a capability categorised under system restoration is the **capability to take part in island operation**. In Art. 2(43), the RfG NC defines island operation as the independent operation of a whole network or part of a network that is isolated after being disconnected from the interconnected system, having at least one power-generating module or HVDC system supplying power to this network and controlling the frequency and voltage. Art. 15(5) and Art. 16(1) further specify that PGMs of type C and D shall be capable of taking part in island operation if required by the relevant system operator in coordination with the TSO. While operating in island mode, the same frequency and voltage ranges for connection apply as under normal conditions. Also, in island operation, a PGM shall be able to operate in FSM, LFSM-O and LFSM-U mode.

Reconnection and re-synchronisation after a fault are also relevant when discussing requirements related to system restoration. In the RfG NC, these are described in Art. 14(4), Art. 15(1) and Art. 16(1) for types B, C and D PGMs. The relevant TSOs are required to specify the conditions under which a PGM is capable of reconnecting to the network after a disconnection. In case automatic reconnection systems are installed, they are subject both to prior authorisation by the relevant SO and to the reconnection conditions specified by the relevant TSO. Article 15 (5.c) of the RfG NC describes the quick re-synchronisation capability required for PGMs of type C and D in case of a disconnection. PGMs with a minimum re-synchronisation time greater than 15 minutes after disconnection must be designed to trip to so-called 'houseload operation', which ensures the continued supply of the in-house loads served by the power-generating facility for a duration specified by the relevant SO in coordination with the relevant TSO.

Article 19(4) of the DC NC requires the relevant TSO to specify the conditions under which a transmission-connected demand facility and a transmission-connected distribution system are entitled to reconnect to the system after a disconnection. As for PGMs, the installation of automatic reconnection systems is subject to prior authorisation by the relevant TSO. If required by the relevant TSO, the transmission-connected demand facility and the transmission-connected distribution system shall also be capable of being remotely disconnected from the transmission system.

8.1.5 General system management requirements

Lastly, a handful of requirements are related to general management requirements. Examples are requirements related to **information exchange** with the relevant system operator (PGM type B-D in the RfG NC; transmission-connected demand facilities and transmission-connected distribution systems in the DC NC), settings of **control and protection schemes** (PGM type B-D in the RfG NC; transmission-connected demand facilities and transmission-connected distribution systems in the DC NC), **instrumentation** needed to provide **fault recording and monitor dynamic system behaviour** (PGM type C-D in the RfG NC) and **simulation models** needed to test compliance of the PGMs with the different technical requirements (PGM type C-D in the RfG NC; transmission-connected demand facilities and transmission-connected distribution systems in the DC NC). For the PGMs, again, the higher the classification of the PGM, the more stringent some requirements can be.

8.2 **To whom do they apply?**

In this section we describe in more depth which PGMs and demand facilities shall comply with the RfG NC and the DC NC, respectively.

8.2.1 RfG NC

This subsection is split into three parts. First, it is described that the RfG NC shall apply to newly connected PGMs with exceptions. Second, we describe the categorisation of the different PGMs. As described in the previous section, different requirements apply to different categories of PGMs. Lastly, we briefly describe the link between the categorisation and the determination of the non-exhaustive requirements listed in the RfG NC.

First, the general rule is that for reasons of grandfathering the requirements laid down in the RfG NC do not apply to existing PGMs. Also exempted from this Regulation are PGMs connected to systems of islands without interconnections, back-up PGMs, modules without permanent connection and storage devices (except for pumped-hydro) (RfG NC, Art. 3(2)). More specifically, RfG NC, Art. 3(1) states that:

'*The connection requirements set out in this Regulation shall apply to **new power-generating modules which are considered significant** in accordance with Article 5, unless otherwise provided*.'[145]

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[145] 'Significant' in this context refers to the capacity of the PGM being larger than or equal 0.8 kW.

New power-generation modules (PGMs) are PGMs of which the final and binding contract for the purchase of the main generating plant is not finalised by 2 years after the entry into force of the Regulation. [146] In specified circumstances, a Member State may provide that the regulatory authority may determine whether the PGM is to be considered existing or new (RfG NC, Art. 4(2)).

There are two exceptions to this general rule regarding existing PGMs. The exceptions are in detail described in RfG NC, Art. 4(1). First, after a notification of the system operator, the NRA can decide that an existing PGM of type C or D is **modernised substantially** and therefore a revised or new connection agreement is needed. Second, the NRA can decide to make existing PGMs subject to (part of) the requirements following a proposal by the TSO (RfG NC, Art. 4(1.b)). That TSO proposal can be made in order to address significant factual changes in circumstances and shall contain a cost-benefit analysis (CBA) (RfG NC, Art. 4(3)).

The second point discussed in the section is the classification of PGMs in different categories. According to RfG NC, Art. 5, PGMs are classified on the basis of the **voltage level of their connection point (in kV)** and their **maximum generation capacity (in MW)**. These different categories need to comply with specific connection requirements. It is interesting to add that a power generating facility with several synchronous machines which can run independently (e.g. several combined-cycle gas turbine installations within one facility) shall be assessed on the capacity of each indivisible unit separately and not the whole capacity of the facility. Non-synchronous connected PGMs (e.g. a utility-scale PV park), where the PGMs are aggregated into an economic unit and where they have a single connection point should be assessed on their aggregated capacity (Recital (9) of RfG NC).

Four categories of PGMs exist in the RfG NC (Art. 5) that are considered: type A to D, from the smallest to the largest. The RfG NC only sets the upper limits for the capacity thresholds used to divide the PGMs into different types. The final thresholds for the different types can be lower than the maximum threshold, except for PGMs of type A. These final thresholds are proposed by the relevant TSO, after coordination with adjacent TSOs and DSOs, and a public consultation, and are approved nationally (RfG, Art. 5(3)). For more information it is recommended to consult ENTSO-E (2016f) in which the key rationales to choose the thresholds are described.

The upper limits for the capacity thresholds in the RfG NC differ per synchronous area and are shown in Table 4 ('upper limit minimum capacity threshold'). Albeit exceptions, it can be seen that the thresholds are generally lower in 'smaller' synchronous areas. [147] As such, there are relatively more PGMs in higher classes (C or D) which generally have more stringent requirements to satisfy. It is important to note that the final thresholds chosen at national level are also strongly dependent on national practices before the entry into force of the RfG NC. For an extensive discussion of connection codes in 'stronger systems' versus 'weaker systems', see e.g. Etxegarai et al. (2015).

[146] 'Binding contract' is not defined in the RfG NC, which led to ongoing discussions in many MS.

[147] In this context 'smaller' and 'larger' synchronous areas are defined according to their annual net electricity generation. An exception are the thresholds for type C-D in the Nordics and GB. Despite a slightly higher electricity generation in the Nordic synchronous area than in GB (372,8 TWh and 312,3 TWh in 2017, respectively, (ENTSO-E, 2018j)), the limits for the thresholds are lower in the Nordics.

Table 4: Connection point and limits for thresholds for different types of power-generating modules (RfG NC, Art. 5).

Type	Connection point	Minimum capacity				
A	< 110 kV	≥ 0.8 kW				
		Upper limit capacity threshold (if connection point < 110 kV)				
		CE	GB	Nordic	IE	Baltic
B	< 110 kV	1 MW	1 MW	1.5 MW	0.1 MW	0.5 MW
C	< 110 kV	50 MW	50 MW	10 MW	5 MW	10 MW
D	≥ 110 kV or < 110 kV[148]	75 MW	75 MW	30 MW	10 MW	15 MW

Box 14 below provides an illustration of a national implementation proposal for the final thresholds for the different types.

Box 14: Illustration of a proposal for the classification of PGMs according to the RfG NC, based on Elia (2018).

Figure 43, illustrates the draft proposal from the Belgian TSO Elia (2018). As can be seen from the left figure, the thresholds specified in the RfG NC (Table 4) are respected.[149] The right figure shows the proposal including derogations. Namely, Elia is proposing to adapt the requirements for PGMs with a maximum installed capacity lower than 25 MW and with a voltage at the connection point higher or equal to 110kV to reflect the specification of the PGM of the same size with a voltage at the connection point lower or equal to 110kV. The requirements will be adapted via derogation as described in Art. 63(1) of the RfG NC. Derogations are further discussed in Section 8.3.2 of this chapter. The reason for this derogation is that there could be small PGMs installed at industrial sites connected to the high-voltage network. Additional requirements (as they would be qualified as type D) would impose too high a cost compared to the benefit.

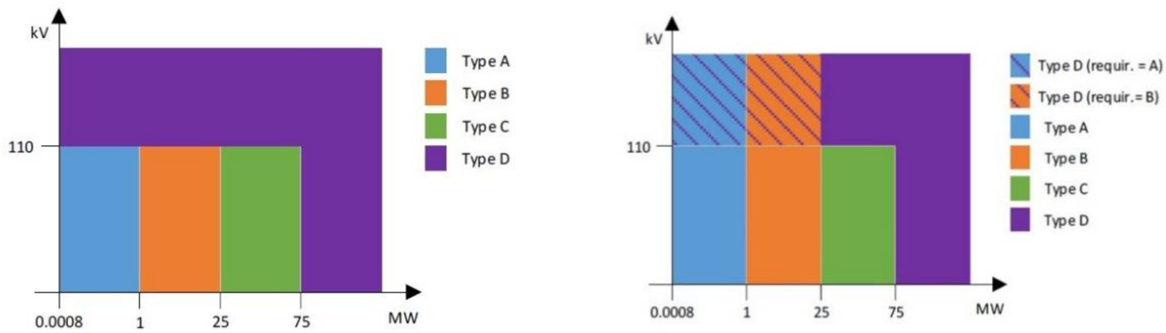

Figure 43: Proposal from Elia regarding the categories of different types of power-generation modules. Left: without derogations. Right: with derogations. (Elia, 2018).

148 In the RfG NC, Art. 5(2.d) it is said that a PGM is also of type D if its connection point is below 110 kV and its maximum capacity is at or above the final nationally specified threshold for type D PGM.

149 For type B: 1 MW ≤ 1 MW; type C: 25 MW < 50 MW and type D: 75 MW ≤ 75 MW. In a previous proposal, the threshold for type B was set at 0.25 MW (Elia, 2017b). It was added that as this was quite low, PGMs considered as type B in the proposal would not be required to respect the full set of requirement for this type and that derogations for this group of PGMs should be considered in the context of further evolutions of the generation mix and system needs.

The category to which a PGM belongs can have a significant impact on the costs the PGM has to incur to comply with certain requirements. Table 5 illustrates which categories should be compliant with a selection of technical requirements.

Table 5: Compliance of the different types of PGMs as described in RfG with a selection of technical requirements.

	A	B	C	D
Frequency ranges	x	x	x	x
Fault-ride through capability		x	x	x
Operation in Frequency Sensitivity Mode			x	x
Voltage ranges				x

A last point raised in this section is that besides the categorisation of the different types of PGMs, TSOs also propose the final parameter settings for non-exhaustive requirements described in the RfG NC. The final choice of these parameter settings should respect specifications stated in the RfG NC. Depending on the requirement the final implementation shall be coordinated by all TSOs per synchronous area. These requirements were discussed in Section 8.1 of this chapter. It is obvious that the final way of categorising the PGMs and the parameter settings of the non-exhaustive requirements per category are interrelated.

8.2.2 DC NC

Similar as with the RfG NC, the general rule is that for reasons of grandfathering the requirements laid down in the DC NC do not apply to existing demand facilities and distribution systems. Again, facilities or distribution systems being installed in islands without interconnections and storage devices (except any pumping module within a pump-storage PGMs that only provides pumping mode (DC NC, Art. 5(2)) are exempted from the DC NC. Further, it is added in Recital (7) that '*the requirements of this Regulation also should not apply to* ***new or existing demand facilities connected at the distribution level*** *unless they provide demand response services to relevant system operators and relevant TSOs*.' Instead, Art. 3(1) of DC NC states that the DC NC applies to:

'(*a.) new transmission-connected demand facilities;*
(b.) new transmission-connected distribution facilities;
(c.) new distribution systems, including closed distribution systems[150]*;*
d.) new demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs.[151]'

New demand connections are defined as connections of which the final and binding contract for the purchase of the demand equipment or the demand unit is not finalised by 2 years after the entry into

[150] A closed distribution system is defined in the DC NC (Art. 2(5)) as a distribution system which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household customers, without prejudice to incidental use by a small number of households located within the area served by the system and with employment or similar associations with the owner of the system. (Classified pursuant to Article 28 of Directive 2009/72/EC as a closed distribution system by national regulatory authorities or by other competent authorities, where so provided by the Member State)

[151] Art. 3(3) adds that '*in case of demand facilities or closed distribution systems with more than one demand unit, these demand units shall together be considered as one demand unit if they cannot be operated independently from each other or can reasonable be considered in a combined manner*.'

force of the Regulation. Again, a Member State may provide that in specified circumstances the regulatory authority may determine whether the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit is to be considered existing or new (DC NC, Art. 4(2)).

As for the RfG NC, two exceptions to this general rule regarding existing facilities exist in the DC NC. Art. 4(1.a) specifies that the requirements do not apply to existing facilities unless a substantial modernisation or replacement of equipment has impacted the technical capabilities of the facility. Included in existing facilities are an existing transmission-connected demand facility, an existing transmission-connected distribution facility, an existing distribution system, or an existing demand unit [that is or can be used for demand response] within a demand facility at a voltage level above 1 kV or [within] a closed distribution system connected at a voltage level above 1 kV.[152] Again, the regulatory authority can decide to make an existing module subject to all or part of the requirements following a proposal by the TSO, which shall contain a cost-benefit analysis (CBA) (DC NC, Art. 4(1.b)). In contrast with the RfG NC, there is no similar further categorisation of demand facilities or distribution systems within the DC NC.

Lastly, it is important to highlight that the DC NC **only applies to demand response services provided to system operators** by connections of demand units (either individually or commonly as part of demand aggregation through a third party) or closed distribution systems. Examples of such demand response services are: active power control, reactive power control, transmission constraint management, system frequency control and very fast active power control. Thus the DC NC does **not apply to parties trading demand in (energy) markets**.

8.3 Implementation, timeline and derogations

The implementation of the CNCs is very different from the market guidelines (CACM GL, FCA GL and EB GL) and the system operation guideline (SO GL). In the guidelines, numerous methodologies at pan-European, regional or national scale need to be developed after entry into force. In contrast, after the entry into force of the CNCs the implementation mainly consists of the specification of technical parameters or processes at national level. In order to allow for a certain degree of harmonisation, the final choice of the non-exhaustive technical parameters at national level needs to respect the boundaries which are set out in the CNCs and shall be done in coordination at synchronous area level or in times at regional/neighbouring countries level. Also, a derogation from one or more provisions of the respective CNC can be requested. No direct equivalent process is in place for market guidelines or the system operation guideline. In the following section, first the way the CNCs are implemented and the respective timelines are described. After, the derogation process is summarised.

8.3.1 Implementation and timeline

The RfG NC and DC NC entered into force as European law on 17 May 2016 and on 7 September 2016, respectively. Figure 44 shows the timeline to be respected. The Member States have an obligation to implement these codes at national level no later than three years after their publication. Within this timeframe, the RSOs (which is in most cases the TSO in coordination with the DSOs) have two years to define and submit the national specifications for the so-called non-exhaustive requirements for

[152] Between [] are own additions to clarify, personal interpretation.

approval by the competent entity (RfG NC, Art. 7(4) and DC NC, Art. 6(4)). In order to support the implementation at national level and also in line with the legal requirements of these network codes ENTSO-E has an obligation to provide non-binding Implementation Guidance Documents (IGDs), see Art. 58 of the RfG NC and Art. 56 of the DC NC and ENTSO-E (2018h). At the time of writing, ENTSO-E drafted a set of 18 of such IGDs.[153]

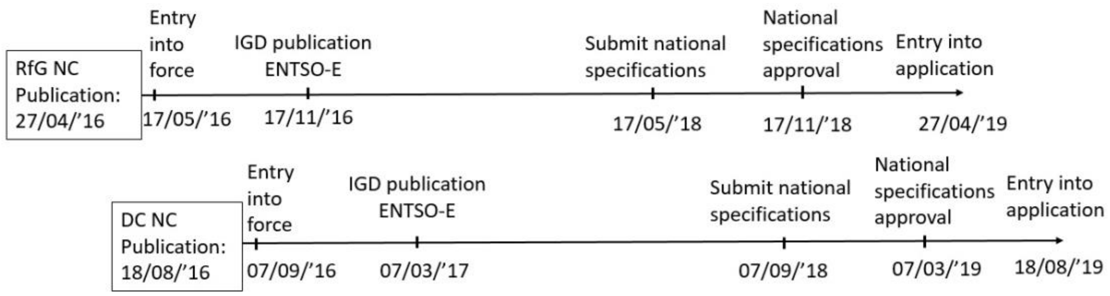

Figure 44: Timeline with important dates RfG NC and DC NC.

After the national specifications are submitted by the RSOs, the competent entity shall take decisions on the proposals for requirements or their methodologies within six months following their receipt. Also, during this third year the impacted parties have the time to comply with the requirements by adopting them into new equipment and power plant specifications. Finally, exactly three years after the publication of the network codes and onwards, all impacted parties have to comply with the Regulations.

It is important to note that the implementation process for the Network Codes is not completed with the 'entry into application' deadline depicted in Figure 44. On the contrary, all relevant stakeholders need to continuously analyse the technical details of the codes and see to it, that the requirements are revised according to the system needs in future grid scenarios with increased vRES penetration.

The classification thresholds of PGMs is one of national specifications to be submitted by the TSOs two years after the entry into force of the RfG NC. It is important to add that the approved capacity thresholds cannot be changed more frequently than every three years after the previous proposal (RfG NC, Art 5(3)). When such a change is made, it will apply by default to new generators going forward the date of application. Also, the same exceptions as described in RfG NC, Art. 4(3) regarding existing PGMs can be applied. Related to the change of threshold values, Box 15 illustrates how TSOs can address changes in circumstances which might lead to insufficient technical capabilities of the grid-connected PGMs to guarantee secure system operation.

Box 15: Addressing changes in circumstances - Two options or their combination (based Annex 2 in ENTSO-E (2016f)).

Imagine a TSO facing changes in circumstances, e.g. a stronger than anticipated increase in smaller renewable generation units connected to the distribution network and a sudden shut-down of some larger synchronous PGMs connected to the transmission network. As a result, the TSO deems that the current technical capabilities of the PGMs connected to the grid might not suffice anymore. The TSO has two options to 'update' these capabilities.

[153] The IGDs can be found on https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementation-guidance-d/consult_view/, last consulted on 11/12/2018

First, the TSO can propose a change to the thresholds used to classify the different PGMs if the previous proposal was made more than 3 years ago (as described in RfG NC, Art. 5(3)). By lowering one or several thresholds, more PGMs would end up in a higher category. This means that there will be more resources with enhanced capabilities when compared to the status quo. However, such change would only affect the newly connected PGMs. Thus, in that case, the TSO has to anticipate the trends in newly connecting PGMs.
However, if the lack of capabilities to deal with a significant factual change in circumstances is deemed pressing, a second option would be to require existing PGMs to comply with all or part of the requirements of the RfG NC. In that case, a CBA is required as described in RfG NC, Art. 4(3). One should note that also this option could require time as existing generators would have to be retrofitted to be compliant to the then imposed requirements.

Also, a combination of both options is possible, e.g. a change of the thresholds while at the same time requiring this change to be retro-active, i.e. requiring that all existing PGMs will have to comply with the new requirements. Again, also in this case a CBA as described in RfG NC, Art. 4(3) and 5(5) will be required.

8.3.2 Derogations

Both in the RfG NC and DC NC derogations from one or more provisions of the respective Regulations can be requested. It is up to the relevant (national) regulatory authorities to grant the requested derogations.

The regulatory authority has 9 months after entry into force of the respective Regulation to specify the criteria for granting derogations. These criteria shall be published on its website and notified to the European Commission (EC). The EC may then require the regulatory authority to amend these criteria if they are not in line with the RfG NC or the DC NC (RfG NC, Art. 61(1); DC NC, Art. 51(1)). Also, if the regulatory authority deems that it is necessary due to a change in circumstances relating to the evolution of system requirements, it may review and amend at most once every year the criteria for granting derogations (RfG NC, Art. 61(2); DC NC, Art. 51(2)). It is also possible for the regulatory authority to decide that the grid user requesting the derogations does not have to comply with the requirement for which the derogation has been requested from the day of filling the request until the decision is made by the regulatory authority (RfG NC, Art. 61(3); DC NC, Art. 51(3)).

Additionally, all decision regarding granted or refused derogations will be notified to ACER and maintained in a register by the regulatory authority which will be updated at least every six months (RfG NC, Art. 64; DC NC, Art. 54). ACER shall monitor the procedure of granting derogations with the cooperation of the relevant national regulatory authorities (RfG, Art. 65 (1); DC NC, Art. 54(1)). ACER and the EC both have the possibility to issue a reasoned recommendation to a regulatory authority to revoke a derogation due to a lack of justification (RfG, Art. 65 (2); DC NC, Art. 54(2)). A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the EC or a reasoned recommendation by ACER (RfG NC, Art 62(11) and 63(11); DC NC, Art. 52(10) and 53(11)). Lastly, the EC may request ACER to report on the monitoring of the procedure of granting derogations and to provide reasons for requesting or not requesting derogations to be revoked (RfG, Art. 65 (3); DC NC, Art. 54(3)).

Regarding the RfG NC, derogations for new and existing PGMs can be requested by a PGM owner or prospective owner, a relevant system operator or a relevant TSO (RfG NC, Art. 60). The RfG NC does not foresee the option to let a group of PGM owners or prospective owners jointly request a derogation. If the request is filled by a PGM owner, the request shall first be sent to the relevant system operator and/or the relevant TSO who then forwards the request with its own assessment to the regulatory authority (RfG NC, Art. 62). The relevant system operators or relevant TSOs may request derogations for classes of PGMs connected or to be connected to their network and submits its request directly to the regulatory authority (RfG NC, Art. 62(1-2)). Where the request for a derogation is submitted by a relevant DSO or closed distribution system operator (CDSO), the regulatory authority shall ask the relevant TSO to assess the request for a derogation in the light of the criteria determined by the regulatory authority (RfG NC, Art. 62(3)).

Regarding the DC NC, derogations for new and existing transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units can be requested by a demand facility owner or prospective owner, a DSO/CDSO or prospective operator, a relevant system operator or a relevant TSO (DC NC, Art. 50). As with the RfG NC, the DC NC does not foresee the option to let a group of transmission-connected distribution facilities, distribution systems and demand units jointly request a derogation. Again, if the request is filled by a demand facility owner or a DSO/CDSO operator, the request shall first be sent to the relevant system operator who then forwards the request with its own assessment, done in coordination with the relevant TSO and any affected adjacent DSO, to the regulatory authority (DC NC, Art. 52). A relevant system operator or relevant TSO may request derogations for (multiple) transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems, or demand units within a demand facility or a closed distribution system connected or to be connected to their network and submits its request directly to the regulatory authority (DC NC, Art. 53(1-2)). Where the request for a derogation is submitted by a relevant DSO, the regulatory authority shall ask the relevant TSO to assess the request for a derogation in the light of the criteria determined by the regulatory authority (DC NC, Art. 53(3)).

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