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INTRODUCTION TO NETWORK TARIFFS AND NETWORK CODES FOR CONSUMERS, PROSUMERS, AND ENERGY COMMUNITIES

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Abstract

To ensure that the new deal for energy customers and citizens materialises, the engagement of consumer organisations, energy communities and NGOs on the topics of network tariffs and network codes is essential. This text, developed for an FSR online training course specifically targeted at this group of stakeholders, aims to facilitate that engagement. In the first chapter, we discuss the main principles of distribution network tariff design, guiding the reader from the (theoretical) first-best distribution network design all the way to why the current practices were adopted. Subsequently, issues with current practices are discussed, and possible tools to overcome these challenges are briefly described. In the second chapter, we focus on EU electricity network codes. On the basis of a discussion around the balancing mechanism, we show that the network codes and guidelines imply certain obligations for all relevant parties, but that they also create opportunities.

Keywords: Distribution Grid Cost Recovery, Distribution Network Tariff Design, Active Consumers, Network Codes and Guidelines, Balance Responsibility, Imbalance Settlement, Balancing Markets

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Abbreviations

ACER: Agency for Cooperation of Energy Regulators

aFRR: automatic Frequency Restoration Reserves

BAU: Business-As-Usual

BRP: Balance Responsible Party

BSP: Balancing Service Provider

CACM GL: Capacity Allocation and Congestion Management Guideline (Commission Regulation (EU) 2015/1222)

CBA: Cost-Benefit Analysis

CEP: Clean Energy Package

CEER: Council of European Energy Regulators

DAM: Day-Ahead Market

DER: Distributed Energy Resources

DNO: Distribution Network Operator

DSO: Distribution System Operator

DLMP: Distribution locational marginal pricing

DCC: Demand Connection Network Code (Commission Regulation (EU) 2016/1388)

EB GL: Electricity Balancing Guideline (Commission Regulation (EU) 2017/2195)

EC: European Commission

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

ER NC: Electricity Emergency and Restoration Network Code (Commission Regulation (EU) 2017/2196)

EP: European Parliament

EU CEP: European Union Clean Energy Package

FCA GL: Forward Capacity Allocation Guideline (Commission Regulation (EU) 2016/1719)

FCP: Frequency containment process

FCR: Frequency Containment Reserves

FRP: Frequency Restoration Process

FRR: Frequency Restoration Reserves

GB: Great Britain

GL: Guideline

HVDC NC: The requirements for grid connection of High Voltage Direct Current systems and Direct Current-connected power park modules Network Code (Commission Regulation (EU) 2016/1447)

ICT: Information and Communication Technology

IDM: Intraday Market

IME: Internal Market for Electricity

ISP: Imbalance Settlement Period

LMP: Locational Marginal Prices

LRMC: Long-Run Marginal Cost

mFRR: Manual Frequency Restoration Reserves

NC: Network Code

NEMO: Nominated Electricity Market Operator

NRA: National Regulatory Authority

ORDC: Operational Reserve Demand Curve

RES: Renewable Energy Sources

RfG NC: Requirements for Grid connection of Generators Network Code (Commission Regulation (EU) 2016/631)

RR: Restoration Reserves

RRP: Reserve replacement process

SCA: Smart Connection Arrangement

SO GL: Electricity Transmission System Operation Guideline (Commission Regulation (EU) 2017/1485)

TCM: Terms, Conditions and Methodologies

TSO: Transmission System Operator

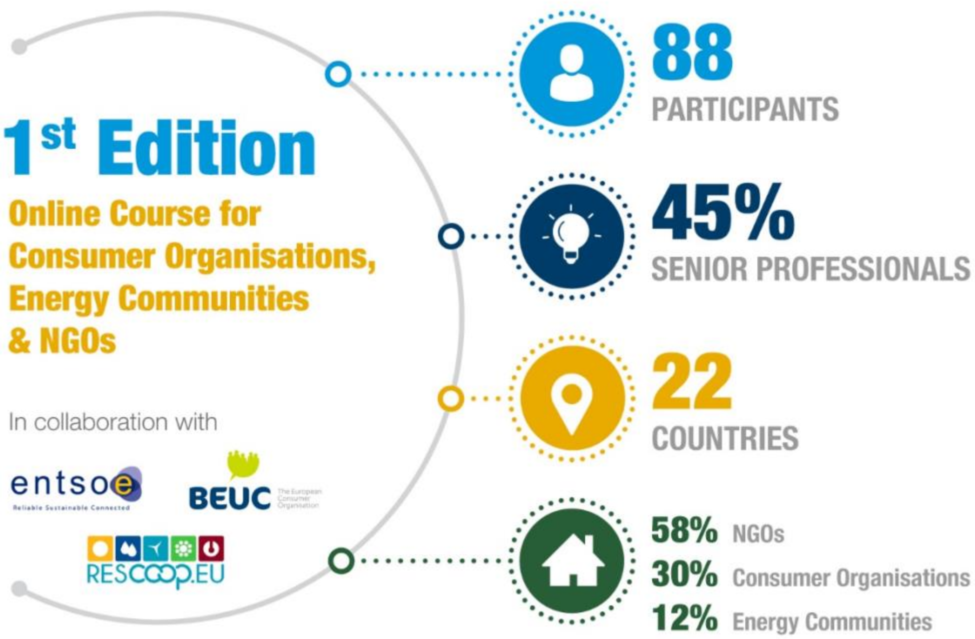
VAT: Value-Added Tax

Context and Acknowledgements

In 2016, FSR and ENTSO-E developed a training course on the EU Electricity Network Codes. In 2017, that collaboration was extended to the European Commission and ACER. In 2018, the [EU Electricity Network Codes] course continues.

In addition, FSR and ENTSO-E decided in 2018 to initiate a training course tailor-made for consumer organisations, energy communities and NGOs. In collaboration with BEUC and RES-COOP, we decided to focus the first edition of this new course on network tariffs and network codes. This text was developed for this online course directed by Prof Leonardo Meeus. The first edition of the course ran from 12-26 April.

This course was free of charge and exclusively open for representatives of consumer associations, energy communities and NGOs. We welcomed over 88 participants from 22 countries. 58% of the participants were representatives of NGOs, 30% came from consumer organisations and 12% were from energy communities.



The participants were invited to contribute to this text, and many did so very actively. We are very grateful for the insights and comments of Albert Ferrari, Anna Halbig, Craig Morris, Eva Schmid, Fabian Reetz, Giordano Alberta, Guillaume Joly, Lucila de Almeida, Marine Cornelis, Nicolo Rossetto, Patrick Gieres, Tara Connolly and Valeria Magnolfi.

Disclaimer: The authors are responsible for any errors or omissions.

1. Distribution network tariff design

1.1 Introduction

1.1.1 The electricity bill: the components and who is responsible for what?

Figure 1 shows the breakdown of consumer electricity bills in capital cities across Europe. It shows that the electricity bill broadly consists of three components: energy costs, taxes and levies, and network charges.

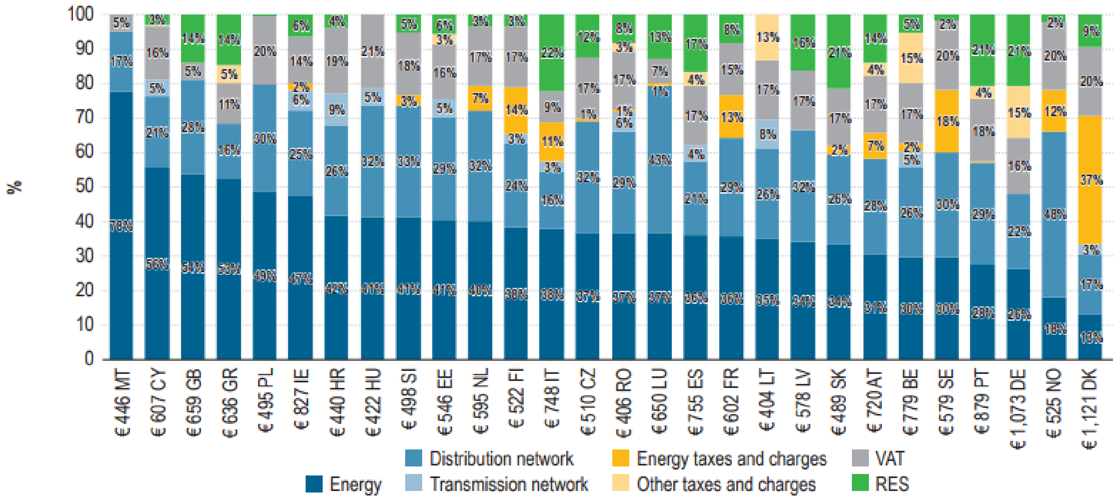


Figure 1: Breakdown of incumbents' standard offers for households in EU capital cities and total bill – November-December 2016 (ACER and CEER, 2017a)

In 2016 energy costs represented on average 35% of the final bill but they have declined (at least relatively) every year since 2012, as is shown in Figure 2. Energy costs depend on **the wholesale electricity market**. In this market, electricity retailers buy electricity on behalf of their contracted customers. The final energy price a consumer sees will reflect the market conditions to a certain extent. Depending on the arrangement with the retailer, the final price for the consumer, expressed in euros per kWh, can be either time-varying or time-invariant.

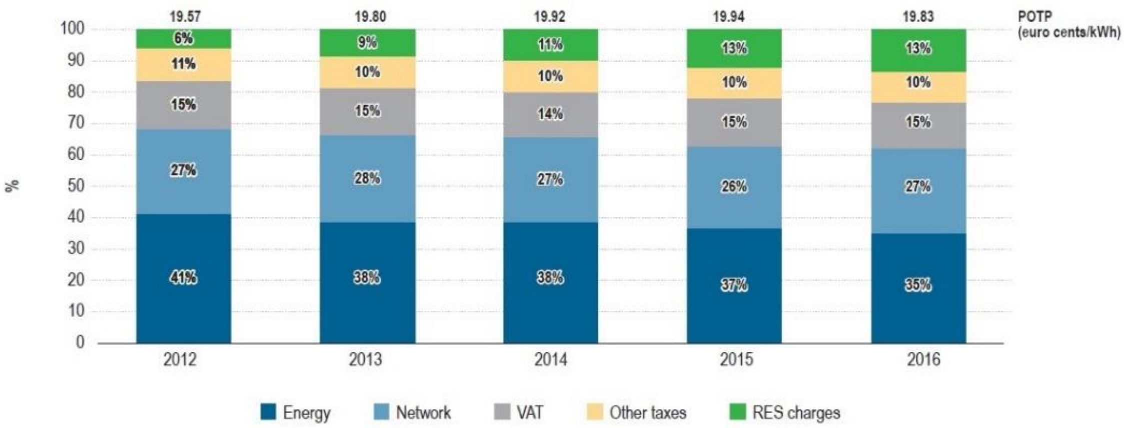


Figure 2: Weighted average of the electricity post-taxes total bill (POTP) and breakdown of incumbents' standard offers for households in EU capitals and Oslo – 2012-2016 (ACER and CEER, 2017a)

Taxes and levies represented on average 38% of the electricity bill in 2016. Value-Added Tax (VAT), averaging 15% in the EU, is added as a percentage of the final electricity bill. Levies in the electricity bill are increasing yearly, as is shown in Figure 2, and made up about 23% of the bill in 2016. Levies are recuperated through the consumer bill to pay for energy policy costs, e.g. renewable subsidies or surcharges. Levies are paid, in most cases, in proportion to the electricity volume consumed, i.e. in euros per kWh or by a fixed charge per consumer. The high-cost burden of energy policy and how these costs are spread across different types of grid users has provoked an intense public debate, see e.g. Bohringer et al. (2017) discussing the German case. The allocation of these costs and whether they should be recovered through the electricity bill at all is up to the **government**. This debate is not the focus of this text.

A topic of even greater interest today is how to design the distribution network (access) tariff, which is currently the main method for recovering distribution network costs from consumers. In 2016, the proportion of total network charges in electricity bills averaged around 27% in the EU. The largest chunk of network charges in a consumer bill are the distribution network charges. Distribution network charges ranged from 16 % to 48% of the bill, while for transmission network charges these percentages were between approximately 0% and 9%. For simplicity, throughout this text, when we refer to network charges, we mean distribution network charges. The reason distribution network tariffs are discussed so much today is generally not because they have been increasing – indeed Figure 2 shows that the proportion of network charges in the bill has been relatively stable in recent years – but, instead, because of their design. Figure 3 shows how distribution network tariffs were designed for EU households in 2016.

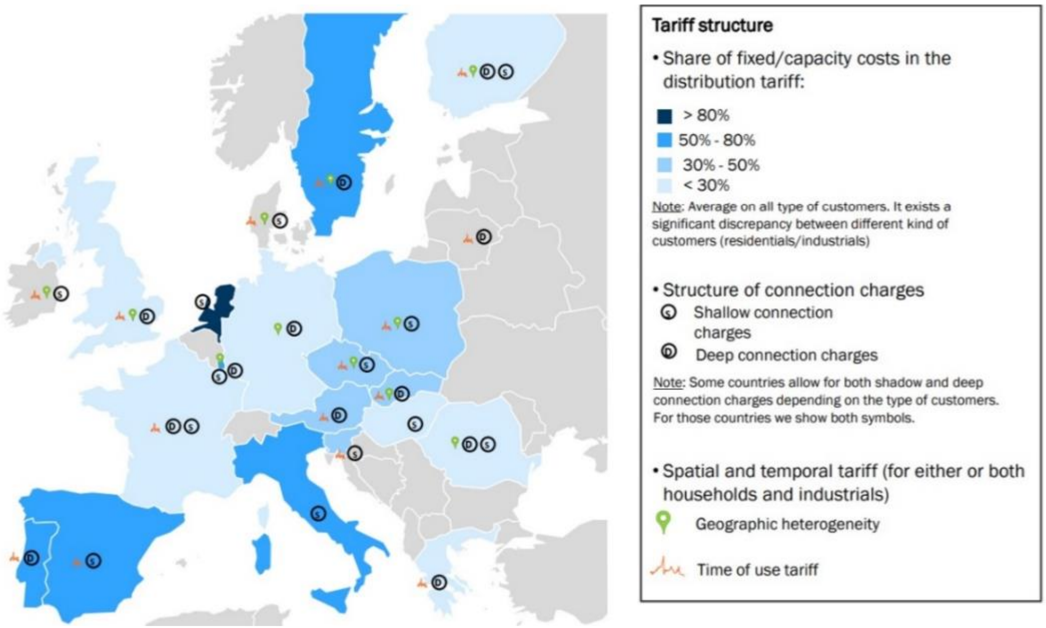


Figure 3: Distribution network cost recovery in Europe by Compass Lexecon (2016) based on European Commission (2015)

The first thing to note in Figure 3 is that methods of grid costs recuperation and the structures of distribution tariffs are not harmonised across Europe. Similarly, as with transmission tariffs, the shares of volumetric/capacity component for distribution tariffs vary significantly across EU countries. A second important fact demonstrated by Figure 3 and also described in a report by the European Commission (EC) (2016), is that the majority of distribution grid tariffs mainly consist of volumetric charges. The EC report specifies that 69% of the revenue from households, 54% for small industrial consumers and 58% for large industrial consumers are recuperated through volumetric tariffs. The Netherlands is an exception as there is no volumetric component in the distribution network tariff for households.

As the network tariff is regulated, it is the **National Regulatory Authority (NRA),** not the market, that has the final say on the distribution network tariff design. In some EU countries, the NRA is solely responsible for the tariff design; in other EU countries NRAs and DSOs share the responsibility, e.g. the NRA decides on higher level principles, while the DSO proposes the tariff structure and level that needs to be approved by the NRA (EC, 2015 and recital 36 of Directive 2009/72/EC).

1.1.2 Other ways than access tariffs to recuperate distribution network costs

In the debate about the recovery of distribution grid costs, the focus is mostly on the distribution network access tariff, i.e. the one you pay as part of your monthly or semestrial electricity bill. Besides the network access tariff, network connection charges and distribution locational marginal pricing (DLMP) are other ways to (partly) recuperate distribution grid costs. In practice, at least today, distribution grid costs will be recovered by a combination of the connection charges and the distribution network access tariff.

Connection charges

Connection charges, as the name indicates, are (in most cases) a one-off charge paid for the connection to the grid. In general, three types of connection charges can be distinguished: **super-shallow, shallow, and deep connection charges**. The degree to which connection charges fully reflect the incremental cost of providing a user with a new or upgraded connection to the network depends on the type of connection charge.

With super-shallow connection charges basically no costs are charged for the connection. Shallow connection charges imply that grid users pay for the local infrastructure connection costs (the cable between a house and local feeder and other necessary equipment); these costs are easily attributed to a specific user. Deep connection charges consist of the shallow charges plus possibly incurred costs for wider network reinforcements needed to accommodate the connection request. Deep connection charges are designed to fully reflect the incremental cost of providing a user with a new or increased connection to the network.

Shallow connection charges solely recover the connection from the user to the grid. Shallow connection charges generally do not 'steer' consumer behaviour, i.e. whether you connect your house or shop to a point in the distribution grid where there is very little or significant congestion, it does not affect your connection charge. On the other hand, deeper connection charges do send a signal to grid users. Namely, you will have to pay a different connection charge whether or not you connect to a point in the grid where there is already significant congestion. Deep connection charges will 'guide' grid users to connect to less congested points of the grid.[1] A major issue with deep connection charges is that new entrants will pay more than users that are already connected to the grid. Grid investment

[1] An innovative tool in that regard are network capacity maps indicating the available hosting capacities at different points in the distribution network see e.g. http://www.westernpower.co.uk/connections/generation/network-capacity-map.aspx and https://www.capareseau.fr/

happens, in practice, in discrete ('lumpy') steps, a grid user connecting at the moment the grid is utilised near its maximum would have to pay the entire upgrade. Another difficulty with this type of charge is that the costs imposed on the network by the user need to be estimated before actual grid usage.

Ofgem (2017), Great Britain's (GB) regulator, describes a practical implementation of distribution connection charges. They state that in Great Britain the distribution connection charging regime is referred to as '*shallow-ish*'. Next to the full cost of assets that will be used solely by the connecting customer[2], connection charges can also recover a portion of the deeper reinforcement costs to the existing network needed to provide the user with firm access to the system. However, charges paid for the deeper reinforcement of the wider grid seem to be limited. Namely, in Ofgem (2014) it is reported that 95% of connections between 2011-2014 did not trigger any network reinforcement. Additionally, where a connection project triggered reinforcement, the connecting customer paid 59% of the associated costs. The other 41% of the costs were socialised through the network access tariff.

Distribution locational marginal pricing (DLMP)

Another way to recuperate grid costs is through Distribution Locational Marginal Pricing (DLMP), meaning that different locations (in the extreme case: nodes) in the network can reflect different energy prices at a certain point in time. The principle applied in DLMP is borrowed from transmission grid cost recovery and could also, in theory, be applied to distribution networks to recover part of the costs. In Figure 4 a simple example of locational pricing applied at nodal level is shown.

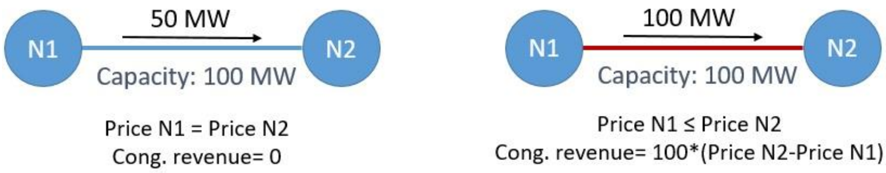
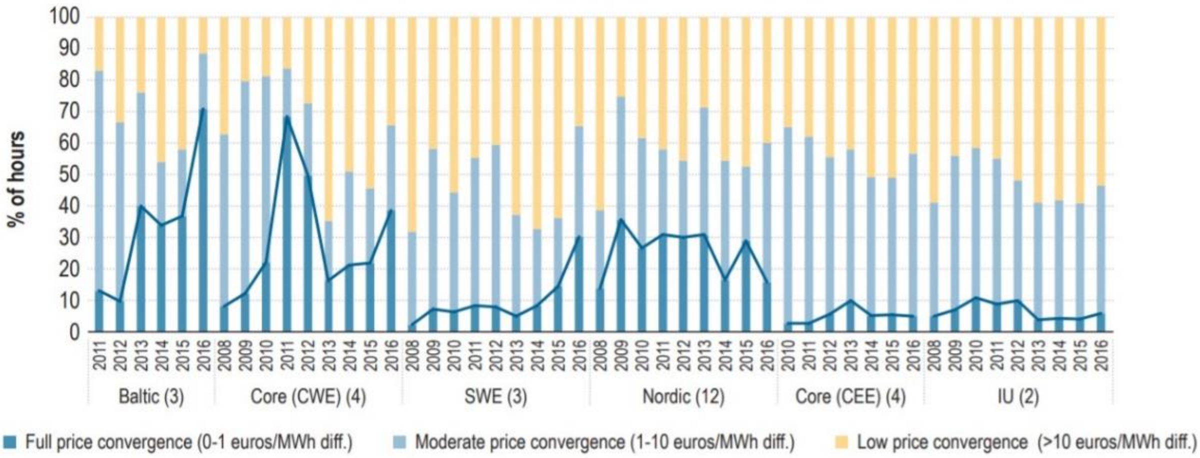


Figure 4: Simple example of locational marginal pricing. Left, no congestion. Right, congestion.

The left side of Figure 4 shows a situation without congestion (meaning the line is not utilised at its full capacity) between the two nodes N1 and N2. The price of the two nodes will be the same if we assume no energy losses. In this case, there is no congestion rent or income for the owner of the line. The right side of Figure 4 shows a situation in which there is congestion between the two nodes. A price difference between the nodes occurs now. Electricity will always flow from the node with the lower price to the node with the higher price. The **congestion rent**, i.e. the income for the line owner, is calculated as the capacity of the line multiplied by the price difference between the nodes. Prices can change during each market time unit (e.g. 1 hour or 15 minutes), i.e. congestion can occur or disappear depending on the electricity flows resulting from electricity trade. Thus, by applying distribution locational prices very short-term price signals are sent, informing grid users about the underlying network constraints.

[2] Ofgem (2014) explains that the cost of the assets solely used by the connecting consumer will be based on the 'minimum scheme'. The minimum scheme is the solution designed solely to provide the capacity needed for the new connection at the lowest overall capital cost. A DSO may design an enhanced scheme (e.g. additional assets to accommodate a larger capacity or assets of a different specification) but the cost to the customer will not exceed that of the minimum scheme. The customer can also request works in excess of the minimum scheme, when it thinks this would be more beneficial.

The concept of locational marginal pricing is applied in European electricity markets at the transmission level. Namely, the European electricity market is organised as a set of bidding zones, which in most cases overlap with national borders. The network within these bidding zones is seen as a copper plate – no congestion is assumed – implying that within a bidding zone the electricity price is always uniform. However, the different bidding zones are connected through transmission lines ('cross-zonal interconnectors') for which the scarce capacity is taken into account by the market, a mechanism called implicit cross-zonal transmission capacity allocation. This means that if the interconnectors between two bidding zones are not congested at a certain point in time, the electricity price will be equal over the two bidding zones (so-called market coupling). If the interconnectors are congested, the electricity price in the two bidding zones will diverge (so-called market splitting).[3] Figure 5 illustrates price convergence between different bidding zones within certain regions in the EU. For example, the Baltics consist of three bidding zones representing respectively Lithuania, Latvia and Estonia. During 2016 the (day-ahead) electricity price between those three countries converged about 70% of the time.



Source: ENTSO-E, Platts (2017) and ACER calculations.

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

Figure 5: Day-ahead price convergence in the EU by region as % of hours, 2011-2016 (ACER and CEER, 2017b)

This also means that 30% of the time at least one bidding zone had a different price due to one or multiple interconnectors being congested. This implies that during those moments congestion rent was generated. This revenue is raised from the day-ahead auction in which the electricity prices in the different bidding zones is jointly determined as illustrated with an example in Box 1.

Box 1: Numerical example: the generation of congestion rent with implicit capacity allocation

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).

[3] For more information, see e.g. Meeus and Schittekatte (2018), Section 2.2, in which the concept of bidding zones is explained more profoundly and Chapter 5, which describes the way cross-zonal capacity is allocated and calculated.

	Price	*Demand*	*Generation*	*Demand cost*	*Generation cost*
Zone A	50 €/MWh	100 MW	150 MW (demand zone A + interconnector)	€ 5,000	€ 7,500
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.

In Figure 6 the average annual congestion revenue and how it was spent per country over the period of 2011-2015 is shown.

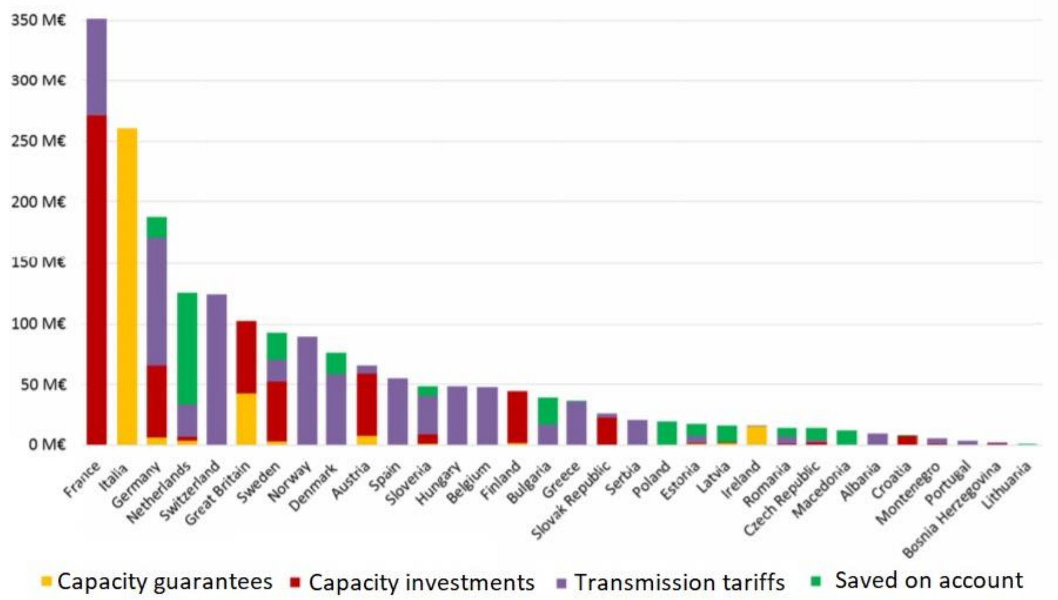


Figure 6: Average annual congestion rent and allocation of the rent per country for the period between 2011 and 2015 (ECN et al., 2017)

There are precise rules specifying how the obtained congestion revenues should be spent. More specifically, Art. 16 (6) of the Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity states that priority should be given to using this money to guarantee the actual availability of the allocated capacity or to maintain or increase cross-zonal interconnection capacity. However, if the revenues cannot efficiently be used for those purposes, they can be used to lower the (transmission) network tariffs up to a maximum amount decided upon by the relevant NRA. Remaining money should be saved to use for priority purposes when necessary in the future.

Obstacles would have to be overcome to apply the locational marginal prices (LMP) to distribution networks in order to recover part of the grid costs. There are two main issues: a public acceptance issue and a technical issue. First, if locational pricing is applied at the distribution level, it would mean that different areas of a distribution network would see different energy prices at certain points in time. This could be perceived as unfair because this price difference is mainly created by the investment decisions in infrastructure by DSOs in the past and not by consumers who happen to live in an area which could see a rise in prices. The technical issue relates to the fact that the number of lines and nodes at the distribution level is much higher than at the transmission level. Applying locational pricing at the transmission level is computationally already challenging, with the number of zones being the main parameter affecting the time to compute all prices. Innovations in algorithms and computational power will be required if a similar calculation is to be made at the distribution level. Also, real-time information about all flows in the lines as well as about the injection and withdrawal of electricity at all nodes is required. This is a very challenging task and will entail significant investments in IT to turn the distribution grid into a 'smart grid'.

Abdelmotteleb et al. (2016) explain that the major difference between LMP used in transmission and distribution are the losses and congestion portions. In distribution networks, losses have a more relevant role than in transmission.[4] Moreover, congestion is rarer in DLMP calculations since distribution network topology is generally radial and feeds energy from one point. Abdelmotteleb et al. (2016) also add that even if DLMP were implemented, complementary network charges are needed to fully recover the network costs and to send efficient long-term signals to network users.

1.2 Principles and theory of distribution network tariff design

After distilling the relevant literature, we came up with three general principles for distribution network tariff design. Namely, a tariff should be cost-reflective, it should allow the recovery of efficiently incurred grid costs and, finally, it should be fair.

1.2.1 Cost-reflectiveness

An important principle of distribution network tariff design is cost-reflectiveness. Cost-reflectiveness implies that the cost a consumer imposes on the network should be reflected by the network tariff. In short, one should pay the price for one's own actions. In theory, by having a cost-reflective tariff the consumer can make an informed decision about whether to use the network at a certain time (for which she will pay the imposed cost) or whether to change her consumption behaviour for which she will have attributed a value or for which she has to invest in Distributed Energy Resources (DER).[5] If network charges are not cost-reflective, it means that consumers will not see the correct trade-off between utilising the network or adjusting their consumption at a certain point in time. Two situations can occur:

- First, the network tariff can be too low, meaning that the consumers' actions impose more costs than the network charges they would have to pay. This means that we end up in a situation with an overly expensive grid as the consumers are not incentivised enough to adapt their actions, leading to a higher total system cost. An example would be that consumers who have an intelligent heating system driven by a heat pump command their house to be heated at moments when the electricity (including the grid) is priced cheaply even when the network

[4] Losses in distribution can vary widely and are typically in the order of 4-10 % of the total energy offtake (see e.g. the MIT Energy Initiative (2016)). In transmission, losses are around 1-2 % of the energy offtake (see e.g. Elia).

[5] In this section we assume the consumer to be the decision-maker, this is not always the case. An example can be a less affluent family renting a flat in the city with little to say on which investments to make in the building, including the heating system, let alone solar panels on a roof. Fairness and inflexible/passive consumers are further discussed in Subsection 3.3.

is near congestion. If many people do so, it would eventually mean that the network needs to be expanded, while this would not have been the case if the network tariff was cost-reflective thus incentivizing the consumer to programme their heating at times when the utilisation of the grid was low. In the end, all consumers will have to pay back the cost of this (avoidable) network expansion through the tariff.

- Second, the network tariff can be too high, meaning that the consumers' actions impose less costs than the network charges they have to pay. Using the same example, if network charges are too high, it could mean that consumers opt for gas heating instead of electric heating. Even though, if the network charges were designed to be cost-reflective, electric heating could have been a cheaper option as the electricity network could accommodate the extra load without issue, under the condition that the heating would be correctly programmed. This would mean that we end up in a situation with overpriced actions by the consumers and an underutilised grid, leading again to a higher total system cost for the final energy service than if the network tariff was designed properly.

In short, the idea is that a cost-reflective tariff will lead a **cost-efficient** outcome. What is meant with a cost-efficient outcome is that the cost-reflective tariff will lead to the overall lowest final cost for serving the electricity needs of all consumers.

When wanting to design a cost-reflective tariff, we need to know what cost to reflect, in other words, what drives the grid cost. Generally, it is agreed in the literature that the main cost driver of an electricity network, whether it is distribution or transmission, is the maximum peak demand aggregated over all consumers, also called the 'coincident peak demand'. A line or feeder is dimensioned to cope with the maximum power in kW or MW it is expected to carry at a certain point in time, not by the volume in kWh or MWh it is expected to transmit over a certain time period. This is very similar to highways or telecom lines. Other cost drivers could include losses or for example, the penetration of solar PV which could induce bi-directional flows and thus require investment in additional electronics (e.g. protection and voltage regulation) in the grid. For more information see also the Future of Solar Report by the MIT Energy Initiative (2015) and Chapter 9 of IEA (2016).

So what does such a cost-reflective tariff look like in theory? For example, the Utility of the Future report by the MIT Energy Initiative (2016)[6] explains that a cost-reflective distribution network tariff consists of a forward-looking peak-coincident capacity charge. The capacity-based charge should be computed as the incremental cost of the network divided by expected load growth, the so-called long-run marginal cost (LRMC) of the network. However, there are constraints making the introduction of this tariff more difficult in reality; we divide them into two groups: **implementation constraints** (due to a lack of information and fairness concerns) and a **cost-recovery issue**.

First, implementation constraints: LRMC pricing is not so easy to implement in distribution grids. Gómez (2013) describes the distribution networks as follows: '*A friend of mine who worked in a distribution company likened electric power generation and transmission to a bull and distribution to a beehive. Whereas generation and transmission comprise comparatively few and very large-scale facilities, distribution involves a much larger number and wider variety of equipment and components.*'

[6] See e.g. also Box 4.6 (p. 115-116) in that report.

In other words, it is hard to get a complete picture of the distribution network. Plus, there is a lack of information about the network flows in real-time requiring significant investments in IT infrastructure in most countries. Without this information, it is almost impossible to truly reflect the grid costs in the tariff as it is not clear what is really going on in the network.

In order to apply LRMC pricing, a value for the LRMC needs to be estimated, and this value should be charged at the moment the coincident peak demand comes near to the maximum capacity of the network. Regarding the LRMC estimate (in €/kW increment in demand), e.g. Cohen et al. (2016) uses Californian data and finds that the LRMC can be very location specific. Additionally, as described by Batlle et al. (2017), a marginal increment must be defined, but such choice is hardly justifiable, and it can alter the outcome of the allocation, especially in industries such as the power sector, characterised by economies of scale and lumpiness or discreteness of investments. Regarding targeting the coincident peak demand, e.g. Passey et al. (2017) use Australian data to show that demand profiles and the timing of the network peaks vary widely across networks and at different voltage levels, mostly depending on the mix of consumers connected. This implies that to implement such optimal cost-reflective tariffs, the regulator should know what is going on in the network in real-time, have good cost estimates of all equipment and adequately define a correct increment. In practice, such information is hard to obtain or lacking.

Also, if all information were available then such tariffs should have a very fine locational and temporal granularity. In the extreme case, in order to apply it perfectly, it would almost be a user-by-user tariff. However, generally, a tariff per region or DSO area is applied in Europe (EC, 2015). This is mostly done for reasons of simplicity and fairness.[7] Batlle et al. (2017) explain that in reality, such fine granularity is impossible and that some degree of consumer clustering is required. The authors continue that in the electricity sector, consumers have traditionally been grouped by voltage level, node location, consumption category (residential versus industrial), or even according to the occurrence of their peak load if a time-differentiation is applied. It is clear that each grouping alternative represents an (arbitrary) approximation of the LRMC and the timing of the peak, that may, to a greater or lesser degree, affect the overall cost-efficiency of the methodology. Moreover, there might be an issue with applying a forward-looking charge. If you announce to grid users that at a certain point in the future the coincident-peak is expected and thus higher network charges will have to be paid, it is possible that users react ex-ante and that the 'expected coincident peak' is no longer a coincident-peak in reality anymore (so-called peak shifting). Alternatively, if the coincident peak is determined ex-post its occurrence, it is hard to send price signals to grid users and their total network charges to be paid become more unpredictable.

[7] Imagine you live in a district that has not seen an upgrade of the local grid infrastructure in the last decade and local demand is increasing. If a cost-reflective network tariff with finer locational granularity were applied, it is possible that grid tariffs would suddenly become substantially higher at certain times in your neighbourhood. This would happen to incentivise grid users to adjust their electricity withdrawal and injection patterns at times the grid is stressed in order to avoid or postpone costly grid reinforcements. Another district could have been upgraded just a couple of years before the implementation of such a tariff with finer locational granularity. This district could then see fairly low and constant grid tariffs as there is little need for reinforcements. The difference in grid tariffs would be caused mainly because of choices of the DSO in the past on which affected grid users had little influence. Very location-specific tariffs could indeed increase cost-efficiency but they remove a certain 'socialisation' of grid costs.

In Schittekatte and Meeus (2018) we demonstrate that if the regulator, in setting the tariff, does not anticipate inaccuracy in the proxy of the network cost driver, self-interest pursuing active consumers can make sub-optimal decisions in terms of DER investment, possibly leading to consumers investing more in DER than the level of grid and energy costs that are avoided; thus resulting in a worse outcome in terms of overall welfare. If the regulator anticipates this inaccuracy, the welfare loss can be reduced.

Next to an implementation issue, there is a cost-recovery issue. It is well known (see e.g. Borenstein, 2016; MIT Energy Initiative, 2016; Ofgem, 2017) that purely cost-reflective charges do not guarantee full cost recovery of the efficiently incurred grid costs. Actually, what cost-reflective network charges do is to send a signal to grid users to optimally make use of the network, leading to a cost-efficient outcome for all. However, cost-efficiency is decoupled from another objective, namely to recover all grid costs. In reality, some of the grid costs will be sunk, i.e. grid investments done in the past to meet future electricity demand and of which the total amount of costs is unaffected by the way the network is utilised. A cost-reflective tariff does not guarantee the recovery of all grid costs including the sunk grid costs. Therefore, a cost-reflective tariff, which is in theory the first-best solution from a cost-efficiency point of view, needs to be complemented with another charge to recuperate these sunk costs. This leads us to the second principle of distribution network tariff design: cost-recovery.

1.2.2 Cost-recovery

The idea behind the cost-recovery principle is that the Distribution System Operator (DSO), the company responsible for maintaining, developing and operating the distribution network, must be able to recuperate its 'efficiently incurred grid costs'.[8] It should be noted that the DSO is a natural monopoly, meaning that it is cheaper to have one company building and operating the distribution network than multiple companies duplicating the necessary lines and competing for consumers to connect to their network. What this implies is that the tariff for using the network is not set by the DSO. Instead, it is the NRA that assesses how high the allowed revenue of a DSO should be and accordingly determines the network tariff. An exception is Spain, where allowed revenues are set by the Government (EC, 2016a).

In general, incentive regulation should aim to guide DSOs to find an optimal balance between costs associated with investment, operation and maintenance, and energy losses on the one hand, and the quality of service provided on the other hand. To achieve higher quality, the company must incur greater costs and vice versa. However, the NRA can judge that some DSO expenditures were incurred inefficiently meaning that these costs cannot be recuperated through the tariff. For more information on incentive regulation of distribution grids see for example the chapter of Gómez in the Regulation of the Power Sector book by Pérez-Arriaga (2013). A recent detailed description of incentive regulation of electricity network companies can also be found in the first two chapters of the book by Meeus and Glachant (2018). In the first chapter, Rious and Rossetto (2018a) describe the history of incentive regulation in the British energy sector which was a pioneer in this respect. In the second chapter, Rious and Rossetto (2018b) discuss the implementation of monopoly regulation in Continental Europe. They explain that the choice of the best regulatory tools depends on the characteristics of the specific tasks of the regulated company and is constrained by the competency and resources of regulators.

[8] The DSO can own the distribution network assets. Alternatively, these assets can also be owned by third parties (often municipalities) but managed by the DSO. In some jurisdictions the DSO is referred to as the Distribution Network Operator (DNO).

The (simplified) cost-recovery process occurs as follows. First, it is the NRA that determines the allowed revenue for x amount of years – the regulatory period.[9] Then the tariffs are set by the NRA, possibly jointly with the DSO, anticipating future usage of the network and aiming to recover exactly the allowed revenue from the consumers. Imagine, for example, that the NRA decides that in the following years a DSO should be allowed to recover €1,000 per year through access charges, the network tariffs are volumetric (€/kWh) and the expected electricity volume consumed by its connected consumer is 20,000 kWh per year. In that case, the network tariff for the next year should be set at 0.05 €/kWh. However, when checking the real consumption after the year has passed, it could be that the actual consumption was higher, meaning the DSO recuperated too much money, or lower, meaning the DSO did not recuperate enough money. In the former case, the DSO will have to give a rebate to its consumers the next time tariffs are set, in the latter case, the DSO will be allowed to set the tariff slightly higher the next time in order to recuperate the missing money. This example suggests that the DSO is indifferent about the tariff setting as they cannot keep more money than the allowed revenue which is set independently of the tariffs. However, this is only true if the tariff recovers the investment costs of the past. To the extent that the tariffs also influence the need for grid investment in the future, the future allowed revenue cannot be completely decoupled from the tariff design.

So, how can the distribution network tariff be designed in the most cost-efficient way while making sure that all grid costs are recovered? In theory, the best way to design such **minimal distortive** charges is by applying **Ramsey pricing**. With this approach, the residual or sunk grid costs, the part of the grid costs not recuperated by purely cost-reflective charges, are assigned to consumers according to their elasticity to price. Inverse proportionality is followed; this means that a higher proportion of the residual network costs are allocated to those consumers who change their consumption behaviour the least in response to price changes. As such, the way the total grid costs are recuperated modifies as little as possible the optimal outcome compared to when consumer decisions are subjected solely to cost-reflective charges. In Schittekatte et al. (2018) we show the relative performance of different tariff designs other than Ramsey pricing in terms of cost-efficiency and distributional effects among consumers under the assumption that all grid costs are sunk. We test four different states of the world in terms of the investment cost of DER technology, in this case solar PV and batteries, and find that the introduced distortions by the different tariff designs are very sensitive to the costs of DER technology.

Although cost-efficient, there is a critical issue with Ramsey pricing. Namely, it is often perceived as **unfair** as it discriminates users on the basis of their elasticity to prices (see e.g. Neuteleers et al. (2017)).[10] For example, network tariffs can be designed so that two consumers who share the same load profile but have a different willingness to pay for electricity, pay a different share of the residual grid costs.[11] As mentioned above, the lower the elasticity, the higher the contribution to the residual grid costs. In the case of network tariffs, consumers with very low elasticity and thus bearing most of the residual costs could be passive consumers with few alternatives to the grid for their electricity supply. Besides, to implement Ramsey pricing the price-elasticity of the different consumers needs to be estimated, something which is not easy to do. Therefore, strictly applying Ramsey pricing is unattainable in practice, leading us to the third principle of distribution network tariff design: fairness.

[9] Usually the duration of the regulatory period lies between 3 and 8 years.
[10] It must be added that unfair does not does imply unlawful.
[11] The same load profile means that they consume the same amount of electricity at the same time.

1.2.3 Fairness

The main reason fairness is a principle of network pricing and not of, for example, the pricing of your sunglasses is the fact that network charges constitute a significant chunk of the cost of electricity which is considered a basic service to which everybody should have access. The notion of fairness is broad and needs more explanation. In this text, fairness encompasses **distributional issues** (inflexibility, affordability and non-discrimination), **transparency** (simple and predictable) and last but not least, **graduality**.[12] In what follows, we describe these concepts one by one. Then we move on to the practical implication for network tariff design. Inevitably, there will be a trade-off between fairness and cost-efficiency when designing tariffs. Distribution network tariffs are in that sense no different to any other practical pricing system for basic needs.

Regarding inflexibility, is using electricity at a certain time always a real choice? Not really, some electricity usage is rather inflexible. In that context, Bunzl (2010) uses the example of a hospital emergency room. It is not considered fair to charge higher network tariffs, even though cost-reflective, at times when consumers do not have a real choice other than consuming electricity.

In addition to the fact that some electricity usage is rather inflexible, there is also an issue with affordability. As mentioned, electricity is considered as a basic need. Some households simply cannot afford to pay the 'real price' of their electricity usage. It would be deemed unacceptable to cut these consumers off. It could be argued that it is not unreasonable to include a 'usage tag' for different needs: basic needs such as heating versus luxury needs such as the charging of your electric car. Such a pricing scheme is however not cost-efficient as different consumers would see a different price for a commodity with possibly the same cost. Also, such a system would be hard to implement. In some cases, it will be opted to supply vulnerable consumers with a cheaper tariff than the 'real price'. This will unavoidably lead to inefficiencies as described in the previous subsection. There are other methods to obtain a similar goal in a more efficient manner, e.g. by exposing consumers to the 'real price' but at the same time offering them a fixed sum as a rebate on their total electricity bill. As such, the consumer incentives are not distorted while electricity remains affordable.

Third, non-discriminatory. It is deemed fair that one is charged the same amount for using the same goods or service, regardless of the purpose for which it is used or any characterisations of the consumers. At first sight, there seems to be a contradiction between having non-discriminatory tariffs and affordability. Indeed, when certain consumer classes such as the vulnerable consumers have a cheaper network tariff for reasons of affordability, the tariff is indeed discriminatory. However, in some contexts, such practice can be regarded as fair.

Furthermore, a tariff should be as simple as possible as most consumers do not want to spend much time analysing tariffs. If a tariff is overly complex, despite being cost-efficient, it might take too much time for the consumer to understand it properly. Such practices lead to high transaction costs (in standard economics terminology) and frustration. When using a service or consuming a good,

[12] In this context, fairness is often used as a synonym for public acceptability or equity. These terms do not imply exactly the same; equity can be defined as a (moral/ethical) principle, fairness as a perception (of a process or a decision) and acceptance as an evaluation (outcome) that someone judges based on his/her subjective and selective assessment. These definitions were provided by Eva Schmid.

consumers want to know how much this action will end up costing them. Network tariff pricing should be predictable.

Finally, this text talks about redesigning tariffs to deal with evolutions at the consumer and network-side. Redesigning implies that we do not start from scratch: there is a tariff in place, and consumers can perceive changes in what they pay for the network (in the extreme case: 'bill shocks') as unfair. In some cases, (passive) consumers can see their electricity bill increase significantly without changing their consumption; others could have invested in DER, e.g. a solar panel, basing their business case partly on the network tariff regime in place. Changing the tariff could render their investment, if irreversible, loss-making. Neuteleers et al. (2017) describe that a price increase is acceptable if the underlying costs for that product have increased.[13] Contrarily, using excess demand (e.g. scarcity because of weather conditions) or an increase in monopoly power (e.g. single seller in a particular community) to raise prices is perceived as very unfair.

In Schittekatte and Meeus (2018) we demonstrate that with active consumers reacting to the way the grid is priced, taking fairness into account when redesigning the distribution network tariff can have a cost in terms of cost-efficiency. The proxy used for fairness in the paper is the increase in the network charges paid by passive consumers (e.g. consumers who do not have the financial means to invest in DER) due to actions of active consumers reacting to the way the network charges are designed; the larger the increase, the more unfair a network tariff is perceived. It is shown that results are sensitive to the grid cost structure, i.e. whether in a network most of the grid investments still have to be made or whether most grid costs are sunk. If the proportion of sunk grid costs is high and the tariff design options are limited, it is an almost impossible task for the regulator to recover all grid costs in a cost-efficient way while limiting the distributional impact at the same time. More creative solutions might be needed to achieve such an objective; examples are differentiated fixed charges or specific low-income programmes. Another option could be to recover the sunk grid costs through general taxation instead of the electricity bill as also discussed in the MIT Energy Initiative (2016).

Recently, the academic literature and debate have focused on **fairness between active and passive domestic consumers**. However, other important debates concerning grid cost allocation are also gaining momentum: for example, the **cost allocation between grid users (residential and smaller/larger industrial/commercial businesses) connected to different voltage levels** of the transmission and the distribution network and, related, the **cost allocation between consumption and production** connected to the same network or even voltage level.

First, the cost allocation between voltage levels. Historically, electricity flowed from the high voltage levels all the way down. As a result, it was acceptable that transmission grid users did not pay for distribution while distribution grid users paid for transmission too. Also, within the distribution grid this cascading practice is applied with domestic grid users paying more than industrial clients connected to higher voltage distribution networks, see for example Brandstätt et al. (2015) explaining the German cascading principle. To the extent that the direction of the flows is changing, also this cascading principle could be challenged from a fairness (and a cost-efficiency) point of view. In some

[13] Neuteleers et al. (2017) adds that at the same time, people deem it acceptable that the price stays the same if costs decrease. Both refer to the entitlements of the seller: changing costs should not decrease the firm's reference profits.

cases, for example in Germany in 2012-2013, certain large electricity users, often connected to higher voltage levels, were exempted from paying any network charges at all. Very recently the European Commission concluded that fully exempting certain large users from these charges was against EU State aid rules as it is an unfair advantage over firms in other countries and increases the financial burden on other electricity users (European Commission, 2018).

Second, the cost allocation between consumption and production units. In transmission, this discussion goes back far in time. Ruester et al. (2012) describe that many countries simply tend to socialise transmission costs among consumers and that this is in part due to historical reasons.[14] Only a few countries applied (non-significant) network charges to generation, a so-called G-component. For more recent data on the transmission network charges, please consult ENTSO-E (2017a) or Sections 3.3 and 3.4 of the report by Glachant et al. (2017). In distribution networks, only since recently significant (mostly renewable) generation capacity is being connected to the network where before the large majority of grid users were solely consuming electricity. Also, prosumers, grid users withdrawing electricity at times while injecting electricity at other times, and large storage facilities become more common distribution grid users. The advent of these new players further complicates cost allocation between consumption and production. In this regard the principle of 'symmetrical network charges' as brought forward by Pérez-Arriaga et al. (2017) is relevant. What is meant with symmetrical tariffs is that an electricity injection in the network at a given time and place should be compensated at the same rate that is charged for withdrawal at the same time and place. This is an important guiding principle, and we expect this discussion to become a topic for future research.

1.3 The current challenge

Until recently, consumers connected to the distribution network were not able to react strongly to price signals; therefore, there was not much gain to be made from using cost-reflective tariffs. The fact that volumetric charges are only slightly cost-reflective was less of an issue. The distribution network tariff had a rather allocative objective, recuperating all the network costs in an acceptable way, instead of 'guiding' consumers to efficient grid behaviour. Also, volumetric distribution network charges were deemed fair as high-usage and thus higher network contributions correlated rather well with more affluent consumers. Further, such tariffs are predictable, simple and most meters were only capable of measuring the cumulated consumed volume thus making more advanced tariffs hard to implement.

However, times are changing and technological evolutions at the consumer-side are challenging the use of volumetric network charges. Specifically, volumetric charges with net-metering, implying that a consumer will be charged for the net consumption from the grid over a certain period (e.g. month), are deemed inadequate with the massive deployment of solar PV.

To give an illustration of the issue: a consumer consumes 300 kWh a month in her house and has a solar panel installed which generates 200 kWh in that month. The electricity consumption in the house and the generation by the PV panel will not always coincide, but the consumer will have a net consumption from the grid that month of 100 kWh for which she will pay network charges. Thus by

[14] Ruester et al. (2012) explain that in the past, when transmission was still part of national vertically integrated utilities, transmission costs were in general simply socialised over all consumers since under cost-of-service regulation and centralised planning it does not make sense to charge generators anything.

installing a PV panel, the consumer has lowered her grid charges to 1/3 of what she would originally have paid (100 kWh/300 kWh). However, the consumer still relies on the distribution grid and her peak usage in the evening, the main cost driver of the network if coincident with the system peak usage, will not change much. Thus, the total grid costs do not lower in proportion to the reduced network charges paid by the PV adopter. Actually, this reduction in network charges could make the business case for solar PV more attractive, thus, by the way the network charges are designed the adoption of this technology could be over-incentivised from a purely economic point of view. Also, it would mean that if cost recovery is respected, other consumers, not having installed solar PV would have to contribute more.

Note that support for solar PV or energy efficiency can be justified, but it is considered the better practice to provide direct support instead of via network tariffs. CEER (2017a) for instance, refers to the Dutch case for the disentanglement of network tariff design and energy efficiency goals. In 2009, fixed network charges were introduced for small electricity and gas users replacing volumetric tariffs. These charges were based on the connection capacity of a household. The consumer now paid less per kWh consumed, but the energy tax (also in €/kWh) was adjusted to compensate for reduced energy efficiency incentives. If more direct support for energy efficiency or renewables is politically sensitive, which is, for instance, more the case in the US, network tariffs could be used for these purposes (Kolokathis et al., 2018). However, this is highly controversial among academics (see e.g. the blog post by Davis (2018)).

Besides solar PV, there are also breakthroughs in (stationary) batteries, heat pumps, electric vehicles, smart appliances etc. Consumers can monitor their interaction with the grid through smart meters, and these new controllable technologies can have not only significant effects on the volumes withdrawn from the network (in kWh) but also on the timing of withdrawal or injection, i.e. the network capacity utilised at each moment by a consumer (in kW).

There are empirical studies and pilots which confirm that consumers do react to (distribution) tariffs by changing their consumption or investing in PV panels. For example, Faruqui et al. (2017) carry out a meta-analysis of the results from 63 pilots containing a total of 337 electricity pricing treatments in nine countries located on four continents. They focus on the complete electricity bill, not solely the distribution network tariff and show that customers do respond to price signals and that these responses are predictable. More specifically, they show that consumers do reduce their peak load in response to higher peak to off-peak price ratios. Another interesting piece of research in this regard is the paper by Gautier and Jacqmin (2018). In their study, they focus on the differences between the distribution network tariffs in place for different municipalities within Wallonia, the Southern region of Belgium, and its effect on solar PV adoption. Applying an econometric model, they find that one euro cent per kWh of tariffs increase leads to, all else being equal, an increase of around 5% in the number of new PV installations. In short, we are just at the beginning of this consumer-centric revolution, and we can expect that consumers will be able to react more and more to the way the network is priced. Active consumer can create opportunities but also risks regarding cost-efficiency and fairness.

- **Cost-efficiency:** We said that, until recently, there was not much gain to be made from cost-reflective tariffs as consumers were not able to react strongly to price signals.

- *Opportunity*: If an adequate cost-reflective tariff is set, consumers can adjust their consumption behaviour so that, for example, costly reinforcement can be avoided or postponed. A cost-reflective tariff will result in a benefit for active consumers and an overall lower total system cost.
- *Risk*: wrong network pricing can have more severe consequences in terms of cost-efficiency as consumers can react stronger to the way the grid is priced. For example, high volumetric network charges with net-metering could over-reward people installing solar PV and therefore overly incentivise the adoption of a technology leading to more of this technology installed than would be optimal from a system point of view.

- **Fairness:** We said that volumetric network charges were perceived as fair as high-usage correlated rather well with more affluent consumers.
    - *Opportunity:* If network charges are cost-reflective and consumers react to this tariff design, a reduction of the total cost to satisfy the electricity needs of all consumers could be realised. These gains could be shared with passive consumers thus actually leading to a situation where everyone is better off.
    - *Risk*: If the distribution network tariff is not cost-reflective and distortive, consumers can react to the way the tariff is designed and exploit privately-beneficial opportunities without such actions having any system benefit. Such a situation would lead to a fairness issue as other grid users will have to contribute more in order to recuperate all grid costs as illustrated by the net-metering example at the start of this section.

Consumers being able to react to the way the network is priced also has implications regarding the third principle we addressed: cost-recovery. Until recently, with volumetric network charges in place it was relatively easy to estimate the future consumption and thus to calculate the magnitude of the volumetric network charge needed to recover all the costs. With harder-to-forecast use of electricity and possibly more advanced network tariffs, the estimation of the tariff which will lead to the recuperation of the efficiently incurred grid costs is a more challenging task. Cost-recovery is also intertwined with the two other principles. The more consumers can actually reduce or increase the network costs due to their change in consumption, whether cost-efficient or not, the harder it becomes to determine what grid costs were efficiently incurred and thus to estimate the allowed revenue for the DSO. Also, political actions aimed at reducing fairness concerns which could result from an inadequate network tariff design could put grid cost recovery in danger.

Now, how can the network tariff be adapted to these changing conditions? It can be said that there are three dimensions of distribution network tariff design:

- the what – the structure or format (in €/kWh, €/kW, and/or €/connection);
- the when – electricity generation and consumption (temporal granularity);
- the where – electricity generation and consumption (locational granularity).

These three dimensions can be seen as the tools that can be used to construct a tariff. There are many possible variations within the tariff structures, and the boundary between the different structures is not strict. Below in Table 1, several examples of more simple or advanced tariffs, categorised by tariff structure but with different implementation or temporal granularity are summarised. Please note that also combinations (so-called multi-part tariffs) can be opted for.

Table 1: Examples of implementations and different tariff structures with possible different temporal granularity

Volumetric	Capacity	Fixed
With net-metering	The connection (kVA)	Per connection
Gross withdrawal or bi-directional charges	The max capacity over a period (ex-ante determined or ex-post measured)	Per income of household
Increasing (progressive) or decreasing block pricing	Multiple measured max capacity in different periods ≈ Time-of-use pricing	Per square meters of property
Time-of-use pricing	…	…
…		

Another innovation in distribution network tariff design are **Smart Connection Arrangements (SCA)**. Anaya and Pollitt (2015) explain that an SCA implies that grid users, mainly new connections for distributed generation such as a windmill connected to the distribution network, have interruptible connections rather than the conventional non-interruptible or firm connections. The idea is that grid users with an SCA would have to pay fewer grid charges as they allow the DSO to curtail their connection for a pre-determined amount of time. By limiting these connections at times of possible network congestion, the DSO can avoid or postpone reinforcement. Thus a win-win situation results. Anaya and Pollitt (2015) show that the smart connection option is by far the best option when compared with Business as Usual (BAU) connections. Hadush and Meeus (2017) discuss another alternative to deal with congestion in distribution grids, namely tradable access rights between TSOs and DSOs or other borders in the distribution grid.

1.4 What is the EU debate about?

On 30 November 2016, the European Commission presented a new package of measures with the goal of providing the legislative framework needed to facilitate the clean energy transition – and thereby taking a significant step towards the creation of the Energy Union. This package was called the EU Clean Energy Package (CEP), also known as the Winter Package. As expected, distribution network tariffs are covered by the CEP. In Article 16(10) of the proposal by the EC for the Regulation on the Internal Market for Electricity (IME) it is said that (EC, 2016b):

'*Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. In particular, they shall be applied in a way which does not discriminate between production connected at the distribution level and production connected at the transmission level, either positively or negatively. They shall not discriminate against energy storage and shall not create disincentives for participation in demand response. Without prejudice to paragraph 3, those charges shall not be distance-related*.'[15]

[15] Paragraph 3: '*Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals at Union level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure*.'

Also, the CEP brings new proposals for distribution tariffs harmonisation and links them to the transmission tariffs harmonisation process. While the harmonisation of transmission tariffs has been debated in the past (see e.g. ECN et al. (2017) and Glachant et al. (2017)), the harmonisation of distribution tariffs has not had a similar focus over the last years. The EC argues that harmonising the principles for distribution tariffs will help the establishment of a well-functioning internal market and limit its cross-border distortions. More precisely, the EC (2016a) states that widely divergent distribution tariff regimes may affect the development of the internal market as they affect the conditions under which Renewable Energy Sources (RES) or other generation resources can access the grid and participate in the national and cross-border energy markets.

In the CEP, the EC proposal for the Regulation on the IME suggested new rules for the harmonisation of the distribution tariffs (EC, 2016b). Concretely, in Article 55(1)(k) the harmonisation of distribution tariffs is added to the areas to be covered by Network Codes:

Article 55: '1. The Commission is empowered to adopt delegated acts in accordance with Article 63 concerning the establishment of network codes in the following areas:

…

*(k) harmonised transmission and **distribution tariff structures** and **connection charges** including locational signals and inter-transmission system operator compensation rules';*

….

Further, for the progressive convergence of transmission and distribution tariff methodologies, Art. 16 (9) of the EC proposal for the Regulation on the IME states that ACER shall provide a recommendation addressed to NRAs within three months of the Regulation entering into force (EC, 2016b). Several questions should be addressed in the recommendation such as the ratio of tariffs applied to producers and to consumers, temporal and locational signals and the relationship between transmission and distribution tariffs.

In the meantime, the Council of the European Union published a provisional position on this proposal which forms the basis for the negotiations with the European Parliament (EU Council, 2017). It is important to note that in this proposal the adoption of a network code for distribution network tariffs has been removed. Plus, it is stated that within three months of entering into force of the Regulation, '*the Agency shall provide a best practice report on transmission and distribution tariff methodologies while leaving sufficient room to take national specificities into account.*' A best practice report is expected to send a weaker signal for harmonisation than recommendations.

Like the Council, not everyone agrees with drafting a network code for the harmonisation of distribution network tariffs. CEER (2017b) clearly opposes this, stating: '*The impact assessment published by the Commission (EC, 2016a) does not provide any justification that the benefits of further harmonisation of tariffs would outweigh the costs for implementation. We consider that harmonisation of both transmission and distribution tariffs at European level could be inefficient and not lead to the right outcomes for European consumers. NRAs are best placed to consider the best regulatory choices within the European framework. Implementing a "one size fits all" approach risks inefficient incentives for network use on a Member State level, particularly with the emergence of more local energy models.*'

EDSO, one of the main organisations representing the DSOs in Europe, agrees with CEER on this point by stating: '*Network and geographical characteristics are very diverse throughout Europe, leading to diverging best practices in terms of network tariffs structures. Network codes do not seem to be the right tool to efficiently enhance distribution tariff structures at European level*.'

Another stakeholder, REScoop (2017), representing energy communities in Europe, provides a more nuanced view about the harmonisation of distribution grid tariff by saying: '*the Electricity Directive should provide national regulators with a duty to ensure that network tariffs for DER are calculated according to an objective and transparent long-term cost-benefit analysis (CBA) that takes into account the wide range of benefits of DER to the energy system, society and the environment. To ensure a holistic approach towards such an analysis, the Electricity Directive must provide a definition of DER.'*
Finally, BEUC (2017) the consumer voice in Europe, recommends the following: '*Network tariffs should better reflect real use of the grid. They should be redesigned in order to reward flexibility and trigger contribution of ancillary services by consumers who engage in self-generation or demand-side flexibility. However, the redesign of network tariffs must not unduly increase the financial burden of households with a low level of electricity consumption or households living in remote areas.*'

2. Network Codes

2.1 Setting the scene: this is just the beginning

The Third Energy Package (Regulation (EC) 714/2009) has led to the development of eight network codes and guidelines which are split up into three groups: the grid connection codes (RfG NC, DCC NC and HVDC NC), the market guidelines (CACM GL, FCA GL and EB GL) and the system operation codes (SO GL and ER NC). All codes and guidelines entered into force by 2017 at the latest, after a 4-year co-creation process by the European Network of Transmission System Operator for Electricity (ENTSO-E), the Agency for the Cooperation of Energy Regulators (ACER), the European Commission (EC) and many other stakeholders from across the electricity sector. These codes and guidelines are a detailed set of rules pushing for the harmonisation (of previously nationally oriented) electricity markets and regulations.

However, just because the codes and guidelines have entered into force does not mean that all the work is done. In many articles of the guidelines (CACM GL, FCA GL, EB GL and SO GL) principles are described that serve as foundations for terms, conditions and methodologies (TCM) which will be developed according to predefined deadlines. The final form of the TCMs is not set in stone and will continue to be discussed in the coming years when nearing the deadlines. Methodologies are mostly developed at Pan-European scale or Regional scale by Transmission System Operators (TSOs) or Nominated Electricity Market Operators (NEMOs).[16] Usually, a public consultation is held before the methodology is submitted to the relevant National Regulatory Authorities (NRAs) to allow for stakeholder involvement. The relevant NRAs can approve, ask to amend or reject the methodology. If the NRAs do not reach an internal agreement on whether to approve the methodology, the decision is handed over to ACER. An overview of the methodologies submitted before May 2017 is displayed in Figure 7. ENTSO-E's tasks, also shown in the figure, are mostly related to monitoring, stakeholder involvement and reporting.

Figure 7: Status of the methodologies within the network codes and guidelines in May 2017 (ENTSO-E, 2017b)

[16] NEMOs are power exchanges certified to organise cross-zonal electricity trade.

There is a different implementation process in place for connection codes (RfG NC, DCC and HVDC NC). In these cases, the Member States have an obligation to implement the codes no later than three years after their entry into force. Within this timeframe, the relevant system operators or TSOs have two years to define and submit proposals for national specifications regarding the so-called non-exhaustive requirements as shown in Figure 8. These proposals are submitted for approval to the relevant NRAs (ENTSO-E, 2018). Finally, exactly three years after the entry into force and onwards, all impacted grid users have to comply with the Regulations.[17]

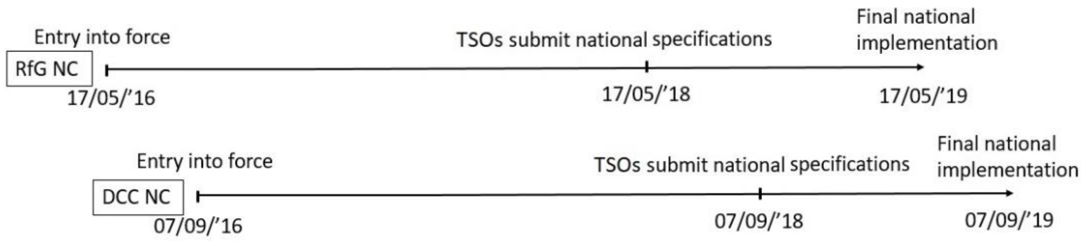


Figure 8: Timeline for the Requirement for Generators Network Code (RfG NC) and Demand Connection Network Code (DCC NC)

Furthermore, these eight existing network codes and guidelines are the first of their kind, and it is very probable that there are many more codes and guidelines to come. In its EU Clean Energy Package (CEP) issued in November 2016, the EC proposed a recast of Regulation (EC) 714/2009. In Article 55 of the recast of the Regulation on the Internal Market for Electricity (IME) a list of areas concerning the establishment of (new) network codes is given (EC, 2016b). The list is shown below. The underlined text refers to newly added text or areas when compared to the Third Energy Package. It should be noted that the European Council in their position removed distribution tariff structures and connection charges in point (k) and fully removed points (n) and (p) from the list of areas for network codes. The Council also amended the text of several other areas to make the exact topics covered within each area more explicit (EU Council, 2017).

Art. 55(1) of the Regulation on the IME as in the proposal by the EC:
'The Commission is empowered to adopt delegated acts in accordance with Article 63 concerning the establishment of network codes in the following areas:

(a) network security and reliability rules including rules for technical transmission reserve capacity for operational network security;

(b) network connection rules;

(c) third-party access rules;

(d) data exchange and settlement rules;

[17] The grids users subject to the connection codes are new power-generating modules, new demand facilities or new HVDC connections. 'New' means that the grid user has concluded the final and binding contract for the purchase of the main elements of its power-generating modules, demand facility or HVDC connection later than two years after the entry into force of the Regulation. Exceptionally, also 'existing' power-generating modules, demand facilities or HVDC connections can be asked to comply with the connection codes by the relevant NRA or the Member State. Such a request would be based on the evolution of system requirements and a full cost-benefit analysis, or where there has been substantial modernisation of those facilities. For more information about the scope the grid connection codes please see Art. 3 and 4 of the RfG NC, Art. 2 and 3 of the DCC and Art. 3 and 4 of the HVDC NC.

(e) interoperability rules;

(f) operational procedures in an emergency;

(g) capacity-allocation and congestion-management rules including curtailment of generation and redispatch of generation and demand;

(h) rules for trading related to technical and operational provision of network access services and system balancing;

(i) transparency rules;

(j) balancing rules including network-related reserve power rules;

(k) rules regarding harmonised transmission and distribution tariff structures and connection charges including locational signals and inter-transmission system operator compensation rules;

(l) energy efficiency regarding electricity networks;

(m) rules for non-discriminatory, transparent provision of non-frequency ancillary services, including steady state voltage control, inertia, fast reactive current injection, black-start capability;

(n) demand response, including aggregation, energy storage, and demand curtailment rules;

(o) cyber security rules; and

(p) rules concerning regional operational centres.'

Additionally, the CEP includes provisions that would modify the governance of the network codes and guidelines. In detail, the CEP provisions attempt to alter the amendment process for existing network codes/guidelines, and the drafting process for newly introduced network codes.[18]

This text aims to demonstrate that while network codes and guidelines imply certain obligations for all relevant parties, they also create opportunities. We illustrate this on the basis of a discussion regarding the balancing mechanism which is impacted by the Electricity Balancing (EB GL) and the System Operation Guideline (SO GL). Both guidelines entered into force recently, respectively on 18 December 2017 and on 14 September 2017. The first drafts of the methodologies comprised within these guidelines are being discussed at the moment. The final implementation of all that is covered in these guidelines is expected to take until 2023 or later (ENTSO-E, 2017c).

In this text, we first look at balance responsibility, which is an obligation that could imply a cost for many grid users. However, depending on the workings of the different markets preceding the balancing mechanism and the specific design of the imbalance settlement mechanism, this cost can be better controlled and possibly even turned into a revenue opportunity. Also, we highlight what the network codes and guidelines and the CEP state about who should be balance responsible. Second, we focus on the 'supply side' of the balancing mechanism. More specifically, we discuss how the market design rules governing the balancing markets affect not only the efficiency of the balancing mechanism but also the possibility for different players to participate in these markets. Finally, we take a look at

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

the total balancing costs in different Member States. We discuss the recuperation of these costs and the relative importance of balancing capacity (reservation) versus balancing energy (activation) costs.

2.2 Obligations in balancing: balance responsibility

In this section, we will first provide a more detailed explanation of imbalances, imbalance prices and the imbalance settlement. While describing the process of trading in the day-ahead market up to the imbalance settlement, we show that choices in market design parameters can impact the costs (or possibly revenues) of Balance Responsible Parties (BRPs). A BRP is defined as a market participant or its chosen representative that is responsible for its imbalances. We finish this section by summarising what is said in the existing network codes and guidelines and the CEP regarding who should be balance responsible.

2.2.1 From trading to imbalance settlement: process and market design parameters

In a power system, generation needs to equal load at every point in time. If at a certain point in time, the load is higher than electricity generated (or vice-versa), the frequency of a system will start to drop (rise). It is undesirable that the frequency deviates from its set point, 50 Hz in Europe or 60 Hz in the US, because protection systems from load and generation which detect such deviation in frequency will disconnect from the central grid to avoid damage to the devices. Such actions will lead to a further frequency drop or rise and can end up in a cascade failure and black-out.

Electricity markets are designed to deal with this particularity. Different types of electricity markets are arranged in sequential order, starting years before the actual delivery and ending after the actual delivery, in which market participants can trade and sell depending on their possibly changing offers or needs. The balancing market comes at the last step to ensure that generation equals demand. The balancing market is operated by the TSO as it is the TSO who is responsible for ensuring the system is in balance per control area.[19] If an imbalance occurs very near to real-time, the TSO has to instruct resources, termed Balancing Service Providers (BSPs), to reduce or raise their generation or load in order to restore the system balance.

Figure 9 provides an example of what is meant by an imbalance. The viewpoint of a (net) electricity buyer is illustrated; the same principles apply for a (net) electricity seller. Before explaining the figure, we introduce the Imbalance Settlement Period (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, a shorter ISP helps the TSO to control the system balance; 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 Art. 53, the EB GL states that by three years after the entry into force (18 December

[19] A control area can be defined as a coherent part of the interconnected system, operated by a single TSO. A control area should not be confused with a bidding zone. A bidding zone is defined as the largest geographical area over which market participants can trade electricity without capacity allocation. For example, in Belgium, the control area operated by Elia equals the bidding zone. This is the case in a majority of European countries, e.g. France, the Netherlands, Spain and Portugal, but is not a standard rule. For example, in Germany there are 4 control areas, operated by TenneT Germany, 50Hz, Amprion and TransnetBW but only one bidding zone (together with Austria and Luxembourg). Alternatively, in Sweden there is one control area operated by Svenska Kraftnät but there are 4 bidding zones.

2020), 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.[20] In both cases, every three years it needs to show ACER that the benefits of having an unharmonised ISP outweigh the costs.[21] For simplicity, in Figure 9 the ISP is assumed to be one hour.

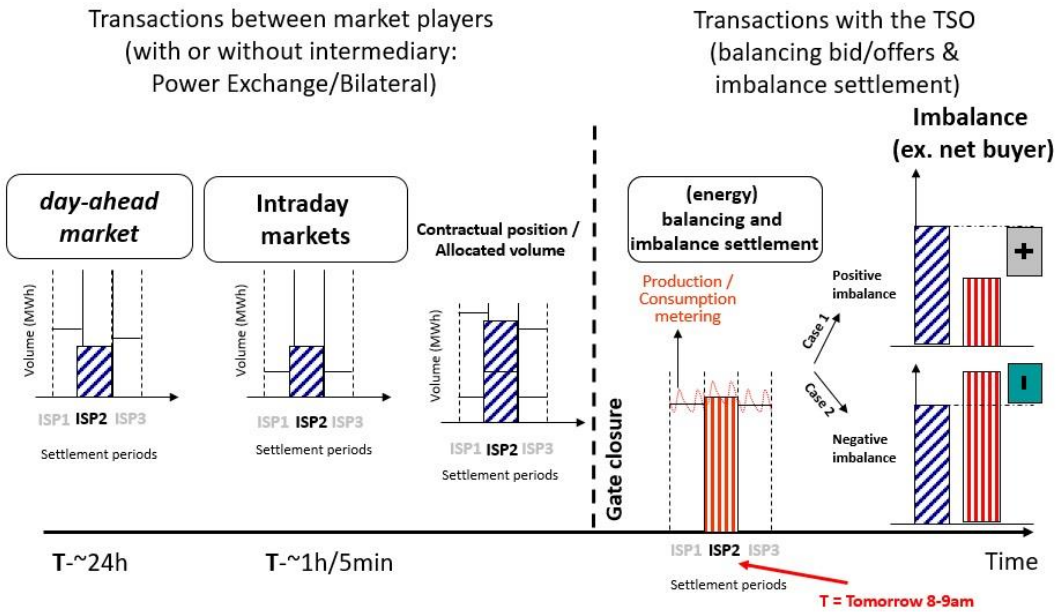


Figure 9: The sequence of electricity markets and the calculation of an imbalance (example for a buyer of electricity). Source: FSR (2018)

An example of a sequence of transactions of an electricity buyer is shown in Figure 9. In this example, we are focusing on the energy block for tomorrow between 8 and 9 am. When looking at Figure 9 chronologically, it can be seen that the market participant first buys a certain volume of electricity in the day-ahead market (DAM) for tomorrow between 8 and 9 am. Then, a couple of hours before 8 am, the market participant realises that she will need more electricity during that time-block and she buys an additional volume in the intraday market (IDM). An important parameter prerequisite for being able to control ones' imbalance volume is the possibility to trade in a **liquid intraday market**.[22] If the intraday market does not function well, BRPs will not be able to hedge themselves adequately against real-time imbalances. Also product design of the intraday market matters, namely it is important that **the products traded in the intraday should have at least the same temporal granularity as the ISP**. In the example in Figure 9, the granularity of the products in the DAM and IDM equal the ISP, namely one hour. But, imagine an ISP of 15 minutes while there are only hourly products being bought and sold in the intraday market. It will become costlier for a market participant to hedge a crucial 15 minutes as she will have to buy or sell a full hour block of energy to do so. In a recent paper, Ocker and Ehrhart

[20] There are 5 synchronous areas in Europe: Continental Europe, the Nordics, the Baltics, the UK and Ireland.

[21] The CEP proposal by the EC states that the imbalance settlement period shall be 15 minutes in all control areas by 1 January 2025 without exemptions (Regulation on IME, Art. 7(4)). The Council's proposal adjusts this Article by stating that by 1 January 2021, the imbalance settlement period shall be 15 minutes in all scheduling areas and the same exemptions as in the EB GL Art 53 hold.

[22] On the one hand, one could argue that BRPs need a liquid intraday market in order to be able to adjust their positions. On the other hand, one could also argue that making more grid users balance responsible will help to make the intraday market more liquid.

(2017) argue that the introduction of an intraday auction with 15-minute products in Germany in 2014 helped to allow more precise scheduling of variable RES and other generation technologies and led to a significant reduction in overall balancing costs. In that regard, the EC proposal for the Regulation on the IME states in Art. 7(2) that market operators 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.[23]

Finally, when the intraday market closes, the market participant has to notify the TSO about his allocated volume (contractual position) which is, in this case, the sum of the electricity bought in the DAM and IDM. The time when the intraday market closes is called the gate closure time and is the moment when trade between market participants is no longer possible, and the TSO takes over (typically one hour up to one minute before real-time). The **intraday gate-closure time** is an important parameter. The closer to real-time the intraday gate closure takes place, the better the final forecast for generation and consumption. The intraday gate closure time is a trade-off between on one hand, the 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 on the other hand, providing TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security. The Capacity Allocation and Congestion Management Guideline (CACM GL), covering the workings of the DAM and IDM and their integration, states in Art. 59(3) that the intraday cross-zonal gate closure shall be at most one hour before the start of the relevant market time unit. It should be noted that the gate closure for intraday trade within a bidding zone can be different than the intraday cross-zonal gate closure time.

Finally, in real-time, the market participant will consume more or less than the allocated volume as it is hard to predict accurately the actual consumption. The imbalance, the net difference between the allocated volume and the actual physical consumption/generation of the BRPs between 8 and 9am, can be calculated. Two cases can occur:

- In case 1, the market participant bought more electricity than she actually consumed during the hour. In that case, the market participant has a positive imbalance or is ‘long’.
- In case 2, the market participant consumed more electricity during the hour than she actually bought. In that case, the market participant has a negative imbalance or is ‘short’.

Ideally, through the imbalance settlement, the balancing cost is reflected to the imbalanced BRPs. In this respect, the **imbalance settlement rule** is an important design parameter. Broadly speaking, there are two options for the imbalance settlement rule: **dual pricing and single pricing**. Under dual pricing, when the individual imbalance of a BRP is in the same direction of the system imbalance, thus the imbalance is aggravating the system imbalance, the imbalance settlement is linked to the cost of balancing energy. However, the reverse price, meaning the price a BRP sees when his individual imbalance is in the opposite direction of the system imbalance and its imbalance is thus helping to restore the system balance, is often linked or capped by a reference or day-ahead market price. This means that the incentive to help the system is limited under dual pricing. Contrarily, under single

[23] This would imply that also 15-minute products are foreseen to be traded in the day-ahead market while currently only hourly products are available.

pricing, the BRP does receive the imbalance price linked to the cost of balancing energy when the individual imbalance of the BRP is helping to restore the system imbalance.[24] Thus, single pricing gives an incentive for BRPs to support the system balance, while with dual pricing the idea is rather to make sure that BRPs balance their own positions, independently of the system's state.

Single pricing is generally accepted as the superior method in the academic literature. An important argument is that dual imbalance pricing discriminates against smaller players. Namely, larger players can aggregate imbalances within a portfolio to lower their total balancing costs under dual pricing (Neuhoff et al., 2015). This is not possible with single pricing. Furthermore, the dual price imbalance design is reputed to be less cost-reflective than the single price design (Newbery, 2006). Lastly, imagine a market party with random uncontrollable imbalances fluctuating around zero, which are completely uncorrelated with the system imbalance and with the system imbalance also being random and fluctuating around zero. In that case, under single pricing, the total imbalance cost of that BRP will net out, while this is not the case under dual pricing in which the total imbalance cost will be positive. Actually, single pricing can create a revenue opportunity for BRPs as they could engage in passive balancing, i.e. having an imbalance in the opposite direction of the system imbalance.

However, passive balancing is only feasible if **close to real-time information is available about the system balancing state** as this is key information for BRPs to anticipate the system state. Fernandes et al. (2016) explain that the Netherlands is an example of best-practice as all information regarding activated reserve volumes and prices is published two minutes after reserve activation. They add that the **length of the ISP** matters in this respect as a shorter ISP facilitates the anticipation of the final system balancing state. This can be explained by the fact that over longer settlement periods it is more likely that both upward and downward reserves are activated. There are also arguments in favour of dual pricing over single pricing. Brijs et al. (2017) 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 recurring issue.

Regarding this rule, the network codes are intended to drive harmonisation. Art. 52(2) of the EB GL is relevant. 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

[24] Typically, in case the system is short, the imbalance price will be higher than the price that could be obtained in preceding markets. Vice-versa for when the system is long.

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.'

Generally, the larger a system imbalance during a particular ISP, the larger the spread between the day-ahead (or intraday) price and the imbalance settlement. If BSPs are paid the marginal price for being activated by the TSO and this price is reflected by the imbalance settlement, more correct signals will be sent to BRPs about the costs or value of their imbalances. Marginal pricing is not always applied today, instead, often the imbalance price is computed as the average cost of balancing actions. There are also 'hybrid solutions', as for example is done in Great Britain (GB). More specifically, in GB the imbalance price is equal to the average price of the most expensive X MWh of balancing purchases during a settlement period. With X being historically 500 MWh but converging to 1 MWh in the winter of 2018.[25]

2.2.2 Balance responsibility in the Network Codes and Guidelines

None of the electricity network codes and guidelines explicitly mention who should be balance responsible under which conditions. However, in the EB GL Art. 18(6) it is stated that no later than six months after the EB GL enters into force (18 June 2018) a proposal regarding the terms and conditions for BRPs should be submitted. The relevant TSO(s) shall submit a proposal for all scheduling areas of the Member State to the NRA. It is interesting to note that this proposal shall contain the **definition of balance responsibility for each connection** (in a way that avoids any gaps or overlaps in the balance responsibility of different market participants providing services to that connection). It is also important to add that 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.

2.2.3 Balance responsibility in the CEP proposal

On balance responsibility, Art. 4(1) of the Regulation on the IME as proposed by the EC indicates in its first paragraph that '***all market participants shall aim for system balance** and shall be financially responsible for imbalances they cause in the system. They shall either be balance responsible parties or delegate their responsibility to a balance responsible party of their choice.*'

Art. 4(2) of the same recast specifies that **Member States may provide derogation** from balance responsibility and allow a grandfathering clause for some existing installation, more precisely:

(a) demonstration projects;

(b) generating installations using renewable energy sources or high-efficiency cogeneration with an installed electricity capacity of less than 500 kW;[26]

[25] For more information about the GB practice, please see Box 7 in Meeus and Schittekatte (2018).
[26] The Council proposal lowers this capacity to 250 kW.

(c) installations benefitting from support approved by the Commission under Union State aid rules pursuant to Articles 107 to 109 TFEU[27]*, and commissioned prior to [OP: entry into force]. Member States may, subject to Union state aid rules, incentivize market participants which are fully or partly exempted from balancing responsibility to accept full balancing responsibility against appropriate compensation.*

The third paragraph of Art. 4 adds that from 1 January 2026, the point (b) of paragraph 2 shall apply only *to generating installations using renewable energy sources or high-efficiency cogeneration with an installed electricity capacity of less than 250 kW*[28] according to the point 3 of the same article.

The proposal by the Council adds to Article 4(2) that when a Member State chooses to provide a derogation according to Article 4(2), they need to ensure that the financial responsibilities of imbalances are fulfilled by another party. For a full overview of the different positions of the EC, Council and European Parliament (EP) regarding balance responsibility, please consult the presentation by the EC (2018).

2.3 **Opportunities in balancing: an additional revenue stream**

While in the previous section we described the 'demand side' of the balancing mechanism, in this section we will describe the 'supply side'. More specifically, we explain how BSPs can offer balancing capacity and energy in markets operated by the TSO. This section is structured as follows. First, we explain how the physical process of system balancing works, while also covering why there are different types of balancing resources. Second, we introduce the two (interrelated) balancing markets: the balancing capacity and balancing energy market. Finally, we discuss important market design parameters of these markets.

2.3.1 How balancing works: the different categories of reserves

Figure 10 shows how the frequency of a system is restored after a frequency deviation. It should be noted that the activation process shown in this figure is the typical activation process for a TSO with a reactive approach to the activation of balancing energy.[29] It can be seen that for this purpose different types of reserves are activated sequentially. These **different types of reserves meet different operational needs; in practical terms, they differ mainly in response time and maximum duration of delivery**. The types of reserves which can be grouped under three processes are summarised in Table 2, the nomenclature as used in the SO GL is applied. Previously, different denominations existed. To clarify, these older denominations are also added.

[27] Treaty on the Functioning of the European Union.
[28] The Council proposal lowers this capacity to 150 kW.
[29] For further explanation of this concept, please see Section 6.4 of Meeus and Schittekatte (2018) or the paper by Haberg and Doorman (2016).

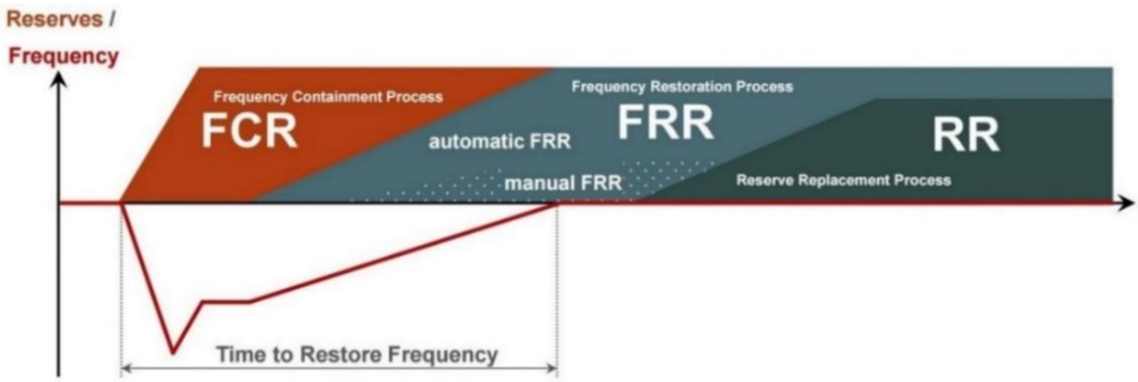


Figure 10: A frequency drop and the reserve activation structure (Elia and TenneT, 2014)

	Frequency containment process (FCP)	Frequency restoration process (FRP)		Reserve replacement process (RRP)
Operational reserves defined by SOGL	**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

Table 2: Terminology for reserve products (based on E-Bridge and IAEW (2016))

Figure 10 shows the occurrence of a frequency drop; a frequency drop is caused due to a deficit of energy in the system, i.e. there is more consumption or less generation than scheduled in real-time. Vice-versa, the frequency would rise. The first source limiting the frequency drop is inertia. Inertia is not depicted in Figure 10. Inertia is an inherent physical property of, for example, turbines.[30] Inertia slows down a frequency drop/spike immediately after a mismatch between supply and demand and does not need any control signal. In other words, with little inertia a small difference in supply and demand can cause a very steep frequency drop/spike. Inertia was always valuable for the system, but it was mostly provided for free as it was abundant in the recent past. However, due to the penetration of DER, there are increasingly times when not many thermal power plants are connected. Consequently, during those moments system inertia and thus reliability decreases. This is a particular concern for smaller or isolated synchronous systems. To address this issue, there are also methods being developed to obtain inertia from sources other than thermal power plants, so-called 'synthetic inertia provision'.[31] In the Art. 21(2.a) of the RfG NC is stated that the relevant TSOs has the right to require synthetic inertia provision from larger power park modules (type C or D).[32]

System inertia slows down the drop/rise in frequency but does not stop the drop/rise. Therefore, almost immediately from the moment the frequency drops/spikes, **Frequency Containment Reserves (FCR)** are activated to stabilise or 'contain' the drop/spike. FCR are the fastest type of reserves and are

[30] In Art. 2 (33) of the RfG NC inertia is defined as '*the property of a rotating rigid body, such as the rotor of an alternator, such that it maintains its state of uniform rotational motion and angular momentum unless an external torque is applied* '. In the same network code also the requirements regarding inertia provision are covered.

[31] in the RfG NC is stated that TSOs can require synthetic inertia provision from larger power park modules (type C or D), see Art. 21(2.a). For more information, see also the short video by the North American Electric Reliability Corporation (NERC) explaining concepts as frequency and inertia: https://vimeopro.com/nerclearning/erstf-1/video/146105419

[32] The RfG NC provides maximum thresholds for the classification of power-generating modules in four categories, A to D (small to large). These maximum thresholds differ per synchronous area. The final thresholds used for the classification are decided on a Member State level (see Art. 5 of the RfG NC).

operated using a joint process involving all TSOs of the synchronous area. Within a couple of minutes after the activation of FCR, the Frequency Restoration Process (FRP) starts. First, **automatic Frequency Restoration Reserves (aFRR)** and later **manual Frequency Restoration Reserves (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. The FRP aims to restore the frequency to its nominal value. Finally, after about 15 minutes or more, **Replacement Reserves (RR)**, the slowest type of reserves, can be activated to support or replace FRR. Not all systems have a Reserve Replacement Process (RRP) in place, and this process is not made mandatory by the SO GL.

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. The EB GL and the SO GL intend to harmonise most elements of the balancing mechanism which also paves the way for more cross-zonal exchange of balancing resources.

2.3.2 The balancing markets

It can be said that two (interrelated) 'balancing markets' exist: balancing capacity markets and balancing energy markets. In this subsection, first, the balancing capacity market is introduced. After, the same is done for the balancing energy market. Then a (non-exhaustive) list of important market design parameters of these markets is discussed. Market design could affect the costs for balancing the system and also the opportunities for different players to generate revenues in these markets.

Balancing capacity market

In the balancing capacity markets, **BSPs are paid in order to reserve capacity for the duration of the contract**. This implies that a BSP cannot commit this capacity to other markets (such as the DAM or IDM). Reserved balancing capacity is expected to be available in real-time, i.e. they have to bid in real-time balancing energy markets. If not, they will have to pay a fine. This does not mean that BSPs, who sold balancing capacity, will finally have to deliver the balancing energy. The activation of balancing energy only occurs when in real-time the balancing energy bid is accepted by the TSO. The idea behind reserving balancing capacity for the different reserve types is to make sure that there is always an adequate safety margin, i.e. enough available back-up balancing resources to deal with unexpected events.

In the balancing capacity market, BSPs offer upward and/or downward balancing capacity. Upward balancing capacity means that a BSP will reserve a margin 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. Balancing capacity markets can take place from months ahead to one day before the actual time of (possible) delivery of the balancing energy. The timing may differ per type of reserve. In general, there are different markets for the different types of reserves (FCR, aFRR, mFRR and possibly RR). Also, there are possibly different products per type of reserve. The demand for reserves procured in the balancing capacity market is determined in the reserve sizing process, i.e. an analysis conducted by the TSO (coordinated or not with other TSOs) to estimate the necessary reserves of each balancing product in real-time.

Balancing energy market

Real-time system imbalances drive the demand for the activation of balancing energy. 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. Upward and downward balancing energy bids for aFRR, mFRR and RR have to be submitted before the balancing energy gate closure time. In most cases the activation of FCR is not remunerated, only its reservation is paid. Van den Bergh et al. (2018) explain that when FCR is symmetric (offering jointly fast upwards and downward energy), its activation is generally not remunerated because (short and fast) activations in both directions would eventually cancel out the payments.

BSPs contracted in the balancing capacity market are expected 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)). Exceptionally, for specific balancing energy products, it is possible to request that this rule is not applied. 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, the balancing energy market bid can be very high in order to avoid commitment. This way the relevant bidder still earns a balancing capacity payment.[33] Other BSPs, without contracted balancing capacity, may also bid in the balancing energy market. Finally, if justified, TSOs have the right to compel BSPs to offer their resources as balancing energy when these resources are not committed in other preceding markets (EB GL, Art. 18(7)).

Key market design parameters of balancing markets

The design of balancing products and the way that balancing markets are organised can enable the participation of new players or hamper their access to these markets. However, before being able to participate in the balancing markets, balancing resources need to go through a **prequalification process**. Most new players, such as RES or demand response are not connected to the transmission network but instead to the distribution network. In that respect, in Art. 182(4) of the SO GL it is specified that '*during the prequalification of a reserve providing unit or group connected to its distribution system, 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 its distribution system, based on technical reasons such as the geographical location of the reserve providing units and reserve providing groups*.' Additionally, in the same article in paragraph 5 it is stated that '*each reserve connecting DSO and each intermediate DSO shall have the right, in cooperation with the TSO, to set, before the activation of reserves, temporary limits to the delivery of active power reserves located in its distribution system*.'

When being qualified for participating in the balancing markets, the design of the balancing products is of importance. An interesting report in that regard is the (yearly) monitoring report on explicit demand response in Europe by SEDC (2017).[34] Examples of crucial balancing product characteristics are:

- ***Minimum bid size***: In the DAM and IDM this parameter is not considered as restrictive as it is set low enough (Agora, 2016). However, in balancing markets, limits are often a lot higher, e.g. for aFRR, the minimum bid size ranged from more than 5 MW in Norway to 1 MW in Belgium in 2016. A lower minimum bid size lowers the entry barriers for new players in the balancing

[33] Such market behaviour is rather unlikely although not impossible in practice.
[34] Recently the SEDC, which stood for the Smart Energy Demand Coalition, changed its name to SmartEn.

market. It should be added that higher minimum volume requirements can be compensated for if aggregation is allowed.

- ***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 variable RES, storage and demand response may be able to participate in the balancing capacity market. Examples of the contract periods for different countries as in 2015 are shown in Figure 11. In that regard, the CEP, more specifically the EC proposal for the Regulation on the IME adds in Art. 5(9) that the maximum balancing capacity contract period shall be one day.

		Belgium	France	Germany	The Netherlands
General	Control areas	1	1	4	1
	TSO	Elia	RTE	50 Hertz, Amprion, TenneT, TransnetBW	TenneT
	Market period	15 min.	30 min.	15 min.	15 min.
Procurement	FCR contract period	Weekly	Mandatory	Weekly	Weekly
	aFRR contract period	Weekly	Mandatory	Weekly	Yearly
	mFRR contract period	Monthly/yearly	Mandatory	Daily (4 h)	Yearly

Figure 11: Contract duration of balancing capacity in four countries as it was in 2015 (Brijs et al., 2017)

Art. 25(4) of the EB GL provides a list of **characteristics for standard products** in the balancing capacity (and energy) market. Examples of characteristics listed other than those already mentioned include the ramping period, i.e. determining how fast a BSP should be able to respond when activated, and, very importantly, the maximum duration of one activation. Other than 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)).

All TSOs have to come up with a proposal for parameter values of these **characteristics of standard products** per reserve type (EB GL, Art. 25(2)). Standard products will allow a more fluid 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 as necessary and non-distortive. Every two years an assessment is made about whether these conditions still hold (EB GL, Art. 26).

Also of importance, and related to the contract period, is **the time-lag between the gate closure of the balancing capacity market (the last moment a bid can be submitted) and the start of the contract period in which balancing energy should be offered to the balancing energy market**. This time-lag can vary from a day to months and may differ by type of reserve. The time lag has an impact on how easy it is for market parties to estimate their opportunity cost, the closer to real-time the better forecasts become, and how well a TSO can estimate its reserve needs. In this regard, Art. 32(2.b-c) of the EB GL states that the procurement process shall be performed on a short-term basis to the extent possible and where economically efficient, and that the contracted volume may be divided into several contracting periods. Art. 5(9) of the EC proposal for Regulation on the IME adds that '*the contracting shall be performed for not longer than one day before the provision of the balancing capacity*'. Further, it is clearly stated in the EB GL that the balancing energy gate closure time for standard products should be harmonised at the EU level.[35] In terms of timing, the EB GL states in Art. 24 that the **balancing energy gate closure time should not be before the intraday cross-zonal gate closure time and as close as possible to real-time.**

One other important choice is whether upward and downward balancing capacity/energy should be procured jointly, called 'symmetric balancing products', or separately, called '**asymmetric balancing products**'. It goes without saying that for some new players it might be easier only to offer balancing capacity/energy in one direction. For example, for a wind park, it might be possible to offer downward balancing capacity, meaning they would curtail part of the production. However, a wind park cannot as easily offer upward balancing capacity. When offering upward balancing capacity it would mean that the turbines would constantly have to generate less than their maximum, thus missing out of electricity generation at near zero marginal cost. Therefore, it is important that Art. 32(3) of the EB GL requires that the procurement of upward and downward balancing capacity, at least for FRR and RR, shall be carried out separately. However, each TSO may submit a proposal to the regulatory authority for a temporary exemption to this rule. Such a proposal must include an economic justification. The EC proposal for the Regulation on the IME tends to go one step further by stating in Art. 5(9) that '*the procurement of upward balancing capacity and downward balancing capacity shall be carried out separately*'. It is assumed that this means that the balancing capacity for all reserve types, including FCR, should be procured asymmetrically.

Again, the **ISP is an important parameter**. Namely, in most balancing mechanisms, the ISP equals the market period of the balancing energy market (as also seen in Figure 11). The market period means the time unit over which balancing energy prices can fluctuate. The shorter this market period, the more flexibility will be valued.

Last but not least, the **settlement rule** for the balancing market is a point of discussion. Balancing prices can be regulated, or the balancing markets can be organised as auctions for which two settlement options are possible: **pay-as-bid or pay-as-cleared (marginal pricing)**. In the case of regulated prices, the prices are set by the regulator, and market participants (mostly large generators) are obliged to be available to offer balancing services. It can be seen in Figure 12 that the settlement rule was far from harmonised in 2015 when looking at different countries. Also, it can be seen that the balancing capacity and balancing energy market apply different rules.

[35] It is unclear whether there can be a different harmonised European balancing energy gate closure per reserve type. This query requires a legal view on EB GL Article 24(1).

		Belgium	France	Germany	The Netherlands
Procurement	FCR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	FCR activation	-	Regulated	-	-
	aFRR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	aFRR activation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-cleared
	mFRR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	mFRR activation	Pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-cleared

Figure 12: Settlement rule for balancing capacity and energy in four countries as it was in 2015 (Brijs et al., 2017)

From a purely theoretical point of view, applying pay-as-bid or pay-as-cleared should give exactly the same outcome. In practice, this is not expected to be the case. The main difference is that when pay-as-bid is applied, a bidder needs to estimate the price of the lowest accepted bid. To maximise its payoff, a market participant should bid that estimated price (if it is higher than its marginal costs). With pay-as-cleared, the optimal strategy for a market participant is to bid its marginal cost, under the condition that the market functions properly. If the market participant bids a price which is higher than its marginal costs, it can be that its bid is not accepted while a profit could be made. If the market participant bids a price which is lower than its marginal cost, it can be that the bid is accepted and a loss is made. From a system point of view, it could be argued that with pay-as-bid more market participants are expected to wrongly anticipate the price, and thus their bidding will lead to a less optimal scheduling of the available resources. **For new players in the balancing market, an important argument in favour of pay-as-cleared pricing is that when pay-as-cleared is used instead of pay-as-bid, the costs of forecasting the expected price can be saved.**[36] A counterargument for applying pay-as-cleared pricing in balancing energy markets are implementation issues. For example, a problem with pay-as-cleared specific to balancing energy markets arises when different products of different reserve types are used at the same time to solve an imbalance.

In the EB GL (Art. 30(1.a)) it is clearly stated that the **balancing energy markets should be based on 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)). This exceptional application of the pay-as-bid rule is no longer allowed in the EC proposal for the Regulation on the IME. Regarding the settlement rule in balancing capacity markets, no statement is found in the EB GL or the CEP. However, 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 it can be obliged to market parties to offer FCR at regulated prices.

2.4 Balancing costs in Europe: capacity versus energy

The balancing costs in several European Member State in 2016 are shown in Figure 13.

[36] For a more complete overview of arguments supporting pay-as-bid or pay-as-cleared, please consult Box 3 in Meeus and Schittekatte (2018).

Figure 13: Overall costs of balancing (capacity and energy) and imbalance prices over national electricity demand in a selection of European markets in 2016 (ACER and CEER, 2017b)[37]

Three observations can be made from Figure 13:

- 1.) The balancing costs can vary strongly from one Member State to another. Differences can occur, for example, due to the generation mix (flexible or not) and the degree of interconnection of a certain Member State. Please note that low balancing costs do not automatically imply that a balancing mechanism is well-functioning. Electricity markets are a sequence of markets; it could be that 'one segment' functions very well due to sacrifices in the efficiency of other segments. The whole sequence should be assessed as a whole.

- 2.) The balancing capacity costs significantly outweigh the balancing energy costs for almost all Member States.

- 3.) The recuperated costs of the balancing mechanism through the imbalance settlement is in most cases slightly higher than the cost of balancing energy but is not sufficient to cover the total balancing costs. The remainder of not-recuperated balancing costs is socialised over grid users through the transmission tariff.

Observations 2 and 3 are quite surprising. Observation 2 means that more money is being spent on reserving capacity ('the insurance') than on the actual delivery of energy. ACER and CEER (2016) describe two options to **lower the balancing capacity costs**. First, cross-border cooperation. Sharing of reserves ('risk pooling') and the exchange of balancing capacity (more efficient allocation of resources) could lead to lower costs. For a recent estimate of the welfare gains of cross-border cooperation in balancing capacity procurement see e.g. Baldursson et al. (2018). Second, a higher degree of participation of all technologies in the provision of balancing capacity, including variable renewables, storage and demand response, could lead to lower reservation costs. The EB GL seeks to support the realisation of both complementary solutions to lower the balancing capacity cost.

[37] Imbalance charges applied in the Nordic market are not included in the figure as data were not available for all Nordic countries. 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.

Observation 3 shows that less than the full cost of balancing is reflected through the imbalance settlement. Observations 2 and 3 are interrelated for the following reasons. Balancing capacity is reserved to make sure that, at all times, there are enough resources to balance the system in real-time. In fact, balancing capacity is dimensioned to deal with extreme events. During these extreme events, in most cases, only the balancing energy price determines the imbalance price for the unbalanced BRPs. However, those instances are the real reason that large balancing capacity needs to be reserved in the first place. Thus, why not reflect the reservation costs in addition to the balancing energy costs at times of an 'extreme event', the instances when the available reserves are scarce, and the system could be at risk? This is the idea behind **'scarcity pricing'** in the balancing energy market. This idea has already been implemented in some form in parts of the US under the name of Operating Reserve Demand Curve (ORDC), see, e.g. Hogan (2005) and Levin and Botterud (2015), and under the name Reserve Scarcity Pricing (RSP) in the GB (Ofgem, 2015). Papavasiliou and Smeers (2017) analyse the implementation of a similar idea in the Belgian power system.

By applying scarcity pricing, imbalance prices could rise above the marginal cost of delivering balancing energy. In the GB implementation, the imbalance prices rise at moments of stress, but not the balancing energy prices paid to the BSPs activated at those moments. Although it is not the main objective of the mechanism, the difference between what is collected from the BRPs and paid to the BSPs can serve to partly recuperate the balancing capacity procurement costs. Also, with rising imbalance prices, BRPs are strongly incentivised to be balanced at moments of system stress. In the US implementation, both the imbalance prices and the balancing energy prices rise at moments of system stress. In that case, not only would BRPs be motivated to be balanced when it is really needed but also the BSPs would have a stronger incentive to be available at the moments when they are needed the most. **As such, very flexible resources (e.g. demand response) would be rewarded more correctly for their services if they are present when they are really needed. Thus, these resources would be more incentivised to participate in the balancing market and also investment in such resources would be incentivised.**

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. An issue, as stated in Hogan (2013), would be that it is very difficult if not impossible to distinguish scarcity prices from the exercise of market power. Please also note the difference between ORDC and a penalty added to the imbalance price as for example 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. The activation of high volumes of balancing energy does not necessarily imply a situation of system stress as there might be an even higher volume of reserves available at that point in time. Regarding 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, administrative costs and other costs related to balancing. 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.'

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