2. Who gets the rights to trade across borders?

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In this chapter we answer five questions. First, how to deal with historical privileges? Second, how to implement market-based allocation of transmission rights? Third, how to implement market coupling in the day-ahead timeframe? Fourth, what about the timeframes before day-ahead? Fifth, what about the timeframes after day-ahead?

2.1 HOW TO DEAL WITH HISTORICAL PRIVILEGES?

Historically, the rights to trade across borders were granted to utilities, often state-owned vertically integrated utilities. The First Directive 96/92/EC already stated that the newly established transmission system operators (TSOs) had to provide different network users with non-discriminatory access to their networks. Despite this provision, the historical privileges of the utilities were maintained. They had long-term contracts with neighbouring utilities that included transmission rights. These contracts, which pre-dated the market integration process, had not yet expired and were kept in place.

This led to a landmark court case. In that case, VEMW, the organization representing the interests of large energy consumers in the Netherlands, the Amsterdam Power Exchange (APX) and ENECO, a large Dutch utility, challenged the decision of DTE, the Dutch regulator, to reserve a significant proportion of the rights to trade across the border for SEP, the former national vertically integrated utility. SEP used these so-called transmission rights to execute its existing long-term contracts with utilities across the border. In 2000, 1500 MW of the available 3200 MW of the rights were reserved for SEP contracts, which would reduce to 900 MW in 2001 and to 750 MW from 2005 to 2009. The European Court of Justice (ECJ) decided that this undermined potential access to the market by new players and protected the position of the incumbent. The Dutch regulator's decision was found to be incompatible with the First Directive and so annulled. Although the First Directive allowed Member States to request a transitional exemption from the relevant article in the legislation, this had not been done by the Netherlands. Other national regulatory authorities (NRAs) used the ECJ decision to take steps to remove transmission right privileges.¹

The next challenge was to allocate the freed-up transmission rights in a non-discriminatory way. Figure 2.1 gives an overview of the transmission right allocation methods applied in the EU in 2004. Priority lists were said to give priority to whoever made it onto the list, often incumbent utilities and large industrial consumers. Pro-rata rationing implied that whoever asked for more got more. Explicit auctions and market splitting were the first market-based approaches to allocate transmission rights. They will be discussed in more detail in the next

Two arrows appearing in the same flow sense in a certain interconnection, mean that, for that interconnection in that flow sense, there is not a unique capacity allocation method or congestion management mechanism jointly applied by the two TSOs involved.

Note: The acronyms used stand for the following. MO: Morocco (non-EU); P: Portugal; E: Spain; I: Italy; F: France; CH: Switzerland (non-EU); A: Austria; SL: Slovenia; G: Greece; H: Hungary; SK: Slovakia; CZ: Czech Republic; PL: Poland; D: Germany; L: Luxembourg; R: Russia (non-EU); DK (E): East Denmark; DK (W): West Denmark; FI: Finland; S: Sweden; N: Norway (non-EU); B: Belgium; NL: Netherlands; UK: United Kingdom; IR: Ireland.

Source: Based on European Transmission System Operators (ETSO) (2004).

Figure 2.1 Implementation of different allocation methods for cross-border transmission rights in Europe in 2004

sections. Finally, please note that on several borders there is not a unique capacity allocation method or congestion management mechanism jointly applied by the two TSOs involved.

2.2 HOW TO IMPLEMENT MARKET-BASED ALLOCATION OF TRANSMISSION RIGHTS?

Regulation (EC) No 1228/2003 was included in the Second Package and required a market-based approach to the allocation of transmission rights. In what follows we describe the evolution from explicit auctions to implicit auctions – or market coupling – in Europe.

First, explicit auctions. Under this approach, TSOs auction transmission rights to the highest bidders separately from the trading of energy. Several auctions are held, from the year-ahead to the day-ahead timeframe. A few years after the adoption of Regulation (EC) No 1228/2003, explicit auctions became the dominant model for allocating transmission rights in Europe. Due to the separation of the auctions of transmission rights and energy trading, coordination issues arose. More precisely, to be able to bid for transmission rights, traders had to predict hourly price differences in different countries, which turned out to be very difficult. The 2007 Sector Inquiry estimated that the lost opportunities to trade across the German–Dutch border in 2004 were as high as €50 million, or half the total value.² Figure 2.2 shows the details. Each dot

Source: European Commission (2007).

Figure 2.2 Explicit cross-zonal allocation: hourly price difference between Germany and the Netherlands (x-axis) versus the hourly sum of nominated net flows from Germany to the Netherlands in 2004 (y-axis)

represents the situation in the market at a certain hour. Two main problems can be observed. First, quadrant 2 and quadrant 4 show hours in which traders moved energy across the border earning the price spread, but they often did not capture all the opportunities. There are many hours in which not all the transmission rights were used although there was still a positive price spread. Second, quadrants 1 and 3 show hours in which traders paid for transmission rights and then moved energy across the border in the wrong direction, losing money. In this example, for about 40 per cent of the hours the electricity price in Germany was higher than in the Netherlands but the electricity was flowing towards the Netherlands (quadrant 1). The opposite also happened, with electricity flowing towards Germany when the price in the Netherlands was higher (quadrant 3).

Second, there was an evolution towards implicit auctions, or market coupling. The solution that emerged was to give the transmission rights to power exchanges. Instead of allocating them in a separate auction to cross-border traders, they were integrated into the clearing of the day-ahead auction organized by power exchanges. The name that was initially given to this solution was ‘implicit auctions’, but it then changed to ‘market coupling’ because the solution implied that the power exchange day-auctions became coupled, as we will discuss further in the next section.

2.3 HOW TO IMPLEMENT MARKET COUPLING IN THE DAY-AHEAD TIMEFRAME?

This section is divided in two subsections. We first describe the evolution from regional initiatives to so-called single day-ahead coupling (SDAC). We then discuss the issues that this solution left open. Power exchanges are key actors with regard to market coupling; a description of the evolution of power exchanges in Europe can be found in Annex 2A.1.³

2.3.1 From Regional Initiatives to Single Day-ahead Coupling

In this subsection, we first discuss three regional initiatives that led to SDAC: market splitting, trilateral market coupling and volume coupling. As Table 2.1 summarizes, we discuss the number of power exchanges that were involved in the initiative, whether they share their order books and by whom the optimization algorithm is run. We conclude with a description of the current status of SDAC implementation.

First, market splitting. Nord Pool's approach was called market splitting because the algorithm worked in two steps. In the first step, the Nordic system price was calculated. The system price is the price that would apply in the whole region if the resulting cross-border flows were feasible. If there were not enough cross-border transmission capacity available to accommodate all trades, the second step was to split the Nordic market into smaller markets with different prices, hence 'market splitting'. It all started with Nordic market splitting. In this approach, there was one power exchange – Nord Pool – with one order book and one optimization algorithm to calculate prices for the whole Nordic region.

Second, trilateral market coupling. The starting point for this project was three power exchanges (APX, Belpex and Powernext) and three TSOs (TenneT, Elia and RTE) which wanted to implement market coupling without consolidating the exchanges into one exchange. Instead of sharing all the information in their order books, they wanted to run an optimization algorithm based on net export curves, which was a way to aggregate their order book information. The algorithm would then decide the trade volumes and directions across the borders, and once these were fixed the exchanges would continue to calculate their own set of prices for their order books. It was a very elegant idea, and we did research to help develop the concept, but our research also showed that the approach had its limitations.⁴ We were therefore not surprised that after a piloting phase with detailed simulations the project partners decided to abandon the approach and went for a slightly more centralized version of market coupling. This was approved by the regulators and went live in 2006. The exchanges did not consolidate into one exchange, but they did agree to share their full order books and to let one optimization algorithm calculate the prices. The compromise was that they would take turns to run the algorithm or they would run it in parallel to build some resilience into the procedure.

Third, volume coupling. Two years after the approach based on net export curves in the trilateral market project was abandoned, it resurfaced in an initiative between Nord Pool (East Denmark) and EEX (Germany). Their approach was called volume coupling, as opposed to price coupling. It was short-lived because the problems that had been anticipated in trilateral market coupling and were analysed in our research unfortunately were realized. After several attempts to fix it, the project was stopped. For a full account of what happened, with an analysis of the performance of volume coupling in each step of the way, see our research on

Table 2.1 *Different design choices for the implementation of market coupling*

	Market splitting	Trilateral market coupling	Volume coupling	Single day-ahead coupling
Number of power exchanges involved	One (Nord Pool)	Three (Belpex, APX and Powernext)	Two (EEX and Nord Pool)	Many, now certified as NEMOs
Order books shared	Only one order book	Yes	No	Yes
Optimization algorithm run by	Nord Pool	Rotational – To validate the others do parallel runs	Both	One NEMO runs the algorithm on a rotational basis. The other NEMOs have the right to do parallel runs to validate the results

the topic.⁵ This short-lived experiment settled the competition between different market coupling implementations in favour of trilateral market coupling, which developed into SDAC. A simple numerical example showing how prices are set and cross-border capacity is allocated between two market-coupled countries can be found in Annex 2A.2.

Fourth, the status of SDAC. The Capacity Allocation and Congestion Management Guideline (CACM GL), which was adopted in 2015, made day-ahead market coupling binding for all. Trilateral market coupling has been growing, and at the time of writing 22 countries representing close to 90 per cent of European electricity consumption are already coupled. More are expected to join in 2020: Greece, the Czech Republic, Slovakia, Hungary and Romania.⁶ The optimization algorithm that is used is called the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA), and it originated in the trilateral market coupling project. The operation of the algorithm is called the market coupling operator (MCO) function in the CACM GL. The MCO function is jointly operated by all the participating power exchanges. To be able to participate, exchanges have to be certified as Nominated Electricity Market Operators (NEMOs).

2.3.2 Open Issues

In this subsection, we discuss three open issues: the governance of NEMOs and the MCO function, cost sharing and the functioning of the optimization algorithm EUPHEMIA.

The first open issue is governance. The default option described in the CACM GL is to have competing power exchanges in each Member State. However, if a national legal monopoly for day-ahead and intraday trading services existed in a Member State at the time of entry into force of the CACM GL, the Member State could decide to continue with a monopolistic power exchange. At the time of writing, Greece, Ireland, Italy, Spain, Portugal, Hungary, Bulgaria, Slovakia, the Czech Republic and Romania have designated one monopolistic NEMO and all the other Member States allow multiple NEMOs to compete in their markets. Competitive NEMOs designated in one Member State also have the right to offer trading services with delivery in another Member State where a competitive model is implemented, unless an exception is justified. Recently, multi-NEMO arrangements (MNAs) have been set up, enabling market coupling with more than one power exchange per country.

From the operational perspective, currently eight NEMOs are running the MCO function on a rotational basis. Each day one NEMO runs the system (acting as the ‘operator’), one acts as the formal ‘coordinator’ (e.g. announcing official results and calling the incident committee when issues arise) and another acts as ‘hot backup’. The remaining NEMOs have the right to compute the same results in parallel. This has put power exchanges in a position in which they must collaborate while they are also competing. The governance of NEMOs and the MCO function was on the agenda of the Florence Forum in 2018. The European Network of Transmission System Operators for Electricity (ENTSO-E) called for a stronger separation of the MCO function and the competitive business activities of NEMOs, preferably with more TSO involvement in the control of the MCO function. The Agency for the Cooperation of Energy Regulators (ACER) acknowledged the issues and hinted at the possibility of having a single independent MCO entity. The solution suggested by ACER was included in the CACM GL as a possible option if the current option does not work well. Finally, in a report published just after the Florence Forum, the Commission decided that it was too early for action.⁷

The governance issue has a history. During the development of the CACM GL, the question arose of whether power exchanges need to be regulated as monopolies now that they have a monopoly on cross-border trade in the day-ahead timeframe. Our research concluded that the competitive model for market infrastructure has its merits. Some of the activities of a power exchange, such as the provision of the interface between traders and the market and all sorts of settlement arrangements, are not necessarily monopolistic activities. Competing means they can differentiate and innovate in their services and also in their membership fees and trade commissions. We also wrote that it is necessary to avoid market coupling becoming a cartel of power exchanges, which did not make us very popular at the time. In 2014, the European Commission imposed fines of about €6 million on the two leading European power exchanges, EPEX SPOT and Nord Pool. They had agreed not to compete in the spot market (day-ahead and intraday) and to divide the European territory between them. In other words, the governance of NEMOs and the MCO function is an important issue to continue to monitor.⁸

The second open issue is cost sharing. The costs of operating and developing the MCO function are shared by the NEMOs. The CACM GL states that TSOs may contribute to the MCO-function-related costs of the NEMOs concerned but they are not obliged to. In the case that a TSO does not contribute to the costs or does not cover all the costs, the NEMOs are entitled to recover residual MCO-function costs by means of regulated fees or other appropriate mechanisms unless the costs are unreasonable. In short, the sharing keys between NEMOs and TSOs for MCO-function-related costs are national, while NEMOs can cover multiple Member States. As not necessarily the same NEMOs are competing in each Member State, due to the non-harmonized national sharing keys some NEMOs might need to top up their fees more than others because of the costs of MCO-related activities.

The third open issue is the algorithm. Technical issues came high on the agenda after the first major incident on 7 June 2019. Due to a software bug at EPEX SPOT – the biggest power exchange in central Europe, operating in countries such as Austria, Belgium, France, Germany and the Netherlands – its order books were not included in the market coupling algorithm EUPHEMIA. This meant that trade could not be scheduled across the borders of these countries. The fall-back solution was to organize local markets without cross-border trade. As a result, prices were unusually low in some countries and extremely high in others.⁹

At the time of writing, EUPHEMIA only has ten minutes to perform its market coupling calculations. Even though the incident on 7 June 2019 was said to have been caused by a software bug at EPEX SPOT, there are also technical issues with the algorithm itself. These issues are attracting more attention because the single-market-coupling approach in Europe relies on this one algorithm. As more countries have been added to the market coupling initiative, insufficient efforts have been made to reduce the complexity of the market that has to be handled by the algorithm. The CACM GL required NEMOs to submit a joint proposal for the bidding formats they will continue to use. In their proposal, which was accepted, they simply listed all the bidding formats that are currently used. These are a mix of multi-part orders with bids that correspond to the technical constraints of thermal power plants, including start-up costs and ramping constraints, and block orders, which allow traders to make their bids indivisible and to link them across periods. Multi-part orders are typical of power-pool type markets, while block orders are typical of power exchanges. EUPHEMIA currently has to deal with both complexities. In power-pool markets, complex bidding formats are typically combined with complex pricing, which means that side payments are used to balance supply and demand in the market on top of the clearing price. This implies that some market players get an additional side payment to avoid losing money, while the others pay or receive the clearing price corrected with an uplift to recover the money paid in side payments. Power exchanges do not do side payments; they instead allow their markets to reject block bids that are in-the-money at the prevailing clearing price (so-called paradoxically rejected blocks). Side payments would require a change in the CACM GL, but they would simplify the algorithm. Our research and that of colleagues has indeed demonstrated that complex pricing can reduce the complexity of the algorithm, but we have come to different conclusions on whether it should be done or not. Our colleagues argued in favour of complex pricing while we argued that the gains in terms of trade would be relatively small in comparison to the side payments that would need to be administered.¹⁰

Stakeholders are under pressure to come up with solutions because the complexity is only expected to increase. More countries will be added to SDAC, and the Clean Energy Package includes provisions that will increase the granularity of day-ahead markets from hourly to half-hourly or even 15 minutes.

Note finally that more progress has been made on another technical issue: the minimum and maximum clearing prices that are used by the different power exchanges have been harmonized. Following the CACM GL, all NEMOs were first asked to come up with a joint proposal which the NRAs had to unanimously approve. The NRAs could not reach an agreement and therefore requested ACER to adopt a decision. ACER decided that the harmonized maximum price in the day-ahead market should be €3000/MWh and the minimum price –€500/MWh. ACER avoided the maximum clearing price being able to act as a price cap by making it dynamic. In the event that the clearing price exceeds a value of 60 per cent of the previously set maximum clearing price, the maximum clearing price is increased by €1000/MWh.

2.4 WHAT ABOUT THE TIMEFRAMES BEFORE DAY-AHEAD?

The timeframes before day-ahead are referred to as forward and futures markets. These mainly involve bilateral deals or over-the-counter (OTC) trading. Power exchanges also play a role, but not by organizing auctions as they do in the day-ahead timeframe. Instead, they offer

platforms that enable continuous trade in standardized future contracts, for example one-year and three-year contracts. This means that there are no power exchange auctions that can be coupled in the timeframes before day-ahead. Cross-border long-term transmission rights can only be allocated in explicit auctions, the market-based solution that was abandoned in the day-ahead timeframe. Indeed, TSOs organize explicit auctions for at least monthly and yearly transmission right contracts. They have also started to collaborate via the Joint Allocation Office (JAO). JAO is a joint service company of currently 20 TSOs from 17 countries with harmonized auction rules and timings, which helps traders reduce their transaction costs in procuring transmission rights. With the Forward Capacity Allocation Guideline (FCA GL), which entered into force in 2016, this bottom-up voluntary initiative became the European platform. Following the FCA GL, in 2017 all the NRAs approved a methodology that proposed JAO becoming the single allocation platform for the whole of Europe. In what follows, we discuss the two main open issues regarding long-term transmission rights: the length and the types of contracts.

The first open issue is the length of contracts. To split the available transmission rights over the different long-term timeframes and contract lengths, the FCA GL foresees the need to develop methodologies at the regional level. At the time of writing, these methodologies are being discussed and have not yet been approved. Traders have made it clear that they prefer to have capacity offered year-ahead or more. Most TSOs propose a somewhat gradual offering by dividing the capacity over the different timeframes. The incentives for TSOs depend on the compensation they have to pay to market parties if they have to curtail long-term transmission rights because they face problems in their networks, and on whether NRAs allow TSOs to recover these payments through their grid tariffs. No compensation payments is not an option because then market parties would have a hedge that they could not rely on because it can be curtailed without any consequences for the TSO that issued the hedging product. This has been an issue in the past and has been addressed in the FCA GL. In the FCA GL, two causes for the curtailment of long-term transmission rights are distinguished. If what happens is considered force majeure, the price of the right in the original auction is refunded. The determination of whether an event classifies as force majeure is, however, still done at the national level. More precisely, the national regulatory authority of the TSO invoking a force majeure event has to assess whether the event qualifies as force majeure. If it is not force majeure, that is, the TSO curtails long-term transmission rights to ensure that all flows remain within the operational security limits, the compensation is the lost opportunity, which is the day-ahead price spread. In this case, the TSOs concerned might propose introducing a cap on the total compensation, which is further specified in the FCA GL.

The second open issue is the type of contract. Most TSOs started by auctioning so-called physical transmission rights (PTRs). A trader that buys such a right can trade across the border and nominate that trade to the TSO, which then subtracts this capacity from the overall volume of transmission rights that remain for the other timeframes. If the trader decides not to use the right, it is compensated for the value of the right in a day-ahead auction, where other traders might be willing to pay for it (use-it-or-sell-it, UIOSI). If the day-ahead stage applies market coupling, the price difference across the border is the implicit price for the transmission right. Most TSOs have already converted or are converting to another type of long-term transmission right referred to as a financial transmission right (FTR). With FTRs, use-it-or-sell-it becomes sell-it-without-the-possibility-of-using-it. Traders still hedge against the day-ahead price

differences between countries, but they cannot nominate a cross-border flow ahead of the day-ahead timeframe. Hence the name financial, because the physical element is no longer there. At the time of writing, FTRs are in place on nine borders in the EU and implementation of FTRs is planned on an additional eight borders.¹¹

The FCA GL leaves it open whether PTRs or FTRs are used. However, among other things, it is required that marginal pricing is applied in the auctions, that for both PTRs and FTRs harmonized allocation rules are followed, and that the two types of transmission right cannot be applied in parallel on one border. Regulators can adopt a coordinated decision not to issue PTRs or FTRs on a border when they can show that there is no need for hedging or by ensuring that there are other cross-border hedging instruments available in the market. For example, in the Nordics an instrument called electricity price area differentials (EPADs) is in place. EPAD contracts hedge the difference between the price in a certain location and the Nordic system price. The Nordic system price is the price that would have emerged if there were no congestion in the Nordic system. This system price is a legacy from the market splitting approach and does not represent an actual location in the Nordic system. Italy does something similar with an instrument that hedges the difference between the price in a certain location for supply and the ‘unique’ national price for demand, that is, *Prezzo Unico Nazionale* (PUN).

2.5 WHAT ABOUT THE TIMEFRAMES AFTER DAY-AHEAD?

The timeframes after day-ahead are intraday and balancing markets. Power exchanges play a role in the intraday stage by organizing continuous trading platforms, and in some cases also auctions. In the day-ahead and forward markets the debate was mainly over how to allocate transmission rights, while for the intraday stage the debate was over keeping the borders open long enough for intraday trade to become international. The CACM GL prescribes that the intraday cross-border gate closure shall be at most one hour before delivery. After the intraday cross-border gate closure, national intraday markets often remain open until even closer to real time.

Progress in the intraday stage has been slower than in the day-ahead stage. The volumes that are traded are smaller so less money can be made by organizing and participating in intraday trade, but intraday markets are important because they allow market parties to avoid imbalances. This is especially important for new players and renewable energy technologies, which would otherwise be exposed to high balancing costs. We will come back to this interaction in Chapter 5 on balancing markets. In what follows, we focus on the two intertwined open issues related to intraday markets: the transmission right allocation method and reservation.

Continuous trade became the dominant model in Europe for intraday in a context where intraday was less important and trade volumes were so low that auctions were not considered a feasible option. Now, this intraday continuous trade can also be cross-border using transmission rights. A main open issue is how to allocate these transmission rights. For most borders, the current practice is that intraday transmission rights are used free of charge by whoever is matched first on the continuous trade platform until the rights are no longer available or the border is closed (i.e. one hour before delivery). After that, the matching of traders can continue locally. However, first-come-first-served is not a market-based allocation method. Therefore, no transmission rights are reserved for the intraday stage; only the rights that have not been used in the day-ahead stage are allocated. Another option is to organize explicit auctions for

intraday transmission rights complementing continuous trade, which at the time of writing is done on several borders. However, we know from experience in the day-ahead market that explicit allocation is not without flaws.

The CACM GL pushes continuous trade in the intraday timeframe, and auctions are tolerated as complementary regional arrangements. The cross-border intraday market project (XBID), based on continuous trading with first-come-first-served allocation of transmission rights, has been formalized as the single intraday coupling (SIDC) to be applied by all Member States. At the time of writing, XBID is composed of members from 21 European countries ('the first and second waves'). However, at the same time, the CACM GL requires a single methodology for intraday cross-zonal pricing reflecting market congestion through an implicit allocation method. Explicit allocation is only allowed as a transitional complementary arrangement. The implementation of this methodology has been challenging. The NRAs could not agree on how to do this, so ACER had to decide. Finally, in 2019 ACER decided that three pan-European auctions will be introduced on top of continuous trading in the intraday timeframe. As soon as there are auctions in the intraday timeframe, transmission rights can be allocated efficiently through market coupling and will no longer be allocated for free. The debate on reservation of transmission rights for this timeframe can even be reopened. How this will play out is very much an open issue.

2.6 CONCLUSION

In this second chapter, on who gets the rights to trade across borders, we have answered five questions.

First, how to deal with historical privileges? In Europe, they had remained in place for a relatively long period until they were challenged in court. Finally, the European Court of Justice found these privileges were incompatible with the First Electricity Directive. This landmark court case opened the door for other countries to also abolish them. The accepted idea was to introduce market-based allocation of transmission rights. However, we had to wait for Regulation (EC) No 1228/2003, adopted as part of the Second Energy Package, for market-based allocation of transmission rights to be made mandatory on all EU borders.

Second, how to implement market-based allocation of transmission rights? Regulation (EC) 1128/2003 did not specify which market-based approach should be used. In Europe, many different approaches were tried before converging towards market coupling. Most borders started with explicit auctions for transmission rights as this solution did not require many changes to national electricity markets. However, it was quite quickly shown that explicit auctions had strong deficiencies in the day-ahead timeframe.

Third, how to implement market coupling in the day-ahead timeframe? Different implementations emerged through regional initiatives. The EU network codes and guidelines made the implementation of market coupling legally binding through the CACM GL. At the time of writing, day-ahead market coupling covers 22 European countries, representing more than 90 per cent of EU electricity consumption. The governance of the market coupling operator (MCO) function and the performance of the algorithm are the main open issues today.

Fourth, what about the timeframe before day-ahead? The network codes and guidelines, more specifically the FCA GL, also impacted cross-border long-term transmission rights. Currently, TSOs are obliged to issue transmission rights at least month-ahead and year-ahead

on a joint allocation platform. However, there are still ongoing discussions on how to divide long-term transmission rights between the year-ahead and month-ahead auctions. Traders want to have as many rights as possible allocated far ahead of delivery, while TSOs generally propose dividing rights more equally over the timeframes. Moreover, the network codes and guidelines do not settle which kind of transmission right should be issued. Historically, on most borders physical transmission rights were in place. Currently, we are seeing a transition from physical to financial transmission rights in Europe.

Fifth, what about the timeframes after day-ahead? Historically, due to low liquidity, intraday markets were organized as continuous trading platforms with few options to trade cross-border. Important progress has been made with the ongoing implementation of XBID, the single intraday market coupling solution. ACER has decided to complement XBID with three pan-European intraday auctions. Currently, no cross-border capacity is planned to be reserved for intraday.

NOTES

1. More in-depth discussion of this case can be found in Hancher (2006).
2. The competition authority of the European Commission opened a Sector Inquiry into the functioning of the European energy markets after significant price increases in the European electricity wholesale markets (European Commission 2007). Generally, the idea was that by integrating markets competition can be fostered. In this regard, Gilbert et al. (2004) show that the way that transmission rights are allocated to generators can also have a strong impact on whether market power can be mitigated or not.
3. Annex 2A.1 is based on our own work and that of our colleagues. Boisseleau (2004) was one of the pioneers discussing the importance of power exchanges. In Meeus et al. (2005b) we discuss the early development of the EU electricity market and the role of power exchanges. In Meeus (2011b) we focus on the governance and business models of power exchanges and power pools in Europe. For market statistics, refer to ACER and CEER (2019) and DG Energy (2019).
4. EuroPex (2003) introduced the concept of net export curves. In Meeus et al. (2005a) we argue that the concept can work if we only consider simple and single-period orders. But, as discussed in Meeus (2006), the problem is block orders, which would require many iterations and the quality of the solution would suffer.
5. In Meeus (2011a) we focus on the experience with volume coupling. We show that volume coupling initially performed worse than the situation without coupling. The implementation of volume coupling was then changed, which slightly improved the performance but not enough to save the project. We also explain mathematically why what happened was to be expected.
6. More specifically, two coupling projects are in parallel operation, namely the Multi-Regional Coupling (MRC) and the 4M Market Coupling (4MMC) projects. At the end of 2019, the MRC connected 22 countries. Furthermore, Greece is also expected to be coupled through the Greece–Italy interconnector in 2020. The other coupling project, the 4MMC, covers the Czech Republic, Slovakia, Hungary and Romania. Both projects are expected to be merged in 2020 (ENTSO-E 2019a).
7. In a report published just after the Florence Forum in 2018, the European Commission (2018) wrote that *‘the Commission sees a need to continue the discussion on the challenges faced so far and assess the various options for a potential change in the governance of the MCO function.’* All the presentations at the Florence Forums can be accessed online through the European Commission’s dedicated website.
8. In Meeus (2011b) we distinguish between merchant and cost-of-service-regulated power exchanges. We show that these models each have pros and cons by referring to experiences in financial markets. We also show that more responsibility for power exchanges comes with market coupling, which might require a governance model to be put in place. At the time of writing we have two main

worries. First, that power exchanges may not implement market coupling properly to protect their own business, as we found in Meeus (2011a). Second, asking them to collaborate to organize market coupling should not result in a cartel. The press release on the antitrust case of power exchanges can be found in European Commission (2014).

9. For more information, consult the NEMO Committee (2019) report on the incident.
10. In Meeus et al. (2009) we use simulations based on market data from APX to compare the results of an algorithm with and without side payments. Madani et al. (2018) further develop the algorithm, which can be used for market coupling with complex pricing, arguing that it would be a simpler way of clearing markets.
11. This is reported in ENTSO-E (2019b). ACER (2019b) keeps track of the status of long-term transmission rights on its website.

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2A.1 ANNEX: THE EVOLUTION OF THE ROLE OF POWER EXCHANGES IN EUROPE

In this annex we describe how the role of power exchanges evolved in Europe. First, we introduce the slow start of power exchanges. Second, we explain the increased focus on them. Third, we discuss the circumstances that led to a consolidation of the number of power exchanges across Europe.

First, the slow start of power exchanges. The evolution of power exchanges in Europe started in 1993 with Statnett Marked AS in Norway. Three years later Sweden joined the initiative, which was renamed as Nord Pool ASA. After, Nord Pool extended to Finland and Denmark in 1998 and 2000 respectively. In Spain, OMEL was founded in 1998. In the Netherlands, the Amsterdam Power Exchange (APX) was launched in 1999. In 2000, Germany saw its first power exchange (APX Deutschland, APXDE) launch and then cease operation after only a couple of months without any trading. In the same year, the Leipzig Power Exchange (LPX) and later the European Energy Exchange (EEX) were created. The French exchange Powernext was launched in 2001, and many other countries followed after. Power exchanges were market infrastructure set up by market parties, financial market institutions, TSOs or a combination of private actors. Over-the-counter (OTC) markets and organized exchanges complement each other but also compete for trading volume, which helps to reduce transaction costs for traders. Power exchanges are trading platforms that facilitate anonymous trade between market parties. By acting as a counterparty in all transactions and clearing all trades either themselves or through their clearing houses, they greatly reduce the counterparty risk for market participants. Power exchanges also enhance market transparency as prices and volumes are published through the platform, while details of OTC trades remain with the negotiating parties. The closer to real time, the more specific the needs of the market participant are and the more difficult it is to find the right counterparty. Despite the early movers mentioned above, it took a long time for all the markets to have a power exchange up and running. Still today, OTC trade constitutes the bulk of electricity trade.

Second, the increased focus on power exchanges. Having a healthy and well-functioning exchange became a benchmark in national market functioning. The Sector Inquiry of 2007 used several indicators to measure the performance of power exchanges, such as the number of players, traded volumes, the price-setting frequency of certain generators and price volatility. Later, price resilience was also added as an indicator. Not surprisingly, the smaller and/or more concentrated markets found that an exchange did not work very well in their contexts. Consequently, various liquidity-supporting measures were implemented to incentivize incumbent utilities and TSOs to trade on power exchanges for the benefit of new entrants, which relied on them to survive. Note that TSOs only purchase energy to offset the losses in their transmission network. Today, day-ahead markets in Europe are generally considered to be liquid enough, while this is not yet the case for intraday markets.

Third, we discuss the circumstances that led to a consolidation of the number of power exchanges across Europe. In the early days of the EU electricity market integration process, every country wanted to have its own market infrastructure. However, after the initial sensitivities faded, the market logic led to consolidation. Often, these national power exchanges had in any case already outsourced a major part of their activities instead of developing their own trading software and/or platforms. Gradually, two large players emerged through mergers and

Figure 2A.1 European power exchange mergers and acquisitions (non-exhaustive)

acquisitions. One large player is Nord Pool AS, which is mentioned in Section 2.3. The other is EPEX SPOT SE, which has a long history of mergers and collaborations, as is shown in Figure 2A.1. In 2002, the Dutch power exchange APX tried to set up a Belgian subsidiary called BPX, a project which was abandoned. Instead, the Belgian TSO Elia established a Belgian power exchange called Belpex in 2006. Belpex was eventually integrated into APX in 2010. Five years later, APX itself was integrated into EPEX SPOT, which was the result of the merger of the German exchange EEX and the French Pownext. At the time of writing, EPEX SPOT and Nord Pool are active in 8 and 14 countries respectively, with more expansions planned for both power exchanges. The south-eastern European countries are still setting up new power exchanges in cooperation with one of the two big players. Examples are the Independent Bulgarian Energy Exchange (IBEX) and the Croatian power exchange (CROPEX), where Nord Pool operates the day-ahead and intraday markets. Another example is the South East European Power Exchange (SEEPEx), which was established as a joint venture between the Serbian TSO and EPEX SPOT. We also see new players coming into the market infrastructure business, and will come back to this in Chapter 8.

2A.2 ANNEX: A SIMPLE NUMERICAL EXAMPLE OF MARKET COUPLING

Imagine two countries, A and B, which each represent one bidding zone. The concept of bidding zones is discussed in more depth in Chapter 3 of this book. Basically, when a country equals one bidding zone it means that the electricity price will be the same for the whole country per market time period.

First, no later than 11.00 Central European Time (CET), available capacities on interconnectors are published. Second, until 12.00 CET market parties have the possibility to submit their buy/sell orders to the power exchange(s) in their country for the day-ahead auction covering delivery in all hours of the next day. Third, each power exchange sends its order books, that is, the collected buy and sell orders, to the market coupling operator (MCO). The following table shows an example for an order book of two countries for a specific hour. Fourth, the prices are calculated by the pan-European algorithm operated by the MCO. Fifth, under normal circumstances, at 12.55 CET the final market coupling results are published by the power exchange(s).

Country A	Sell orders	Inelastic demand
	Ga1: 20 MWh at €20/MWh	80 MWh
	Ga2: 30 MWh at €50/MWh	
	Ga3: 70 MWh at €60/MWh	
Country B	Sell orders	Inelastic demand
	Gb1: 130 MWh at €20/MWh	100 MWh
	Gb2: 20 MWh at €30/MWh	
	Gb3: 40 MWh at €40/MWh	

We can consider four cases, which differ in the amount of commercial cross-border capacity between the countries indicated by the relevant TSOs. For simplicity, an inelastic demand is considered, and the price is set by the marginal sell order unconditional on whether it is fully filled or not.

Case 1: no commercial cross-border capacity between countries A and B

This means there are two different clearings, one for each country.

	Price	Demand	Supply	Export to other country
Country A	€60/MWh	80 MWh	80 MWh	0
Country B	€20/MWh	100 MWh	100 MWh	0

In this case, there is no cross-border trade. The spread between the two countries is €40/MWh. In country A, Ga3 sets the price. In country B, Gb1 sets the price. There is no congestion rent as there is no volume traded between the two countries.

Case 2: unlimited commercial cross-border capacity between countries A and B

This means there is one joint clearing for both countries, that is, the supply (and demand) curves of the two countries are aggregated.

	Price	Demand	Supply	Export to other country
Country A	€40/MWh	80 MWh	20 MWh	– 60 MWh
Country B	€40/MWh	100 MWh	160 MWh	+ 60 MWh

In this case, the price reduces in country A and increases in country B. There is cross-border trade but no price spread. Gb3 sets the price for both countries. Implicitly, 60 MW of cross-border capacity is allocated by the MCO from country B to A for the particular hour. There is no congestion rent as there is no price spread between the two countries.

Case 3: 100 MW/h commercial cross-border capacity is available in both directions between countries A and B

This means there is one joint clearing for both countries, that is, the supply (and demand) curves of the two countries are aggregated unless the exchange exceeds the commercial capacity available.

	Price	Demand	Supply	Export to other country
Country A	€40/MWh	80 MWh	20 MWh	– 60 MWh
Country B	€40/MWh	100 MWh	160 MWh	+ 60 MWh

This case is no different to case 2 as the exchange between the two countries is not limited by the commercial cross-border capacity available.

Case 4: 40 MW/h commercial cross-border capacity between countries A and B is available in both directions

This means there is one joint clearing for both countries, that is, the supply (and demand) curves of the two countries are aggregated unless the exchange exceeds the commercial capacity available.

	Price	Demand	Supply	Export to other country
Country A	€50/MWh	80 MWh	40 MWh	– 40 MWh
Country B	€30/MWh	100 MWh	140 MWh	+ 40 MWh

In this case, compared to case 1, the price reduces in country A (but not as much as in cases 2 and 3) and the price increases in country B (but not as much as in cases 2 and 3). There is cross-border trade and a price spread. The commercial exchange between the countries is limited due to the capacity available. In country A, Ga2 sets the price; in country B, Gb2 sets the price. Implicitly, 40 MW of cross-border capacity is allocated from country B to A for the particular hour by the MCO. There is a congestion rent of $40 \text{ MWh} \times €20/\text{MWh} = €800$ for this particular hour. More information about the calculation of congestion rent can be found in Annex 4A.1 of Chapter 4.

2A.3 ANNEX: REGULATORY GUIDE

Table 2A.1 Regulatory guide

Section of this chapter, topic and relevant regulation	Relevant articles
Section 2.1 The First Directive 96/92/EC stated that TSOs had to provide different network users with non-discriminatory access to their networks. The First Directive 96/92/EC allowed Member States to ask for a transitional exemption from the relevant article in the legislation.	 Art. 7(5) states that ‘ <i>The system operator shall not discriminate between system users or classes of system users, particularly in favour of its subsidiaries or shareholders.</i> ’ In accordance with Art. 24, the Member States were entitled to ask the Commission to allow an exemption up to one year after the entry into force of the Directive.
Section 2.2 Regulation (EC) No 1228/2003 required a market-based approach for the allocation of transmission rights.	 The first point under ‘general’ in the annex to Regulation (EC) No 1228/2003 states that ‘ <i>Congestion management method(s) implemented by Member States shall deal with short-run congestion in a market-based, economically efficient manner whilst simultaneously providing signals or incentives for efficient network and generation investment in the right locations.</i> ’
Section 2.3 The CACM GL makes day-ahead market coupling binding for all. The operation of the algorithm is called the market coupling operator (MCO) function in the CACM GL. According to the CACM GL, to be able to participate in market coupling, exchanges have to be certified as Nominated Electricity Market Operators (NEMOs). According to the CACM GL, the NEMO function is jointly operated by all participating power exchanges. The default option described in the CACM GL is to have competing power exchanges in each Member State.	 Art. 42(1) states that ‘ <i>The day-ahead cross-zonal capacity charge shall reflect market congestion and shall amount to the difference between the corresponding day-ahead clearing prices of the relevant bidding zones.</i> ’ Art. 2(30) defines the MCO function as ‘ <i>the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities.</i> ’ Art. 2(23) defines a NEMO as ‘ <i>an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling.</i> ’ Art. 7(2) states that ‘ <i>NEMOs shall carry out MCO functions jointly with other NEMOs</i> ’ and lists the different tasks. The competitive model is the default (preferred) arrangement. See Art. 4(1, 5). However, a monopoly is still possible according to Art. 4(6.a) and Art. 5(2). Art. 5(2) states ‘ <i>a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services.</i> ’ Art. 5(3) continues ‘ <i>if the Commission deems that there is no justification for the</i>

Section of this chapter, topic and relevant regulation	Relevant articles
	<i>continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another MS, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States.'</i>
According to the CACM GL, the regulator (or other competent authority) designates the one or more power exchanges that can organize cross-border trade in the day-ahead and intraday markets.	Art. 4(3): <i>'Unless otherwise provided by Member States, regulatory authorities shall be the designating authority, responsible for NEMO designation, monitoring of compliance with the designation criteria and, in the case of national legal monopolies, the approval of NEMO fees or the methodology to calculate NEMO fees. Member States may provide that authorities other than the regulatory authorities be the designating authority. In these circumstances Member States shall ensure that the designating authority has the same rights and obligations as the regulatory authorities in order to effectively carry out its tasks.'</i>
According to the CACM GL, competitive NEMOs designated in one Member State also have the right to offer trading services with delivery in another Member State where a competitive model is implemented, unless an exception is justified.	This is described in Art. 4(5). On top of not having the right to offer trading services in another Member State when the NEMO is a legal monopoly in its Member state or where a legal monopoly is in place in the Member State of delivery, two other exceptions are listed in Art. 4(6): technical obstacles and incompatible trading rules.
Multi-NEMO arrangements (MNAs) in the CACM GL.	Arrangements concerning more than one NEMO in one bidding zone are described in Art. 45 for day-ahead and Art. 57 for intraday.
Operational MCO implementation according to the CACM GL.	Art. 7(3) requires all NEMOs to come up with a plan that sets out how to jointly set up and perform the MCO functions. The MCO plan (All NEMOs 2017c) was approved by all NRAs on 26 June 2017.
Having a single independent MCO entity is a possible option according to the CACM GL.	Recital 15 states that <i>'The Commission, in cooperation with the ACER may create or appoint a single regulated entity to perform common MCO functions relating to the market operation of single day-ahead and intraday coupling.'</i>
The CACM GL states that TSOs may contribute to the MCO-function-related costs of the NEMOs concerned but are not obliged to.	Art. 76(1) states that the costs of establishing, amending and operating the algorithms, systems and procedures for market coupling (day-ahead and intraday) are borne by all NEMOs. Art. 76(2) adds that TSOs may contribute to the costs subject to approval by the relevant regulatory authorities.
The CACM GL requires NEMOs to submit a joint proposal for the bidding formats they will continue to use.	Art. 40 and Art. 53 describe the methodology for the products to be accommodated in the SDAC and SIDC respectively. For both market timeframes, the orders resulting from these products should be expressed in euros and make reference to one or multiple market time units. In January 2018, all NRAs approved the amended proposals for SDAC and SIDC products (All NEMOs 2017a, 2017b).

Section of this chapter, topic and relevant regulation	Relevant articles
Side payments would require a change to the CACM GL.	Art. 38(1.b) states that <i>‘The price coupling algorithm shall produce the results set out in Article 39(2), in a manner which: ... (b) uses the marginal pricing principle according to which all accepted bids will have the same price per bidding zone per market time unit.’</i>
Regulation (EU) 2019/943 of the Clean Energy Package includes provisions that will increase the granularity of day-ahead markets from hourly markets to half-hourly or even 15 minutes.	More specifically, in Art. 8(2) of Regulation (EU) 2019/943, it is stated that <i>‘NEMOs shall provide market participants with the opportunity to trade in energy in time intervals which are at least as short as the imbalance settlement period for both day-ahead and intraday markets.’</i> In the same Regulation and article it is stated at point 4 that <i>‘By 1 January 2021, the imbalance settlement period shall be 15 minutes in all scheduling areas, unless regulatory authorities have granted a derogation or an exemption. Derogations may be granted only until 31 December 2024. From 1 January 2025, the imbalance settlement period shall not exceed 30 minutes where an exemption has been granted by all the regulatory authorities within a synchronous area.’</i>
Following the CACM GL, all NEMOs were asked to come up with a joint proposal for minimum and maximum prices in the SDAC and SIDC.	Arts. 41 and 54 describe the methodology for the harmonized minimum and maximum prices for the SDAC and SIDC respectively. With decisions 04/2017 and 05/2017, ACER (2017a, 2017b) adopted the final version of the harmonized min-max clearing prices to be applied, respectively, to SDAC and SIDC in November 2017.
Section 2.4	
According to the FCA GL, JAO became the European platform for long-term transmission right allocation.	Recital 5 states that <i>‘Harmonised long-term cross-zonal capacity allocation rules require the establishment and operation of a single allocation platform at European level. This central platform should be developed by all TSOs to facilitate the allocation of long-term transmission rights for market participants and should provide for the transfer of long-term transmission rights from one eligible market participant to another.’</i> Arts. 48, 49 and 50 respectively describe the establishment, functional requirements and tasks of the single allocation platform.
To split the available transmission rights over the different long-term timeframes and contract lengths, the FCA GL foresees the need to develop methodologies at the regional level.	Art. 16 describes the methodology for splitting long-term cross-zonal capacity.

Section of this chapter, topic and relevant regulation	Relevant articles
In the FCA GL, two causes for curtailment of long-term transmission rights are distinguished.	First, the curtailment of transmission rights in the event of force majeure. A force majeure is defined in the CACM GL Art. 45(2) as ' <i>any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation.</i> ' Second, long-term transmission rights can also be curtailed prior to the day-ahead firmness deadline to ensure that operation remains within operational security limits, defined in CACM GL Art. 2(7) ' <i>as the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.</i> ' Lastly, there can be a special case when bidding zone borders cease to exist. This could happen when two bidding zones are merged or bidding zone borders are redrawn.
According to the FCA GL, if what happens is considered force majeure, the price of the right in the original auction is refunded.	Art. 56(3) states that in the case of force majeure, the holder of long-term transmission rights will receive compensation from the TSO which invoked the force majeure. This compensation will be equal to the amount initially paid for long-term transmission rights. Art. 27(2) states that similarly in the special case that a bidding zone border ceases to exist, the transmission right holders shall also be entitled to reimbursement by the TSOs concerned based on the initial price paid for the long-term transmission rights.
If it is not a force majeure, i.e. curtailment of the right to ensure operation remains within operational security limits, the compensation is the lost opportunity, which is the day-ahead price spread. In this case, the TSOs concerned might propose introducing a cap, which is further specified in the FCA GL.	In the case of a curtailment due to operational security limits, Art. 53(2) specifies that the TSOs concerned on the bidding zone border where long-term transmission rights have been curtailed shall compensate the holders of these rights with the market spread. Furthermore, Art. 54(1) adds that the TSOs concerned on a bidding zone border may propose a cap on the total compensation to be paid to all holders of curtailed long-term transmission rights.
The determination of whether an event is classified as force majeure is, however, still done at the national level.	Art. 56(5) states that ' <i>Where a Member State has so provided, upon request by the TSO concerned, the national regulatory authority shall assess whether an event qualifies as force majeure.</i> '

Section of this chapter, topic and relevant regulation	Relevant articles
The FCA GL leaves it open whether PTRs or FTRs are used. If a trader decides not to use a PTR, the trader is compensated for the value of the right in the day-ahead auction, where other traders might be willing to pay for it (use-it-or-sell-it).	Art. 31(1) states: ‘Long-term cross-zonal capacity shall be allocated to market participants by the allocation platform in the form of physical transmission rights pursuant to the UIOSI principle or in the form of FTRs – options or FTRs – obligations.’ Art. 2(6) defines UIOSI as ‘the principle according to which the underlying cross-zonal capacity of physical transmission rights purchased and non-nominated is automatically made available for day-ahead capacity allocation and according to which the holder of these physical transmission rights receives remuneration from the TSOs.’
The FCA GL requires that marginal pricing is applied in the auctions.	Art. 28(1) states that ‘The allocation of forward capacity shall take place in a way which: (a) uses the marginal pricing principle to generate results for each bidding zone border, direction of utilization and market time unit.’
The FCA GL requires that for both PTRs and FTRs harmonized allocation rules are followed.	Art. 51 describes the introduction of harmonized allocation rules. Art. 52 describes the requirements for the harmonized allocation rules. The revised proposal by all TSOs regarding harmonized allocation rules was not unanimously approved by all NRAs. Finally, ACER adopted a decision in August 2017.
The FCA GL states that the two types of transmission rights cannot be applied in parallel on one border.	Art. 31(6) states that ‘The allocation of physical transmission rights and FTRs – options in parallel at the same bidding zone border is not allowed. The allocation of physical transmission rights and FTRs – obligations in parallel at the same bidding zone border is not allowed.’
Regulators can adopt a coordinated decision not to issue PTRs or FTRs on a border when they can show that there is no need for hedging or by ensuring that there are other cross-border hedging instruments available in the market.	Art. 30(1) states that ‘TSOs on a bidding zone border shall issue long-term transmission rights unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border. When adopting their decisions, the competent regulatory authorities of the bidding zone border shall consult the regulatory authorities of the relevant capacity calculation region and take due account of their opinions.’ The remainder of Art. 30 states that an assessment needs to show that no hedging needs are unmet by ensuring that there are other cross-border hedging instruments available in the market.
Section 2.5	
The CACM GL prescribes that the intraday cross-border gate closure shall be at most one hour before delivery. After the intraday cross-border gate closure, national intraday markets often remain open until even closer to real time.	Art. 59(3) states that ‘one intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be at most one hour before the start of the relevant market time unit and shall take into account the relevant balancing processes in relation to operational security.’ The intraday cross-zonal gate closure time is defined in Art. 2(3): ‘the point in time where cross-zonal capacity allocation is no longer permitted for a given market time unit.’

Section of this chapter, topic and relevant regulation	Relevant articles
Continuous trade is the default trading arrangement in the intraday timeframe, and auctions are tolerated as a complementary regional arrangement.	Art. 51 states that <i>‘From the intraday cross-zonal gate opening time until the intraday cross-zonal gate closure time, the continuous trading matching algorithm shall determine which orders to select for matching.’</i> Art. 63(1) adds that the relevant NEMOs and TSOs on bidding zone borders may jointly submit a common proposal for the design and implementation of complementary regional intraday auctions. Complementary regional intraday auctions may be implemented within or between bidding zones in addition to the single intraday coupling solution referred to in Art. 51.
The CACM GL requires a single methodology for intraday cross-zonal pricing reflecting market congestion through an implicit allocation method.	Art. 55(3) states that all TSOs shall develop a proposal for a single methodology for pricing intraday cross-zonal capacity. Art. 55(1) adds that <i>‘Once applied, the single methodology for pricing intraday cross-zonal capacity developed in accordance with Article 55(3) shall reflect market congestion and shall be based on actual orders.’</i> The revised proposal by all TSOs regarding a single methodology for pricing intraday cross-zonal capacity was not unanimously approved by all NRAs. Finally, ACER (2019a) adopted a decision in January 2019.
According to the CACM GL, explicit allocation is only allowed as a transitional complementary arrangement.	Art. 64 states the provisions related to explicit allocation under the section title ‘Transitional intraday arrangements’. In Art. 64(1) it is stated that <i>‘Where jointly requested by the regulatory authorities of the Member States of each of the bidding zone borders concerned, the TSOs concerned shall also provide explicit allocation, in addition to implicit allocation, that is to say, capacity allocation separate from the electricity trade, via the capacity management module on bidding zone borders.’</i> Art. 65 explains the removal of explicit allocation.