3. How to calculate border trade constraints?

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In this chapter we answer five questions. First, why do we focus so much on constraints? Second, why do we calculate trade constraints on virtual borders? Third, who is best placed to do virtual border calculations? Fourth, how to organize the data exchange in support of the calculations? And fifth, why are there still open issues?

3.1 WHY DO WE FOCUS SO MUCH ON CONSTRAINTS?

In this section, we explain that transmission lines are currently the only economically viable way to transport electricity, transmission planning is challenging and transmission operation is critical to avoid blackouts.

First, transmission lines are currently the only economically viable way to transport electricity. In other industries, transport and logistics follow the rest of the value chain. There are many companies that compete to supply transport services. In those industries, transport is considered a cost rather than a constraint. Maybe in the future we will have competition to transport electricity, with market parties carrying large-scale batteries on trucks, trains or ships to transport it over long distances. However, for the moment there are no alternatives. In the EU, we have transmission system operators (TSOs), which own networks and perform the system operator tasks in a certain geographical area that is called a control area. In most countries, the control area coincides with the national territory. Germany is one of the exceptions, having four control areas. Some countries have chosen to separate the system operator role from the asset owner, in which case the system operator is referred to as an independent system operator (ISO). For example, Ireland and Great Britain follow this model, which is also the dominant one in the US. Regardless of the specific model, the transmission network is centrally planned and regulated, and therefore by definition imperfect. In economic terms, we consider the transmission network to be a natural monopoly. We discussed how incentive regulation has been used to manage these imperfections in our previous book.¹

Second, transmission planning is challenging. Transmission planning by TSOs (or ISOs) under the supervision of regulators tries to anticipate the decisions of market parties on where they will invest in power plants or where they will consume electricity. Investments in the network are then planned accordingly. However, as there are many uncertainties involved and large transmission projects take longer than most power plant projects, there are typically many transmission-capacity constraints in the system. Due to these constraints, the cheapest resources cannot reach the consumers with the highest willingness to pay. This planning problem is becoming even more pressing with greater numbers of renewable energy technologies. Indeed, wind turbines and solar parks are faster to build than coal or nuclear power plants.

Third, transmission operation is critical to avoid blackouts. If we do not account for limitations in the network, the market will result in consumption and production patterns that are not feasible. If we then force the flows through the network lines, they overheat and disconnect. The weakest link disconnects first, which redistributes the flows to other lines. This can create additional overheating, which is followed by a cascade of disconnections, ending in a blackout. The same cascade of events can take place if something unexpected happens to a transmission line. An example of such an event is the blackout that took place in Italy in 2003 after a line tripped on the Swiss–Italian border (Box 3.1). Normally, these problems are avoided by applying the N–1 redundancy principle. There is always some reserve kept in the system to avoid a complete collapse if one of the elements fails.

BOX 3.1 THE ITALIAN BLACKOUT OF 28 SEPTEMBER 2003

On 28 September 2003 at 03.28 in the morning, a blackout affected more than 56 million people across Italy and some areas of Switzerland. The consequences were huge. For example, 30 000 people were stranded on trains in the Italian railway network. Estimates of the number of fatalities directly related to the loss of power vary. Much of Italy was energized again before 08.00, the central part around noon and the rest of the mainland at 17.00. Sicily was only fully energized at 21.40. Some commercial and domestic users even suffered disruption in their power supplies for up to 48 hours.

The sequence of events was triggered by the 380 kV Swiss Mettlen–Lavorgo line tripping at 03.01 as a result of a tree flashover. Tree flashovers happen when a line comes too close to trees because they have not been trimmed properly and/or when a line sags more than normal due to overheating.

Following the N–1 principle, other lines were able to take over the flows, but only for a short time. The system needed to be restored to return to a secure state. The Swiss TSO therefore asked the Italian TSO to reduce Italian imports by 300 MW. At this time, Italy was importing up to 300 MW more than the already high import schedule, which amounted to 6400 MW on the northern border. However, the import reduction, together with some internal countermeasures taken within the Swiss system, was insufficient to relieve the overload. At 03.25, the Sils–Soazza line in proximity to the Mettlen–Lavorgo line also tripped after another tree flashover. Almost simultaneously and automatically the remaining lines towards Italy also tripped, and the Italian system was isolated from the European network about 12 seconds after the loss of the Sils–Soazza line.

After this separation, the Italian system had a large shortage resulting in a frequency drop and a disconnection of power plants in the north of Italy. This then accelerated the frequency drop. The Italian TSO tried to save the situation with emergency load shedding, but the frequency reached the threshold of 47.5 Hz and the whole system collapsed in a blackout 2 minutes and 30 seconds after the isolation of Italy from the rest of Europe. In Chapter 6 we will come back to the role of power plants and other grid connections in this kind of incident.

Note: UCTE (2004) provides a detailed investigation of the incident. Ranci (2019), the first president of the Italian regulator and founding director of the Florence School of Regulation, describes from his point of view how he saw the blackout that happened in the last months of his mandate. He states that it was an unexpected failure, showing how limited the regulator's powers were to coordinate international relations. He also comments that the Italian regulatory authority had to learn how difficult it can be to explain a highly technical issue to the media, to the public at large and even to members of government.

3.2 WHY DO WE CALCULATE TRADE CONSTRAINTS ON VIRTUAL BORDERS?

In this section, we start by introducing the zonal congestion pricing approach that is currently in place in the EU. Afterwards, we discuss why the calculation of net transfer capacities between bidding zones is problematic. Last, we explain that flow-based market coupling allows moving away from net transfer capacities.

First, the zonal congestion pricing approach. When electricity trading started in Europe, the general view was that transmission constraints would not be an issue within a country. At the national level, investments had been made to avoid constraints, while internationally a more minimalistic approach had been followed. Therefore, it seemed logical to define trade borders between countries – so-called bidding zones – and allocate a limited amount of transmission rights on these borders, so-called net transfer capacities. This approach is referred to as a bidding-zone market configuration. This implies that prices are zonal, meaning that within a predefined bidding zone the wholesale electricity prices at each market time unit are the same and trade is unlimited. Of course, everybody knew that bidding zone borders were virtual because a border is an aggregation of physical lines. In some cases, there was awareness that the actual constraint was not necessarily the physical lines crossing the border but another network component deeper inside the national network that was strongly impacted by an increase in cross-border trade. However, this initially did not lead to questioning the approach. Figure 3.1 shows the bidding zone configuration in Europe in 2019. Bidding zone borders still mostly coincide with national borders. The exceptions are Sweden, Norway, Denmark and Italy, which are divided into several bidding zones, and Luxembourg, which shares a bidding zone with Germany.

Second, the calculation of net transfer capacity (NTC). TSOs had the impossible task of calculating the amount of energy that could be traded over a virtual border. First, the amount depends on how the flow will be distributed over the different border lines, which in turn depends on production and consumption patterns, which are only known after trade takes place. TSOs therefore predict the outcome of trade when deciding how much capacity to make available for trade. Second, it depends on what happens on other borders. The amount of capacity that a certain TSO can make available on one border depends on what other TSOs are doing on other borders. There are many flow paths between two points in a transmission network, and the flow will automatically distribute itself over all the paths. As a result, TSOs were very conservative in estimating NTC values to avoid getting it wrong and having to pay penalties for not delivering the capacity they had made available to the market.

Third, the evolution towards flow-based market coupling (FBMC). FBMC essentially means that now virtual border capacity and virtual flow distribution factors are calculated. By doing this, TSOs can be less conservative in the amount of capacity they make available.

Figure 3.1 Bidding zones in Europe as of November 2019

This is because the interdependencies between different bidding zones are considered using virtual flow factors in the market coupling algorithm. The algorithm allocates the interdependent flows over the different borders to maximize welfare from cross-border trade. The Capacity Allocation and Congestion Management Guideline (CACM GL) refers to FBMC as the primary approach for day-ahead and intraday capacity calculations. Even though the NTC method is still allowed, FBMC is already the dominant model. The idea was discussed long ago in the central western Europe (CWE) regional initiative. The original launch in that region was foreseen for 2009, but due to delays and implementation issues it took until the adoption of the CACM GL in 2015 to finally implement the FBMC method. For a more detailed discussion of the FBMC concept and the key parameters that play a role, see Annex 3A.1.²

3.3 WHO IS BEST PLACED TO DO VIRTUAL BORDER CALCULATIONS?

Regional collaboration among TSOs started voluntarily and was then formalized. In what follows, we first discuss the steps from regional security coordination initiatives (RSCIs) to regional security coordinators (RSCs) to finally regional coordination centres (RCCs). After,

we discuss the connection of RCCs with capacity calculation regions (CCRs), which play a key role in the implementation of FBMC.

First, the steps from RSCIs to RSCs to RCCs. Around 2008, the first RSCIs set up were CORESO (based in Brussels) and TSCNET services (based in Munich). In 2015, another RSCI was created in south-eastern Europe (SEE) in Belgrade. In 2016, Nordic and Baltic RSCIs were established. A system operation guideline (SO GL) adopted in 2017 formalized these initiatives by stating that each control area was to be covered by at least one RSC. The left-hand side of Figure 3.2 gives an overview of the geographical coverage of the five RSCs as of January 2019. RSCs are owned or controlled by TSOs and perform different tasks. The SO GL defines five core tasks for the RSCs, and the Clean Energy Package (CEP), more specifically Regulation (EU) 2019/943, has recently added additional tasks. The CEP also renamed the RSCs as regional coordination centres and enhanced their governance.

Second, the connection between RCCs and the CCRs. Within a CCR there is a high degree of interdependence of capacity calculation across borders. CCRs play a key role in the implementation of FBMC. The CACM GL includes the methodology for defining CCRs and requires a coordinated capacity calculation methodology to be developed per CCR. It is this capacity calculation methodology that specifies the implementation of FBMC using parameters, which we discuss in Annex 3A.1. The definition of the geographical scope of the CCRs was a very sensitive topic, with the Agency for the Cooperation of Energy Regulators (ACER) deciding to merge central western Europe (CWE) and central eastern Europe (CEE) into one region, referred to as the Core region. Remember that ACER can only decide on the adoption of methodologies if the national regulatory authorities (NRAs) cannot agree, which was the case for this methodology. For each CCR, the relevant RCC is appointed as coordinated capacity calculator. In the case that there is more than one established RCC active in a CCR, it is expected that one RCC will be responsible for assuming the function of the coordinated capacity calculator on a rotating basis. The right-hand side of Figure 3.2 shows the resulting map of the CCRs. Two of the ten CCRs, the Core and the Nordic CCR, agreed to implement FBMC for the day-ahead timeframe. FBMC spanning the full Core region is expected to go live on 1 December 2020. For the Nordics, the go-live is planned for 1 July 2021. The idea is that gradually CCRs will merge and as such coordinated capacity calculation can be performed over wider geographical areas.

Note finally that even though RCCs take up the role of coordinated capacity calculators, TSOs remain responsible for maintaining operational security. TSOs can decide not to implement a coordinated action proposed by the RCC, whether it is an action related to capacity calculation or grid operation, but only for security reasons, and not for economic considerations. They then need to report the detailed reason to the RCC and the TSOs of the region. This will be further investigated. The RCC may then propose a different set of actions. How this will work is an open issue. In Chapter 6, we describe the incident that led to the start of RSCIs and the tasks they and their grandchildren perform.

3.4 HOW TO ORGANIZE THE DATA EXCHANGE IN SUPPORT OF THE CALCULATIONS?

To understand how the data exchange supporting regional capacity calculations is organized, it is necessary to read multiple EU network codes and guidelines. The CACM GL, Forward

Figure 3.2 Left: the five regional security coordinators (RSCs) as of 1 January 2019; right: the ten capacity calculation regions (CCRs)

Capacity Allocation Guideline (FCA GL) and System Operation Guideline (SO GL) each contain methodologies that when combined explain how the data exchange is organized. All these methodologies have already been approved by the NRAs and adopted. In what follows, we provide an overview of who provides the input data to the TSOs, the process for integrating the data from the TSOs into a common grid model (CGM), how this CGM is used and the physical infrastructure used to exchange these data.

The first question is who provides the input data to the TSOs? The CACM GL and FCA GL each include generation and load data provision methodologies (GLDPM). These set out the generation and load data that TSOs can request from grid users. This applies mainly to the grid users connected at voltages of 220 kV or above. It can also apply to voltages below 220 kV if they are used in regional operational security analysis of the capacity calculation timeframe concerned. These data provisions apply regardless of whether the units are operated by the TSO or a distribution system operator (DSO), including closed distribution systems (a type of private network). TSOs can only use the GLDPM to request data if those data are not already available to them through other national or EU legislation (e.g. the ENTSO-E Transparency Platform), which can help to avoid double reporting. In addition, the TSOs can only use information received under the GLDPM for capacity calculations.

The second question is what is the process for integrating the data from the TSOs into a common grid model? Figure 3.3 summarizes the process. It starts with the TSOs' individual grid models (IGMs). The IGMs cover the power system characteristics, such as generation, load and grid topology. They are scenarios with a forecast representation of the power system for a given timeframe. The RCCs then merge the IGMs into CGMs, one for each timeframe. The merging process is a continuous cycle updating the information available on the grid situ-

Source: Adapted from ENTSO-E (2018a).

Figure 3.3 The common grid model (CGM) merging process

ation to ensure that each TSO has enough information for its area and each RCC has the necessary pan-European view to do the capacity calculations for the region. Note that the CGMs are pan-European, even though the capacity calculation is done regionally. It is expected that the RCCs will take turns to merge the IGMs into CGMs. Note too that ENTSO-E stores the IGMs and the CGMs in a portal called the pan-European Operational Planning Data Environment (OPDE).

The third question is how is the CGM used? The SO GL, the CACM GL and the FCA GL each require the establishment of CGMs. The difference between these different models lies in the timeframes for which they are calculated and used. Following the CACM GL, the RCCs must use the CGMs for their capacity calculations in the day-ahead and intraday timeframes. Following the FCA GL, the RCCs can use the CGMs for their capacity calculations in the timeframes before day-ahead, but they can also opt for a statistical approach. The SO GL refers to the use of CGMs for various system operation processes.

The fourth question is what is the physical infrastructure used to exchange these data? A new physical infrastructure called the Physical Communication Network (PCN) will be built for the purpose of exchanging CGM-related data. In 2017, the TSOs decided to merge the PCN with their existing network to exchange real-time data (the Electronic Highway). Both types of data exchange are equally critical for TSOs to perform their tasks.

In conclusion, the days when each TSO was using its own grid model to perform capacity calculations are behind us. There is widespread agreement on the benefits of a common approach to reducing costs and improving performance. The organization of data exchanges to support the ongoing market integration process is a topic that is being increasingly discussed. One of several open issues is the data exchange between the TSO and DSOs and access rights to different grid users' data. In this regard, the key organizational requirements, roles and responsibilities (KORRR) methodology is relevant. The KORRR methodology, which is part of the SO GL, covers data needed beyond capacity calculation – for example, data for real-time operations – and it complements the GLDPMs. The approved version of this

methodology states that it is to be decided at the national level whether distribution-connected significant grid users (SGUs) have to provide their data directly to the TSO or through the connecting DSOs.³

3.5 WHY ARE THERE STILL OPEN ISSUES?

FBMC was expected to improve the availability of transmission capacity thanks to a more sophisticated capacity calculation. To monitor if the approach delivered, ACER and the Council of European Energy Regulators (CEER) developed the concept of a benchmark capacity, which is the capacity they expect TSOs to make available on a certain border. In the first full year of FBMC in 2016, on average only 59 per cent of this capacity was made available in central western Europe. This was slightly better than what was available before the implementation of FBMC, but there was less improvement than expected. ACER also estimated that we are losing several billions of euros a year by not reaching the benchmark capacity.⁴

The reason is that FBMC does not address today's most pressing issue, which is that the real constraints in the network are no longer at the outdated virtual borders but within the bidding zones. In what follows, we discuss how Directorate-General for Competition (DG COMP – the European competition authority), the EU network codes and guidelines, and the EU Clean Energy Package (CEP) have started to address the issue. Finally, we discuss the US approach to this problem.

First, the approach by DG COMP. This started with an antitrust case against the Swedish TSO Svenska Kraftnät (SvK) and continued with a case against the German TSO TenneT DE. The SvK case started in 2006 after a complaint by the Danish energy industry association that it suffered high prices because the Swedish TSO was blocking cheap imports from Norway to Denmark via Sweden. DG COMP concluded that SvK had indeed constrained cross-border trade to reduce internal congestion problems. This was found to be an abuse of the TSO's dominant position and discrimination against cross-border flows in favour of internal flows. SvK initially stated that it would remedy the situation by investing in the constrained internal transmission lines, but this was not enough for the Commission. To avoid being fined, in 2010 SvK agreed to split Sweden into four bidding zones. This was the best solution because traders in Sweden now compete on a level playing field with cross-border traders for the limited internal capacity that is available in Sweden. When Sweden was one bidding zone, national trade was unlimited and cross-border trade could only use the national trade's leftovers.⁵

The TenneT DE investigation started in 2018. In this case, the complaint was that TenneT DE limited the export of cheap renewable wind energy from Denmark to Germany. This TSO also agreed to remedies to avoid being fined by DG COMP. TenneT DE guaranteed it would make significantly more capacity available on the Danish border a few months after the agreement with DG COMP, and would further increase capacity by 2026, when additional investment projects will have been completed. This solution is not a good one, but it currently seems to be the only politically feasible solution in Germany. Germany does not want to split up the national bidding zone into smaller bidding zones to deal with internal constraints. Its long-term solution is transmission investment, and in the meantime it has agreed to allow more cross-border trade, although it knows that it does not have enough internal transmission capacity to handle it. The German TSOs therefore intervene in the market with so-called redis-

patching actions. Germany is basically changing the market outcome to prevent its internal lines from overloading. These interventions are costly, and they also lead to market distortions. The result is paying those that caused the problem to solve the problem. They can then create more problems and earn more money. ACER estimated that in 2017 redispatch costs in the EU had already reached 2 billion euros.⁶

Second is the approach followed by the CACM GL. This introduced a bidding zone review process. The first bidding zone review was requested by ACER in 2016 for the central Europe region, and ENTSO-E published the results in 2018. Four alternative bidding zone configurations were assessed using a multi-criteria analysis. Following the CACM GL, the three main criteria considered were the stability and robustness of the bidding zones, network security and overall market efficiency. No alternative bidding zone configuration was found to outperform the status quo on all the criteria. The review therefore proposed keeping the current configuration. The TSOs did not feel comfortable carrying out this politically sensitive review, and together with most observers we have been disappointed with the outcome. This explains why this issue has again been picked up in the CEP.

Third is the approach followed by the CEP. Regulation (EU) 2019/943 introduced an improved bidding zone review process. The implementation of this new process has already started with the submission of a bidding zone review methodology and alternative configurations by TSOs. All the NRAs then have three months to reach a unanimous decision on the proposal. If they fail to reach a decision, then ACER will decide within an additional three months. The TSOs will do the bidding zone review and analyse alternative configurations using the agreed-upon methodology. They will then provide the relevant Member States or their designated competent authorities with a joint proposal to amend or maintain the current bidding zone configuration. This process is similar to that described in the CACM GL. However, the end of the process is new. If Member States that opt to change the existing bidding zone configuration cannot reach a unanimous decision, as a last resort the European Commission will adopt a decision to amend or maintain it.

The European Commission had originally proposed legislation that would put it in charge of configuring bidding zones. However, the European Council (representing the Member States) opposed this and compromised with the European Parliament on what came to be known as one of the most controversial elements in the CEP. In the final version of Regulation (EU) 2019/943, the European Commission only has last resort powers when it comes to the bidding zone configuration, but Member States have to comply with a transmission capacity availability threshold. Regulation (EU) 2019/943 states that the available transmission capacity of all transmission elements possibly limiting the amount of electricity that can be exchanged between different bidding zones should be at least 70 per cent of a benchmark value. A process has been set in motion to assess the extent to which different countries already comply with this threshold and how they intend to comply by 2025. Basically, countries need to choose between the two DG COMP cases – whether to follow the Swedish or the German approach to stopping discrimination between cross-border and national trade.

Fourth is the US approach to this issue, that is, nodal pricing. If it is not possible to agree on bidding zones, they could simply be abolished or reduced to the physical nodes in the transmission network. This would mean that, instead of a simplified network with virtual borders and flow factors, the physical constraints of the transmission network are represented in the market coupling algorithm. If none of the constraints are binding and thermal losses are

excluded, there would be a single price for the whole of Europe. If one of them is binding, the result would be a ‘weather map’ in which every point or node in the transmission network would have a different price depending on where it is in relation to that network constraint. The price map would change with weather conditions as the availability of wind and solar is becoming an important factor in electricity production. In addition, temperature influences electricity consumption. US markets have experience with nodal pricing in smaller-scale markets; Europe could be the first to do it on a much larger international scale. We shall see how this open issue plays out.⁷

3.6 CONCLUSION

In this chapter on the calculation of cross-border trade constraints, we have answered five questions.

First, why do we focus so much on constraints? Transmission lines are currently the only economically viable way to transport electricity. Transmission planning is challenging and transmission operation is critical to avoid blackouts. The N-1 redundancy principle means that there is always some reserve kept in the system to avoid a complete collapse if one of the elements fails.

Second, why do we calculate trade constraints on virtual borders? It seemed natural to define virtual trade borders between countries and assign a limited capacity to these borders. The FBMC algorithm captures the interdependencies between borders and the CACM GL mandates it to be the primary approach for day-ahead and intraday capacity calculation.

Third, who is best placed to do these virtual border calculations? Collaboration among TSOs started voluntarily and evolved into being more formal. The CACM GL introduced the concepts of CCRs and RSCs and the Clean Energy Package added responsibilities for RSCs and renamed them as regional coordination centres (RCCs).

Fourth, how to organize the data exchange in support of the calculations? The SO GL, the CACM GL and the FCA GL require the establishment of CGMs. They ensure that each TSO has information to manage its area and each regional coordination centre has the pan-European view. Interestingly, a dedicated European physical communication infrastructure supporting multiple real-time and non-real-time services has been built up to support the data exchange.

And fifth, why are there still open issues? The current bidding zone configuration is outdated. Too many countries have a national bidding zone with internal congestion within it. They therefore discriminate against cross-border trade in favour of national trade. The best solution is to split bidding zones, but some countries prefer to keep their national bidding zone despite the very high cost.

NOTES

1. In Meeus and Glachant (2018) we discuss how TSOs and distribution systems operators (DSOs) are regulated as monopolies over transmission and distribution assets. We also show that the border between what is considered a market, transmission or distribution is not always clear, which is referred to as seams issues or grey areas in regulation.
2. A comprehensive comparison between the NTC approach and FBMC can be found in Van den Bergh et al. (2016).
3. A distribution-connected significant grid user (SGU) is a generator connected to a distribution network with a connected capacity higher than a certain threshold. This threshold, typically between

several hundred kW and 1 MW, depends on the national implementation of the Requirements for Generators Network Code (RfG NC), which is discussed in more depth in Chapter 6. In addition, distribution-connected demand facilities, directly or aggregated, which provide demand response to the TSO are considered SGUs.

4. The benchmark capacity is calculated as if the ACER (2016b) recommendation on common capacity calculation, redispatching and countertrading cost sharing methodologies is applied. This recommendation emphasizes that internal network elements should not limit available tradable cross-zonal capacity and that loop flows and other unscheduled flows should be minimized. Loop flows are explained in Annex 3A.2. Making comparisons with how much available capacity was offered in the past is not straightforward. This is first because it is not easy to compare available tradable capacity under an NTC and an FBMC approach, and second because the concept of a benchmark capacity was introduced for the first time in the ACER and CEER (2017) market monitoring report of 2016. For example, the market monitoring analysis in ACER and CEER (2016) shows that approximately 31 per cent of the interconnector's physical capacity on CWE borders was used for trading in 2015. The same report found that the ratio between NTC and thermal capacity in CWE was 27 per cent.
5. A more detailed legal discussion of the SvK case can be found in the work of our colleagues de Hauteclocque and Hancher (2011).
6. The discussion regarding the TenneT DE case is based on press releases from the European Commission (2018). The €2 billion estimate of EU-wide redispatch costs in 2017 is based on the ACER and CEER (2018) market monitoring report. Using simple cases, Stoft (1999) shows the possibility of gaming between the wholesale market and redispatching, the so-called incremental–decremental (inc–dec) game. Purchala (2019) describes how the zonal market does not facilitate correct incentives for efficient behaviour.
7. The book *Spot Pricing of Electricity* by Schweppe et al. (1988) and the paper ‘Contract networks for electric power transmission’ by Hogan (1992) were seminal works which laid the foundations for the implementation of nodal pricing in the US. Neuhoff and many colleagues (2013) quantify the Europe-wide operational savings of nodal relative to zonal market design to be in the order of €0.8–2 billion/year (representing 1.1–3.6 per cent of operating costs). Similarly, Green (2007) calculates that moving from a uniform zonal price to optimal nodal prices for England and Wales could raise welfare by 1.3 per cent of the generators' revenues, and would be less vulnerable to market power. Both papers add that nodal pricing would send better investment signals but would also cause politically sensitive redistributions. More recently, the concept of distribution locational marginal pricing (DLMP) or nodal pricing all the way down to distribution grids is gaining attention. Caramanis et al. (2016) propose a DLMP framework in which the market and reserves are cleared simultaneously (co-optimization) with inclusion of flexible loads and distributed energy resources (DERs) and while considering line-flow constraints and distribution-bus voltage limits. Papavasiliou (2018) provides an analysis of three DLMP approaches. He discusses price formation under each approach and their strengths and limitations. MIT Energy Initiative (2016) highlights the need for advanced meters, inexpensive information and communications technology (ICT) solutions and DERs in order to make effective use of DLMP.

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3A.1 ANNEX: FLOW-BASED MARKET COUPLING (FBMC)

FBMC is a process, not a one-step calculation, which starts two days before real time (base case) and ends the morning one day ahead. At that moment, the coordinated capacity calculators deliver the necessary parameters to the market coupling operator (MCO) that is in charge of the day-ahead market-clearing algorithm. In FBMC, market clearing and the allocation of cross-zonal transmission capacity are done jointly. By considering interdependencies between network elements in the market clearing, the transmission capacity is allocated in a way that total welfare from trade is maximized. To arrive at a simplified network model without having to consider all the individual lines, each TSO defines critical network elements (CNEs) in its control area. In the literature, CNEs are also called critical branches. CNEs include cross-zonal lines, but they can also include internal lines or transformers that are significantly impacted by cross-zonal exchanges. By considering a CNE in the capacity calculation process, a CNE can limit the amount of power that can be exchanged. The flow-based parameters incorporated in the market-clearing algorithm are challenging to determine. We briefly introduce two of these: zonal power transfer distribution factors (PTDFs) and CNE availability margins.

First, zonal PTDFs describe the linear relationship between the physical flow in a CNE and the net exchange position of a specific bidding zone. The net exchange position is equal to the total production minus the total consumption within the zone. If production is higher than consumption, the zone will be a net exporter; vice versa, the zone would be a net importer. PTDFs are formulated in a matrix with all the bidding zones in one dimension and all the CNEs in the other dimension. With zonal pricing, nodes are grouped in zones. This implies that in order to correctly represent flows between zones, zonal PTDFs need to be approximated from what happens at the nodal level within a zone. Generation shift keys (GSKs) and load shift keys (LSKs) may also be used to ‘translate’ changes in generation/consumption at the nodal level to impacts on the net exchange level of a zone. GSKs are not easy to determine as they are based on predictions of the market outcome and subject to forecast errors. Each TSO calculates the GSKs for its control area.

Second, CNE available margins (AMs). The AM is the maximum flow from day-ahead trade that can be carried by CNEs. The available margin is also referred to as the remaining available margin (RAM). Determining the AM involves identifying the CNEs within a control zone and the contingencies (critical outages) to be considered for system security. More precisely, AMs are the maximum flow an element can carry corrected by three types of flows to what is left for day-ahead trade. The first correction is for the reference flow to a CNE. This is caused by transactions between or within bidding zones other than the day-ahead market, such as bilateral transactions or transactions in forward markets. The second correction is for a final adjustment value, a margin which is TSO-specific and depends on, for example, costly remedial actions such as redispatch possibilities. To determinate this value it is important to ensure that there is no discrimination between internal and cross-zonal flows. The third correction is for a flow reliability margin, a safety margin compensating for approximations made in the flow-based approach.

3A.2 ANNEX: TRANSIT FLOWS AND LOOP FLOWS

Two types of flow can ‘consume’ cross-zonal capacity between two bidding zones at the expense of capacity available for trade between the two bidding zones. First, transit flows. Some cross-zonal capacity of one bidding zone will be used by parallel flows resulting from trade between other bidding zones. For example, trade between Germany and France can flow through Belgium. Thus, the cross-zonal transmission capacity available for trade between Belgium and its neighbours will be impacted. Transit flows are unscheduled when the exchange causing the flow is cross-zonal and the capacity calculation is not coordinated with the zone facing the flow. A flow is called an unscheduled flow when the physical flow in the network differs from commercial exchanges between consumers and producers within a bidding zone or between two different bidding zones. If the cross-zonal capacity calculation is coordinated between the zones causing the transit flow and the zone facing it, the transit flow is scheduled, as it can be accounted for in the transmission calculation process. A transit flow is illustrated on the left-hand side of Figure 3A.1.

Second, loop flows. Transactions within a bidding zone can have an impact on the flows through adjacent bidding zones. For example, if there is a commercial transaction between the north and the south of Germany, it is possible for electricity to flow through Poland to reach its destination. Thus, the cross-zonal transmission capacity available for trade between Poland and its neighbours (mostly Germany in this case) will be impacted. By definition loop flows are always unscheduled as they occur between two nodes within the same bidding zone. A loop flow is illustrated on the right-hand side of Figure 3A.1.

Transit flows are exactly the kind of flows that can be dealt with by FBMC, but loop flows cannot. Loop flows can only be addressed by revising the bidding zone configuration.

Figure 3A.1 Scheduled flows (black), transit flows (white, left) and loop flows (white, right); the different rectangular areas represent bidding zones

3A.3 ANNEX: REGULATORY GUIDE

Table 3A.1 Regulatory guide

Section of this chapter, topic and relevant regulation	Relevant article
Section 3.2 The CACM GL refers to FBMC as the primary approach for day-ahead and intraday capacity calculations. Even though the NTC method is still allowed, FBMC is already the dominant model.	Art. 20(1) states that ‘ <i>For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.</i> ’ Art. 20(7) states that ‘ <i>TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach in regions and bidding zone borders (other than those referred to in paragraphs 2 to 4), if the TSOs concerned are able to demonstrate that the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.</i> ’
Section 3.3 The SO GL formalizes RSCIs by stating that each control area shall be covered by at least one regional security coordinator (RSC).	Art. 3(89) defines RSCs as ‘ <i>the entity or entities, owned or controlled by TSOs, in one or more capacity calculation regions performing tasks related to TSO regional coordination.</i> ’ Art. 77 describes the organization of regional operational security coordination. Art. 77(2.a) states that each TSO shall be covered by at least one RSC.
Regulation (EU) 2019/943, part of the CEP, renamed RSCs as regional coordination centres (RCCs) and enhanced their governance.	Art. 35 in Regulation (EU) 2019/943 describes the establishment and mission of RCCs. Art. 35(2) specifies ‘ <i>Following approval by regulatory authorities of the proposal [for the establishment of regional coordination centres], the regional coordination centres shall replace the regional security coordinators established pursuant to [SO GL] and shall enter into operation by 1 July 2022.</i> ’
The SO GL defines five core tasks of the RSCs.	Art. 77(3) lists four tasks of the RSCs: (a) regional operational security coordination; (b) building a common grid model; (c) regional outage coordination; and (d) regional adequacy assessment. The fifth task, coordinated capacity calculation, is indirectly mentioned in the CACM GL. In recital 6 of the CACM GL it is stated that ‘ <i>capacity calculation for the day-ahead and intraday should be coordinated at least at regional level.</i> ’ Additionally, Art. 6(3) of the Emergency and Restoration Network Code (ER NC) states that RSCs will be consulted to assess the consistency of measures described in a TSO’s system defence and restoration plan. Last, RSCs also provide critical grid situation support to TSOs, a responsibility that was introduced with the cold spell in the winter of 2017/2018.

Section of this chapter, topic and relevant regulation	Relevant article
Regulation (EU) 2019/943 adds more tasks for RSCs, renamed as regional coordination centres.	Recital 55 of Regulation (EU) 2019/943 states that ‘ <i>The tasks of regional coordination centres should cover the tasks carried out by [RSCs pursuant to SO GL] as well as additional system operation, market operation and risk preparedness tasks. The tasks carried out by regional coordination centres should not include real-time operation of the electricity system.</i> ’ In Art. 37(1), all 16 tasks are listed. Annex I of the same regulation provides additional information.
The CACM GL includes a methodology to define capacity calculation regions (CCRs).	Art. 15 requires CCRs to be determined. A CCR is a geographical area in which coordinated capacity calculation is applied. Each CCR comprises a set of bidding zone borders. Finally, ACER (2016a) approved the revised proposal of all the TSOs, under the condition of merging central western Europe and central eastern Europe into one Core region.
The CACM GL asks for the development of a coordinated capacity calculation methodology for each CCR.	Art. 20(2) states that ‘ <i>no later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region.</i> ’ A methodology for both day-ahead and intraday capacity calculation is to be proposed. Delayed submission was permitted for certain CCRs (CACM GL, Art. 20(3–4)). ACER and CEER (2019) report that as of June 2019 the relevant NRAs approved capacity calculation methodologies in all CCRs except Italy North.
TSOs remain responsible for maintaining operational security. They can decide to not implement a coordinated action proposed by the RCC. They then need to report the detailed reason to the RCC and the TSOs of the region. This will be further investigated. The RCC may then propose a different set of actions.	Art. 42 of Regulation (EU) 2019/943 describes the adoption and review of coordinated actions and recommendations. This article states that TSOs shall implement the coordinated actions issued by RCCs except where the implementation would result in a violation of the operational security limits defined by each TSO in accordance with the SO GL. It adds that RCCs may propose a different set of coordinated actions in the case that TSOs decide not to implement their recommendations.
Section 3.4	
The CACM and FCA GL each include a generation and load data provision methodology (GLDPM).	Art. 16 of the CACM specifies the GLDPM methodology. Art. 17 of the FCA GL states that the GLDPM developed under the FCA GL shall take into account and complement the GLDPM provided in Art. 16 of the CACM GL.
The GLDPM sets out the generation and load data that TSOs can request from grid users. This applies mainly to grid users connected at voltage levels of 220 kV or above. It can also apply to voltage levels below 220 kV if they are used in regional operational security analysis of the capacity calculation timeframe concerned.	Art. 16(2) of the CACM GL states that the proposal for the GLDPM shall specify which generation units and loads are required to provide information to their respective TSOs for the purpose of capacity calculation. Details on which grid users have to provide what data can be found in the approved versions of the respective GLDPMs, e.g. All TSOs (2016).

Section of this chapter, topic and relevant regulation	Relevant article
TSOs can only use the GLDPM to request data if that data is not already available to them through other national or EU legislation (e.g. the ENTSO-E Transparency Platform), which can help to avoid double reporting.	Art. 3(1) of the GLDPM approved according to the CACM GL (All TSOs (2016)) states that <i>'Each TSO shall have the right but not the obligation to obtain these data from the owner of the corresponding network element or the party responsible for providing the information, as the case may be, provided that all of the following conditions are met ...'</i> One of the conditions is that the data are not already available to the TSO through other national or EU legislation.
According to the CACM GL, TSOs can only use the information received under the GLDPM for the purpose of capacity calculation.	Art. 16(5) specifies that the information received under the GLDPM shall only be used for capacity calculation purposes.
The three network codes (CACM GL, FCA GL and SO GL) introduce individual grid models (IGMs).	CACM GL Art. 2(1) defines an IGM as <i>'a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the common grid model.'</i> CACM GL Art. 19, FCA GL Art. 20 and SO GL Arts. 66 and 70 provide more information about the respective IGMs.
RCCs merge the IGMs into common grid models (CGMs).	According to the CEP, more specifically Regulation (EU) 2019/943, RCCs take over the tasks of RSCs. Art. 77(3) of the SO GL states that one of the tasks of the RSCs is to build a common grid model (CGM). The CGM is defined in the CACM GL as <i>'a Union-wide data set agreed between various TSOs describing the main characteristics of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.'</i>
The three network codes (CACM GL, FCA GL and SO GL) describe the IGM merging process in the different CGMs. The difference between these different models lies in the timeframe in which they are calculated and used.	Art. 17 of the CACM GL describes the CGM methodology. Point b in the second paragraph specifies that this methodology shall contain a description of the process for merging IGMs to form the CGM. Art. 18 in the FCA GL introduces the CGM methodology for long-term capacity calculation. Art. 67 in the SO GL describes the year-ahead CGMs and Art. 70 in the same regulation describes the methodology for building day-ahead and intraday CGMs. The SO GL refers to the use of CGMs for various system operation processes.
It is expected that the RCCs will take turns to merge the IGMs into CGMs.	Art. 28 of the CACM GL describes the creation of the common grid model. Art. 28(2) states that <i>'each TSO shall deliver to the TSOs responsible for merging the individual grid models into a common grid model the most reliable set of estimations practicable for each individual grid model.'</i> Art. 77(3) of the SO GL states that one of the tasks of the RSC is to build the CGM. The CGM is pan-European while the capacity calculation is done for the CCRs. Therefore, it is expected that the RCCs will rotationally take the role of the 'merging agent'.
ENTSO-E stores the IGMs and the CGMs in a portal that is called the pan-European Operational Planning Data Environment (OPDE)	The SO GL describes the general provisions for the OPDE in Art. 114.

Section of this chapter, topic and relevant regulation	Relevant article
<p>Following the FCA GL, the CCRs can use the CGMs for their capacity calculations in the timeframes before day-ahead, but they can also opt for a statistical approach.</p> <p>The SO GL requires a key organizational requirements, roles and responsibilities (KORRR) methodology. The approved version of this methodology will be decided at the national level whether distribution-connected significant grid users (SGUs) have to provide their data directly to the TSO or through the connecting DSOs.</p>	<p>Long-term capacity calculation may be based on the CGM. Alternatively, CCRs may opt to use the statistical approach pursuant to Art. 10(4.b) of the FCA GL.</p> <p>Art. 40(6) states that ‘<i>all TSOs shall jointly agree on key organisational requirements, roles and responsibilities in relation to data exchange. Those organisational requirements, roles and responsibilities shall take into account and complement where necessary the operational conditions of the [GLDPM developed in accordance with Article 16 of the CACM GL].</i>’ In December 2018, the revised KORRR methodology proposal by All TSOs (2018) was approved by all NRAs. Art. 3(3) in this approved methodology states that ‘<i>Subject to approval by the competent regulatory authority or by the entity designated by the Member State and according to Article 40 of the SO GL, it shall be determined at a national level whether distribution-connected SGUs in their TSO’s control area shall provide the structural, scheduled and real-time data to the TSO directly or through their connecting DSOs or to both. The decision on the data exchange model may be independent for each type of information and SGU, if required. When the data is provided to the DSO, the DSO shall provide the required data to the TSO with a data granularity necessary to comply with the requirements of the SO GL provisions.</i>’ Art. 2 of the SO GL gives more detail on which SGUs the SO GL applies to.</p>
Section 3.5	
<p>The CACM GL introduced a bidding zone review process.</p>	<p>Art. 32 states who can launch a bidding zone review process and how this process is performed by reviewing existing bidding zone configurations. The first bidding zone review (ENTSO-E 2018b) was initiated by a letter from ACER dated 21 December 2016 specifying central Europe as the relevant region.</p>
<p>Following the CACM GL, the three main criteria considered are the stability and robustness of the bidding zones, network security and overall market efficiency.</p>	<p>The three criteria for reviewing bidding zone configurations are listed and elaborated upon in Art. 33.</p>
<p>Regulation (EU) 2019/943 introduces an improved bidding zone review process.</p>	<p>Regulation (EU) 2019/943 Art. 14 describes the bidding review process.</p>
<p>The implementation of this new process has already started with the submission of a bidding zone review methodology and alternative configurations by TSOs.</p>	<p>Art. 14(5) in Regulation (EU) 2019/943 states that ‘<i>By 5 October 2019 all relevant transmission system operators shall submit a proposal for the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered to the relevant regulatory authorities for approval.</i>’</p>

Section of this chapter, topic and relevant regulation	Relevant article
According to Regulation (EU) 2019/943, if Member States that have opted to change the existing bidding zone configuration cannot reach a unanimous decision, as a last resort the European Commission shall adopt a decision to amend or maintain the bidding zone configuration.	Art. 14(8) states that ' <i>For those Member States that have opted to amend the bidding zone configuration ..., the relevant Member States shall reach a unanimous decision within six months of the notification ... Other Member States may submit comments to the relevant Member States, which should take account of those comments when reaching their decision. The decision shall be reasoned and shall be notified to the Commission and ACER. In the event that the relevant Member States fail to reach a unanimous decision within those six months, they shall immediately notify the Commission thereof. As a measure of last resort, the Commission after consulting ACER shall adopt a decision whether to amend or maintain the bidding zone configuration in and between those Member States by six months after receipt of such a notification.</i> '
Member States have to comply with a transmission capacity availability threshold. Regulation (EU) 2019/943 states that the available transmission capacity of all transmission elements possibly limiting the amount of electricity that can be exchanged between different bidding zones should be at least 70 per cent of a benchmark value.	<p>Art. 16(8) states that '<i>Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones.</i>' Art. 16(8) continues that the following minimum levels of available capacity for cross-zonal trade that have to be reached (at any market time unit) are (a) for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70 per cent of the transmission capacity respecting operational security limits after deduction of contingencies, as determined in accordance with the CACM GL; (b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 per cent of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies, as determined in accordance with the CACM. Lastly, Art. 16(8) adds that a total amount of 30 per cent can be used for reliability margins, loop flows and internal flows on each critical network element.</p> <p>There are three exceptions to the 70 per cent rule: (a) where structural congestion has been identified, in the case that Member States opt for a multinational action plan, the linear trajectory according to Art. 15(2) has to be reached. Compliance with the 70 per cent rule shall be reached by 31 December 2025; (b) Art. 16(9) states that at the request of TSOs in a CCR, the relevant regulatory authorities may grant a derogation from the 70 per cent rule on foreseeable grounds where necessary for maintaining operational security. This derogation shall be granted for no more than one year at a time or, provided that the extent of the derogation decreases significantly after the first year, up to a maximum of two years; (c) Art. 16(3) adds that where RCCs conclude that the available remedial actions in the capacity calculation region or between capacity calculation regions are not sufficient to reach the minimum capacities provided (or the linear trajectory) while respecting operational security limits, they may, as a measure of last resort, set out coordinated actions reducing the cross-zonal capacities accordingly.</p>

Section of this chapter, topic and relevant regulation	Relevant article
A process has been set in motion to assess the extent to which different countries already comply with this threshold and how they intend to comply with the threshold by 2025.	<p>Note that the 70 per cent minimum capacity available for trade in Regulation (EU) 2019/943 applies from January 2020, the date of entry into application of Art. 71(2). In addition, Art. 15(2) says that if a Member State opts for an action plan, the minimum capacity, as described in Art. 16(8), shall be reached by 31 December 2025.</p> <p>Art. 16(3) states that RCCs shall submit a report to the relevant regulatory authorities and to ACER on any reduction of capacity or deviation from coordinated actions due to operational security threats. The RCCs shall assess the incidences and make recommendations, if necessary, on how to avoid such deviations in the future.</p> <p>ACER and CEER (2019) are also already monitoring compliance with the 70 per cent rule in their market monitoring report.</p>
Countries need to choose between the two DG COMP cases. They can follow the Swedish or the German approach to stop discrimination between cross-border and national trade.	<p>Art. 14(7) states that where structural congestion has been identified, the Member State concerned shall, in cooperation with its TSOs, decide to establish national or multinational action plans, or to review and amend its bidding zone configuration.</p> <p>Structural congestion is defined in Art. 2(6) as '<i>congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions.</i>' The identification of long-term structural congestion can be done in three ways: using ENTSO-E's report on structural congestion (Art. 14(2)); using TSO assessments; or the bidding zone review itself (Art. 14(7)).</p> <p>According to Art. 16(8), in the case that a Member State fails to respect the 70 per cent rule while not opting for a multinational action plan or if a Member State has opted for a multinational action plan but does not respect the linear trajectory, a bidding zone reconfiguration can result (Arts. 15(7) and 15(5)).</p>