Market Design Options for Congestion Management

June 2026

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Mission Statement

ENTSO-E – the European Network of Transmission System Operators for Electricity – brings together 40 electricity Transmission System Operators (TSOs) from 36 countries. ENTSO-E members are responsible for the secure and coordinated operation of Europe's electricity system. Together, they operate a system of around 500,000 km of power lines **– the largest interconnected electrical grid in the world –** and serve about 520 million citizens.

Electricity is not merely a market commodity, it is an essential service, and TSOs are fully regulated public service entities whose work is essential to powering Europe. The grid is the backbone of the electricity system and has extended over the whole Continent, beyond the borders of the EU. TSOs working together guarantee a functioning infrastructure that makes the trade of electricity possible, contributes to decarbonisation goals, and ensures a reliable and efficient power supply for all members of society.

These shared public service responsibilities need close cooperation beyond national borders, which led to the creation of ENTSO-E. Today, the association serves two main complementary purposes:

1. Cooperation of European TSOs

The foundations of this cooperation date back to the 1950s with the creation of electrical synchronous areas and interconnections, which laid the groundwork for today's interconnected European power system. TSOs established associations to work together on their own mandates and missions, that came together into what today is ENTSO-E. The European electricity system is one of the most stable and reliable grids in the world and is supported by the cooperation and coordination of TSOs both within the European Union and closely interconnected European countries. ENTSO-E strives to build consensus for decision-making amongst its member TSOs as this forms the strongest foundation for cooperation.

2. Fulfilling EU legal mandates

With the adoption of the Third Energy Package in 2009, ENTSO-E's role was formally recognised by European institutions. ENTSO-E was granted legally mandated tasks to further develop the European interconnected grid and to facilitate the integration of European electricity markets. These mandates cover a large spectrum of tasks, including system operation, system development, market integration, information technologies, R&D and innovation.

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1 Introduction

As the European electricity sector moves towards a decarbonised, less predictable and more interconnected power system, Transmission System Operators (TSOs) are facing growing challenges to ensure the stability, resilience and efficiency of the electricity system. In this context, reducing grid congestion in the long run while ensuring effective and efficient congestion management and redispatch in the short- to medium-run are critical for integrating renewable energy sources (RES), maintaining security of supply, ensuring cross-border trading in the internal European energy market, maximising socio-economic welfare, and controlling system costs to ensure affordable electricity for all European citizens.

Recent events such as the 28 April 2025 Iberian, 18 May North Macedonian, and 4 July Czech incidents underscore that, even when congestion is not the root cause, system operation is becoming more fragile and dependent on robust operational planning, security analyses and real-time voltage control. While ENTSO-E and TSOs are constantly striving to improve their system operation practices, tools and processes, it is also essential to identify market design solutions that can bridge and better manage the gap between market outcomes and the physical constraints (incl. improved operational handling where unavoidable) of the power system.

The more market design rules incentivise or require generators, consumers and storage operators to make investment and dispatch/consumption decisions in line with system needs, the more efficient the market will be in fulfilling its primary role of ensuring efficient dispatch and allocation of resources and the less TSOs will need to intervene to prevent or correct operational issues and grid congestions. The different strategies (e. g. stronger locational signals) considered in this paper can improve alignment with system needs, but may increase complexity, create redistribution effects and come with implementation costs.

On the other hand, relying on corrective actions preserves a simpler market but can raise congestion management volumes and costs. This trade-off is valid for a whole range of market design solutions leading to different implications, risks and costs for the power system as a whole, for TSOs, for market parties and for consumers. Overall system and market efficiency should be considered, also to ensure potentially limited flexibility solutions for TSOs are sufficient.

ENTSO-E and its member TSOs deal with congestion management challenges continuously and on different levels: in their day-to-day system operation tasks; in the drafting and implementation of EU-wide, regional, and national methodologies and market rules; in the study and assessment of market design solutions and their possible improvement. Grid flexibilities can potentially be a first step before market solutions, depending on how the grid has been developed and structured: topological and costless actions can be taken preventively and curatively to solve congestions.

In this paper, we aim to offer a comprehensive and forward-looking ENTSO-E vision on the challenges and possible market design solutions associated with reducing congestion in the long-run, managing congestion in the short- to medium-run and maintaining congestion management at volumes and complexity that remain operationally manageable for TSOs under all system conditions, with a particular focus on the evolving context of the European power system, its electricity markets, and the regulatory framework. As an example, the recent European Market Design Reform has established the obligation to move the intraday trading closure time till 30 minutes before real time. With less time between market closure and real time, a market design that better aligns market outcome with the physics of the system to minimise congestion and efficient tools for managing congestions that cannot be prevented will be increasingly important to maintain safe and secure system operation. While TSOs are already working on a number of solutions to be implemented in the upcoming years as part of the Regional Operational Security Coordination (ROSC) process, they also see the need to explore further policy options in this paper.

Purely from congestion management perspective, it would be neither efficient to dimension the power grid for every conceivable peak load nor to permanently accept the high costs of congestion management and forgo further grid expansion. TSOs together with NRAs aim to identify the cost-optimal configuration for the overall system, by balancing costs for both grid expansion and congestion management costs on the one side, and associated benefits in terms of welfare, resilience and operational security.

This paper focuses exclusively on congestion management and redispatch challenges at the transmission level and on **market-design-related measures** that can improve the efficiency, predictability and robustness of congestion management across Europe. The comparative evaluation of the considered solutions, as well as the conclusions contained in this paper are based on a high-level qualitative assessment performed by ENTSO-E experts. Such experts' assessment builds on concrete experiences at national and European level, literature review and regular engagement with policy makers and stakeholders. During drafting, the paper was submitted for an external review by selected external consultants[1] to check the robustness of our analysis.

Transmission grid investments or network expansion, as well as technical and operational measures aimed at increasing transport capacity, while essential to prevent, mitigate and manage grid congestions, are out of the scope of our analysis. Although out of the scope, for the sake of completeness high level descriptions of some examples of these technical and operational measures to mitigate congestions are available in Annex 1. Moreover, broader operational security processes, such as real-time system operation, detailed security analyses, or defence plans fall outside the scope and are addressed only where necessary for contextualisation. For simplicity, the solutions explored in this paper are grouped into four categories: (i) Spatial granularity in energy markets, (ii) locational siting incentives, (iii) Preventive measures outside of wholesale markets and (iv) congestion-management tools.

1 Neon Neue Energieökonomik GmbH (Lion Hirth and Alexander Neef), Magnus Energy B.V. (Gerard Doorman), DNV Energy Systems Germany GmbH (Hans de Heer, Carlotta Ferri and Bart Stoffer), AFRY Management Consulting Limited (Stephen Woodhouse and Kostas Theodoropoulos), Consentec GmbH (Christoph Maurer, Philipp Baumanns and Christian Zimmer).

2 Underlying Causes and Emerging Challenges in Congestion Management and Redispatch

The European power system is facing growing challenges in managing grid congestion, driven by a widening gap between the pace of grid development and the rapid transformation of the generation mix. As renewable energy sources and storage systems proliferate, often in a decentralised and uncoordinated manner, existing grid infrastructures are increasingly strained, while the current market design assumes full freedom of investment and dispatch. Congestion becomes more frequent and less predictable with weather-dependent, often remotely located RES and changing flow patterns; in parallel, the withdrawal of conventional units reduces available controllable flexibility. This results in more redispatch interventions by TSOs, affecting overall system efficiency, increasing consumer grid tariffs, and risking curtailed RES output and reduced cross-border capacity.

While many of the **root causes** are beyond the direct influence of TSOs, it is important to acknowledge them to provide context for the framework within which proposed solutions are developed. The following interrelated factors have been identified as underlying issues of the growing congestion management challenges:

- **Slow and insufficient grid development:** The pace of grid expansion and reinforcement has been lagging behind compared to the rapid changes in generation and consumption patterns, as well as to the increase of physical flows and cross-border trading. Administrative, regulatory, technological and financial bottlenecks have contributed to a mismatch between grid capacity and the evolving needs of the European energy system. Building transmission lines has been historically lengthier than commissioning new power plants and decommissioning of power plants having impact on structural congestion, but this mismatch has further increased in recent years as build-up of RES, batteries, electrification and new large loads (electric vehicles, heat pumps, electrolysers, data centres) has accelerated while grid development hasn't. While TSOs were often stuck in lengthy planning and permitting procedures over the past decade, the number of commissioned grid reinforcements and new transmission lines has increased significantly in the past 2–3 years.

  In the decade ahead, grid expansion is expected to progress even more rapidly than during the previous one. Nevertheless, a gap will continue to exist in the near future between the available transmission capacity and the required one. This can result in localised surpluses or deficits, further complicating congestion management..

- **Increasing gap between market outcomes & physics:** Current market structures and price signals often fail to accurately reflect physical flows and internal network constraints in space and time as well as inadequate bidding zone configuration not reflecting internal constraints, weakening locational signals. This misalignment can exacerbate congestion by incentivising generation or consumption in locations where the grid is already under strain. To pick an example, in some electricity systems a relevant part of the RES installations for energy transition consists of small assets that are unresponsive to price signals. Due both to this unresponsiveness and to their increasing number, they are becoming relevant from the congestion management point of view across all voltage levels.

The above-mentioned root causes collectively manifest in increasingly frequent, less predictable, and more complex congestion patterns across the European transmission system[2].

2 As it can be appreciated when comparing ENTSO-E's Bidding Zone Configuration reports from 2025 and 2021

This leads to the below mentioned key challenges, which are anticipated to intensify further over the coming years, underscoring the need for identifying and addressing these challenges:

- **Increasing congestions and associated costs:** The growth in variable and weather-dependent renewable generation, flexible demand, storage systems and more complex cross-border flow patterns compounded by grid constraints lead to more and frequent congestions and greater reliance on congestion management measures. This results in higher volumes, peaks of RES curtailment and upward redispatch and controlled load shedding, driving up costs for TSOs and, ultimately, consumers.

- **Shorter time to deal with higher variability and uncertainty of congestion patterns:** In addition to increasing frequency and depth of congestions, the rise of renewable energy sources also leads to higher uncertainty of load flows through the grid, increasing volatility of congestion and the need of more frequent intervention closer to delivery. While load flow forecast accuracy is inherently limited, the need for accurate load flow forecasts becomes essential in this context, as they enable TSOs to implement timely countermeasures, such as redispatch, to maintain grid security and prevent overloads. This development can be further exacerbated by emerging market opportunities, such as those in the intraday timeframe, which encourages flexible injection and withdrawal by storage units. From current statistics, it can be seen that significant shares of intraday volumes are traded in the last two hours before delivery[3]. Moreover, the shortening of cross-zonal intraday gate closure time to 30 minutes before real time (as requested by the recent Electricity Market Design Regulation) will further increase cross-border trades taking place close to real time. These market evolutions lead to increased uncertainty in redispatch and require TSOs to react more swiftly and flexibly than current processes allow. Traditional redispatch mechanisms may not be capable of responding effectively to changes closer to real time. This results in greater operational challenges and often market inefficiencies, such as higher costs and increased operational risks.

- **Integration of new renewables capacities and flexibilities:** The surge in renewable installations, energy storage, electrification of demand – while essential for decarbonisation – pushes greater volumes of energy trading closer to intraday gate closure time reducing visibility of energy market results making the secure operation of the energy system increasingly complex. This new paradigm, compared to the historical system based on inflexible demand and conventional generation, creates a need to assess upgrades of rules and regulations to allow for congestion management strategies more suitable for the integration of large-scale renewables and flexibilities into energy markets and TSO processes.

- **Risk of insufficient grid-serving (including balancing) system flexibility:** The withdrawal of conventional dispatchable power plants from the market reduces available flexibility. As shares of variable renewables increase and while modern RES can provide some services, system flexibility needs grow requiring, flexible resources such as demand response, grid-scale storage[4], and interconnections become increasingly vital for balancing supply and demand. Some of these resources, however, may not have the technical capability or incentives to provide the same flexibility amount/attributes to TSOs' congestion management processes as the decommissioned generation capacity. Greater electrification of demand (industry, transport, heating & cooling) and new loads (e.g. data centres, electrolysers) further increase challenges of having sufficient system flexibility at the right locations and at the right time.

- **Policy and market Participant dependencies:** The adaptation of the power system is frequently contingent on political decisions, as for example the ongoing revision of Capacity Allocation and Congestion Management (CACM), and addition of new/expanding market participants (e.g., data centres, electrolysers, large batteries) with possibly major impact on the power system, adding layers of uncertainty. This makes it difficult for TSOs to anticipate location, size and timing of congestions, as well as the available means to address such congestions.

3 For example, this share amounted to around 50 % in Single Intraday Coupling for 2024 (https://www.nemo-committee.eu/assets/ files/cacm-annual-report-2024.pdf)

4 Please see ENTSO-E Policy Paper on Market Design for Utility-Scale Energy Storage (https://www.entsoe.eu/news/2025/12/16/entso-e-policy-paper-on-market-design-for-utility-scale-energy-storage/)

- **Complex cross-border coordination:** Effective congestion management increasingly necessitates coordination between TSOs across national borders. However, despite the well-coordinated and fully coupled European Electricity Market there are additional national congestion management frameworks and market structures. The complexity of changing regulations requires rapid adaptations, alignment of internal, local and cross-border relevant constraints, cost-sharing aspects, multilateral dependencies on various actors (including NEMOs and market parties) make the implementation of coordinated redispatch solutions particularly challenging.

- **Effectiveness of relying on remedial actions to implement the minimum 70 % rule:** In accordance with Article 16(8) of Regulation (EU) 2019/943, TSOs are required to make at least 70 % of cross-zonal capacity available for the market, whereby it is allowed to deviate or derogate when necessary to maintain operational security. The minimum 70 % rule aims to avoid undue discrimination between internal and cross-zonal exchanges and thus to foster greater market integration by increasing cross-zonal capacity available to market participants.

  However, meeting this requirement poses important operational challenges for TSOs, who must reconcile it with the requirement to maintain operational security. When the market uses virtual margins, it means the resulting dispatch is not operationally secure and TSOs must correct this dispatch through remedial actions. By definition, this approach undermines efficient dispatch and price formation, while creating a barrier for the market to have foresight on the capacities. Last but not least, while non-costly and costly remedial measures can help to manage associated challenges (such as loop flows) to a certain extent, their effectiveness is limited by availability.

Collectively, these factors make congestion management more challenging by forcing TSOs to prepare for potential adjustments and make more frequent and reactive adjustments, which comes along with an increased risk to grid reliability and for controlled load shedding. In addition, these factors can increase operational complexity and may increase system costs ultimately borne by consumers as well as other negative externalities such as reduced cross-border capacity, RES curtailment and possibly higher CO_2 emissions. Ultimately, the higher system costs may make the transition towards a renewables dominated power system less affordable for end-consumers.

3 Possible Solutions

Rules, regulations, market incentives, products and processes must be developed to strike a balance between (1) enabling market participants to efficiently trade in the internal electricity market; and (2) equipping TSOs with the tools to reconcile market outcomes with physical constraint of the system and to intervene in critical situations to continuously ensure a secure system operation. To simplify this trade-off, the more market outcomes are aligned with physics and market participants are incentivised to support – rather than complexify – system operation, the less tools and intervention will be needed by TSOs.

This section provides insights into a wide range of potential solutions for the challenges described above. Solutions described are not one-size-fits-all and the applicability depends on context and preconditions. The aim is to map the design space and trade-offs, not to prescribe universal deployment.

It must be noted that many of the market design options identified are not intended to address the root cause of congestions or to represent a comprehensive solution for the full scope of challenges. Furthermore, when assessing the effects of specific market design measures in the broader context, policymakers should consider that certain goals or incentives for grid users may be better achieved with targeted instruments.

Before presenting the individual solutions, it is important to clarify that these measures are not standalone options, but parts of a coherent toolbox whose effectiveness depends on how they interact across timeframes and decision layers.

Therefore, we cluster the different measures as following:

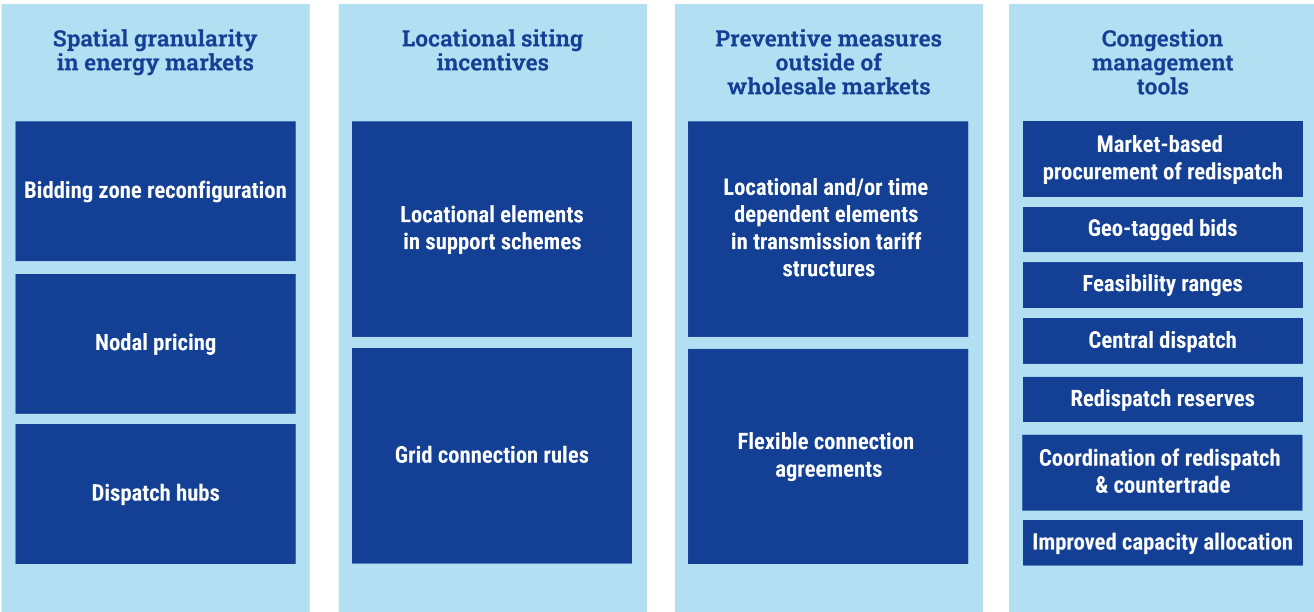


Figure 1: Overview of market design measures.

3.1 Spatial granularity in energy markets

This first category of market design options aims to improve the coordinating function of the electricity price. This can be done by increasing the spatial granularity to make sure that structural limitations in grid capacity are correctly reflected in the market. Increasing spatial granularity in energy markets can lead to price differences between geographical areas. These price differences reflect network constraints and can improve congestion management and dispatch efficiency by creating the incentive for grid users to adjust their behaviour in both the short-term dispatch and the long-term investments. At the same time, they may raise concerns related to social impact, distributional effects and market acceptance, in particular for consumers.

The introduction of more granular market arrangements therefore needs to balance efficiency gains with the market's need for predictability and stability, which is especially important for long-term investment.

To support acceptance, additional mitigating measures may be required, such as arrangements enabling efficient hedging, averaging prices for consumption, or measures addressing redistributional effects.

Bidding zone reconfiguration is the current default way in European legislation to improve economic efficiency and to maximise cross-zonal trading opportunities, by basing bidding zone borders on long-term, structural congestions in the transmission network. But so far, the bidding zone reconfiguration process via extensive bidding zone review studies have not yet led to any bidding zone reconfigurations. Two additional approaches are also presented in this paper: nodal pricing, also known as Locational Marginal Pricing, and the Dispatch Hubs concept.

3.1.1 Bidding Zone Re-configuration

A bidding zone (BZ) is an area within the electricity market where electricity can be bought and sold without considering physical grid limitations. Optimal bidding zone configurations should maximise economic efficiency and cross-zonal trading opportunities, while maintaining security of supply. BZ reconfiguration is already an existing tool for congestion management as described in article 14 of European Regulation 2019/943, and a Bidding Zone Review report[5] has been published by TSOs in 2025. Introducing changes in the BZ configuration is subject to a political decision. Because the current BZ review process is rather complex and lengthy, TSOs believe simplification is needed. However, while the current process of a BZ review has room for improvement, suggestions for such improvements are not in scope for this report. Instead, we focus on the potential the solution has to address the issues identified assuming an optimal review process.

In the Nordics there is a long tradition of applying bidding zones to handle congestion. Currently, the Nordic synchronous area including Finland, Sweden, Norway and the eastern part of Denmark is divided into eleven bidding zones (SE1 – 4, NO1 – 5, FI and DK2). Also, Italy applies a zonal market and the actual bidding zone configuration is based on seven bidding zones.

BZ configurations, designed to reflect structural congestions in the grid, provide accurate and transparent price signals to guide market behaviour and highlights where grid infrastructure needs reinforcement. Such properly defined bidding zones support an efficient, market-driven operation of the electricity system enabling effective congestion management, minimizing the need for redispatch and/or countertrade. BZ reconfiguration thereby helps addressing all the key challenges identified in Chapter 2, to varying extent: primarily they improve dispatch signals, enable a market outcome that reflects the underlying physics of the grid, and they provide locational investment signals for future generation and consumption, while they only partially help manage uncertainty and volatility of congestions. In addition, loop flows can cause congestions in neighbouring member states. More granular bidding zone configurations reduce those congestions through the reduction of loop flows and could thereby facilitate the fulfilment of the minimum 70 % requirement without extensive reliance on redispatch and/or countertrade. As seen in the 2025 BZ Review report, smaller BZs can also lead to higher levels of loop flows inside the split area as flows that were previously considered internal flows now become loop flows or market flows. A more in-depth explanation on the effects that changing BZs have can be found in the 2025 Bidding Zone Review report.

5 See Bidding Zone Review Report for the target year 2025

In the transforming power system TSOs and Member States need to ensure that the BZs are optimal and support an efficient operation of the power system. Any change of the configurations must be carefully assessed, and the analysis must capture the impact of the change from many perspectives, such as operational security, market efficiency, market liquidity, implementation costs, energy transition goals and security of supply.

The complexity makes the process both resource and time-consuming, especially when the review covers multiple countries; an alternative delineation may be beneficial from some perspectives but challenging from other. Any change of BZs must have political acceptance as the decision is taken at Member State level. The level of political and social acceptability of different price zones within a country varies considerably across Europe, also in function of historical reasons and legacy market design choices.

3.1.2 Nodal Pricing (Locational Marginal Pricing – LMP)

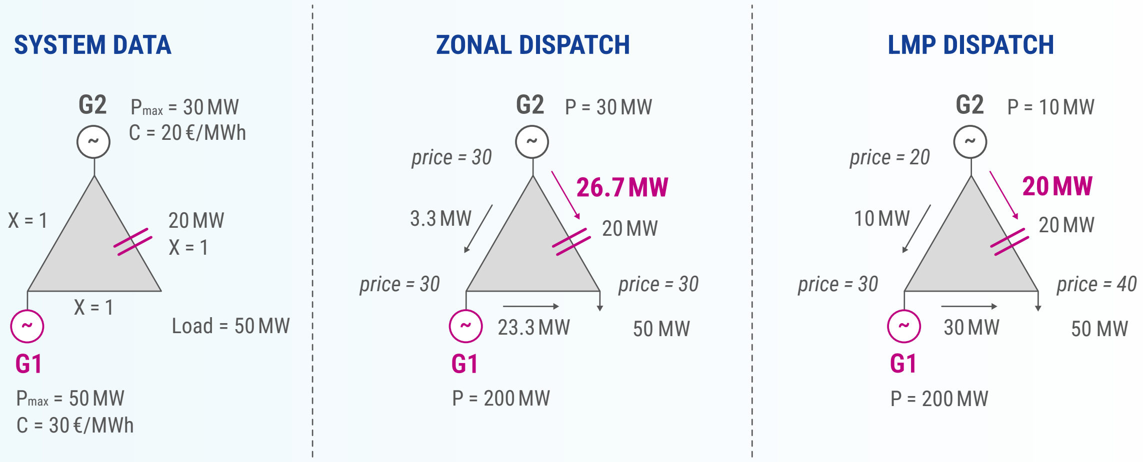
Introduction

The purpose of this solution is to align market operations with the physical constraints of the transmission grid at a fundamental level, drawing on approaches successfully implemented in e.g. some U.S. electricity markets, as well as in Singapore, Chile and New Zealand. With LMP, also known as nodal pricing, the price in each node of the grid reflects the marginal cost of serving an additional unit of load in that particular node taking into account grid congestions and losses. Such an increase may be supplied by a marginal generator or demand bid in the same node (in which case the price is equal to that generator's offer price or demand bid price), by a generator or demand bid at another node fully deliverable over uncongested lines (then the price becomes that generator's offer price or demand bid price plus losses), or by a combination of several generator(s) or demand bids in a congested, meshed grid. The calculation of LMPs uses a grid model with the voltage level and level(s) of detail corresponding to the desired nodal pricing resolution, typically (but not necessarily restricted to) representing the transmission grid (≥ 220 kV in a European context). Generators and demand submit unit-based offers and bids, including their nodal pricing location. The market clearing is based on Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). SCUC includes startup related costs, minimum up- and downtimes, ramping constraints etc. and is performed as a mixed-integer optimisation problem with significant computational complexity.

SCED on the other hand, does not consider startup-related costs and other complex constraints and is typically performed as a linear optimisation problem after SCUC. In addition, AC load flow programs and if necessary dynamic calculations are used to estimate non-linear constraints (e.g. voltage based) used in SCUC/SCED and to verify that the optimisation results satisfy grid security constraints. The concept of how LMP prices are determined is illustrated with the simple example in Figure 2.

Existing LMP markets run in two time horizons: day-ahead and real time. The day-ahead market is used to create financially binding schedules that are "simultaneously feasible", meaning that they satisfy all relevant grid constraints. Therefore, under the theoretical assumptions of the LMP model, redispatch is not required, as illustrated in the example below. However, in real-world operations, some additional actions are likely still necessary as iterative process until real time. The day-ahead market clearing uses an SCUC process that calculates the LMPs and schedules that reflect transmission constraints, unit dynamic constraints, etc. The real-time markets typically clear every 5 minutes, using SCED, which is a much faster process. SCED does not consider commitment decisions, which are not relevant at a 5-minute time horizon. The real-time market reflects the real time operating constraints of generators, demand side bids and the transmission grid, and the resulting dispatch thus satisfies all these constraints. They are also reflected in the real-time price, at which all remaining imbalances are settled.

Example



The **left-hand panel** shows a three-node system with equal impedances of the lines. Because of this, the flow from G1 will be distributed as ⅓ on the line G1-G2-Load, and ⅔ on G1-Load, and correspondingly for G2. The line between Generator 2 and the load has a maximum constraint of 20 MW. The generator capacities P_{max} and offer prices c are given in the figure.

The **middle panel** shows the result of the zonal market clearing. The cheapest generator G2 runs at its maximum of 30 MW, while G1 provides the remaining 20 MW. The price is equal to the offer price of G1, 30 €/MWh for all nodes, by design of the zonal market. However, the flow on the line between G2 and load is 26.7 MW, exceeding the maximum value of 20 MW. To solve this, the system operator would redispatch by reducing the production of G2 and increase the production on G1.

The **right-hand panel** shows the dispatch resulting from LMP. In this case, an optimisation algorithm would include the line constraint and directly yield the shown result that satisfies this constraint (and that also would be the final dispatch after redispatch of the zonal result). In the generation nodes, the prices equal the offer prices of the generators, because neither is at their maximum. However, in the load node, the price equals 40 €/MWh, which looks surprising at first glance. The reason is that to increase the load 1 MW, generator G2 needs to reduce production by 1 MW (reducing the flow on G2-Load), and generator 1 must increase production with 2 MW (increasing the flow on G2-Load). As a result, the flow on the line G2-load is still at its maximum. The cost of this is 2 × 30 – 1 × 20 = 40, which is the marginal cost of increasing the load, thus setting the price in this node.

The example illustrates two important facts about LMP:

One constraint can cause many different prices, and nodal prices can exceed the individual generator offer costs (although the effect is rather extreme in the simple example).

Figure 2: Example – Zonal Market Dispatch Compared to LMP Pricing

Advantages of LMP compared to the EU zonal approach

A key characteristic of the nodal pricing approach is that the physical characteristics of the transmission grid including relevant thermal, voltage and security constraints are explicitly represented in the market clearing process through LMP. This allows congestion to be addressed ex ante through the market outcome, whereas in a zonal model a part of these constraints is typically managed ex post through redispatch.

The LMP approach provides locational price signals for each individual node, reflecting the marginal cost of energy, congestion and losses. These signals support economically efficient operational decisions by market participants, including the dispatch of generation, demand response and storage, in a manner that is consistent with the underlying network constraints in particular, flexible resources can respond to locational price differentials by adjusting injections and withdrawals in space and time.

By consistently reflecting the cost of congestion in prices, nodal pricing markets can provide transparent locational signals relevant for longer-term investment decisions. Persistent nodal price differentials may indicate areas where network reinforcements, new generation, storage or demand-side flexibility could contribute to system efficiency, thereby supporting informed grid development and resource siting decisions.

The nodal pricing model does not rely on Generation Shift Keys (GSKs) or other approximations linking commercial exchanges to physical flows. Thus, more transmission capacity can be made available to the market as the associated uncertainties in Flow-based capacity calculation are reduced.

There is no differentiation between internal and cross-zonal transactions within the region and thus no capacity reservation for loop and internal flows. The capacities of individual grid elements are directly represented in the market clearing.

The capacities of individual grid elements, including relevant security constraints as N-1, are directly represented in the market clearing process, supporting market outcomes that are consistent with operational feasibility and system security requirements.

Transmission losses are typically considered in the market clearing algorithm, allowing prices to reflect the marginal cost of delivering energy to each location and supporting more efficient dispatch and siting decisions from a system perspective. Existing LMP markets integrate reserves procurement with the day-ahead market, as well as balancing with congestion management in the real-time market. Such an integrated design can enhance overall system efficiency and contribute to cost-effective and secure system operation under uncertainty.

Challenges and weaknesses of LMP compared to the EU zonal approach

Implementing any existing LMP market in Europe – whether at regional or pan-European level – would require substantial policy action, amounting to a fundamental overhaul of existing market rules. This includes changes to bidding formats, clearing algorithms, dispatch approaches and governance structures. In theory, the current European zonal target model does not explicitly exclude very small bidding zones, which could be seen as similar to nodes. However, transitioning to a nodal pricing system in the EU power market with the current regulatory framework is unrealistic.

Transitioning to an LMP market model based on international experiences would likely require changes to the current roles and responsibilities concerning system operation and market operation. While practical applications of LMP today have taken place only in contexts with Independent System Operators (ISOs), any potential transposition of LMPs to European markets should explore how to ensure compatibility with existing roles and responsibilities.

Interfacing a nodal pricing market with neighbouring countries operating under a zonal model would be challenging and it would potentially require coupling algorithm adaptations. Current SCUC/SCED formulations were originally developed for thermal units with constraints such as startup costs, minimum up/down times, and ramp rates. Renewable energy sources, demand response and energy-limited resources like batteries operate under fundamentally different constraints (state of charge, cycle limits, multi-hour optimisation horizons). Further, the energy transition leads to vastly different characteristics of the European power system as compared to the lightly integrated US power systems utilising largely conventional generation. Existing LMP models have not adequately captured these intertemporal dynamics to date, highlighting the need for analysis on how these models can cope with the more challenging system dynamics of a system based on a highly integrated market running on renewable generation with very low inertia[6].

6 These challenges are also present in zonal markets, although part of the optimisation could be done by market participants themselves via complex bidding products where present.

In the absence of continuous intraday trading, LMP may provide weaker trading opportunities for market participants to react to temporal signals and provide flexibility needed for RES integration. This lack of intraday trading may also reduce TSOs' visibility of congestion occurring as a result of differences between day-ahead market results and physical dispatch in real-time, especially where generation or demand is inflexible in regards to the real-time price signals and for generation and demand that are only participating on an aggregated basis. However, this may be solved in LMP by the introduction of several intraday auctions similarly to existing European IDAs in opposition to currently existing nodal pricing market. Moreover, as we transition towards a system featuring decentralised, flexible resources situated at the low-voltage level, it is necessary to integrate these decentralised assets (for instance via aggregation, local markets or even Distribution Locational Marginal Pricing[7]) in order to account for local congestion and voltage constraints. Nodal pricing markets typically require unit-based bidding, eliminating portfolio bids and their associated advantages for traders and resource owners.

An additional notable challenge in adopting nodal pricing for the European electricity market is the redefinition of the reference market. In contrast to the prevailing EU zonal framework, which designates the day-ahead market as the core spot market and primary price reference – underpinning numerous contractual arrangements, investment signals, regulatory mechanisms, and risk-management practices – a nodal pricing system would instead position the real-time balancing market as the principal benchmark. This would mean reliable valuation of generation assets and transmission infrastructure emerges solely from real-time prices, where supply and demand interact under binding grid constraints. This shift would require careful policy planning to address potential disruptions to existing dependencies on the day-ahead reference.

Finally, from an optimisation problem perspective, it should be noted that both the size (i. e.: more than 15,000 nodes above 220 kV) and the meshed nature of European transmission grid (many capacities connected to more than one node) compared to existing smaller and more radial system managed by LMPs would entail a significant challenge.

On the one hand, listed advantages and analyses highlight the potential benefits of Locational Marginal Pricing (e. g. "Locational Price Signals in Europe" by JRC 2025). On the other hand, implementing a nodal pricing market design in Europe presents several challenges listed above.

A potential transition from a zonal to a nodal pricing market in Europe cannot be achieved by simply adopting an off-the-shelf solution. It would require a tailored design that combines the most effective elements from both U.S. and European experiences, and a large amount of dedicated resources from all TSOs as well as NRAs and market representatives. Any potential transition should also consider different implementation pathways, such as a gradual rollout starting with selected countries or limiting nodal pricing to the real-time (balancing) market while keeping day-ahead and intraday markets under the zonal model.

Political and social acceptance may be difficult to achieve due to the inherent complexity of the nodal pricing design and to the significant changes to be made to market and regulatory frameworks. Such acceptance would also be lower in specific areas expected to be affected by higher consumer prices (in absence of mechanisms to average such prices over larger areas), as for other solutions leading to geographically differentiated end-user prices. Expectations of significant efficiency gains would need to be sufficiently robust to enhance acceptance.

Lastly, a nodal pricing system is also typically combined with a switch to central dispatch in order to manage the system closer to real time, whose benefits and challenges are described in Chapter 3.4.4 of this paper.

7 See for instance Karsten Neuhoff et al. (2025): Local Market Places: Market design options, ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg.

3.1.3 Dispatch Hubs

Dispatch Hubs are a conceptual market design solution whereby a group of nearby units (generation, storage, load) located in strategic locations in the grid to manage grid congestions are placed in a dedicated virtual bidding zone to increase the efficiency of dispatch. For the flow-based market coupling algorithm, dispatch hubs are equivalent to small bidding zones within existing bidding zones. As such, imports/exports from dispatch hubs are optimised by the market coupling algorithm to maximise welfare, subject to flow-based constraints, resulting in clearing prices and net positions for the dispatch hubs and the rest of the bidding zones.

Please note that further analysis will be required to settle the design of the dispatch hubs, including the compensation and their impact on congestion management.

A key benefit of this tool is to reduce out-of-market redispatch by capturing the impact on all critical network elements. It also better addresses certain welfare distribution concerns (because of the impact of price differences on a more limited amount of grid users). Compared to a bidding zone split, the application of dispatch hubs is considered in this paper within the market coupling algorithm for the single day-ahead market (SDAC) and intraday auctions (IDA), while any potential broader application could be subject to further analysis. Dispatch hubs could be introduced or changed with a shorter and more flexible process targeting frequent congestions being 'structural' but of temporary nature, looking 1 to 5 years ahead. This tool can therefore be complementary to the bidding zones re-configuration.

Should this solution be implemented, it should be carefully designed to ensure level playing-field between units placed in and out of the Dispatch Hubs. A trade-off between this flexibility and predictability and stability for market participants should be sought. Also, this solution would require regulatory evolutions such as the review of virtual margins from the 70 % framework established in Article 16 of Regulation 2019/943, since they carry significant collateral consequences for the power system operations, especially in combination with dispatch hubs. A more comprehensive explanation on the general concept of Dispatch Hubs can be found in Elia Group reports[8].

Dispatch Hubs have an effect on the dispatch of the system and hence can affect flow patterns. This can make them a particularly interesting tool to manage congestions in the market in an efficient and effective way. Dispatch Hubs internalise the cost of solving congestions directly in the market, leading to reduced redispatch costs in case the grid restrictions are sufficiently considered in the market clearing. Hence, in terms of congestion management, Dispatch Hubs can, under a suitable regulatory framework, including additional internal critical network element and contingency (CNECs) being considered in the market coupling optimisation, lead to effects similar to a split of bidding zones. However, Dispatch Hubs can be defined in a more flexible way whereas a bidding zone split is a more static and structural decision. Indeed, the governance and extensive studies required in the bidding zone review (BZR) make it a slow process. The dispatch hub review process should therefore occur more frequently (i.e., on a yearly basis) to follow new congestion patterns.

8 See for instance Future-proofing the EU energy system towards 2030 – 2019

With a lighter and less formal governance framework, these reviews could be carried out more easily. While the first implementation may take more time, once the principles are established and running, the review process would become more efficient. They can be seen as a tool complementary to bidding zone reconfiguration, to address congestions which are 'structural' yet temporary in nature (congestion patterns are expected to become more dynamic and shifting over time).

Illustrative example: two Dispatch Hubs are integrated in an existing bidding zone, located at the opposite sides of an observed north-south congestion. The Dispatch Hubs will behave like small virtual bidding zones. Units located within the Dispatch Hubs must submit bids specifically for the Dispatch Hub. An alternative design would be that TSOs place forecasted redispatch potential along with a price in the Dispatch Hubs, in which case the Dispatch Hubs define the redispatch that the TSO must perform post-market to make the market results technically feasible.

The Dispatch Hubs give the market the possibility to stop the lignite unit in the north and start the gas unit in the south. The market would only do so in a case when the additionally generated welfare would exceed the extra costs generated in the Dispatch Hubs. In this example, extra costs are absorbed directly in the market coupling, leading to reduced redispatch volumes and cost.

The advantages of Dispatch Hubs in this example are multiple: congestion is solved in the market, redispatch costs and loop flows are reduced and the system can allow more cross-zonal exchanges.

In terms of practical implementation, the impact on the performance of the EUPHEMIA market clearing is to be assessed as, like a new BZ, each Dispatch Hub would require a new dimension in the flow-based domain. In case of units bidding directly in the Dispatch Hubs, it should be considered whether a compensation scheme would be needed while at the same time mitigating risks of market power abuse.

In general, the positive benefits of the Dispatch Hubs on congestion management require the market (allocation) to have a sufficient view on the grid on its constraints. The overall concept is to bring physics and markets closer together. This implies to include the important internal lines i.e. those that are significantly impacted by cross-border exchanges into the allocation, and to refrain from the use of virtual margins (a feature of the min. 70 % framework). In case these preconditions are not fulfilled, the additional capacity in the redispatch potential variant being available to the market is likely to be used to push trading to even more infeasible solutions leading to more need for congestion management, while at the same time having reduced redispatch potential at hand.

3.2 Locational siting incentives

3.2.1 Locational Elements in Capacity Mechanisms and RES Support Schemes

Investment support schemes and market mechanisms, such as capacity mechanisms, RES auctions, and Non-Fossil-fuel Flexibility Support Schemes (NFFSS) could incorporate locational elements that influence the siting of new assets, either by providing incentives for system-friendly locations or by disincentivising development in congested areas. This could be part of a solution to indirectly reduce congestion and the associated redispatch costs, provided that the locational element does not distort market participants' behaviour or response to market price signals.

Locational elements can take a variety of forms. One option is differentiated remuneration by area, potentially down to the level of internal bidding zones. Another approach involves volume limitations for specific areas. A third method is the use of non-price awarding or prequalification criteria in auctions, where projects in certain locations are prioritised or excluded, as seen in France and Spain. Finally, targeted incentives for co-location of RES and storage can ensure that flexibility resources are sited near variable generation.

The introduction of locational elements in investment support schemes directly addresses several challenges. By differentiating remuneration levels across regions, the mechanisms can encourage developers to locate assets in less congested areas of the grid, such as siting storage or flexible demand close to renewable generation hubs. In cases where developers choose to locate the asset in congested areas, lower remuneration ensures that part of the negative externalities is absorbed by the investor rather than the system, reducing the burden on public finances. Volume limitations ensure that no public funding is provided to specific assets above a certain threshold (for a given area or region) considered inefficient, hence controlling more directly the risk of aggravating congestions (and hence redispatch costs) in certain areas.

At the same time, this approach faces limitations and risks. Calibrating locational elements to provide the appropriate locational signals is challenging, inherently complex and may potentially distort other price signals. Many systems face congestion which is, to some degree, dynamic, therefore making it difficult to provide accurate signals.

Moreover, financial incentives may be ineffective to steer investments in desired locations as many other variables influence investment decisions. These additional complexities may in turn significantly delay implementation.

Excessive penalisation or restrictions may deter investment altogether, potentially shifting capital to other countries, leading to less efficient renewable siting from a national decarbonisation and security-of-supply perspective.

Importantly, assets developed outside of regulated schemes – such as merchant renewable projects financed through power purchase agreements (PPAs) or large data centres remain unaffected, limiting the scope of applicability of this solution. Another limitation of investment support schemes and market mechanisms is that locational elements only influence new assets, providing no corrective impact on the existing ones.

3.2.2 Grid connection rules

The first-come-first-served principle, which is currently applied when handling grid connection requests in many, if not most, countries, does not give TSOs or in some cases DSOs any possibility to prioritise projects according to their level of readiness or their relevance for the system (i.e. will the assets likely be contributing to alleviating grid congestion or rather aggravate it or does it provide other grid supporting services such as flexibility). This leads to long waiting times for project developers with a serious intention to build, as other project developers that apply for grid connection at a very early stage in the project and ultimately do not proceed to construction at all. These speculative applications then block nodes for other, more mature projects, both ready for operation and important for the system. Also, multiple applications are observed, where project developers apply for grid access at different nodes and then develop their project at the location where the earliest connection date is assigned to them, blocking several connection nodes for other developers. The long waiting times are exacerbated as projects connecting to the grid also require additional permits (such as environmental or spatial approvals) which fall under national or local authorities, not TSOs. These processes can take significantly longer than grid-connection procedures and may delay project progress.

To address these issues, a shift towards a more holistic and strategic approach to grid connection management is needed. This would allow TSOs and DSOs, if relevant, to prioritise projects not only according to their readiness but also based on their strategic relevance for the system. As the European Commission guidance on efficient and timely grid connections[9] recommends "the first-come, first-served principle should be abandoned in favour of a prioritisation framework based on objective non-discriminatory criteria that would contribute to alleviating the congestion".

Some of the alternatives to the first-come-first-served principle are beyond the scope of this paper (e.g. speed of the connection procedure or connection request evaluation process; project maturity, introduction of application fees etc.).

However, incorporating additional assessment criteria may have a direct positive effect on congestion management. In this context, national legislation could allow TSOs to define these criteria (potentially together with the regulator) and apply them accordingly when assessing applications. These criteria must be transparent, non-discriminatory and publicly available. They could include location-based incentives: lump sum grid connection fees could differ by location, based on whether an asset at a certain location would improve or worsen grid conditions (c.f. Baukostenzuschuss in DE). This might not always be straightforward and can differ depending on the specific grid situation and the operating mode. Therefore, this measure should be assessed in combination with flexible connection agreements (see Chapter 3.3.2 (FCA solution)) and dynamic tariffs to incentivise grid-friendly behaviour (c.f. S3RENR in France). A transparent definition of grid-friendly behaviour would be a prerequisite. However, a credible definition of grid-friendly and grid-forming behaviour should be reflected not only in economic incentives, but also in harmonised technical connection requirements via connection network codes (CNCs)[10].

Another example is auctioning grid connections, as in Spain where aspects that reduce system costs were considered in highly congested areas. Such a measure could effectively prevent speculative or multiple connection requests, but would likely favour well-funded projects (e.g., large data centres), so careful consideration is needed to balance fairness and system needs. Also freezing dates may allow for assessing multiple projects together enabling prioritisation using criteria that help mitigate congestions. It should be noted that while system operators can provide important and helpful guidance on the appropriate design of grid connection rules, it will ultimately be the responsibility of the (national) regulatory authorities and governments to decide on their implementation, taking into consideration relevant stakeholders.

9 See the European Commission Guidance on efficient and timely grid connections here

10 The EU Connection Network Codes (CNC) define binding Requirements for Generators (NC RfG), Demand Connection (NC DC) and HVDC (NC HVDC).

3.3 Preventive measures outside of wholesale markets

3.3.1 Locational and/or time dependent elements in transmission tariff structures

Network tariff structures can provide incentives and price signals for grid users'[11] decisions on investment locations and/or on dispatch/consumption over time[12]. In this section we will focus on transmission tariff structures; however, similar considerations would be valid for distribution tariffs. For these reasons, it is recommended to consider possible changes to transmission and/or distribution tariff structures in coordination with TSOs, DSOs and, most importantly, the competent National Regulatory Authorities.

The main principle when designing grid tariff structures should remain cost-reflectivity, combined with fairness, simplicity, transparency and predictability. Promoting flexibility, supporting congestion management or addressing other policy goals related to system efficiency, can be accessory design principles, provided that they are linked to cost reflectivity. If properly designed, tariffs have the potential to support multiple goals, while avoiding excessive complexity and potential undesired effects. In particular, it should be avoided that energy market incentives and grid tariff incentives undermine each other.

Additionally, this solution does not possess the inherent capability to deliver incentives addressing congestion management issues in a reliable manner, as the incentives provided do not guarantee to help reducing congestion challenges significantly. Therefore, this solution should only be seen as a complementary measure.

Transmission tariffs are composed of different elements such as access/subscription charges (e.g. €/year), capacity-based components (€/kW or €/kVA, e.g. based on annual or monthly peaks, or connection capacity), energy component (€/kWh), and system charges (incl. losses), etc. Some of them can be differentiated by location, timing, or type of user. There are many possible combinations as shown in the variety of transmission tariffs around Europe[13]. As seen in the figure below, different ways exist to provide signals that may help to prevent or mitigate congestion in tariff structures, via either temporal components (time of use or dynamic tariffs), spatial (e.g. spatial differentiation in energy component, as a way to incentivise investment locations) or both (e.g. dynamic tariffs with regional differentiation). In the next paragraphs we focus on the two latter cases.

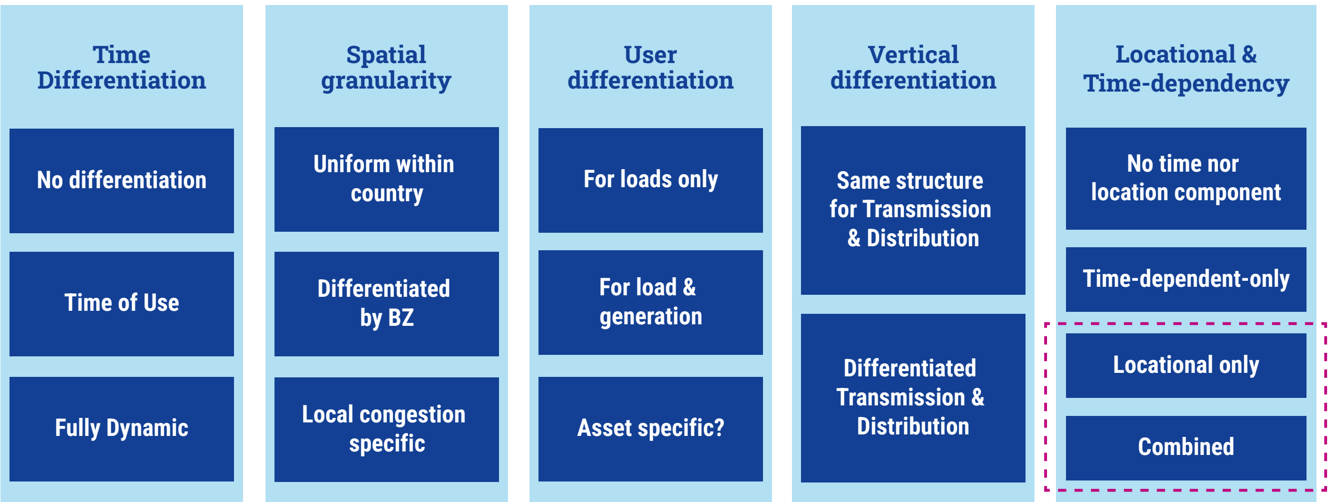


Figure 3: Different design components for tariff structures and selected focus of this section's analysis

11 In this section, the term "grid users" refers to both consumers and generators. However current regulatory constraints, such as the caps on G-charges under EU Regulation 838/2010, limit the scope for fully cost-reflective charges for generation. Also, as connection charges seldom reflect the full long-term marginal cost of the meshed grid, appropriate locational signals for generation investment are also being prevented by the existing regulation.

12 See ACER Report on electricity Transmission and Distribution Tariff Methodologies in Europe. This report provides an overview of how temporal (time-dependent) tariff structures are used to deliver cost-reflective price signals and influence consumption patterns over time.

13 See for instance ENTSO-E Overview of transmission tariffs

One potential instrument is the use of locational and/or time dependent elements in tariffs – price signals linked to network conditions that incentivise consumers and producers to adjust their behaviour to ease congestion.

This type of tariff can be differentiated along several dimensions:

- Regional differentiation allows addressing congestion selectively via targeted congestion management by applying higher tariffs in stressed network areas and lower tariffs in uncongested ones.
- Vertical differentiation with dynamic prices for transmission and/or distribution grid costs.
- Time differentiation can take the form of static time-of-use tariffs, suitable for recurring congestion patterns such as evening peaks, or fully dynamic tariffs that reflect irregular or weather-driven congestion.
- User differentiation with tariffs either limited to loads or extended to both loads and generators, ensuring system-wide incentives.

Therefore, to enable a differentiated evaluation in Chapter 4 we introduce two possible tariff design options. Their impact on congestion management depends on relevant factors such as regulatory feasibility, implementation complexity, and system needs.

- The first design option is a locational differentiation of TSO grid tariffs based on existing regulatory frameworks or established practices. While this approach leverages current regulation or replicates models already in use[14], the practical implementation still involves some complexity. For example, spatially differentiated use of network charges can provide targeted investment signals with minimal adaptation, effectively steering new assets toward grid-friendly locations.
- The second design option is a dynamic, locational and time-dependent tariff design aimed at maximising congestion relief. This option updates tariffs daily until day-ahead market closure to reflect forecasted grid conditions at a TSO/DSO level and incentivise system-supporting dispatch and consumption. While this approach may offer higher contribution to dispatch efficiency, it requires significant regulatory adaptation, higher complexity in TSOs' processes, advanced IT infrastructure, close TSO – DSO coordination, and increases uncertainty for grid users.

By distinguishing between a readily applicable model and a more ambitious, high-impact design, the assessment can more accurately reflect the trade-offs and contextual considerations that play a role in their implementation and effectiveness.

The efficiency of tariffs to alleviate congestion depends on their specific design. For instance, tariffs could be published before the closure of the day-ahead or aFRR capacity markets providing market participants with the necessary information to incorporate them into bidding and scheduling decisions. The main theoretical benefit of dynamic tariffs is their ability to place an explicit price on grid constraints, thereby providing more accurate price signals which can be reflected in individual market behaviour and align with system needs. This could, in theory, contribute to relieving transmission congestion, supporting distribution grid operations, and is especially effective for predictable, recurring congestion. However, in practice, several limitations and open issues should be mentioned. As publication of tariffs would typically happen before day-ahead or aFRR capacity market closure, dynamic tariffs would depend on forecasts of congestion. At this point in time, network operators have at best a rough idea of the actual congestion situation that will occur in real-time. In addition, the reaction of network users to the published tariffs is uncertain, especially when they are first introduced. These effects lead to efficiency losses from forecast errors and uncertain market reactions. When dynamic tariffs are published this far in advance, they would not be able to address short-term, intra-day issues such as sudden battery repositioning. At the same time, it would be impractical to publish tariff elements after the day-ahead as it may be too technically complex for TSOs to calculate these accurately and too close to real time for market participants to efficiently react to such signals[15].

14 Denmark and Sweden apply geographically differentiated injection charges, while Portugal implements varying Time of Use schedules based on location. For a comprehensive review of current national practices, please consult ACER (2025).

15 For additional information and a detailed analysis, see the German TSOs' consultation responses, which critically evaluates the feasibility and effectiveness of dynamic tariff design options to inform ongoing regulatory and market discussions.

Other potential disadvantages are:

- The response to different tariff designs is uncertain – market actors can act against price signals, and the effect is thus difficult to predict. This is particularly true when upholding one of the core principles of tariffs, namely cost reflectivity, as price differentials can become rather small. This is the result of the relatively small marginal impact of each individual user on the overall system costs
- The fluctuation of tariff revenues could mean that the revenue base for network operators becomes more uncertain, which in turn could lead to more frequent changes in the tariff setting procedure. The revenue base is however largely fixed and therefore, cost-reflective dynamic tariffs are not expected to have a major impact on the revenue collected by network operators.
- The volatility of tariffs over time also introduces uncertainty for long-term investment decisions, weakening their provision of a stable investment signal.
- Changes in domestic consumption induced by tariffs may affect cross-border flows, sometimes offsetting the intended congestion relief.
- There is a significant coordination and implementation challenge. Successful implementation requires close coordination between transmission and distribution operators at multiple levels to avoid conflicting incentives. Many practical and concrete operational parameters would have to be defined and implemented which is a complex process.
- From a political and social perspective, the perceived fairness, or rather perceived unfairness, of regionally differentiated tariffs may be a concern, particularly if used to address frequently congested regions. Improving cost-reflectivity with more dynamic or time varying tariffs can however better reflect the impact of specific users or regions on overall system costs, leading to a fairer allocation of costs.

Based on the considerations above, grid tariff structures, if acceptable by grid users and not too complex, may help to prevent or mitigate congestion and associated costs. Tariff design may have to deviate from some of the current core principles, such as predictability, but should adhere cost-reflectivity, transparency, and simplicity to avoid undue discrimination, predictability in market actor response, and reduce overall system costs.

3.3.2 Flexible Connection Agreements (FCAs)

The general idea of flexible connection agreements (FCAs) is that an asset's access to the grid is not guaranteed at 100 % all the time in congested areas, usually based on a contract in exchange for privileges like discounted grid connection costs, accelerated grid connection process or discounted grid tariffs.

As shown in Figure 4, there are many different design options for FCAs in addition to the type of compensation. For example, FCAs can take various general forms, including static FCAs that restrict grid usage to predetermined fixed time slots, models that limit feed-in and off-take capacity in a defined maximum number of hours per year, or fully flexible arrangements regarding frequency, timing and volume of the limitations.

A slightly different approach is the concept of shared connection agreements, where multiple facilities – such as solar parks and battery systems – share a single grid connection point, provided their combined feed-in never exceeds the maximum capacity (note that even though this approach can be reasonable, it does not solve the challenges described in this paper). FCAs can further be designed to apply across different market timeframes (e.g., day-ahead, intraday or even real-time[16]), and across asset types. While FCAs based on voluntary participation are easier to implement, compulsory FCAs with appropriate compensation mechanisms may offer a more effective and scalable solution. Furthermore, FCAs can be implemented permanently or temporarily, across various voltage levels and for existing or new assets, or both.

16 FCAs in real-time can be activated to protect operational security whenever available capacity is insufficient to maintain criteria such as N-1.

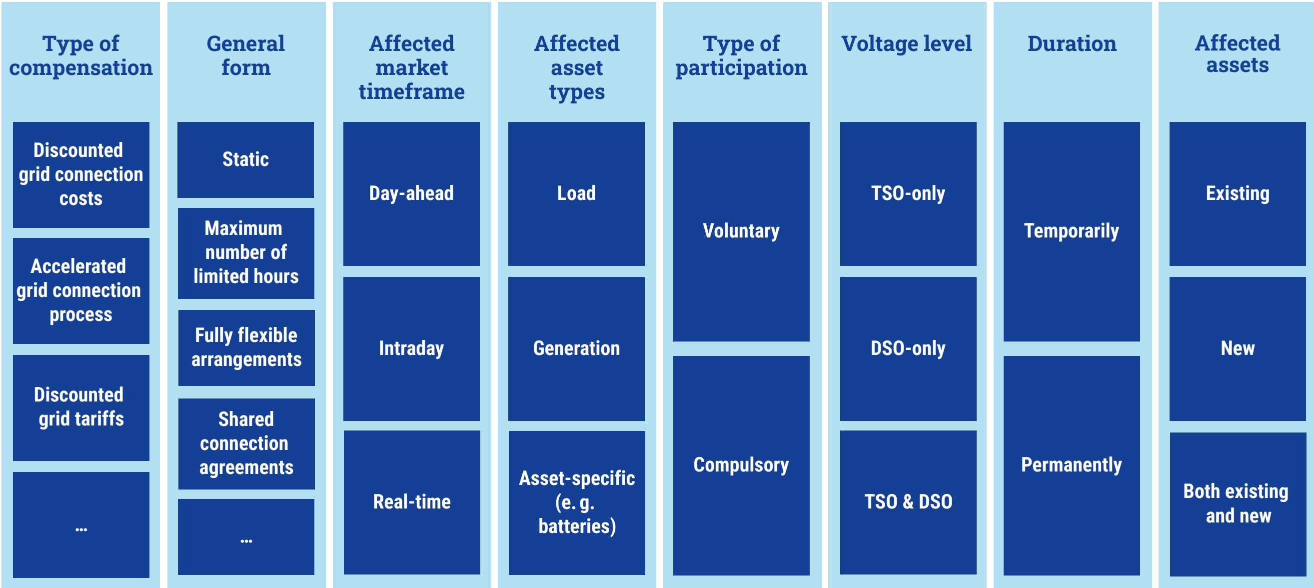


Figure 4: Different design options for FCAs

Highly dependent on these design choices, FCAs can effectively address several key challenges in grid operation. If TSOs can impose restrictions before day-ahead, FCAs can help reduce peak redispatch demand. The risk of new short-term redispatch needs can be reduced by limiting the possibility of short-term adjustments in the schedule, which reduces the uncertainty in the final load flow. This lower uncertainty in inner-zonal trade and resulting congestions enables increased cross-zonal capacity. Compared to other potential solutions, FCAs can achieve these benefits without requiring financial compensation for individual offers.

Depending on whether the goal is to target short-term dispatch behaviour or long-term investment decisions, a temporary (until the required capacity is reached) or permanent implementation of FCAs might be the better choice.

Similar to our approach for locational and/or time dependent elements in tariffs, we introduce two different design options for FCAs for the evaluation in Chapter 4.

- The first option, as partly already implemented in the Netherlands, is the introduction of FCAs that apply to both TSO and DSO and are activated on a day-ahead basis, with no limit in the amount of hours in which they can limit feed-in and off-take (called "Volledig Variabel Transport Recht", which translates to Fully Variable Transmission Right). These contracts are voluntary for both existing and new connections in congested areas and only available temporarily for the duration of the congestion. Market players are compensated with a reduction in grid fees that effectively reduces total grid fees by around 50 %. While this option might not be the most effective, it is an example for a readily applicable model and therefore worth evaluating.
- The second option is the introduction of fully flexible FCAs in the intraday time frame that apply to all assets (existing and new, and all asset types) on the TSO and DSO level on a compulsory and permanent basis. This option can be expected to have the highest impact from congestion management perspective, while some regulatory and process development might be needed.

Again, this selection illustrates the trade-offs and contextual considerations that play a role in the implementation and effectiveness of FCAs.

While FCAs offer promising potential for improving grid efficiency and managing congestion, several limitations and open questions must be carefully considered in their design and implementation. One of the key challenges lies in legal feasibility, particularly when FCAs are applied to existing assets and designed to be permanent and/or compulsory. On the other hand, weaker design choices that are easier to implement from a legal perspective potentially deliver significantly reduced system benefits. For example, restricting the application of FCAs to new assets has a limited effect because fewer assets are targeted, and it might also not be the most efficient choice of assets – there could potentially be existing assets with a higher willingness to accept the restrictions imposed by FCAs (due to lower resulting costs). In this case, this could be determined by conducting corresponding auctions involving both existing and new assets. Another critical issue is the timing of intervention. Depending on the concrete design, FCAs might require action before the day-ahead market optimisation, based on forecast data. This early intervention can introduce inefficiencies, especially if forecasts deviate from actual system conditions, due to the long lead times involved. On the other hand, early intervention helps preserve the efficiency of subsequent market timeframes, in case these are not targeted by interventions.

There might also be a risk of strategic behaviour, such as increase – decrease gaming[17], again depending on the concrete design. The success of FCAs also depends heavily on efficient coordination between system operators and market participants. High dependency on such processes can pose a risk to system resilience, especially in the face of IT infrastructure or communication failures. In terms of system operation, FCAs may limit the potential for short-term balancing, depending on the country-specific liquidity of the balancing system. This could lead to higher costs for maintaining system balance. From an implementation perspective, the frequent and comprehensive usage of FCAs is likely to require several years to roll out.

Finally, FCAs may reduce revenue opportunities for flexibility providers, which could have a negative impact on investment security. In addition, this limitation of flexibility imposed by FCAs might also have a negative effect on several other instruments discussed in this paper, for example market-based redispatch and capacity mechanisms.

Similarly to grid connection rules, it should be noted that while system operators can provide important and helpful guidance on the appropriate design of FCAs, it will ultimately be the responsibility of the (national) regulatory authorities and governments to decide on their implementation taking into consideration relevant stakeholders.

3.4 Congestion management tools

3.4.1 Market-based procurement of redispatch

A solution aiming at providing more resource potential to resolve congestions is the use of market-based procurement of redispatch. Such market design arrangement aims to leverage competitive mechanisms to improve efficiency, transparency, and cross-border coordination of redispatch. It should be noted, however, that this solution does not contribute to structurally prevent or mitigate congestions but rather to manage them more efficiently.

Legally, Article 13 of Regulation (EU) 2019/943 requires that redispatching "shall be open to all generation technologies, all energy storage and all demand response" and be "selected […] using market-based mechanisms". While market-based redispatch is thus intended by EU legislation as the default design, some derogations are possible if (a) no market-based alternative is available; or (b) all available market-based resources have been used; or (c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or (d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8). In practice, several countries still use cost-based redispatch as the conditions (a), (b), (c) and (d) above often occur. The current legislation thus recognises that such solution is not suitable for all markets, as we also elaborate further below.

A market-based redispatch framework can involve several design features. First, congestion management redispatch markets at different time horizons (from day-ahead to real time) can be used to smoothly ensure technical feasibility of results of the different energy markets while keeping moderate redispatch costs. Moving away from cost-based pricing, redispatch would clear at a market price (or pay as bid), which would likely improve efficiency assuming sufficient competition in redispatch markets and would align with the broader European trend toward market integration.

A specific design feature of market based redispatch is also the pooling of resources from the distribution grid, including demand-response, distributed generation, and storage units such as batteries. This would broaden the resource base, increase liquidity, and – assuming effective competition – lower procurement costs for TSOs, while also enabling smaller resources to participate through aggregation. The implementation of so-called "local flexibility markets" allows the participation of such distributed resources. A prerequisite for participation of distributed resources is that participation in redispatch markets to solve TSO-level congestions is coordinated with DSO's to not inflict congestions on DSO-grid and potentially to coordinate activation of flexibility to solve DSO-level congestions.

The adoption of market-based redispatch may address several key challenges mentioned in this report. It provides a scalable framework to manage increasing redispatch volumes, promotes harmonisation of procedures and requirements across TSOs, supporting more efficient cross-border coordination.

17 This refers to market participants intentionally adjusting their bids to create or worsen congestion, anticipating that they can profit from the required corrective measure afterwards.

Furthermore, market-based redispatch may incentivise investment in flexibility resources and generation at locations most valuable for congestion management.

At the same time, despite its potential, this solution faces several important limitations and open issues which can be more or less severe depending on the specific market and grid conditions. Firstly, the introduction of market based redispatch in zonal markets is inevitably exposed to risks of market power abuse and gaming strategies (so-called inc-dec gaming[18]), as the spatial resolution of day-ahead and intraday markets is different than the one of redispatch market (more granular). These risks are particularly severe in situations where redispatch needs are concentrated geographically, congestions are stable and easily predictable, and only a limited set of actors can provide the service (or even only one in some extreme cases). Strategic bidding also complicates forecasting of congestions making it difficult to predict real congestions and real redispatch needs. Effective monitoring, regulatory oversight and specific market rules[19] can be helpful to mitigate such risk but cannot in all cases prevent gaming and is costly and complex to implement and enforce. In addition, the allocation of redispatch volumes between different timeframes and products requires careful market design, as well as coordination with DSOs, to avoid inefficiencies.

As such, the further use of market-based redispatch needs to be subject to careful considerations, as also recognised by EU legislation, at least in countries with predictable congestions and limited market liquidity to solve such congestions. Hybrid approaches, combining non-market redispatch (e.g. for conventional generators) and market-based redispatch (e.g. for storage and demand response) could be an effective compromise in some cases[20]. As flexibility available from storage and demand response assets will further increase in the future it is essential to identify ways to efficiently exploit the use of such flexibility for redispatch purposes, which cost-based approaches are unable to achieve.

Case example: the GOPACS platform enabling market-based redispatch

To enable market based redispatch, the Dutch TSO and DSO's have developed the grid operator platform for congestion solutions (GOPACS). GOPACS is a platform that allows both DSO's and the TSO to solve congestion problems in a coordinated way. This means the platform will take care of the DSO-TSO coordination and DSO – DSO coordination to ensure an activation by one grid operator does not cause new congestion problems for other grid operators. It also enables the grid operators to make use of flexible capacities in each other's grids. For parties that offer their flexibility the GOPACS platform has the benefit that they only need to connect to one uniform platform to be able to offer multiple products to all the DSO's and the TSO at once.

The following products are currently supported by the GOPACS platform:

- **Redispatch**, buy or sell orders with a geo-tag offered in intraday timeframe through a connected trading platform. The platform automatically selects the best combination of orders inside the congested area and counter orders outside the congested area to keep the grid balanced.
- **Contracted redispatch**, using a mandatory bidding contract where the participant is obligated to always place a redispatch bid when a congestion situation is announced.
- **Capacity limitation contract with time** (CLC-T), also called static capacity limitation. Participants therefore know in advance exactly when to limit their capacity. In return, they receive a fixed payment for availability and any activations during those periods.
- **Capacity limitation contract on request** (CLC-A), also known as dynamic capacity limitation. The participant makes flexible capacity available, which the grid operator can activate when congestion threatens. Notification is given at the latest the day before (day-ahead).
- **Time Duration Transport Right** (TDTR), a flexible connection agreement offered by the TSO in which transport capacity is only guaranteed for at least 85 % of the hours in a year. The grid operator must announce the restrictions on the remaining 15 % at least one day in advance (before 8:30 a.m.).

The platform facilitates the registration and prequalification of connections (assets) and the registration of contracts for the different products, as well as the activations of the products and the verification of delivery. It provides the market participants and grid operators with a user interface and options for automated messaging. Flexible consumers and producers can choose to either connect directly with GOPACS or through a Congestion Service Provider. GOPACS was founded in 2017 and is operational since 2018, new products and services continue to be developed.

18 See for instance the paper by Hirth & Schlecht (2020)

19 See for instance the "three pivotal supplier" test used in nodal pricing markets in PJM and CAISO in USA.

20 For instance, Redispatch 3.0 is a proposed evolution of Germany's congestion management system. It builds on Redispatch 1.0 and 2.0 by introducing a hybrid model that combines cost-based and market-based mechanisms to better integrate decentralised, consumer-side flexibility into grid operations. Where Redispatch 2.0 primarily targets large generators (>100 MW), Redispatch 3.0 aims to include small-scale assets

3.4.2 Geo-Tagged Bids and Integration of Redispatch and Balancing

One solution is integration of redispatch and balancing by special regulation as done, for example, in the Nordic countries. By reusing liquidity from balancing markets for congestion management, this solution enables market participants to access multiple revenue streams, while TSOs can activate bids where the value is highest.

In special regulation the TSO uses balancing bids to relieve the congestion by activating upregulation in the area where there is a deficit of electricity and downregulation in the area where there is surplus of electricity. As the regulations are implemented simultaneously and in opposite direction, it does not impact the overall system balance. In such cases bids taken out of the merit order for normal balancing regulation are remunerated on a pay-as-bid basis rather than pay-as-cleared, ensuring compensation for the flexibility, without setting marginal price for balancing. This is crucial as according to electricity balancing guideline (EBGL) methodology Article 29(3) the cost of ancillary services activated for congestion management shall not affect the price of balancing energy and imbalance settlement. However, activation of balancing bids for congestion management purpose might lead to upward markups on balancing energy prices and inefficiencies in bidding behaviour and imbalance price formation. Finally, the systematic use of balancing bids for redispatch can be factored into capacity dimensioning, strengthening system planning.

In Denmark, the TSO has taken the geographical granularity even further by introducing geo-tagged balancing bids. The central design feature is that all balancing bids must be tagged with a specific TSO station (132, 150, 200 or 400 kV). Where an asset is connected at the distribution level, the TSO can map the relevant DSO station to a corresponding TSO station. This enables the control center to assess the geographical location of each bid and determine its impact on congestion. Bids that would exacerbate congestion can be marked as unavailable, while those that help relieve congestion can be selected for activation. Moreover, portfolio bidding is allowed, where BSPs may include multiple assets under one bid, assigning multiple geo-tags to represent the physical locations of each unit. This approach is particularly relevant for aggregators such as aggregators of EVs.

However, multiple geo-tags increase the likelihood that bids will be excluded if any part of the portfolio is located on the "wrong" side of a congestion point. In resolving congestion, only bids with geo-tags located entirely on the unconstrained side of the bottleneck are eligible for activation. As mentioned previously, Denmark is currently using this practice for activation markets of manual Frequency Restoration Reserve (mFRR) products but extended the option of marking bids unavailable for automatic Frequency Restoration Reserve (aFRR) products as well as implemented geo-tags on capacity markets on mFRR. This improves redispatch supply and accommodates uncertainty in redispatch demand. Geo-tagged bids provide TSOs with a firm tool to manage congestion, reducing the need for conservative preventive curtailment of RES. It further allows development of automatic bid filtering and congestions management solutions to relieve operational stress.

Despite the advantages listed above, several limitations and challenges remain. The integration of redispatch into balancing markets introduces a degree of interference between parallel market functions, potentially reducing transparency for market actors in balancing markets. In addition, both balancing and congestion management activities are using the same resources and there is a risk that sometimes in certain cases the liquidity of the market is insufficient, e.g., all bids are required for balancing and there are no bids left for congestion management. In such case the market is ineffective. Balancing markets are designed primarily for balancing purpose. Even though the same resources can serve both balancing and congestion management, redispatch is typically done much earlier than balancing. It is important to ensure that sufficient amount of these flexible resources is available for balancing purposes despite the activations done for congestion management. Restrictions on portfolio bidding may limit the flexibility of market actors, leading to more expensive bids. In cases where large numbers of bids are marked unavailable due to congestion, balancing market liquidity may be reduced. The approach also forces TSOs to consider whether internal grid capacity should be kept available for the flow of balancing energy. Finally, the solution requires robust forecasting approximately 30 minutes before real time to align with the MARI process, where bids are submitted to the activation optimisation function (AOF). Forecast quality may lead to a risk of either over or under managing congestion.

3.4.3 Feasibility ranges or one-sided limitations for congestion management

Another solution to proactively address some of the mentioned challenges is the use of feasibility ranges. This mechanism establishes and updates maximum and/or minimum operating schedules for generating (and possibly also consuming) units following the energy market results (i.e.: day ahead or intraday), based on a security analysis carried out by TSOs. These limits must then be respected by market participants during subsequent market participation, ensuring that trading activity does not create or worsen congestion problems identified in advance, making this solution a very suitable mechanism to handle volatile congestions.

Once the DA market is cleared, the TSO conducts a security analysis of the system to identify potential congestions and network constraints. Based on this assessment, feasibility ranges, which are defined as maximum and minimum schedules, are assigned to specific units. Market participants are obliged to follow them and are penalised for violations. This incentivises them to incorporate them into their bidding strategies for the ID market. Further updates of feasibility ranges can be applied throughout the ID timeframe. This approach has already been implemented in Spain and Italy.

The use of feasibility ranges addresses several challenges mentioned in Chapter 2 in the following way:

- It can lower redispatch volumes and costs for TSOs by limiting schedules proactively, they reduce the risk of congestion arising from market outcomes.
- improves management of peak demand by allowing TSOs to better forecast potential redispatch needs in both volume and location.
- Reduces the volume of energy redispatch needs as it proactively identifies and establishes where limits to schedules variations in specific units are needed following security analysis based on updated information of network situation.
- Improves cross-border coordination by supporting the availability of resources to manage international congestions and contributes to compliance with the 70 % transmission capacity rule, mitigating congestion risks linked to intraday flows.
- addresses short-term congestion issues as these ranges are derived from a security analysis based on actual market results.
- May implicitly guide investment decisions to locations where feasibility ranges are applied less often, i.e. generation in areas that have too little generation and load to areas with a surplus of generation.

Despite their advantages, there are also still open questions, prerequisites and possible negative externalities.

Geographic aggregation

Unlike traditional congestion management, in which only individual plants are subject to redispatch, feasibility ranges need to apply to a sufficient number of plants that could potentially cause short-term congestions as a result of dispatch adjustments. How exactly units in an affected area are to be aggregated into geographic regions that have similar effectiveness on the congestion needs to be decided by TSOs or regulators.

Compensation

Feasibility ranges are applied to translate the effect of limited transmission capacities into the market. Feasibility ranges are applied without compensation. However, they do introduce limitations to the freedom of market participants to participate in the subsequent markets, which may lead to competition issues. Moreover, in some countries there may be an obligation of the TSO to ensure full availability of the connection capacity, so regulatory changes or some form of compensation in case the limitation triggers a redispatch may be necessary there.

Prerequisites

A key prerequisite is the availability of schedules of sufficient quality for each unit following the DA market for TSOs. Alternatively, unit-based bidding might be introduced, though this would require enhancements of the performance of the Single Day-Ahead Coupling (SDAC) and Single Intraday Coupling (SIDC). Another prerequisite is a relevant regulatory framework granting TSOs the authority to impose feasibility ranges and obliging market participants to comply.

Restriction of flexibility

Feasibility ranges restrict the bidding flexibility of market participants, particularly those unable to manage portfolios at scale.[21] While portfolio-based participants can reallocate nominations across units, single-unit actors face a greater loss of flexibility. Furthermore, to be effective on a specific congestion, a large group of units in the areas with effectiveness on the congestion may be restricted. The units must be restricted, even when the potential trades they would make would sometimes be offset within the same geographic area, i.e., even the trades that would leave the congestion unaffected would be restricted. This problem can be mitigated by applying the feasibility ranges closer to real time.

21 This may be mitigated by applying them very conservatively and closer to real-time (for example, Elia applies them 45 min) but this also limits their effectiveness for congestion problems appearing longer before real-time. In Spain, it is done after DA market and updated in real time with the latest forecast and security analysis updates.

Gaming incentives

Feasibility ranges provide gaming incentives for market participants to strategically communicate a schedule to the TSO to minimise the impact on their operations. Market participants have an incentive to "exaggerate" their intended position in the direction of the expected restriction to keep open the option of dispatching in this direction. In the case of compensation for the application of feasibility ranges, there may be an incentive for market participants to provoke the application of the ranges to profit from the compensation. This is particularly relevant for countries with congestions that can be estimated in advance.

While acknowledging that gaming aspects are to be mitigated, this aspect would not interfere with the positive effect of TSOs' ability to reduce uncertainties with regards to the occurrence of short-term congestions.

Impact on balancing

The application of feasibility ranges narrows the scope to correct forecast errors within balance responsible party (BRP) portfolios, potentially increasing imbalances and balancing costs.

It might additionally impact the availability of balancing resources (depending on the level of liquidity in balancing markets and how conservatively feasibility ranges are applied), which could lead to higher system costs for balancing services.

Level playing field

In order to ensure a level playing-field and minimise market distortions, should feasibility ranges be implemented, their design should be based on technical and transparent criteria established by means of dedicated regulation ensuring technology-neutrality in their application.

Quality of schedules

Feasibility ranges require reliable schedules at plant-level after day-ahead market clearing. Currently, these are often not available in many countries.

Harmonisation of processes and process-dependencies

The large-scale application of feasibility ranges requires new processes to be established, involving coordination and communication of many stakeholders – TSO's, DSO's, BRP's and plant operators. If feasibility ranges become a critical element for congestion management, reliance on these processes also becomes critical.

Day-ahead market participation

Units that prefer to market their flexibility in intraday markets or maintain them for portfolio balancing will be economically obligated to market their flexibility in the day-ahead market with unreliable forecasts in order to avoid being limited, reducing market efficiency.

3.4.4 Central dispatch

The main distinguishing feature of central dispatch systems is that the final generation and consumption schedules, as well as dispatch instructions, are determined directly by the TSO through an Integrated Scheduling Process (ISP). This process does not imply arbitrary central decision-making; it is rather based on input from market participants. A number of European countries operate under a central dispatch model, including Greece (IPTO), Italy (Terna), Poland (PSE), and Ireland (EirGrid).

More specifically, within a central dispatch framework, the bidding process is structured on a unit basis, whereby participants submit offers per unit directly to the energy markets. The submitted bids accurately reflect the technical capabilities and economic parameters of each unit. Moreover, each unit is required to submit to the TSO its technical characteristics, such as:

- static/registered data (e.g. location, minimum and maximum output limits, ramping rates, start-up/shutdown times, minimum up/down times etc.)
- dynamic data (e.g. declaration of unavailability or major outage, maximum operating time per activation, maximum daily energy injection, maximum number of activations per day, fuel cost by fuel type etc.).

All information submitted by units – including bids, location, and technical characteristics – is aggregated and processed by the TSO through the ISP. This process optimises unit commitment and dispatch across the system, aiming not only to ensure security of supply and grid stability but also to minimise overall system costs. This centralised approach requires the TSO to simultaneously coordinate balancing, and/or congestion management, and/or reserve procurement within a single integrated framework, thereby ensuring coherent system operation while respecting market signals and technical constraints.

In a central dispatch system, the TSO may establish a capacity threshold (in MW), above which individual units are required to participate in the market as stand-alone resources. Units below the established threshold may be aggregated to form a combined resource eligible for market participation. Aggregating smaller units reduces administrative complexity compared to managing thousands of individual units participating directly in the market. A central dispatch framework does not impede the participation of individual or aggregated units in the Day-Ahead and Intraday markets. Participation is maybe conditional only upon adherence to the congestion-related constraints established by the Integrated Scheduling Process (ISP).

In a central dispatch framework, congestion management and redispatching are embedded in the optimisation process of the ISP through operational/system and locational constraints (for example ensuring that generation in congested areas is limited based on network topology and the location of the generating units). Hence, central dispatch utilises constraints to optimise redispatch actions in real time, allowing for the proactive management of both anticipated and unforeseen congestion. This includes addressing bottlenecks identified ahead of real time, as well as responding rapidly to emergency situations as they arise. It should be emphasised that through repetitive execution of the ISP, emerging congestion is resolved before it becomes critical. Through this process, the TSO ensures that system security is maintained while maximising the efficient use of available resources. This is particularly valuable in systems with high shares of variable renewables, where rapid adjustments are often required to maintain grid stability and security of supply.

However, the adoption of central dispatch is not without challenges. It requires robust communication infrastructure, clear operational protocols, and strong regulatory support to ensure transparency and fairness in dispatch decisions. It should be noted that, under the current EU legislation (Article 14 of the EBGL), a transition from self-dispatch to a central dispatch model is not permitted. Furthermore, beyond potential amendments to EU and national legislation, the shift from self-dispatch to unit-based bidding and central dispatch would necessitate close coordination between TSOs and market participants to maintain efficient market functioning. In addition, as in all market-based solutions, repetitive constraints may be exploited for gaming. Finally, central dispatch must evolve alongside emerging system needs. As power systems decarbonise, new technologies – such as hybrid units, energy storage, and demand-side flexibility – will increasingly participate in the ISP. Integrating these resources requires updates to bidding formats, enhanced representation of technical constraints, and possibly new classes of bids or services. Ensuring that the dispatch algorithm remains sufficiently flexible and technologically neutral is essential to support innovation and maintain long-term system efficiency. It should be noted that these challenges and adaptation needs arise across different market and dispatch paradigms and are driven by the broader transformation of the power system rather than by the choice of a specific dispatch model.

3.4.5 Redispatch Reserves

Redispatch reserves – sometimes referred to as grid reserves or congestion management reserves – represent a dedicated block of generation or flexible demand capacity that is contractually secured by TSOs to be available exclusively for redispatch measures. These measures may consist of last-minute instructions to adjust unit outputs upward or downward to relieve an overloaded transmission element, while maintaining overall system balance between generation and demand.

Redispatch reserves directly address key operational challenges by ensuring that the right capacity is available at the right locations to manage congestion effectively. By keeping otherwise seasonally idled capacity or decommissioned capacity available, TSOs can respond to security violations and alleviate congestion in a timely manner. This approach increases the overall volume of redispatch resources available to the system, reducing the risk of shortfalls during critical events.

The deployment of redispatch reserves entails limitations, prerequisites, and potential externalities. First, such schemes require approval under EU state aid guidelines, since they involve capacity payments that may distort market outcomes. In addition, the concentration of redispatch needs in specific geographical areas raises concerns about local market power, as a limited set of units may gain disproportionate influence over procurement outcomes in the dedicated redispatch reserve market segment.

Furthermore, redispatch reserves typically come at high cost of keeping old, inefficient and highly polluting plants, while at the same time, they do not provide effective incentives for new investment. Their presence might also delay investments in necessary grid infrastructure. Finally, redispatch reserves must be designed with respect to their interaction with existing balancing markets.

As both types of reserves might draw on overlapping resources, there is a risk that units co-optimise their income from both market segments. However, since redispatch reserves are typically procured well in advance and balancing procurement is done day-ahead, possibility of speculation between markets is reduced. Without appropriate coordination, inefficiencies and distortions could occur in reserve allocation, driving up system costs or reducing the liquidity of balancing markets.

In Austria, a redispatch reserve (grid reserve) has been implemented in 2021 and is currently approved under EU state aid until 2030. In the Austrian context redispatch reserves are particularly targeted at known, recurring congestion patterns (also expected to evolve in the future in line with the network development) and are a prerequisite to fulfil the requirement of Article 16(8) of Regulation 2019/943, requiring 70 % of cross border transmission capacity to be available for trade between Member States, thereby maintaining critical redispatch capacity[22]. In Austria, plants participating in the mechanisms are not allowed to participate in any other market (spot-market, balancing), as set out in the EU state aid approval, thus avoiding market distortions.

In summary, redispatch reserves provide TSOs with a targeted and location-specific tool to maintain security of supply and manage congestion effectively, especially in systems where seasonal decommissioning of units threatens redispatch availability. Their successful implementation, however, depends on careful state aid and regulatory approval, robust dimensioning methodologies, and clear segregation from wholesale and balancing markets to mitigate risks of inefficiency and market distortion. Due to these risks, they are in place for limited approved periods and not as long-term structural solutions.

22 For generation units a decommissioning notification is a binding requirement to participate in the grid reserve process

3.4.6 Coordination of Countertrade and Redispatch

Today some TSOs do a substantial amount of countertrading to help neighbouring TSOs resolve challenges on the opposite side of interconnectors. At the same time many TSOs experience a rising need for internal redispatching. Since countertrading and internal redispatching for many TSOs is carried out at different times in the market chronology there is a lack of coordination and optimisation across countertrading and internal redispatching leading to a potential overall increased societal cost across redispatching objectives.

In the Danish case Denmark assists Germany with countertrading on the DK1 – DE border. At the same time Denmark experience internal bottlenecks in the DK1 bidding zone. Countertrading is carried out as a formalised solution in the continuous intraday market. In this market typically thermal plants, arbitrage trading and electrical boilers deliver downregulation to decrease flows from DK1 to DE. The internal Danish bottleneck is caused by excess wind and solar in local parts of the DK1 bidding zone. Denmark does a redispatch process in the balancing market using geo-tagged mFRR bids. This entails downregulating wind in the problem area and a corresponding upregulation action on the opposite side of the bottleneck. The upregulation is potentially done on assets that were just bought to downregulate in the intraday auction for countertrading. This leads to a triple activation of solving both countertrading needs and internal bottlenecks.

As an alternative, the summarised need of countertrading and redispatching could have been solved by just downregulating wind and solar in the problem area of DK1. Additionally, countertrading needs on the DK1 – DE border could also be alleviated by downregulations in NO or SE bidding zones, which relieve internal bottlenecks in these zones. This means that there could be a potential in a market solution created to resolve the regional need for redispatching across multiple TSOs, rather than solving redispatch needs one by one.

In general, some of these benefits are sought through development of the ROSC methodology. ROSC is a methodology to where the regional security coordinators (RSC)/regional coordination centres (RCC) build coordinated operational security models for the grid, including a process for coordination of remedial actions, hereunder redispatching and countertrading. The aim of the project is to reduce redispatching costs and volumes at the capacity calculation region (CCR) level, while ensuring fair cost-sharing by enforcing the polluter-pays principle targeting excessive loop flows. The implementation of ROSC can vary between regions and RCCs but does include coordination of remedial actions and cost sharing. The process of implementing ROSC is not at the same maturity level in all RCCs. It is therefore uncertain at this stage, to what extent ROSC will be able to achieve this coordination to the full potential.

3.4.7 Improved Capacity Allocation: PSTs and internal HVDCs in allocation

According to the current market design, the flexibility to change load flow pattern by using Phase Shifting Transformers (PST) tab positions and setpoints of future internal high voltage direct current (HVDC) transmission lines is partly given to the capacity calculation step ahead of the market coupling to optimise and validate capacities available for cross zonal trading. The remaining flexibility of those PSTs and internal HVDCs can be used by the TSOs (real time) operational processes.

The underlying idea of the concept *Improved Capacity Allocation: PSTs and internal HVDCs in allocation* is to give more flexibility to the allocation: the decision on how to use parts of / the full technically available capacity[23] of PST taps and internal HVDC set points is thereby moved from the capacity calculation to the allocation step and allows the market coupling/capacity allocation step to select the setpoints of HVDC lines and PSTs, as it is currently foreseen for those HVDCs which cross BZ borders. Every PST or internal HVDC added to the market coupling is an additional degree of freedom ideally to manage congestion and maximise welfare.

A potential advantage is that it enables the market to utilise those elements more efficiently instead of having to rely on an ex-ante forecast during the stage of capacity calculation.

In general, as for the Dispatch Hubs, the positive benefits of the concept on congestion management requires the market (allocation) to have a sufficient view on the grid on its constraints.

The overall idea is to bring physics and markets closer together. This implies to include the important internal lines i.e. those that are significantly impacted by cross-border exchanges into the allocation, and to refrain from the use of virtual margins (a feature of the min. 70 % framework). Otherwise, this concept is likely to lead to an excess of trading capacity being offered to the market, resulting in increasing congestions, which can potentially no longer be handled in system operation where non-costly remedial actions like PSTs and internal HVDCs play a key role in ensuring operational security: Exhausting remedial actions to increase the cross-border capacities even beyond virtual margins implies that they could not be available when they are needed in operation. The concept would therefore come along with less flexibility to cope with variability or incidents in system operation. Furthermore, as the setting of these non-costly remedial actions would be considered in the market allocation and not like today in the capacity calculation step, they could not be used anymore in their crucial role in capacity calculation to validate if it is safe to provide 70 % capacity to the market.

In the future, shifting the use of non-costly remedial actions to allocations could potentially be beneficial to the market as it would optimise the use of such actions. The precondition for such an implementation is a suitable regulatory framework. Even in case of a change of the 70 % regime (by changing EU 2019/943), a thorough feasibility analysis would be needed to assess the benefits versus potential drawbacks and implementation difficulties.

23 Technically available capacity means the technical capability of the equipment. Whether this technical capability is used by the market coupling/the capacity allocation mainly depends on the underlying technical restrictions of the grid being considered during the market coupling / the capacity allocation.

4 Evaluation of solutions

The selection of evaluation criteria (and their clustering in macro-categories for simplification) for market design solutions, is a complex exercise which can lead to different outcomes depending on the problem statement, on the scope of solutions considered, and on the perspective of the analysis. For the specific scope and objectives of this paper, and for the intention to offer a TSO-perspective to the challenges and solutions of congestion management, we have decided to focus on 5 main criteria, defined as follows:

Evaluation Criterion 1 (EC1):

Dispatch and congestion management efficiency

- Efficiency in solving or preventing congestion (impacts on costs for congestion management, countertrade and redispatch (quantity and price effects))
- Effect on costs of balancing reserves, balancing energy and imbalance price
- Socio-economic effects (impacts on wholesale prices, congestion income, losses, producer surplus, consumer surplus)
- Efficiency of market integration (efficient use of transmission capacity offered to the market)
- Improved price signals for renewables and flexibility assets to accurately reflect congestions in time and space

Evaluation Criterion 2 (EC2):

Operational security

- Effectiveness in relieving congestion and operational security violations
- Operational robustness under uncertainty and stress conditions
- Impact on the location, frequency and size of the operational security violations, the need for corrective measures
- Effect on availability of balancing reserves and energy products
- Impact on the need for TSO corrective measures after market clearing
- Degree of uncertainty/risk/complexity remaining to be handled in the operational processes – including forecasts needs/impact

Evaluation Criterion 3 (EC3):

Investment efficiency (long-term power system impacts)

- Impacts on price signals to incentivise more efficient siting decisions for new generation, storage and flexibility assets
- Impacts on price signals to incentivise co-location of supply and demand
- Impacts on price signals for more efficient transmission infrastructure development
- Impacts on need & costs of state support schemes (contracts for difference (CfDs), capacity markets, etc.)
- Impacts on investment risk and financing costs Weighted Average Cost of Capital (WACC) investment efficiency

Evaluation Criterion 4 (EC4):

Market Impacts

- Impacts on market liquidity and transaction costs across market timeframes (DA, ID, BAL and forward markets)
- Impact on producer surplus and profitability for generation, storage, demand response
- Affordability and impact on overall costs for consumers
- Impacts on the level of harmonisation vs. regional/national flexibility of power market design and implementation
- Cross-border distributional effects (through changes to market flows, loop flows, wholesale prices and changed siting decisions for assets)

Evaluation Criterion 5 (EC5):

Transition & implementation challenges

- TSO implementation costs
- Market participant implementation costs
- Implementation complexity/time from legal (need to update EU/national regulations) or update EU/national regulations
- Implementation complexity/time from technical perspective
- Efficiency in managing distributional effects (e. g. through grandfathering of transmission rights for incumbent generators or compensation)
- Political and social acceptability (e. g. in terms of distributional effects or implementation complexity/time)
- Robustness to future system/market evolutions

The **ranking system** used in this study evaluates how each solution reduces challenges for congestion management and redispatch. **See the ranking as below:**

Positive					Negative			
High	Medium high	Medium	Low	Neutral	Low	Medium	Medium high	High
●	◕	◑	◔	○	◔	◑	◕	●

Solutions overview

	EC1 Dispatch and congestion management efficiency	EC2 Operational security	EC3 Investment efficiency	EC4 Market Impacts	EC5 Transition & implementation challenges
Cluster 1: Spatial granularity in energy markets					
Nodal pricing (Locational Marginal Pricing – LMP)	●	◕	◑	◑	●
Bidding Zones Re-configuration	◕	◑	◑	◔	◑
Dispatch Hubs	◑	◔	◔	○	●
Cluster 2: Locational siting incentives					
Locational Elements in Capacity Mechanisms and RES Support Schemes	○	◔	◑	○	◔
Grid connection rules	◔	◔	◑	○	◔
Cluster 3: Preventive measures before outside of wholesale markets					
Locational and/or time dependent elements in transmission tariff structures					
Design Option 1: Already implemented	○	○	◔	○	○
Design Option 2: Advanced	◔	◔	◔	◔	◑
Flexible connection agreements					
Design Option 1: Already implemented	○	○	◔	○	○
Design Option 2: Advanced	◑	◔	◔	◑	◑
Cluster 4: Congestion management tools					
Market-based procurement of redispatch	◔	◔	◔	◔	◔
Geo-Tagged Bids and Integration of Redispatch and Balancing	◔	◔	◔	○	◔
Feasibility ranges or one-sided limitations for congestion management	◑	◑	◔	◔	◑
Central Dispatch	◕	◕	◔	◔	●●
Redispatch Reserves	◔	◑	◔	◔	◔
Coordinated Redispatch & Countertrading	◑	◔	○	○	◑
Improved Capacity Allocation: optimise PSTs and HVDCs in allocation	◔	◔	○	◔	◔

Cluster 1: Spatial granularity in energy markets

EC		Comments
Nodal pricing full implementation		
EC1 – Dispatch efficiency		It enables significant dispatch efficiency for a given system state. Since the nodal pricing market considers the full network model, there is no need for redispatch. Price signals are provided at each node, reflecting local supply, demand and transmission constraints facilitating integration of flexible resources.
EC2 – Operational security		By considering the full network model, the nodal pricing market inherently embeds operational security within its market processes from day-ahead to real time.
EC3 – Investment efficiency		Nodal pricing market provides precise locational price signals at each node, supporting efficient siting of new generation, storage and demand assets, including co-location strategies. On the other side, associated volatility in prices may increase uncertainty for investment decisions. It also indicates where transmission expansion is most needed – nodes with the largest price differences. Like zonal models, nodal pricing markets typically still require capacity mechanisms, especially during the energy transition.
EC4 – Market impacts		Like zonal models, nodal pricing markets have limited impact on system adequacy and capacity mechanisms often remain necessary. Nodal pricing design requires tailored solutions to ensure liquidity across market timeframes, potentially increasing complexity and costs. No need for remedial actions in nodal pricing markets can reduce tariffs for consumers. Reduced loop flows improve cross-border market efficiency.
EC5 – Transition & implementation		High initial implementation costs for TSOs and market participants due to system upgrades and process changes for the migration from zonal to nodal pricing. It also requires fundamental changes to EU and national regulations that may take several years to be implemented. Technical implementation is complex and time-consuming. Political and social acceptability may be challenging due to complexity.

Bidding Zones Re-configuration		
Generic remarks		Some criteria could be scored higher, but we wanted to leave some room to show differences compared to nodal pricing which can be seen as the more extreme case of more optimal BZs. The effect of more accurate prices may in some cases be limited as other factors could be more decisive, however we have evaluated if they correctly represent the underlying value of electricity and (avoided) grid investments.
EC1 – Dispatch efficiency		Significant increase in dispatch efficiency as it enables a market-driven congestion management reducing the reliance on redispatch/countertrading, with potential to increase socio-economic welfare, accuracy of price signals and reduce loop flows.
EC2 – Operational security		Significant reduction in N-1 violations, but some need for redispatch will remain.
EC3 – Investment efficiency		More accurate prices would help to steer investments but may also create some uncertainty.
EC4 – Market impacts		Market impacts are mixed with negative impact on liquidity, mixed re-distributional effects, reduction of LFs will enable more cross border trading.
EC5 – Transition & implementation		No change in regulation needed, but high implementation costs (for MSs that currently operate a single BZ). The political aspect of the BZ redefinition may be challenging.

EC		Comments
Dispatch Hubs		
EC1 – Dispatch efficiency		Potential increase in dispatch efficiency of day-ahead and intraday (IDAs) markets as congestion is solved in the market reducing the reliance on redispatch/countertrading, but less than optimal BZ configuration.
EC2 – Operational security		A proper selection of assets placed in Dispatch Hub can reduce redispatch needs and operational constraints especially if accompanied by an appropriate regulatory framework. More flexible in concept to model congestions with a higher level of granularity in the allocation (compared to BZR). Concept of 'a zone within a zone' introduces an element of nodal into the zonal market design. The removal of virtual margins (in case deemed acceptable for European policy makers) and the integration of additional CNEC significantly impacted by cross-zonal exchanges into the market coupling puts the market and physics closer together.
EC3 – Investment efficiency		Limited improvement of locational investment efficiency, uncertainty depending on DH definition and review process.
EC4 – Market impacts		Market impacts are mixed with negative impacts on the capacities due to the removal of virtual margins and the integration of further internal CNECs, reduction of LFs will enable more cross border trading. Positive effects for end user prices as the costs for managing congestion are co-optimised within the market coupling.
EC5 – Transition & implementation		Implementation requires review of EU regulation, in particular the removal of virtual margins from the min. 70 % framework in Regulation 2019/943, while from market participants perspective it could be less controversial than BZs or Nodal pricing but still challenging as untested approach. Role of compensation payments can improve acceptability but not so straightforward.

Cluster 2: Locational siting incentives

EC		Comments
Locational Elements in Capacity Mechanisms and RES Support Schemes		
In general		The overall impact on congestion management and reduction of congestion is expected to be fair although not transformative on its own. If capacity is supported through a capacity mechanism or RES support or flex support, TSOs should consider the possibility of utilising locational elements to steer the capacity towards locations where it offers the greatest system benefits. Nevertheless, due to the dynamic nature of congestion in many systems, providing accurate locational signals is inherently complex and may thus become a source of market distortion. It should also be noted that locational elements in investment support schemes and capacity mechanisms increase complexity and therefore cost of the measure itself and reducing the potential benefits. Lower system-wide costs are still expected.On EC1 and EC2, the effect and the target group are smaller than the tariffs solution as this solution would potentially apply for new assets and would be limited to assets that receive support schemes and participate in capacity mechanisms.
EC1 – Dispatch efficiency		In principle locational element should have a minor impact on dispatch efficiency in the short-term but more efficient siting decisions of RES, flexibility, and capacity should improve dispatch efficiency in the long-term. This is of course dependent on the design and poor design would, in the long run, lead to less efficient dispatch decisions.
EC2 – Operational security		Likely minor reduction of the need to undertake operational measures to manage congestion.
EC3 – Investment efficiency		Likely to lead to more efficient siting of capacity and could therefore reduce the capacity need and costs associated with the mechanism. Improved locational signals for RES will likely improve RES utilisation and can therefore reduce financing cost and risk. Inefficient design of mechanism and locational signal will however risk overcompensating capacity providers.
EC4 – Market impacts		A capacity mechanism is implemented to improve security of supply and recognising that the value of additional capacity is greater in certain areas will aid in this. Depending on the design of the mechanism, incumbent generators may be negatively impacted
EC5 – Transition & implementation		Likely to slightly increase implementation complexity and cost. Could be politically challenging as, according to Clean Industrial Deal State Aid Framework (CISAF), areas with increased need for capacity should also be exposed to a greater share of the cost.Given that incorporating locational elements in the aforementioned support schemes may prove difficult within the current legislative framework, it is likely that certain reforms would be necessary.

Grid connection rules		
EC1 – Dispatch efficiency		The impact on redispatch and countertrading is indirect and long-term, materialising only through changes in the connected asset mix. Where prioritisation favours congestion-alleviating or flexible assets, a marginal reduction in structural congestion and corrective actions may occur over time.
EC2 – Operational security		By enabling earlier connection of system-relevant assets, the risk that new connections exacerbate operational constraints would be reduced. However, as the solution does not directly affect real-time operational tools, the overall impact on operational security would remain limited.
EC3 – Investment efficiency		Medium positive impact by improving investment efficiency through a more credible and predictable connection pipeline. By reducing queue distortions (e. g. speculative and multiple applications) and improving the alignment between reserved capacity and projects that actually reach construction, the measure can improve the investment climate for grid users by limiting risks and increasing predictability. Cleaning the queue through defined criteria reduces uncertainty, supports more reliable investment planning and can lower project delays and associated financing risks.
EC4 – Market impacts		No modification of market design across market timeframes and therefore no direct impact on market liquidity, transaction costs, or short-term price formation.
EC5 – Transition & implementation		Implementation requires regulatory changes, as well as careful design of transparent and non-discriminatory prioritisation criteria. System operators and market participants would face additional implementation and administrative costs, and distributional effects may raise acceptability concerns.

Cluster 3: Preventive measures outside of wholesale markets

EC		Comments
Locational and/or time dependent elements in transmission tariff structures (For the assessment we consider the two models introduced in Section 3.3.1)		
Option 1: Already implemented		
EC1 – Dispatch efficiency		While a potential positive impact is recognised, its ability to significantly influence dispatch decisions remains uncertain.
EC2 – Operational security		Similar to EC1, no clear positive or negative effect can be identified. While it could be argued that encouraging assets to locate in grid-friendly areas may bring about a positive influence on the location, frequency, and scale of operational security violations – potentially reducing the need for corrective actions – this effect is too uncertain to be stated with confidence.
EC3 – Investment efficiency		The option might have a slight positive impact, making price signals somewhat more effective in guiding the optimal siting of new assets and encouraging more efficient transmission infrastructure development.
EC4 – Market impacts		Impact neutral – slightly negative impact related to cross-border distributional effects due to changes in asset siting decisions. As new assets are incentivised to locate in certain areas, this may alter market flows and wholesale prices, potentially leading to less optimal outcomes for neighbouring regions and increasing disparities in benefits across borders.
EC5 – Transition & implementation		The impact is expected to be neutral. This is because an appropriate regulatory framework is already in place, minimising the need for extensive new legal or technical adaptations. As a result, implementation efforts are not anticipated to be significant, while still some complexity might remain. Political and social acceptability should remain stable.
Option 2: Advanced		
EC1 – Dispatch efficiency		Solution can lower peak demand for redispatch when dealing with predictable, regular congestion and predictable user behaviour. High granularity possible. However, tariffs would most likely have to be determined before day-ahead gate closure: Therefore, no effect on short-term congestion issues (e. g. due to behaviour of batteries) and possible inefficiencies (because of reliance on forecasts). Also, since tariffs are set on a national level, one cannot rule out the possibility of changes in international flows that do not take into account the grid constraint reflected in the national tariff and might lower the desired positive effect.
EC2 – Operational security		Same as EC1. No negative effect on system resilience if tariffs are set day-ahead.
EC3 – Investment efficiency		Impact on investments is unclear, as the dynamic tariffs may change over time, so they don't provide a stable investment signal (to be discussed for predictable, regular congestion issues).
EC4 – Market impacts		As described under EC1, potential undesired cross-border effects. Depending on design choices.
EC5 – Transition & implementation		Regionally differentiated tariffs may introduce distributional effects. Political acceptability probably higher than for other solutions. Implementation (especially settlement and forecasting congestions) highly complex (at least in Germany, need to coordinate with hundreds of DSOs).

EC		Comments
Flexible connection agreements (For the assessment we consider the two models introduced in Section 3.3.2)		
Option 1: Already implemented		
Both TSO and DSO, activated on a day-ahead basis, with no limit in the amount of hours in which they can limit feed-in and off-take, only available temporarily for the duration of the congestion.		
EC1 – Dispatch efficiency		Neutral effect since it is only applied on a voluntary basis and the generally positive effect is limited to a rather low number of market participants.
EC2 – Operational security		The dispatch, therefore the operational security, is improved overall but system resilience might be impacted negatively due to reliance on market participants and processes for coordination among the market parties.
EC3 – Investment efficiency		The overall impact would be low-positive if we assume that appropriate compensation is in place. Depending on the duration of the limitation, this solution might have negative impact on the business cases (i. e. investment security). Shall there be no appropriate compensation, the effect would be negative as the investment decision would be riskier.
EC4 – Market impacts		Potential higher costs for balancing due to less short-term flexibility (depending on the country-specific liquidity of the balancing system), as well as the risk premiums to be priced-in from producers. Potential gaming impacting the effects of this solution negatively.
EC5 – Transition & implementation		Considering the acceptability, implementation, and operational challenges, TSOs and market participants might be negatively affected. However, general feasibility already proven in the Netherlands, so neutral score.
Option 2: Advanced		
Fully flexible FCAs in the intraday time frame that apply to all assets (existing and new, and all asset types) on the TSO and DSO level on a compulsory and permanent basis.		
EC1 – Dispatch efficiency		Medium positive effect, since all assets are included. However, there might be the problem of imperfect information by the market actor that determines the FCA, so no full green score. Related to this, FCAs do not incentivise competition on the basis of the costs of being limited, which can potentially lead to not choosing the most economical parties to limit and thereby reducing the efficiency of the instrument.
EC2 – Operational security		The dispatch, therefore the operational security, is improved overall (higher compared to Option 1) but system resilience might be impacted negatively due to reliance on market participants and processes for coordination among the market parties.
EC3 – Investment efficiency		Low- to medium-negative without compensation and neutral with appropriate compensation for the limitation being in place.
EC4 – Market impacts		Same concerns as for Option 1, but applying to more/all assets, so even more negative effect
EC5 – Transition & implementation		Feasibility questionable due to complex implementation, resistance by market parties and, most relevant, legal challenges to implement FCAs for existing assets

Cluster 4: Congestion Management Tools

Market Based Redispatch

EC		Comments
EC1 – Dispatch efficiency		Assuming market-based redispatch enables TSOs to attract more resources that can be used in congestion management, this will result in a more efficient redispatch (but not dispatch). The advantages will be diluted by efficiency losses of inc-dec gaming in cases where congestions are predictable and/or there is no real competition to provide the required service in a given location.
EC2 – Operational security		Increased redispatch potential becomes available to solve congestions, this could also be contracted in advance. Benefits offered by higher number of redispatch providers may be offset by increased complexity.
EC3 – Investment efficiency		Additional revenues, especially for demand response and storage, could incentivise siting in locations beneficial for mitigating grid congestions. Their improved business case may reduce the need for NFFSS. However, the impact may be rather limited; investment distortions driven by inc-dec gaming are also possible.
EC4 – Market impacts		Theoretically, if implemented where competition can be effective, market based redispatch can have a positive effect on market efficiency, liquidity, end-user prices. At the same time, if not well designed, these may also lead to higher redispatching costs than in case of cost-based schemes.
EC5 – Transition & implementation		Implementation has already started in some countries, so it should not be too complicated. However, an efficient design is non-trivial, especially in countries with predictable congestions. Differentiation of schemes between generation assets on one side and storage and demand response on the other likely needed. Coordination with DSOs is also necessary.

Integrate Balancing & Redispatch

EC		Comments
EC1 – Dispatch efficiency		Optimises use of flexible units. Market participants offer flexibility in one market, and TSO optimises use of flexibility for multiple purposes. Available for balancing when there is no redispatch need. In general, increased liquidity in redispatch and balancing markets. Depending on transparency and predictability, it sends some local price signals with regards to internal bottlenecks. If gamed by the market, could have some negative impact on wholesale prices and redispatch cost and needs.
EC2 – Operational security		High precision and increased information in location of activations for operation. Possibility of avoiding activation of balancing bids which would increase congestions. Handling is done close to real-time operation. Good knowledge of bottlenecks, but short reaction time. Reliance on forecasts due to timeline of MARI activations. Upper limit to amount ideally handled by solution due to counter activation need
EC3 – Investment efficiency		Sends a signal to place balancing reserves places in the grid, where activation can be allowed and with possibility of additional revenue stream from congestion management support. Requires transparency in solutions.
EC4 – Market impacts		Benefit of reusing known and established market platforms.
EC5 – Transition & implementation		Limited transition cost for establishing market. Requires some IT development for sorting bids and marking unavailable bids and require development of forecasting tools. Potentially easy legal procedure.

EC		Comments
Feasibility Ranges		
EC1 – Dispatch efficiency		Depends on when feasibility range is applied: before DA-market closure or in intraday. Day-ahead FRs can preventively reduce Redispatch needs, intraday FRs mainly address short-term issues. Effective in relieving congestions and operational security violations. Opportunities for market participants for more efficient dispatch closer to real time are limited. When FRs are applied before DA already, market opportunities are strongly limited.
EC2 – Operational security		Effective in relieving congestions and operational security violations that may appear closer to real-time. When applied after day-ahead, they cannot be used preventively to pre-empt large peaks in redispatch demand.
EC3 – Investment efficiency		Market actors may take into account the impact of FRs when deciding on new investments. However, applications of feasibility ranges also introduce a new risk in the investment decision.
EC4 – Market impacts		Market opportunities are limited when FRs are applied, which limits market efficiency somewhat. However, if application happens closer to real time, these limitations may not be very strong. If they are not compensated, this may result in losses for market participants. If they are compensated, this results in costs for TSOs.
EC5 – Transition & implementation		New processes and coordination channels have to be set up at TSOs and market participants. Relies on communication and coordination processes with a large number of actors.

Central Dispatch		
EC1 – Dispatch efficiency		Significant increase in dispatch efficiency. Optimisation of energy dispatch taking into consideration system constraints within an Integrated Scheduling Process (ISP) can reduce costs. The centralised approach may improve the predictability of system imbalances and enables timely congestion relief, especially in areas with high-RES penetration.
EC2 – Operational security		Great effectiveness in relieving congestions known before real-time. Volatile and temporary congestion issues can be tackled through repetitive ISPs. Central dispatch inherently embeds operational security within its market processes from day-ahead to real time ensuring adequate reserve procurement and improved resource allocation.
EC3 – Investment efficiency		The solution allows for more efficient balancing of supply and demand. Investors of new generation, storage, and flexibility assets might be directed to areas with significant grid limitations and higher local demand. The solution has no effect on the need for support schemes.
EC4 – Market impacts		The solution has positive impact on system adequacy. However, capacity mechanisms often remain necessary. The impact on wholesale prices might be heterogeneous depending on geographic and market conditions.
EC5 – Transition & implementation		High implementation costs for TSOs and market participants (unit-based bidding) are expected due to system upgrades and process changes. It also requires updates to national and EU regulations (currently a change from a self-dispatching to a central dispatching model is not possible according to article 14 of EBGL). Depending on the elements of central dispatch already incorporated and the starting point of the market, the transition might be lengthy and costly, with high complexity.

EC		Comments
Redispatch Reserves		
EC1 – Dispatch efficiency		Suitable for specific known congestions. Effective in relieving congestions and operational security violations. It is considered a state aid measure, meaning that the decision to apply redispatch reserve should be well prepared and considered thoroughly.
EC2 – Operational security		Can be an effective instrument for congestion which is known to be regularly occurring.
EC3 – Investment efficiency		Is considered as a state support. May hinder the price signals for more efficient transmission infrastructure development. Otherwise, it has been evaluated as neutral under this criterion.
EC4 – Market impacts		Market impacts should be considered in the design of this reserve. There is a risk, that the solution has an impact on liquidity of other markets or it might enable gaming opportunities causing a risk for market manipulation. However, with careful design and planning these risks and impacts should be mitigated to zero.
EC5 – Transition & implementation		To be approved under state aid guidelines by European Commission. Dimensioning and cost of reserving production.
Coordinated Redispatch & Countertrading		
EC1 – Dispatch efficiency		Increased efficiency in solving bottlenecks across different redispatch measures. Increases cost of handling countertrade to lower cost of internal redispatching but leading to a total saving across measures. Lower need for counter activation in redispatching, leading to lower price impact on balancing measures and imbalance prices from redispatching measures. Potential effect on wholesale prices due to current arbitrage in countertrading.
EC2 – Operational security		Potential negative impact from moving higher amount of redispatch close to operation, depending on design of redispatch and countertrading and improved reliance of forecasts. Potential benefit from decreased redispatch counter activation and higher availability of balancing resources.
EC3 – Investment efficiency		Potential changes in wholesale prices and markets for redispatching and countertrading will probably lack transparency for investment purposes.
EC4 – Market impacts		Removes market potential for some market participants as TSO-costs are decreased. Lower redispatch impact on balancing could be a benefit for RES.
EC5 – Transition & implementation		Requires legal clarification of cost-sharing and benefit sharing. Increased need for TSO-coordination with regards to congestions management. Requires development of procedures and forecasts for this purpose.
Improved Capacity Allocation: optimise PSTs and HVDCs in allocation		
EC1 – Dispatch efficiency		Every PST/HVDC added to allocation is a degree of freedom for the market to optimise the dispatch and create market welfare. The total amount of PSTs and HVDC lines in the system represent additional degrees of freedom for the market. The socio-economic welfare effect (positive or negative) mainly depends on the underlying regulatory framework i. e. the existence of virtual margins and the amount of internal grid elements being reflected within the capacity allocation.
EC2 – Operational security		Assuming a suitable regulatory framework, the concept brings markets and physics closer together as it removes the forecast inefficiencies in capacity calculation and therefore reduces parts of the corrective measures needed after the allocation. However under the current regulatory framework i. e. the existence of virtual margins, the concept is likely to increase congestions while reducing available redispatch potential.
EC3 – Investment efficiency		No impact on investments. This measure is about creating consistency and efficiency across the operational processes of capacity calculation / allocation / security analysis.
EC4 – Market impacts		Improves capacity offered to the market (coupled with removal of virtual capacities). Positive effects for end user prices assuming no significant increase in redispatching costs.
EC5 – Transition & implementation		There are already examples in operation as the HVDC interconnector ALEGrO between Belgium and Germany. Scaling up this solution is an attention point for the performance of Euphemia yet anticipated in the R&D work already. Furthermore, the regulatory framework would need to be adjusted (in particular refrainment from virtual margins) to make the solution suitable for reducing congestion management.

5 Possible system-specific policy pathways

This paper provides an overview of possible market design solutions to tackle the congestion management challenges associated with the Energy Transition. While no single market design solution can fully address these challenges, different coherent sets of complementary measures can significantly improve the alignment between market outcomes and physical grid constraints, reduce redispatch volumes and costs, and safeguard operational security.

This paper identifies a set of possible "policy pathways", combining complementary solutions, tailored to three main power system "archetypes", which reflect typical system configurations and congestion patterns observed across Europe. For each archetype, three alternative policy pathways are presented illustrating different approaches that can be followed. While all of them have the potential to effectively address the specific congestion challenges of their archetype, they also come with different trade-offs to be considered. Some of these trade-offs have already been described in the evaluation of the individual market design options in chapter 4. As such, we do not evaluate pros and cons of the different pathways in this chapter.

In the description and representation of each pathway, we distinguish between essential market design solutions (as part of the "backbone" of that pathway) and optional/complementary ones. Further, in the graphical representation we characterise them depending on the necessary implementation time. Lastly, it is important to emphasise that this analysis is not exhaustive and there are undoubtedly other system configurations, cases and potential policy pathways beyond those considered here. Even if in a simplified manner for illustration purposes, we consider the presentation of archetypes and pathways in this Chapter instrumental to visualise how the 14 different market design options may be combined in a suitable manner depending on the specific system specificities and related congestion challenges.

5.1 Archetype 1: Systems with predictable Internal Congestion addressed via finer spatial granularity

This archetype represents countries where congestion is generally stable in the long-term and predictable, occurring mainly internally to the country because of the topology of their grids. Such countries would typically feature moderate – yet important – levels of interconnection, while congestion would often be driven by the geographical concentration of renewable generation and/or of main demand centers. Further, to better define this archetype, we refer to countries that have addressed, or plan to address, congestions described above mainly via finer spatial granularity, for instance by introducing internal Bidding Zones.

To address these conditions, the following policy pathways are considered:

- Internal Bidding Zones and Self-dispatch
- Internal Bidding Zones and Central Dispatch
- From Internal Bidding Zones to Nodal Pricing

5.1.1 Internal Bidding Zones and Self-dispatch

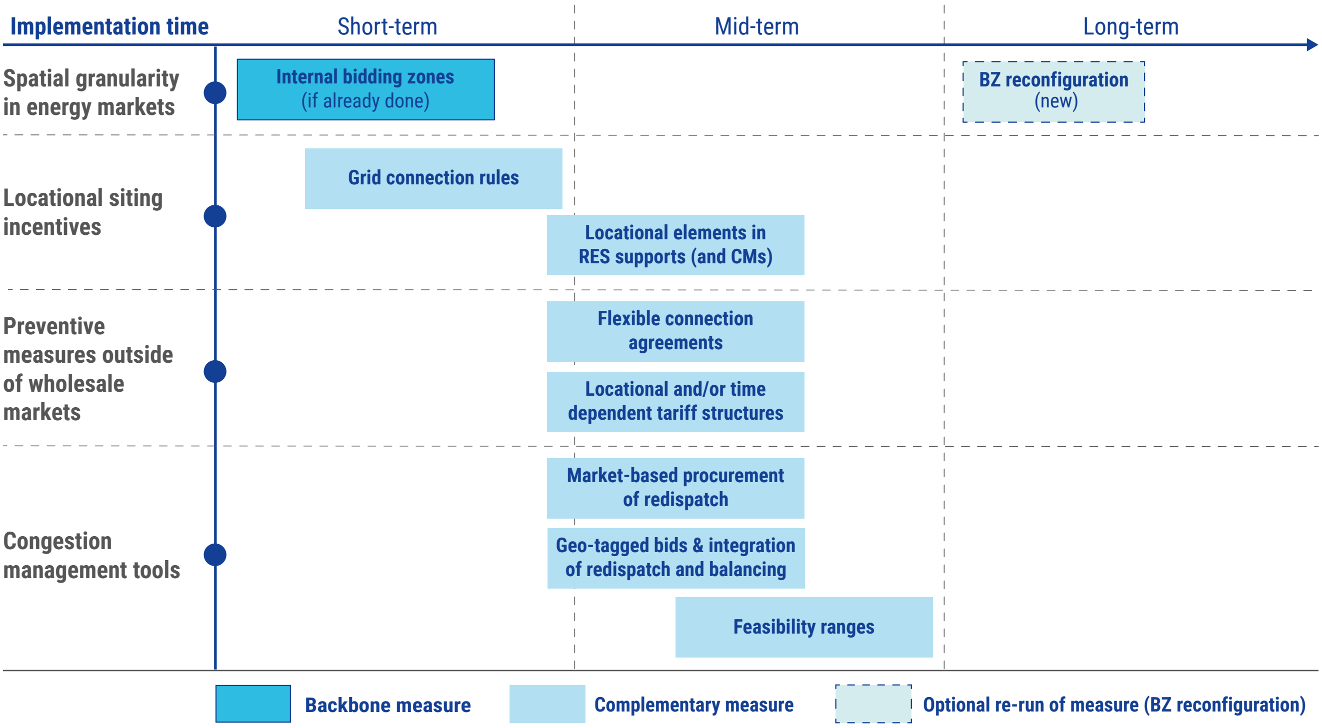


Figure 5: Internal Bidding Zones and Self-Dispatch

In the policy pathway with internal bidding zones and self-dispatch, structural congestion should largely be addressed by the current bidding zone configuration, with the potential to reconfigure bidding zones in order to address changes to structural congestion patterns. If necessary, additional locational signals can be provided to generators, storage, and consumers by including locational elements in transmission tariffs, RES support schemes, adjustments to grid connection rules, and capacity mechanisms. The spatial granularity of locational incentives can be adapted based on the needs of the system and could reflect a similar granularity as the bidding zone configuration or with a finer spatial granularity to better reflect inter-zonal congestion. Correctly applied, these measures should reduce congestion and the need for congestion management in the long-term.

Moreover, tariffs can be designed to provide time-varying elements, which similarly to FCAs could be used to proactively alleviate congestion closer to real-time. In a self-dispatch regime, resources dispatch based on their own economic criteria, energy is largely produced and traded DA and ID based on their own initiative, rather than being determined centrally by the TSO. The balancing mechanism, which operates close to real-time, following gate closure, is however centrally run by the TSO with resources procured subject to a competitive process. Measures to improve liquidity and competitiveness is likely to make close to real-time management of congestion more efficient. Furthermore, if non-structural congestion is frequently identified following DA-closure, feasibility ranges can be implemented to ensure that ID-trading does not create or worsen congestion that has been identified in advance.

5.1.2 Internal Bidding Zones and Central Dispatch

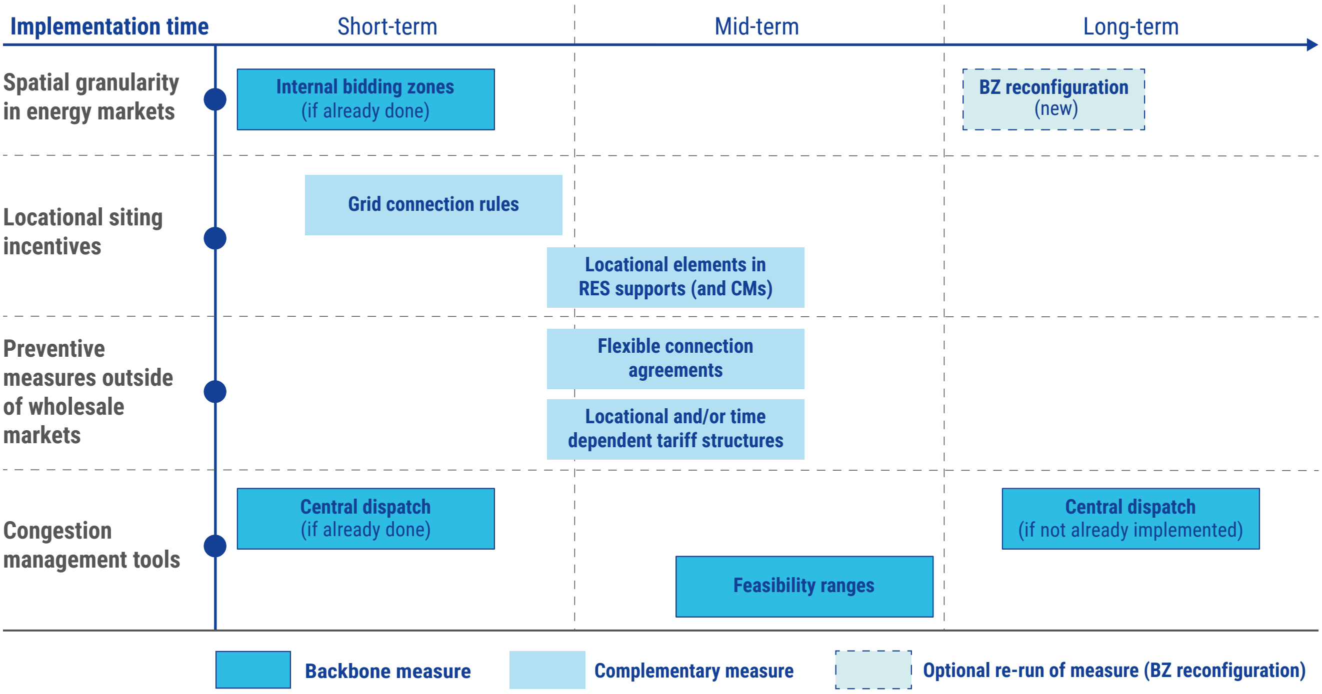


Figure 6: Internal Bidding Zones and Central DIspatch

In this policy pathway, the internal bidding zones allow to address structural congestions to a large extent. If necessary, additional locational elements can be given to generators, storage and consumers via transmission tariffs, RES support schemes, and capacity mechanisms (if present), either with similar spatial granularity as BZs or with a finer granularity if needed to influence asset siting within a specific BZ. These locational signals could be introduced relatively quickly, especially in case of new RES auctions, while for Capacity Mechanisms their design and implementation would typically be a bit longer. The effect of these measures would take some years to materialise as they would affect only new investments. This package assumes a combination of internal bidding zones and central dispatch, where the management of congestions in the operational timeframe, is carried out by the TSO via central dispatch and/or via feasibility ranges. The latter can be seen as an interim solution towards full central dispatch (in which feasibility ranges are embedded).

As explained in section 3.4.4, Central dispatch uses grid constraints and unit bids to optimise redispatch in real time, proactively managing congestion both expected and suddenly occurring. For systems currently using self-dispatch, moving to central dispatch would entail significant implementation challenges and thus a relatively long lead time. On the contrary, countries already using central dispatch and applying internal bidding zones, would "only" need to focus on complementary market design solutions for congestion management. Apart from locational signals in RES supports, FCAs – and to a lesser extent grid connection rules – can also further contribute to managing congestions in these systems. While they can be implemented in the short term and produce effects quicker than other instruments, they appear less necessary as central dispatch and internal bidding zones should be able to efficiently address congestions alone.

5.1.3 From Internal Bidding Zones to Nodal Pricing

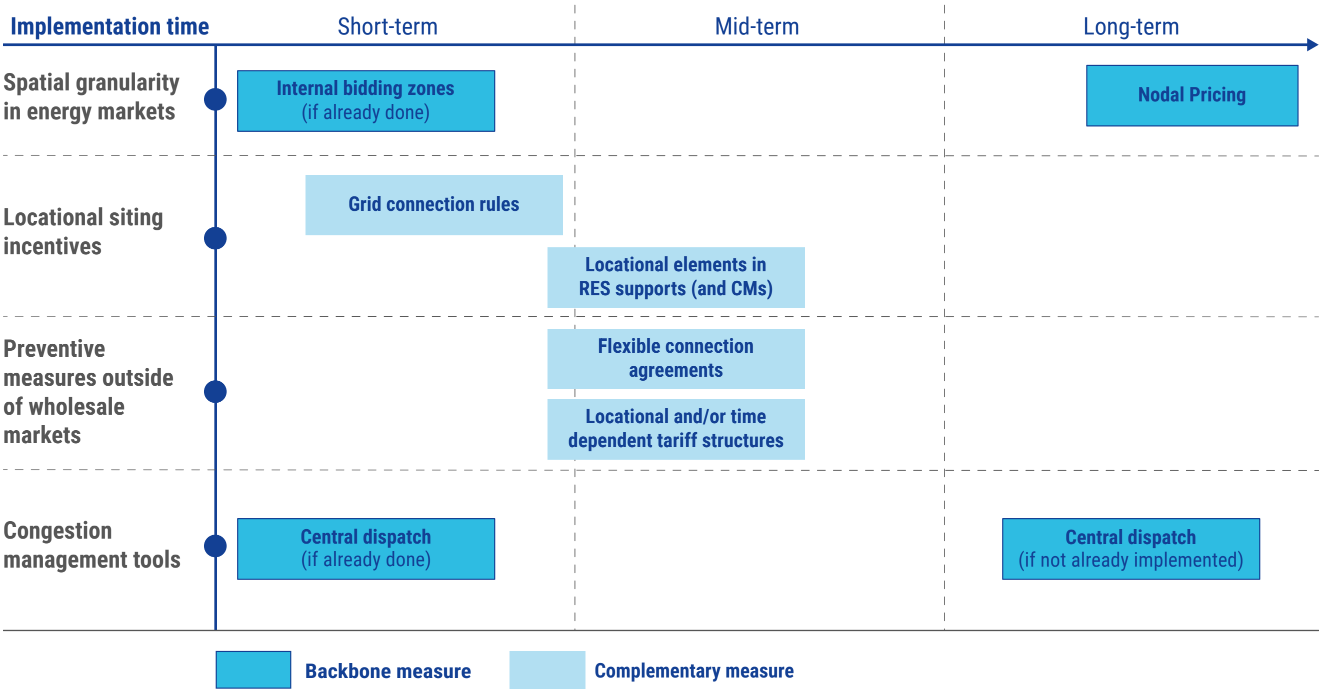


Figure 7: From Internal Bidding Zones to Nodal Pricing

This policy pathway could be considered for countries where locational signals via bidding zones reconfiguration (and/ or internal national bidding zones) are not sufficient to efficiently address structural congestions, even in the presence of additional locational signals (in RES supports, tariffs and/ or Capacity Mechanisms) and of complementary market design solutions. As such, it can be seen as a further evolution of the previous pathway "Internal Bidding Zones and Central Dispatch" or of the policy pathway "Internal Bidding Zones and Self Dispatch". In case of the presence of internal bidding zones and of central dispatch (which is an inherent feature of existing nodal pricing market models), a move to nodal pricing would require less implementation time and transaction costs compared to situations with single country/ large bidding zones and self-dispatch. Where internal bidding zones are already implemented with self-dispatch, moving to a nodal pricing model with central dispatch would still take significant time for the design and implementation phase.

Countries with internal bidding zones may want to move to nodal pricing to improve price signals by reflecting local congestion and supply-demand conditions more accurately, thus enhancing operational security and efficient grid use. As for the previous case, spatial granularity and central dispatch would normally address most of congestion issues. However, additional locational signals could be delivered also through RES Support Schemes, Capacity Mechanisms or Flexible Connection Agreements either before the introduction of nodal pricing, or – if still necessary – after.

From a geographical coverage point of view, the considerations above are valid mostly for individual countries. In case nodal pricing was to be applied at larger scale by a group of neighbouring countries, this would further increase implementation complexity on the one hand, while bringing benefits in the management of cross-border congestions. In any case, as already concluded by ENTSO-E in 2021, a nodal pricing model is neither a feasible nor a desirable option on a European scale.

5.2 Archetype 2: Highly Interconnected Congestion Systems

This archetype includes systems that are highly interconnected and strongly affected by cross-zonal interactions, such as loop flows. Congestion in these systems would be long-term stable but influenced by both domestic and neighbouring network conditions, making coordination across bidding zones particularly important. At the same time, the shortening time to deal with higher variability and uncertainty could lead to more volatile, short-term congestion patterns, requiring more frequent interventions closer to delivery.

In such contexts, the following packages are considered:

- New Internal Bidding Zones
- Without Bidding Zone Reconfiguration
- From Internal Bidding Zones to Nodal Pricing – described in the previous archetype is deemed relevant these types of systems as well.

5.2.1 New Internal Bidding Zones

This policy pathway primarily uses a BZ reconfiguration to tackle most of the congestions as they are long-term stable. By increasing the spatial granularity such long-term stable congestions can be managed while limiting the cross zonal impact on the region. The use of BZ reconfiguration as fundamental solution to address long-term stable congestions, is supplemented by additional measures to be able to handle the remaining congestions, as even with smaller bidding zones some congestion is expected to remain. Furthermore, due to the highly interconnected nature the remaining congestions are also expected to become more volatile and harder to predict.

This package of complementary measures is summarised in figure 8:

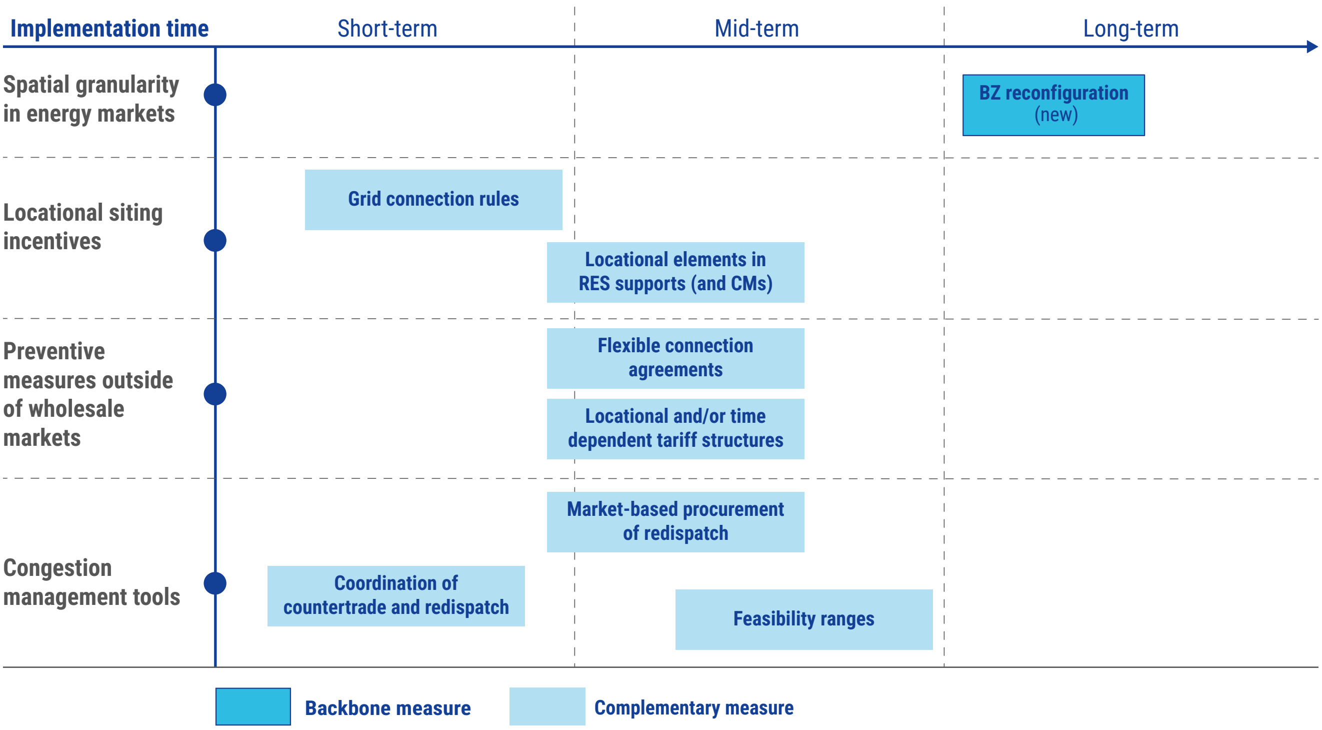


Figure 8: New Internal Bidding Zones

Complementary short-term measures

Even though no regulatory changes are needed, the implementation of new BZs could take a few years in which case the effects on dispatch and investment decisions would only materialise in the mid-term. In the shorter term FCAs, market-based redispatch and new Grid Connection Rules can already help to better manage the congestions as they give the TSO better access to flexible potential at generation, demand and storage facilities. Coordination of countertrade and redispatch can be seen as a no-regret measure as a coordinated approach is expected to be more efficient, especially in the highly interconnected setting.

Complementary longer-term measures

Depending on the size of the BZs some additional longer-term measures can be considered to complement them. To handle the more volatile and harder to predict congestions it can be considered to supplement the BZ reconfiguration with Feasibility ranges, allowing the TSO to restrict trading in case insufficient redispatch potential is expected to be available in time. Locational elements in the Support Schemes and Capacity Market can be considered in case the smaller BZs alone do not give enough locational steering. The same applies for grid tariff structures, if the price formation from the wholesale market doesn't reflect the grid conditions enough.

5.2.2 Without Bidding Zone Reconfiguration

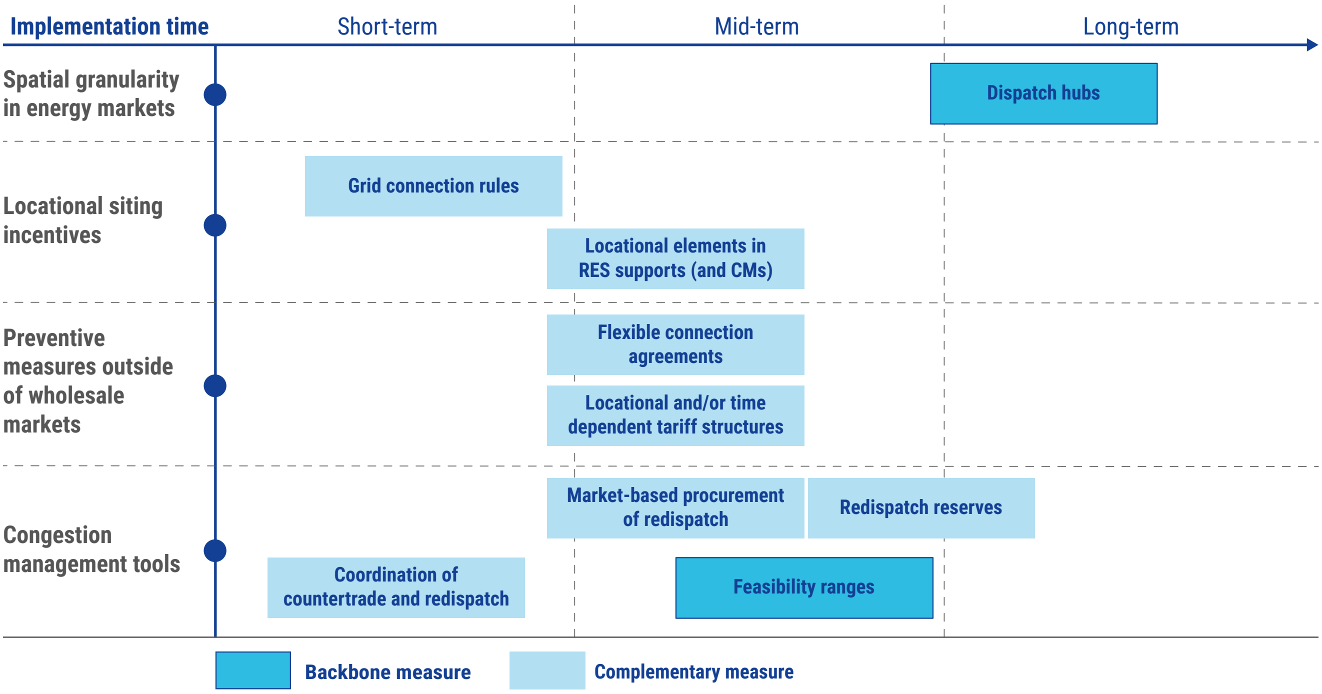


Figure 9: Without Bidding Zone Reconfiguration

This package relies on solutions/instruments that better align market outcomes with network constraints while preserving the existing zonal design. The core steering tools are Feasibility Ranges and Dispatch Hubs. Feasibility ranges allow TSOs to set maximum or minimum unit schedules after the day ahead market based on security analyses, ensuring that subsequent intraday trading does not aggravate predictable congestions. When updated throughout the intraday timeframe and closer to delivery, they can effectively handle volatile, short-term congestion patterns and reduce the need for corrective redispatch. Dispatch Hubs introduce additional spatial granularity within a bidding zone, enabling congestions to be addressed directly in the day ahead and intraday auctions. By acting as small virtual bidding zones at system-relevant locations, they can reduce redispatch volumes and internalise part of the congestion costs while offering more flexibility than a Bidding Zone Reconfiguration. The effective deployment of Dispatch Hubs requires that capacity allocation fully integrates system relevant internal constraints and refrains from the use of virtual margins; without these regulatory preconditions, additional market accessible capacity would risk incentivising infeasible dispatch outcomes and increasing the need for congestion management.

Both core instruments – Feasibility Ranges and Dispatch Hubs – are solutions with a mid-term and long-term implementation horizon and typically generate mid-term impacts. Their implementation requires regulatory adaptation, methodological preparation, and technical integration in operational and market processes. At the same time, their effects on congestion patterns and market behaviour materialise progressively as market participants adapt to the new arrangements.

Depending on the design and geographical scope of the Dispatch Hubs, the extent to which Feasibility Ranges need to be applied may be lower.

A well targeted hub design can internalise part of the structural or recurrent congestion directly in the market coupling, thereby limiting the number of units that would otherwise require feasibility restrictions. Conversely, where hubs are deliberately narrow and focused, Feasibility Ranges may still be needed more broadly to address residual congestion. In any case, feasibility ranges would be needed for solving volatile, short-term congestion patterns – the degree to which they are required would still depend on the specific market design adopted.

Short-term complementary measures

Since the core instruments of this package require mid-term preparation and implementation, short-term measures are needed upfront to support congestion management and reduce uncertainty during the transition. Flexible Connection Agreements can be implemented in congested areas to help reduce short-term redispatch requirements and mitigate uncertainty. In addition, redispatch reserves act as a targeted measure in regions experiencing predictable congestion. These reserves ensure that adequate resources are available for redispatch when necessary, which is especially important in situations where seasonal decommissioning or limited local flexibility might otherwise jeopardise operational security.

Medium-term complementary measures

In the medium term, grid connection rules can be designed to incorporate system-relevant prioritisation criteria and location-based assessments. By doing so, new assets are connected in regions where they provide tangible system benefits, rather than intensifying existing congestion challenges. Market-based redispatch can be used to leverage competitive mechanisms to improve efficiency, transparency, and cross-border coordination of redispatch. In systems where inc-dec gaming risks are particularly severe, combining traditional cost-based redispatch and market-based redispatch model – such as for instance the Redispatch 3.0 hybrid approach – can be an effective compromise. This model integrates cost-based redispatch for conventional generators with market-based procurement of flexibility from storage and demand response. The combined strategy enhances redispatch liquidity, minimises incentives for gaming, and supports operational feasibility.

Long-term complementary measures

Regarding potential long-term effects, locational elements in capacity mechanisms, RES support schemes and flexibility support schemes can complement the short- and medium-term measures by steering new generation, storage and flexible demand toward areas where they support congestion reduction. Such locational elements help ensure that future assets contribute to alleviating long term transmission constraints rather than increasing redispatch needs.

5.3 Archetype 3: Limited-Interconnection Systems with variable congestions

This archetype represents systems with limited interconnection capacity, where congestion would mostly be internal and variable rather than structurally persistent. Given the temporary nature of congestions in this archetype, none of the pathways include modifications in terms of spatial resolution of energy markets. In these systems, congestion management would often rely on operational tools and preventive approaches, supported by targeted investment signals.

For these conditions, the following packages are considered:

- Preventive congestion management before intraday gate closure in self-dispatch framework
- Preventive congestion management before intraday gate closure in central dispatch framework
- Preventive congestion management after intraday gate closure combined with proactive investment signals

5.3.1 Preventive congestion management before intraday gate closure in self-dispatch framework

This package combines the utilisation of locational siting incentives for mitigating the risk of new long-term stable congestions together with the utilisation of preventive operational measures and corrective congestion management tools to handle the evolving congestion patterns.

This set of solutions could correspond with a strategy for a system facing significant changes in the congestion management pattern due to either entry of new market actors (e.g.: storage, demand response…) or rapid increase of RES or electrification without a significant forecast of long-term stable congestions. To facilitate efficient integration into the system, capacity auctions reflecting the level of congestion along the transmission network can guide new siting decisions. This would allow aligning the deployment of new capacities with the development of the transmission network mitigating the risk of appearance of long-term stable congestions.

In the day-to-day energy trading, under a proactive congestion management strategy the TSO can perform security analysis in pre-defined windows (e.g.: between Day-Ahead and Intraday markets) to assess the level of congestions and establish curative measures via a market based redispatch and preventive schedule variation limitations via feasibility ranges. The implementation of Flexible Connection Agreement could be used as a facilitator for the implementation of Feasibility Ranges.

Depending on the severity of the congestion challenges in the balancing timeframe, the TSO could also implement geo-tagged bids in balancing timeframe to mitigate the appearance of congestions after balancing markets.

An overview of the solution package described above is provided in figure 10:

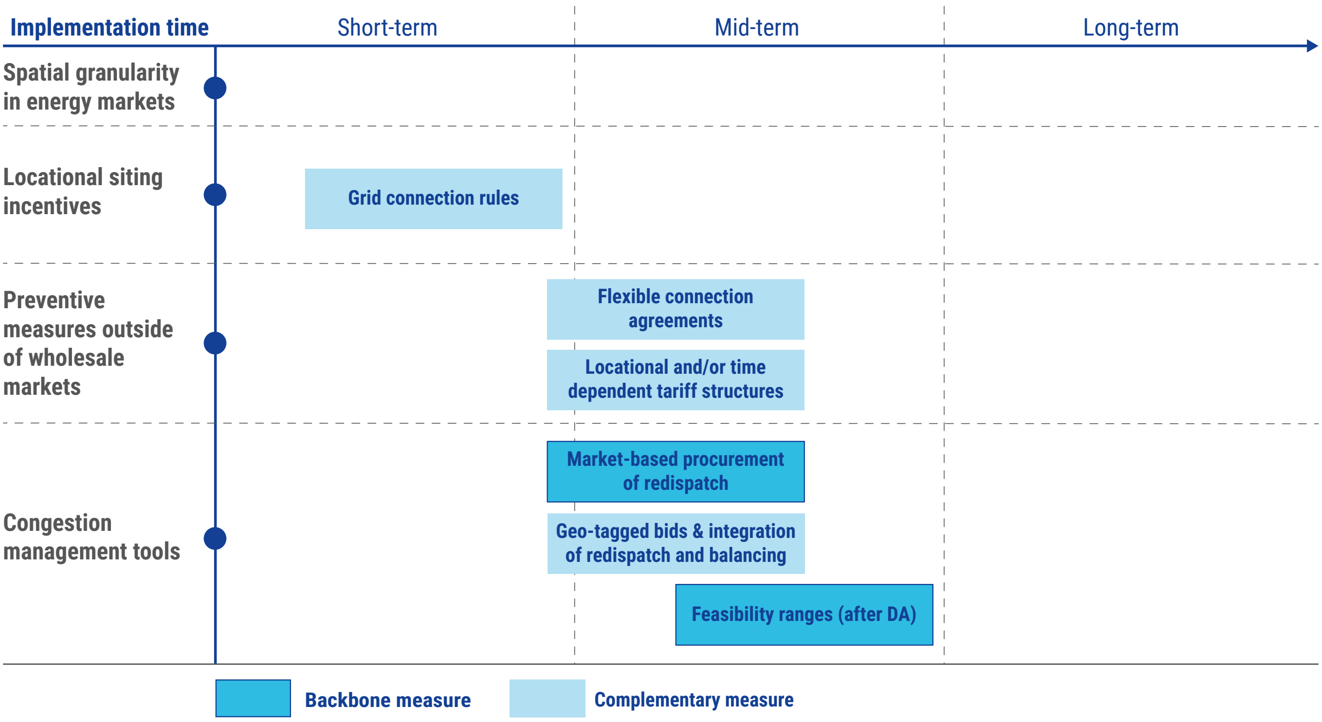


Figure 10: Preventive congestion management before intraday gate closure in self-dispatch framework

5.3.2 Preventive congestion management before intraday gate closure in central dispatch framework

This package primarily relies on Central Dispatch as an existing basis to address both significant and manageable network congestions. Central Dispatch incorporates to a certain degree the following solutions, Feasibility Ranges, Geo-Tagged Bids and Integration of Redispatch and Balancing. More specifically, Central Dispatch through the Integrated Scheduling Process (ISP), takes into consideration locational information, bids and technical capabilities of units (above a certain threshold) in combination with potential operational/system or locational constraints. Subsequently, the ISP simultaneously coordinates balancing, and/or congestion management, and/or reserve procurement allowing for the proactive management of both anticipated and unforeseen congestions within a single integrated framework. The output of the ISP algorithm optimises unit commitment and dispatch across the system, ensuring both security of supply and effective congestion management. The centralised approach enhances the effectiveness and timeliness of congestion relief.

Complementary to Central Dispatch solution, Time-dependent Elements in Transmission Tariff Structures are employed to provide signals and incentives for grid users to make more system-efficient bidding decisions over time, thereby contributing to congestion alleviation. In this way predictable or recurring congestions could be mitigated via individual market behaviour that is better aligned with system needs. Moreover, the Grid Connection Rules solution allows the TSO to prioritise connections not solely on the basis of project readiness but also by considering their strategic relevance for the system and their potential contribution to congestion relief.

Flexible Connection Agreements (FCAs) could be deployed as a mid-term solution with significant potential to enhance grid efficiency and address long-term, structural congestions, if present.

Depending on the severity of increasing congestion levels, Dispatch Hubs solution could be considered as an additional long-term measure to complement the solutions outlined above. Specific geographical areas affected by local system challenges – such as network congestion, voltage constraints, or other operational issues – could be identified and defined accordingly. Portfolios of distributed energy resources exceeding a predefined capacity threshold within a given area could then be required to be disaggregated by location, enabling a more granular assessment of local conditions at the planning stage and preventing dispatch decisions that could compromise system security. In this policy pathway, the Dispatch Hubs solution is preferable to the Bidding Zones Reconfiguration option, as it requires fewer regulatory changes and can be implemented more quickly and efficiently within a Central Dispatch framework. Moreover, Dispatch Hubs may serve as a temporary solution, which can be reversed once the underlying causes of congestion are resolved (for example, through new infrastructure investments addressing local congestion issues that led to the introduction of a specific Dispatch Hub).

An overview of the solution package described above is provided in figure 11:

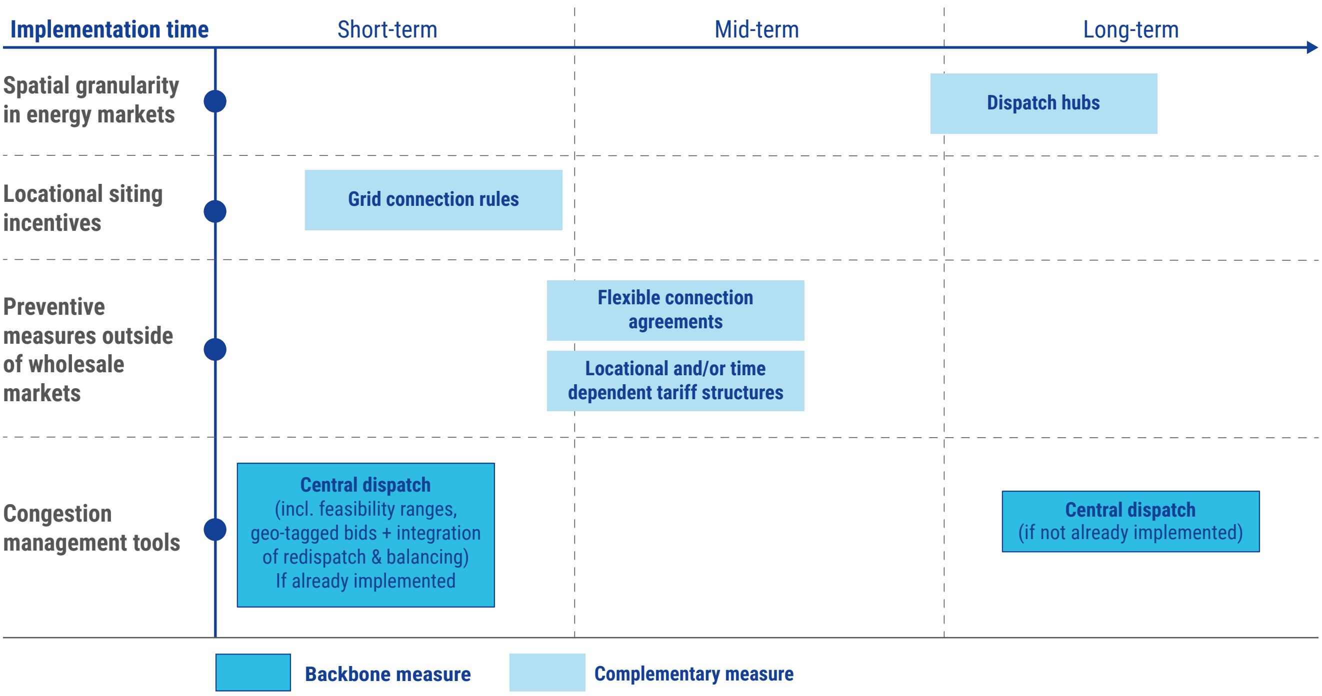


Figure 11: Preventive congestion management before intraday gate closure in central dispatch framework

5.3.3 Preventive congestion management after intraday gate closure combined with proactive investment signals

In terms of preventive congestion management in the energy markets, compared to the previous pathways this one only establishes preventive measures via feasibility ranges once intraday market is closed.

A more proactive approach for predictable congestions is followed which relies on locational signals in tariffs.

In the longer term, to prevent congestion from becoming structural, connection rules and locational elements in support schemes are used to maintain a balanced buildout of capacity across the country.

If this turns out to be insufficient to keep volatile congestions manageable, a nodal pricing granularity in balancing could optionally be added to ensure that balancing markets do not introduce congestions in the network.

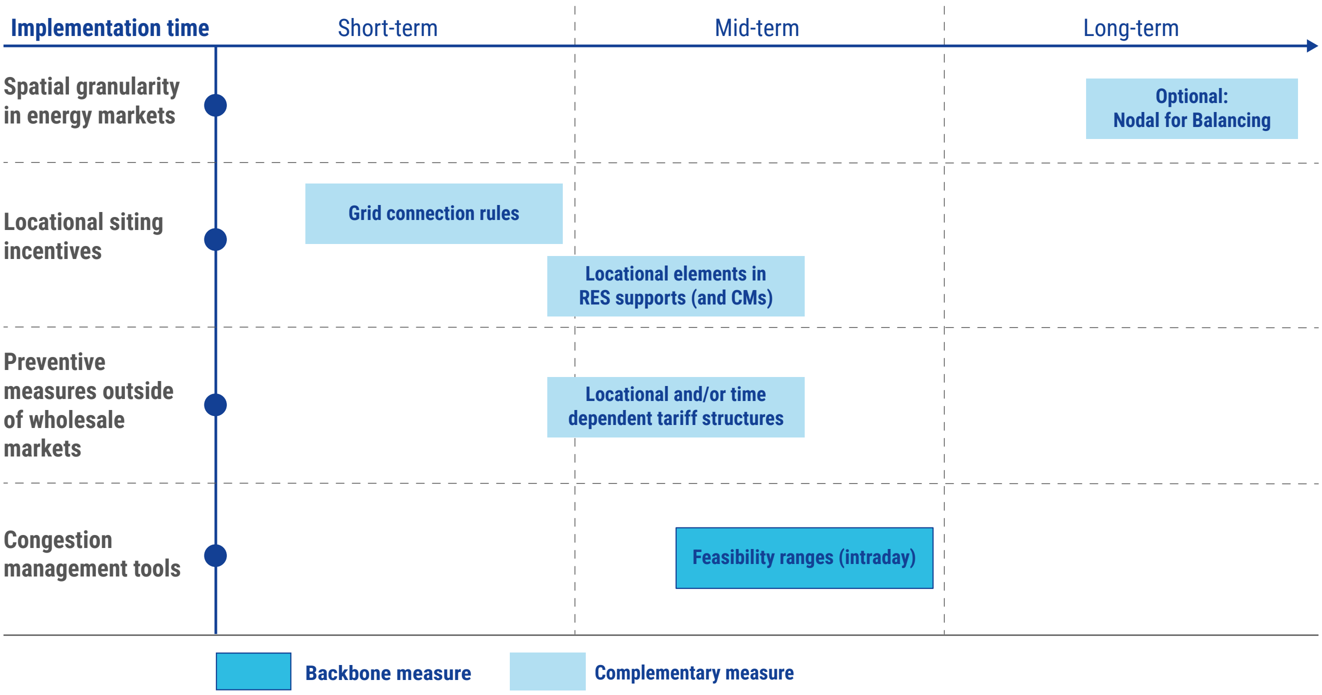


Figure 12: Preventive congestion management after intraday gate closure combined with proactive investment signals

6 Conclusions and Recommendations

The recommendations below reflect an ENTSO-E perspective and aim to balance operational robustness, economic efficiency, market functioning and feasibility of implementation. They recognise the need for both long-term structural measures and pragmatic, no-regret actions that can be deployed incrementally, while preserving flexibility for future market design evolution.

General

- To ensure system security in a cost-efficient manner, policy makers should enable solutions to bridge the gap between markets and physics. Such solutions should aim at maximising trading opportunities for a truly integrated internal electricity market, but respect technical and operational limits as a priority.
- One current limitation to bring physics and market closer together is the use of virtual margins in the capacity calculation processes, as these carry significant collateral consequences for the power system operations. In current regulation virtual margins are a key feature of the min. 70 % framework. The principle behind the min. 70 % framework, i.e. make a significant part of the grid available to achieve market integration and hereby avoid undue discrimination between internal and cross-zonal exchanges, remains fundamental. It is imperative that alternative ways of aligning market and physics are explored to which this paper contributes.

Spatial granularity in energy markets

- Recognise increased spatial granularity as a structurally effective long-term solution from congestion minimisation perspective, while acknowledging market impact together with implementation challenges and political implications.
- Consider context and region-specific pathways (e.g. bidding zone reconfiguration and/or dispatch hubs or potentially even nodal pricing, where proven to be feasible and efficient) depending on the significance and variability of the structural congestions, while ensuring internal electricity market efficiency.
- Ensure that any increase in spatial granularity addresses market parties' need of liquidity, risk hedging and investment certainty.
- Balance the need for periodic assessment/update of spatial granularity with predictability and stability for market participants (i.e. avoid too frequent or unpredictable reconfiguration).

Locational siting incentives

- Where appropriate, integrate locational elements into capacity mechanisms, RES support schemes and flexibility support schemes where such schemes already exist.
- Consider using locational criteria in grid connection rules to steer new investments toward grid-supportive locations and to ensure that investment decisions reflect part of the congestion and redispatch costs they may impose on the system.
- Acknowledge that locational incentives are complementary instruments with primarily long-term effects and should not be expected to solve short-term congestion challenges.
- Ensure transparency, non-discrimination, cost-based design, and consistency with EU state aid and internal market principles.

Preventive measures outside of wholesale markets

- Promote preventive measures that reduce redispatch volumes and uncertainty, while carefully balancing efficiency gains against forecast errors and implementation complexity.
- Consider flexible connection agreements as a tool in congested areas, with design choices (scope, timing, compensation, voluntariness) taking into account regulatory framework, system needs and market implications. In particular, the use of voluntary flexible connection agreements in congested areas should be expanded building on existing national experiences.
- Transmission and distribution tariffs can provide stable and transparent locational or time-dependent dispatch signals. More dynamic signals with locational elements should be carefully analysed to evaluate potential benefits against disadvantages.
- Ensure strong TSO–DSO coordination and clear communication to market participants to limit operational and behavioural risks.

Congestion management tools

- Ensure the continued availability of timely, location-specific congestion management and redispatch resources to safeguard operational security under increasing uncertainty.
- Prefer market-based and integrated solutions (e.g. market-based redispatch, integration of balancing and redispatch) where sufficient liquidity and competition between service providers can be ensured, while recognising their limits depending on locational congestion patterns and carefully assessing overall market impacts.
- Apply intervention tools (e.g. redispatch reserves) only as targeted or temporary measures, not as permanent substitutes for less costly structural solutions.
- In systems where it is already applied, leverage the benefits of central dispatch approaches to balance market efficiency with the need to keep the system secure while optimising congestion management costs. Similarly, systems that apply or want to make use of the feasibility ranges concept should find an appropriate balance in their application.
- Continue improving cross-border coordination of redispatch and countertrade, including through regional operational frameworks, to minimise total system costs.

Annex: Technical Enablers for More Efficient Congestion Management

This chapter outlines complementary technical and operational measures that can support or enhance the effectiveness of the market design solutions presented in this report. These measures do not seek to alter market arrangements, but they improve the utilisation of existing grid infrastructure, reduce operational uncertainty and strengthen the ability of system operators to anticipate and manage congestions.

Improved security conditions

Dynamic Asset Rating and Granular Asset Monitoring

Increasing the utilisation of existing grid assets can be achieved through more dynamic and accurate assessments of equipment capacity, enabled by:

- Dynamic line and transformer rating (e.g. temperature-based ratings for cables and transformers, conductor sag/distance for overhead lines, operational voltage adjustments).
- Real-time or dynamic asset measurements supported by more granular data acquisition.

Conditional lifting of redispatching criteria

Under a set of specific situations, TSOs could identify units which would not be redispatched for security criteria such as N-1 or N-2 (e.g.: units able to automatically reduce their active power in case of incident could remain unredispatched and only their power would be automatically reduced in case of incident).

Risk-Based Operational Criteria

Temporary and carefully assessed relaxation of deterministic criteria can unlock additional transfer capacity, for example moving toward a more fully risk-based approach, balancing the costs and benefits of incremental reliability improvements. However, finding the appropriate balance between acceptable system risk and maximising asset utilisation remains a key challenge.

These capabilities provide transmission system operators already today in some jurisdictions with a more precise view of actual asset behaviour contributing to reducing the need of redispatch and can also directly support forecasting improvements by delivering higher-quality real-time inputs.

Moreover, some targeted reinforcements such as replacing conventional conductors with high-temperature low-sag (HTLS) technologies or replacing components with lower-impedance alternatives to increase overloading capability can also deliver significant gains without requiring major new infrastructure.

Increasing grid capacity and flexibility

- Upgrading the limiting equipment (replacing conductor by HTLS, upgrading to higher voltage levels)
- Grid booster batteries – serving as a virtual transmission line, increasing the utilisation of existing assets and avoiding costly preventive redispatch actions.[24]
- Phase-shifting transformers (PSTs) can improve utilisation of existing grids and support congestion management by actively redistributing power flows across parallel lines—shifting load away from overloaded circuits so lines can operate closer to their thermal limits and avoid bottlenecks.

24 More details on the Grid booster batteries can be found in ENTSO-E Policy Paper: Design for Utility-Scale Energy Storage page 25

Improved Forecasting

Forecasting of renewable generation and electricity demand already plays a central role in operational planning and congestion management. As the share of variable generation increases and market activity shifts closer to real time, the need for accurate, frequent and consistent forecasting becomes more pressing. Moreover, increasing RES variability and more frequent extreme weather events heighten the mismatch between day-ahead generation plans and actual intraday dispatch. Therefore, future improvements in forecasting can significantly enhance operational planning by:

- Strengthening the quality and frequency of input data, including more granular real-time measurements.
- Using advanced methods (e.g. machine learning, AI) where traditional models are stretched by variability.
- Integrating market-relevant factors (price signals, trading behaviour) to better anticipate actual dispatch patterns.
- Establishing minimum quality requirements for forecast accuracy and update frequency, supported by continuous assessment of data used for individual grid models.

In the medium to long term, progress could be supported by:

- Coordinated regional approaches and shared forecasting methods.
- Pilot projects to develop common standards and improve cross-border consistency.

More accurate and frequently updated forecasts would not remove the need for congestion management but could enable more optimised security margins, reduce redispatch volumes and support better price convergence. Ultimately, improved forecasting is a key enabler for secure, efficient system operation during the energy transition. Together, these technical and operational enablers provide opportunities to unlock additional grid capacity, reduce uncertainty, and enhance the efficiency of system operation without altering the underlying market design. While none of these measures alone can eliminate the need for congestion management, their combined effect can significantly improve the performance, reliability and cost-efficiency of the power system during the transition to a more variable and interconnected energy landscape.

Harmonised technical connection requirements

A credible definition of grid-friendly and grid-forming behaviour should be reflected not only in economic incentives, but also in harmonised technical connection requirements via Connection Network Codes (CNCs). Such requirements can help ensure that new inverter-based generation, storage and large demand connect with minimum system-supportive capabilities.

Over time, a more system-supportive asset mix can reduce the need for corrective actions such as redispatch by improving operational flexibility and reducing the risk that new connections exacerbate local or system-wide constraints.

Abbreviations

AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserve
AOF	Activation Optimisation Function
BRP	Balance Responsible Party
BZ	Bidding Zone
BZR	Bidding Zone Review
CACM	Capacity Allocation & Congestion Management
CLC-A	Capacity Limitation Contract on Request
CLC-T	Capacity Limitation Contract with Time
CNCs	Connection Network Codes
CM	Capacity Mechanism
CT	Countertrade
DC	Direct Current
DLR	Dynamic Line Rating
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	Electric Vehicle
FCAs	Flexible Connection Agreements
GOPACS	Grid Operator Platform for Congestion Solutions

HTLS	High-Temperature Low-Sag
HVDC	High Voltage Direct Current
HVDCs	High Voltage Direct Current transmission lines
IDA	Intraday Auctions
ISO	Independent System Operators
ISP	Integrated Scheduling Process
LMP	Locational Marginal Pricing
mFRR	manual Frequency Restoration Reserve
NFFSS	Non-Fossil-fuel Flexibility Support Schemes
PPAs	Power Purchase Agreements
PST	Phase Shifting Transformer
RCC	Regional Coordination Centre
RD	Redispatch
RES	Renewable Energy Sources
ROSC	Regional Operational Security Coordination
SCED	Security Constrained Economic Dispatc
SCUC	Security Constrained Unit Commitment
SDAC	Single Day-ahead Market
SIDC	Single Intraday Coupling
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital

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