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The New EU Electricity Market Design: The Main Measures for Traders, Electricity Producers and Transmission System Operators

1. Introduction

On 13 June 2024, Regulation 2024/1747 and Directive 2024/1711 of the European Parliament and Council were officially adopted. The main purpose of these new Regulation and Directive is to amend Regulation 2019/943 ('Electricity Regulation') and Directive 2019/944 ('Electricity Directive') in order to improve the Union's electricity market design ('EMD').

Some measures will be inserted in a consolidated version of the Electricity Regulation ('the New Electricity Regulation') and entered into force on 17 July 2024. Other measures will be inserted in a consolidated version of the Electricity Directive ('the New Electricity Directive') and need to be transposed by Member States by 17 January 2025.

A distinction between the different measures can also be made depending on the markets where the different operators are active: (i) the market for wholesale and production of electricity; (ii) the market for electricity transmission (high-voltage grid); (iii) the market for electricity distribution (low-voltage grid); and (iv) the retail market for electricity supply.

On each of these markets, different operators are active: traders and producers, transmission system operators ('TSOs'), distribution system operators ('DSOs') and electricity suppliers. This Newsflash gives an overview of the measures for traders, electricity producers and TSOs active on the market for wholesale and production of electricity and on the market for electricity transmission.

A second Newsflash, which will be published later, will deal with the measures for electricity suppliers and DSOs.

2. Measures on the market for wholesale and production of electricity

Within the wholesale and production market, a further distinction can be made between the measures directly affecting the short-term market and measures directly affecting the long-term market.

a) Measures on the short-term market for wholesale and production of electricity

There was no reform of the main principle underlying the short-term electricity market. The merit order principle will continue to apply, so that the marginal cost of the marginal (fossil or non-fossil) unit necessary to meet electricity demand still determines the clearing price on the short-term wholesale market and, thereby, the allocation of cross-zonal capacities.

However, the new electricity market design will result in four main measures which will affect traders and electricity producers on the short-term market for wholesale and production of electricity:

- Day-ahead and intraday markets will be organised in such a way as to ensure that the entities which organize the coupling of the different "national" power exchanges (i.e., the nominated electricity market operators ('NEMOs')) will have to share the **liquidity** of their respective **order books** until the latest point in time where day-ahead or intraday trade is allowed and will be prohibited to organize trading of identical products outside the day-ahead and intraday couplings (Article 7 of the New Electricity Regulation). For instance, this means that in practice in the German bidding zone, orders from all NEMOs must be submitted to the Shared Order Book until five minutes before delivery.

- From 1 January 2026, the **intraday cross-zonal gate closure time** shall be reduced from 60 minutes before real time[1] to 30 minutes before real time. A national regulatory authority ('NRA') can, at the request of the concerned TSO, grant a derogation until 1 January 2029 on the basis of an impact assessment and an action plan. An additional derogation is possible until 30 June 2028 by up to two-and-a-half years from the date of the first derogation (Article 8 of the New Electricity Regulation).

- NEMOs will provide **products for trading with minimum bid sizes of 100 kW (0.1 MW)** instead of minimum sizes of 500 kW (0.5 MW) (Article 8 of the New Electricity Regulation).

- Member States may request TSOs in case of a regional or Union-wide electricity price crisis (see our next Newsflash on this) to propose the **procurement of peak shaving products**, i.e., products where market participants reduce their electricity consumption from the grid at peak hours at the request of the TSO (Article 7a of the New Electricity Regulation). The difficulty will be to redefine what are "peak hours" (i.e., hours where (i) the gross electricity consumption, (ii) the gross consumption of electricity generated from sources other than renewable sources or (iii) the day-ahead electricity price is expected to be the highest). Peak hours were usually defined as the hours taking place between 08:00 am and 08:00 pm. However, with the recent significant increase in solar energy capacity throughout Europe, this set of hours can no longer be considered as being peak hours.

b) *Measures on the long-term market for wholesale and production of electricity*

Five main measures will affect traders and electricity producers on the long-term market for wholesale and production of electricity:

- In addition to possible changes (i) in the frequency of allocation of **long-term transmission rights** ('**LTRs**'), (ii) in the maturities of LTRs (extended up to at least three years), (iii) in the nature of LTRs and (iv) in the way LTRs are traded on the secondary market, the Commission will be able to introduce regional virtual hubs for the forward markets through the adoption of an implementing act (Article 9 of the New Electricity Regulation). These **regional virtual hubs** consist of a nonphysical region covering more than one bidding zone for which a reference price is set on the basis of a methodology.

- Regional virtual hubs are not really a novelty in Europe. In fact, regional virtual hubs and LTRs are respectively part of the two forward market designs which have emerged in Europe.

- The first design (to which **regional virtual hubs** belong) was implemented in the Nordic and Baltic countries and within Italy in the context of **multi-zone hubs.** This design relies mainly on the market and a variety of products developed through various market platforms. It contains a set of hedging contracts for a group of bidding zones. These contracts are linked to a hub price (system price). In the case of the Nordic and Baltic areas, the system price represents a physically unconstrained day-ahead price. In Italy, the hub price represents an average day-ahead price within the group of zones constituting the Italian multi-zone hub. Market participants hedge the bidding zone price risk by combining (i) a forward product with respect to the hub price with (ii) a contract for differences between their bidding zone and the hub. The forward product hedges the hub price. The contract for differences covers the difference between the hub price and the bidding zone price (see also below for more explanation about the mechanism of contract for differences). Market participants particularly need contracts for differences when the price-correlation between the hub and their bidding zone is poor.

- The second design (to which **LTRs** belong) was implemented in nearly all Member States in Continental Europe in the context of **single-zone hubs**. For each bidding zone, this design relies on a set of hedging contracts, which are linked to the day-ahead clearing price of this bidding zone. These contracts may be sufficient to hedge the price risk of market participants. However, market participants in a given bidding zone may want to hedge their exposure to risk using a hedging contract of a neighbouring bidding zone (i.e., proxy hedging). This could be a sufficient hedge if prices in the two bidding zones are highly correlated. If it is not the case, market participants need an additional hedging tool to cover the price differential between the two bidding zones. In this context, the second design gives an additional and specific role to TSOs. They are responsible for calculating long term capacities in a coordinated way and for auctioning (either physical or financial) LTRs, enabling market participants to hedge against the specific risk of short-term zonal price differentials.

- Member States shall promote the uptake of **Power Purchase Agreements ('PPAs')** by ensuring in a coordinated manner that instruments to reduce the financial risks associated to offtaker payment default in the framework of PPAs (such as guarantee schemes at market price) are in place and accessible to customers that face entry barriers to the PPA market (Article 19a of the New Electricity Regulation). These guarantee schemes may include, among others, statebacked guarantee schemes at market prices, private guarantees, or facilities pooling demand for PPAs. In particular, statebacked guarantee schemes shall include provisions to avoid lowering the liquidity in electricity markets and shall not provide support to the purchase of generation from fossil fuels. In addition to the annual assessment of the PPA market at Union and Member State level, the EU Agency for the Cooperation of Energy Regulators ('ACER') will have to assess the need to develop and issue voluntary templates for PPAs adapted to the needs of the different categories of counterparties by 17 October 2024 (Article 19b of the New Electricity Regulation).[2]

- **Direct price support schemes for investment in new power-generating facilities** concluded on or after 17 July 2027 for the generation of electricity from wind energy, solar energy, geothermal energy, hydropower without reservoir and nuclear energy[3] must now take the form of **two-way contracts for difference** or equivalent schemes with the same effects (Article 19d of the New Electricity Regulation). A two-way contract for difference ensures a fixed price (the strike price) to the investor for the electricity generated by its facility. Under this contract, the buyer (which is a public entity) virtually "pays" the strike price to the seller (the investor) for the contracted volume of electricity. In reality, the buyer does not necessarily consume the purchased electricity but only effectively pays or receives the difference between the reference price (usually, the day-ahead market price) and the strike price. In practice, the seller pays to the buyer the revenues generated when the reference price (usually, the day-ahead market price) is above the strike price. On the other hand, the seller receives from the buyer the revenues generated when the reference price is below the strike price. For example, an electricity producer invests in a new wind generation facility and "sells" all the volume that will be generated to the Belgian State under a two-way contract for difference at a strike price of 50 €/MWh. In day-ahead, if the electricity producer sells all the contracted volume at a price of 60 €/MWh on the Belgian day-ahead power exchange, this producer will need to pay 10 €/MWh to the Belgian State. If the same electricity producer sells all the contracted volume at a price of 40 €/MWh on the Belgian day-ahead power exchange, it will receive 10 €/MWh from the Belgian State. The obligation to use two-way contracts for difference does not apply to support schemes not directly linked to electricity generation, such as energy storage, and which do not use direct price support, such as investment aid in the form of upfront grants, tax measures or green certificates.

- National authorities will have to assess their flexibility needs every two years and define on this basis an indicative (provisional) national objective for non-fossil flexibility resources such as demand response and energy storage such as batteries and hydropower with reservoir (Articles 19e and 19f of the New Electricity Regulation). Such assessments are crucial given the increasing frequency of negative prices on spot markets following the significant roll-out of solar capacity. Indeed, such an increasing frequency indicates that it is urgent to increase the flexibility of the power system by making generation and demand more price-responsive, by increasing storage capacities, and by expanding interconnections with neighbouring bidding zones. Where investment in non-fossil flexibility is insufficient to achieve the indicative national objective, Member States may apply **non-fossil flexibility support schemes** consisting **of payments for the available capacity** of non-fossil flexibility (Article 19g of the New Electricity Regulation).

- **Capacity mechanisms**, i.e., measures to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, are no longer temporary (Article 2(22), 21 and 22 of the New Electricity Regulation). Member States may request that fossil generation capacity that started commercial production before 4 July 2019 exceptionally be committed or receive payments or commitments for future payments after 1 July 2025 under a capacity mechanism approved by the Commission before 4 July 2019.

Finally, it is important to note that PPAs (when statebacked), direct price support schemes in the form of two-way contracts for difference, and capacity mechanisms are without prejudice to the application of State aid rules. In particular, it should be noted that, when the Commission will assess two-way-contracts for difference under State aid rules, it will have to ensure compliance with the design principles set out under the New Electricity Regulation (as it is the case in the current in-depth State aid investigation in relation to the lifetime extension of two nuclear reactors in Belgium[4]).

3. Measures on the market for electricity transmission

On the market for electricity transmission, four main measures have been taken:

- **Tariff methodologies** should incentivise TSOs to operate and expand the networks cost-efficiently. To that end, network tariffs should be designed to take into account both operational and capital expenditures, including anticipatory investments.[5] Regulatory approval of these costs will play a central role in ensuring that sufficient investment is provided not only to foster market integration and security of supply, but also to foster the integration of renewable energy, promote flexibility services, and facilitate energy storage and demand response. The requirement for cost-reflectiveness should not restrict the opportunity to redistribute costs efficiently where locational- or time-variant network charges are applied. This could enable a lower transmission tariff where energy storage facilities are located (Article 18 of the New Electricity Regulation).

- NRAs or any other Member State's designated competent authority shall develop a framework for TSOs to offer the possibility of establishing **flexible connection agreements** in areas where there is limited or no network capacity availability for new connections. Such flexible connection agreements would, for example, take into account energy storage or limit the times in which a generation power plant can inject electricity to the grid or the capacity that can be exported, enabling its partial connection. Network reinforcements providing structural solutions must be prioritised so that flexible connection agreements are made firm as soon as the networks are properly developed and ready. However, for areas where network reinforcements are not deemed the most efficient solution by the national competent authority, flexible connections must be enabled as a permanent solution, including for energy storage (Article 6a of the New Electricity Directive).

- **Congestion income** of the TSOs will also be used to compensate offshore renewable electricity generation plant operators in an offshore bidding zone directly connected to two or more bidding zones where access to interconnected markets has been reduced in such a way that the operators are unable to export their electricity generation and, where relevant, the wholesale price is lower than what it would have been if the access to the interconnected market had not been reduced (Article 19 of the New Electricity Regulation).

- TSOs shall publish in a transparent manner **clear information on the capacity available for new connections** in their areas of operation with high spatial granularity, respecting public security and data confidentiality, including the capacity under connection request and the **possibility of flexible connection in congested areas** (Articles 50 and 57 of the New Electricity Regulation and Article 6a of the New Electricity Directive). TSOs shall provide in a transparent manner clear information to system users about the status and treatment of their connection requests within three months of the submission of the request (including, where relevant, information related to flexible connection agreements).

If you have any question or if you want to discuss any aspect of your energy transition, please do not hesitate to contact your usual Strelia contact person or one of the key contacts below:

Pierre Goffinet
pierre.goffinet@strelia.com

Mediona Shehu
mediona.shehu@strelia.com

[1] See ACER Decision 04/2018.
[2] For more information on ACER's assessment on the introduction of voluntary templates for PPAs, see ACER's website.
[3] In the case of offshore hybrid asset projects connected to two or more bidding zones, it applies to new investments concluded on or after 17 July 2029.
[4] See Commission press release of 22 July 2024.
[5] For more information on anticipatory investments, see the Commission's EU Action Plan for Grids, November 2023 (available here); and ACER and CEER Position paper on anticipatory investments, March 2024.