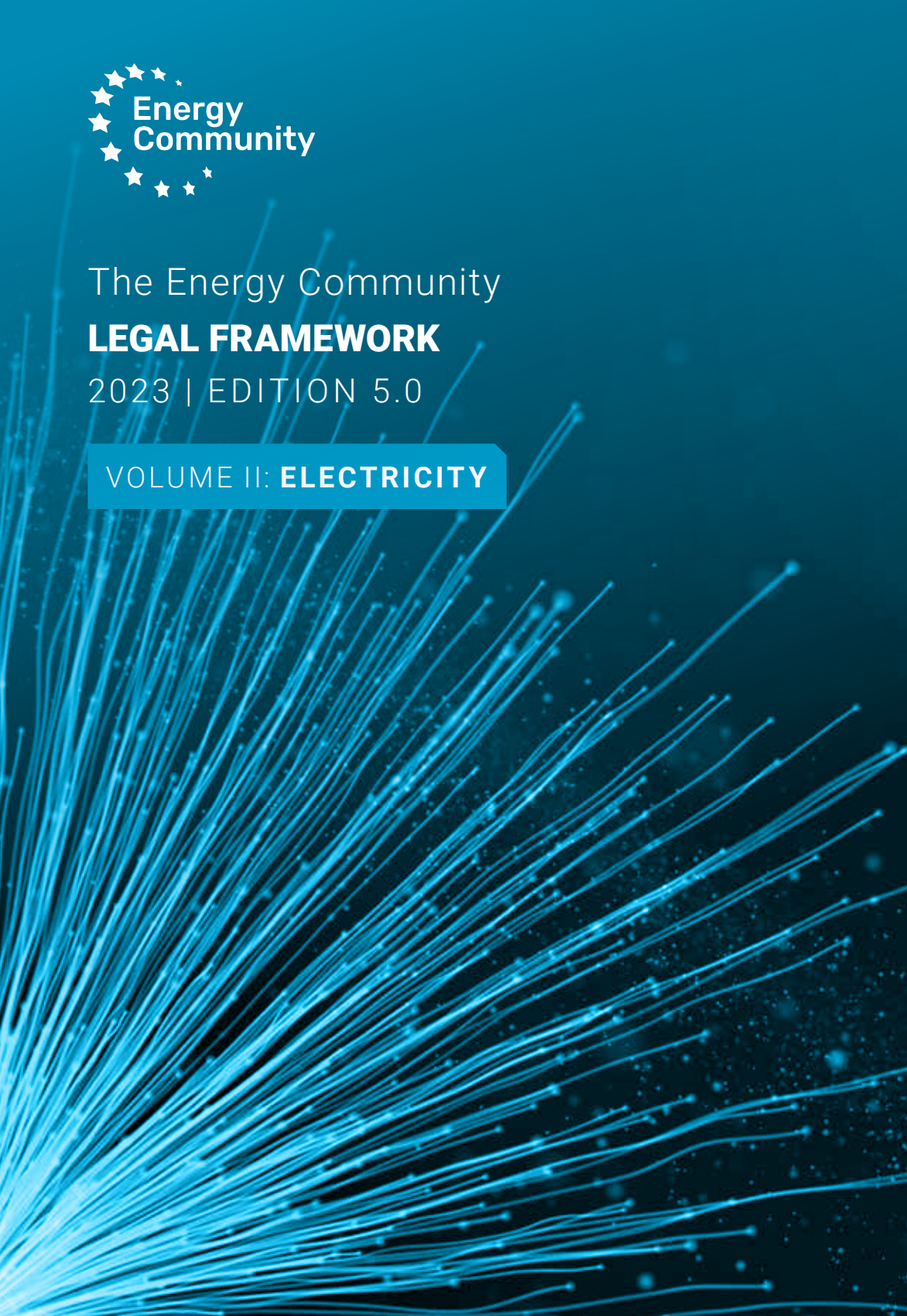
Energy Community

The Energy Community

LEGAL FRAMEWORK

2023 | EDITION 5.0

VOLUME II: **ELECTRICITY**



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I. PART

ELECTRICITY DIRECTIVES AND REGULATIONS

DIRECTIVE (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity

Incorporated and adapted by the Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021 amending Annex I to the Treaty Establishing the Energy Community and incorporating Directive (EU) 2019/944 and Regulation (EU) 2019/941 in the Energy Community acquis communautaire, and amended by Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

The adaptations made by the Ministerial Council Decisions 2021/13/MC-EnC and 2022/03/MC-EnC are highlighted in ***bold and blue****.*

CHAPTER I
SUBJECT MATTER AND DEFINITIONS

Article 1
Subject matter

This Directive establishes common rules for the generation, transmission, distribution, energy storage and supply of electricity, together with consumer protection provisions, with a view to creating truly integrated competitive, consumer-centred, flexible, fair and transparent electricity markets in the **Energy Community**.

Using the advantages of an integrated market, this Directive aims to ensure affordable, transparent energy prices and costs for consumers, a high degree of security of supply and a smooth transition towards a sustainable low-carbon energy system. It lays down key rules relating to the organisation and functioning of the **Energy Community** electricity sector, in particular rules on consumer empowerment and protection, on open access to the integrated market, on third-party access to transmission and distribution infrastructure, unbundling requirements, and rules on the independence of regulatory authorities in the **Contracting Parties**.

This Directive also sets out modes for **Contracting Parties**, regulatory authorities and transmission system operators to cooperate towards the creation of a fully interconnected internal market for electricity that increases the integration of electricity from renewable sources, free competition and security of supply.

Article 2
Definitions

For the purposes of this Directive, the following definitions apply:

(1) ‘customer’ means a wholesale or final customer of electricity;

(2) 'wholesale customer' means a natural or legal person who purchases electricity for the purpose of resale inside or outside the system where that person is established;

(3) 'final customer' means a customer who purchases electricity for own use;

(4) 'household customer' means a customer who purchases electricity for the customer's own household consumption, excluding commercial or professional activities;

(5) 'non-household customer' means a natural or legal person who purchases electricity that is not for own household use, including producers, industrial customers, small and medium-sized enterprises, businesses and wholesale customers;

(6) 'microenterprise' means an enterprise which employs fewer than 10 persons and whose annual turnover and/or annual balance sheet total does not exceed EUR 2 million;

(7) 'small enterprise' means an enterprise which employs fewer than 50 persons and whose annual turnover and/or annual balance sheet total does not exceed EUR 10 million;

(8) 'active customer' means a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a **Contracting Party**, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity;

(9) 'electricity markets' means markets for electricity, including over-the-counter markets and electricity exchanges, markets for the trading of energy, capacity, balancing and ancillary services in all timeframes, including forward, day-ahead and intraday markets;

(10) 'market participant' means a market participant as defined in point (25) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(11) 'citizen energy community' means a legal entity that:

(a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises;

(b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and

(c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders;

(12) 'supply' means the sale, including the resale, of electricity to customers;

(13) 'electricity supply contract' means a contract for the supply of electricity, but does not include electricity derivatives;

(14) 'electricity derivative' means a financial instrument specified in point (5), (6) or (7) of Section C of Annex I to Directive 2014/65/EU of the European Parliament and of the Council, where that instrument relates to electricity;

(15) 'dynamic electricity price contract' means an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency;

(16) 'contract termination fee' means a charge or penalty imposed on customers by suppliers or market

participants engaged in aggregation, for terminating an electricity supply or service contract;

(17) 'switching-related fee' means a charge or penalty for changing suppliers or market participants engaged in aggregation, including contract termination fees, that is directly or indirectly imposed on customers by suppliers, market participants engaged in aggregation or system operators;

(18) 'aggregation' means a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market;

(19) 'independent aggregator' means a market participant engaged in aggregation who is not affiliated to the customer's supplier;

(20) 'demand response' means the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/2014, whether alone or through aggregation;

(21) 'billing information' means the information provided on a final customer's bill, apart from a request for payment;

(22) 'conventional meter' means an analogue or electronic meter with no capability to both transmit and receive data;

(23) 'smart metering system' means an electronic system that is capable of measuring electricity fed into the grid or electricity consumed from the grid, providing more information than a conventional meter, and that is capable of transmitting and receiving data for information, monitoring and control purposes, using a form of electronic communication;

(24) 'interoperability' means, in the context of smart metering, the ability of two or more energy or communication networks, systems, devices, applications or components to interwork to exchange and use information in order to perform required functions;

(25) 'imbalance settlement period' means settlement period as defined in point (15) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(26) 'near real-time' means, in the context of smart metering, a short time period, usually down to seconds or up to the imbalance settlement period in the national market;

(27) 'best available techniques' means, in the context of data protection and security in a smart metering environment, the most effective, advanced and practically suitable techniques for providing, in principle, the basis for complying with the **applicable** data protection and security rules;

(28) 'distribution' means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply;

(29) 'distribution system operator' means a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity;

(30) 'energy efficiency' means the ratio of output of performance, service, goods or energy, to input of energy;

(31) 'energy from renewable sources' or 'renewable energy' means energy from renewable non-fossil sourc-

es, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas;

(32) 'distributed generation' means generating installations connected to the distribution system;

(33) 'recharging point' means an interface that is capable of charging one electric vehicle at a time or exchanging the battery of one electric vehicle at a time;

(34) 'transmission' means the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply;

(35) 'transmission system operator' means a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity;

(36) 'system user' means a natural or legal person who supplies to, or is supplied by, a transmission system or a distribution system;

(37) 'generation' means the production of electricity;

(38) 'producer' means a natural or legal person who generates electricity;

(39) 'interconnector' means equipment used to link electricity systems;

(40) 'interconnected system' means a number of transmission and distribution systems linked together by means of one or more interconnectors;

(41) 'direct line' means either an electricity line linking an isolated generation site with an isolated customer or an electricity line linking a producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and customers;

(42) 'small isolated system' means any system that had consumption of less than 3 000 GWh in the year 1996, where less than 5 % of annual consumption is obtained through interconnection with other systems;

(43) 'small connected system' means any system that had consumption of less than 3 000 GWh in the year 1996, where more than 5 % of annual consumption is obtained through interconnection with other systems;

(44) 'congestion' means congestion as defined in point (4) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(45) 'balancing' means balancing as defined in point (10) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(46) 'balancing energy' means balancing energy as defined in point (11) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(47) 'balance responsible party' means balance responsible party as defined in point (14) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(48) 'ancillary service' means a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management;

(49) 'non-frequency ancillary service' means a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability;

(50) 'regional coordination centre' means a regional coordination centre established **in accordance with Annex IV of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(51) 'fully integrated network components' means network components that are integrated in the transmission or distribution system, including storage facilities, and that are used for the sole purpose of ensuring a secure and reliable operation of the transmission or distribution system, and not for balancing or congestion management;

(52) 'integrated electricity undertaking' means a vertically integrated undertaking or a horizontally integrated undertaking;

(53) 'vertically integrated undertaking' means an electricity undertaking or a group of electricity undertakings where the same person or the same persons are entitled, directly or indirectly, to exercise control, and where the undertaking or group of undertakings performs at least one of the functions of transmission or distribution, and at least one of the functions of generation or supply;

(54) 'horizontally integrated undertaking' means an electricity undertaking performing at least one of the functions of generation for sale, or transmission, or distribution, or supply, and another non-electricity activity;

(55) 'related undertaking' means affiliated undertakings as defined in point (12) of Article 2 of Directive 2013/34/EU of the European Parliament and of the Council, and undertakings which belong to the same shareholders;

(56) 'control' means rights, contracts or other means which, either separately or in combination and having regard to the considerations of fact or law involved, confer the possibility of exercising decisive influence on an undertaking, in particular by:

(a) ownership or the right to use all or part of the assets of an undertaking;

(b) rights or contracts which confer decisive influence on the composition, voting or decisions of the organs of an undertaking;

(57) 'electricity undertaking' means a natural or legal person who carries out at least one of the following functions: generation, transmission, distribution, aggregation, demand response, energy storage, supply or purchase of electricity, and who is responsible for the commercial, technical or maintenance tasks related to those functions, but does not include final customers;

(58) 'security' means both security of supply and provision of electricity, and technical safety;

(59) 'energy storage' means, in the electricity system, deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier;

(60) 'energy storage facility' means, in the electricity system, a facility where energy storage occurs.

(61) Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

CHAPTER II
GENERAL RULES FOR THE ORGANISATION OF THE ELECTRICITY SECTOR

Article 3

Competitive, consumer-centred, flexible and non-discriminatory electricity markets

1. **Contracting Parties** shall ensure that their national law does not unduly hamper cross-border trade in electricity, consumer participation, including through demand response, investments into, in particular, variable and flexible energy generation, energy storage, or the deployment of electromobility or new interconnectors between **Contracting Parties of the Energy Community or between Contracting Parties and Member States of the European Union,** and shall ensure that electricity prices reflect actual demand and supply.

2. When developing new interconnectors, **Contracting Parties** shall take into account the electricity interconnection targets set out in point (1) of Article 4(d) of Regulation (EU) 2018/1999, **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**.

3. **Contracting Parties** shall ensure that no undue barriers exist within the internal market for electricity as regards market entry, operation and exit, without prejudice to the competence that **Contracting Parties** retain in relation to third countries.

4. **Contracting Parties** shall ensure a level playing field where electricity undertakings are subject to transparent, proportionate and non-discriminatory rules, fees and treatment, in particular with respect to balancing responsibility, access to wholesale markets, access to data, switching processes and billing regimes and, where applicable, licensing.

5. **Contracting Parties** shall ensure that market participants from third countries, when operating within the internal market for electricity, comply with applicable **Energy Community** and national law, including that concerning environmental and safety policy.

Article 4

Free choice of supplier

Contracting Parties shall ensure that all customers are free to purchase electricity from the supplier of their choice and shall ensure that all customers are free to have more than one electricity supply contract at the same time, provided that the required connection and metering points are established.

Article 5

Market-based supply prices

1. Suppliers shall be free to determine the price at which they supply electricity to customers. **Contracting Parties** shall take appropriate actions to ensure effective competition between suppliers.

2. **Contracting Parties** shall ensure the protection of energy poor and vulnerable household customers

pursuant to Articles 28 and 29 by social policy or by other means than public interventions in the price setting for the supply of electricity.

3. By way of derogation from paragraphs 1 and 2, **Contracting Parties** may apply public interventions in the price setting for the supply of electricity to energy poor or vulnerable household customers. Such public interventions shall be subject to the conditions set out in paragraphs 4 and 5.

4. Public interventions in the price setting for the supply of electricity shall:

(a) pursue a general economic interest and not go beyond what is necessary to achieve that general economic interest;

(b) be clearly defined, transparent, non-discriminatory and verifiable;

(c) guarantee equal access for **Energy Community** electricity undertakings to customers;

(d) be limited in time and proportionate as regards their beneficiaries;

(e) not result in additional costs for market participants in a discriminatory way.

5. Any **Contracting Party** applying public interventions in the price setting for the supply of electricity in accordance with paragraph 3 of this Article shall also comply with point (d) of Article 3(3) and with Article 24 of Regulation (EU) 2018/1999 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**, regardless of whether the **Contracting Party** concerned has a significant number of households in energy poverty.

6. For the purpose of a transition period to establish effective competition for electricity supply contracts between suppliers, and to achieve fully effective market-based retail pricing of electricity in accordance with paragraph 1, **Contracting Parties** may apply public interventions in the price setting for the supply of electricity to household customers and to microenterprises that do not benefit from public interventions pursuant to paragraph 3.

7. Public interventions pursuant to paragraph 6 shall comply with the criteria set out in paragraph 4 and shall:

(a) be accompanied by a set of measures to achieve effective competition and a methodology for assessing progress with regard to those measures;

(b) be set using a methodology that ensures non-discriminatory treatment of suppliers;

(c) be set at a price that is above cost, at a level where effective price competition can occur;

(d) be designed to minimise any negative impact on the wholesale electricity market;

(e) ensure that all beneficiaries of such public interventions have the possibility to choose competitive market offers and are directly informed at least every quarter of the availability of offers and savings in the competitive market, in particular of dynamic electricity price contracts, and shall ensure that they are provided with assistance to switch to a market-based offer;

(f) ensure that, pursuant to Articles 19 and 21, all beneficiaries of such public interventions are entitled to, and are offered to, have smart meters installed at no extra upfront cost to the customer, are directly informed of the possibility of installing smart meters and are provided with necessary assistance;

(g) not lead to direct cross-subsidisation between customers supplied at free market prices and those supplied at regulated supply prices.

8. **Contracting Parties** shall notify the measures taken in accordance with paragraphs 3 and 6 to the

Energy Community Secretariat within one month after their adoption and may apply them immediately. The notification shall be accompanied by an explanation of why other instruments were not sufficient to achieve the objective pursued, of how the requirements set out in paragraphs 4 and 7 are fulfilled and of the effects of the notified measures on competition. The notification shall describe the scope of the beneficiaries, the duration of the measures and the number of household customers affected by the measures, and shall explain how the regulated prices have been determined.

9. By 1 January **2025** and 1 January **2028**, **Contracting Parties** shall submit reports to the **Energy Community Secretariat** on the implementation of this Article, the necessity and proportionality of public interventions under this Article, and an assessment of the progress towards achieving effective competition between suppliers and the transition to market-based prices. **Contracting Parties** that apply regulated prices in accordance with paragraph 6 shall report on the compliance with the conditions set out in paragraph 7, including on compliance by suppliers that are required to apply such interventions, as well as on the impact of regulated prices on the finances of those suppliers.

10. By 31 December **2028**, the **Energy Community Secretariat** shall review and submit a report to the **Ministerial Council** on the implementation of this Article for the purpose of achieving market-based retail pricing of electricity **< ... >**.

Article 6

Third-party access

1. **Contracting Parties** shall ensure the implementation of a system of third-party access to the transmission and distribution systems based on published tariffs, applicable to all customers and applied objectively and without discrimination between system users. **Contracting Parties** shall ensure that those tariffs, or the methodologies underlying their calculation, are approved in accordance with Article 59 prior to their entry into force and that those tariffs, and the methodologies — where only methodologies are approved — are published prior to their entry into force.

2. The transmission or distribution system operator may refuse access where it lacks the necessary capacity. Duly substantiated reasons shall be given for such refusal, in particular having regard to Article 9, and based on objective and technically and economically justified criteria. **Contracting Parties** or, where **Contracting Parties** have so provided, the regulatory authorities of those **Contracting Parties**, shall ensure that those criteria are consistently applied and that the system user who has been refused access can make use of a dispute settlement procedure. The regulatory authorities shall also ensure, where appropriate and when refusal of access takes place, that the transmission system operator or distribution system operator provides relevant information on measures that would be necessary to reinforce the network. Such information shall be provided in all cases when access for recharging points has been denied. The party requesting such information may be charged a reasonable fee reflecting the cost of providing such information.

3. This Article shall also apply to citizen energy communities that manage distribution networks.

Article 7

Direct lines

1. **Contracting Parties** shall take the measures necessary to enable:

(a) all producers and electricity supply undertakings established within their territory to supply their own premises, subsidiaries and customers through a direct line, without being subject to disproportionate administrative procedures or costs;

(b) all customers within their territory, individually or jointly, to be supplied through a direct line by producers and electricity supply undertakings. 2. **Contracting Parties** shall lay down the criteria for the grant of authorisations for the construction of direct lines in their territory. Those criteria shall be objective and non-discriminatory.

3. The possibility of supplying electricity through a direct line as referred to in paragraph 1 of this Article shall not affect the possibility of contracting electricity in accordance with Article 6.

4. **Contracting Parties** may issue authorisations to construct a direct line, subject either to the refusal of system access on the basis, as appropriate, of Article 6 or to the opening of a dispute settlement procedure under Article 60.

5. **Contracting Parties** may refuse to authorise a direct line if the granting of such an authorisation would obstruct the application of the provisions on public service obligations in Article 9. Duly substantiated reasons shall be given for such a refusal.

Article 8

Authorisation procedure for new capacity

1. For the construction of new generating capacity, **Contracting Parties** shall adopt an authorisation procedure, which shall be conducted in accordance with objective, transparent and non-discriminatory criteria.

2. **Contracting Parties** shall lay down the criteria for the grant of authorisations for the construction of generating capacity in their territory. In determining appropriate criteria, **Contracting Parties** shall consider:

(a) the safety and security of the electricity system, installations and associated equipment;

(b) the protection of public health and safety;

(c) the protection of the environment;

(d) land use and siting;

(e) the use of public ground;

(f) energy efficiency;

(g) the nature of the primary sources;

(h) the characteristics particular to the applicant, such as technical, economic and financial capabilities;

(i) compliance with measures adopted pursuant to Article 9;

(j) the contribution of generating capacity to meeting the **Contracting Party's share in contributing**

to the Energy Community target for 2030 target referred to in Article 3(1) of Directive (EU) 2018/2001, as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC;

(k) the contribution of generating capacity to reducing emissions; and

(l) the alternatives to the construction of new generating capacity, such as demand response solutions and energy storage.

3. **Contracting Parties** shall ensure that specific, simplified and streamlined authorisation procedures exist for small decentralised and/or distributed generation, which take into account their limited size and potential impact.

Contracting Parties may set guidelines for that specific authorisation procedure. Regulatory authorities or other competent national authorities, including planning authorities, shall review those guidelines and may recommend amendments thereto.

Where **Contracting Parties** have established particular land use permit procedures applying to major new infrastructure projects in generation capacity, **Contracting Parties** shall, where appropriate, include the construction of new generation capacity within the scope of those procedures and shall implement them in a non-discriminatory manner and within an appropriate time frame.

4. The authorisation procedures and criteria shall be made public. Applicants shall be informed of the reasons for any refusal to grant an authorisation. Those reasons shall be objective, non-discriminatory, well-founded and duly substantiated. Appeal procedures shall be made available to applicants.

Article 9

Public service obligations

1. Without prejudice to paragraph 2, **Contracting Parties** shall ensure, on the basis of their institutional organisation and with due regard to the principle of subsidiarity, that electricity undertakings operate in accordance with the principles of this Directive with a view to achieving a competitive, secure and environmentally sustainable market for electricity, and shall not discriminate between those undertakings as regards either rights or obligations.

2. Having full regard to the relevant provisions of the **Energy Community Treaty**, **Contracting Parties** may impose on undertakings operating in the electricity sector, in the general economic interest, public service obligations which may relate to security, including the security of supply, regularity, quality and price of supplies and environmental protection, including energy efficiency, energy from renewable sources and climate protection. Such obligations shall be clearly defined, transparent, non-discriminatory and verifiable, and shall guarantee equality of access for electricity undertakings of the **Energy Community** to national consumers. Public service obligations which concern the price setting for the supply of electricity shall comply with the requirements set out in Article 5 of this Directive.

3. Where financial compensation, other forms of compensation and exclusive rights which a **Contracting Party** grants for the fulfilment of the obligations set out in paragraph 2 of this Article or for the provision of universal service as set out in Article 27 are provided, this shall be done in a non-discriminatory and transparent way.

4. **Contracting Parties** shall, upon implementation of this Directive, inform the **Energy Community**

Secretariat of all measures adopted to fulfil universal service and public service obligations, including consumer protection and environmental protection, and their possible effect on national and international competition, whether or not such measures require a derogation from this Directive. They shall subsequently inform the **Energy Community Secretariat** every two years of any changes to those measures, whether or not they require a derogation from this Directive.

5. **Contracting Parties** may decide not to apply Articles 6, 7 and 8 of this Directive insofar as their application would obstruct, in law or in fact, the performance of the obligations imposed on electricity undertakings in the general economic interest and insofar as the development of trade would not be affected to such an extent as would be contrary to the interests of the **Energy Community**. The interests of the **Energy Community** include, inter alia, competition with regard to customers in accordance with **Annex III of the Energy Community Treaty** and this Directive.

CHAPTER III
CONSUMER EMPOWERMENT AND PROTECTION

Article 10
Basic contractual rights

1. **Contracting Parties shall ensure that all final customers are entitled to have their electricity provided by a supplier, subject to the supplier's agreement, regardless of the Party to the Energy Community in which the supplier is registered, provided that the supplier follows the applicable trading and balancing rules. In that regard, Contracting Parties shall take all measures necessary to ensure that administrative procedures do not discriminate against suppliers already registered in another Party to the Energy Community**.

2. Without prejudice to **stricter national** rules on consumer protection, **< … > Contracting Parties** shall ensure that final customers have the rights provided for in paragraphs 3 to 12 of this Article.

3. Final customers shall have the right to a contract with their supplier that specifies:

(a) the identity and address of the supplier;

(b) the services provided, the service quality levels offered, as well as the time for the initial connection;

(c) the types of maintenance service offered;

(d) the means by which up-to-date information on all applicable tariffs, maintenance charges and bundled products or services may be obtained;

(e) the duration of the contract, the conditions for renewal and termination of the contract and services, including products or services that are bundled with those services, and whether terminating the contract without charge is permitted;

(f) any compensation and the refund arrangements which apply if contracted service quality levels are not met, including inaccurate or delayed billing;

(g) the method of initiating an out-of-court dispute settlement procedure in accordance with Article 26;

(h) information relating to consumer rights, including information on complaint handling and all of the

information referred to in this paragraph, that is clearly communicated on the bill or the electricity undertaking's web site. Conditions shall be fair and well known in advance. In any case, this information shall be provided prior to the conclusion or confirmation of the contract. Where contracts are concluded through intermediaries, the information relating to the matters set out in this paragraph shall also be provided prior to the conclusion of the contract.

Final customers shall be provided with a summary of the key contractual conditions in a prominent manner and in concise and simple language.

4. Final customers shall be given adequate notice of any intention to modify contractual conditions and shall be informed about their right to terminate the contract when the notice is given. Suppliers shall notify their final customers, in a transparent and comprehensible manner, directly of any adjustment in the supply price and of the reasons and preconditions for the adjustment and its scope, at an appropriate time no later than two weeks, or no later than one month in the case of household customers, before the adjustment comes into effect. **Contracting Parties** shall ensure that final customers are free to terminate contracts if they do not accept the new contractual conditions or adjustments in the supply price notified to them by their supplier.

5. Suppliers shall provide final customers with transparent information on applicable prices and tariffs and on standard terms and conditions, in respect of access to and use of electricity services.

6. Suppliers shall offer final customers a wide choice of payment methods. Such payment methods shall not unduly discriminate between customers. Any difference in charges related to payment methods or prepayment systems shall be objective, non-discriminatory and proportionate and shall not exceed the direct costs borne by the payee for the use of a specific payment method or a prepayment system **< ... >**.

7. Pursuant to paragraph 6, household customers who have access to prepayment systems shall not be placed at a disadvantage by the prepayment systems.

8. Suppliers shall offer final customers fair and transparent general terms and conditions, which shall be provided in plain and unambiguous language and shall not include non-contractual barriers to the exercise of customers' rights, such as excessive contractual documentation. Customers shall be protected against unfair or misleading selling methods.

9. Final customers shall have the right to a good standard of service and complaint handling by their suppliers. Suppliers shall handle complaints in a simple, fair and prompt manner.

10. When accessing universal service under the provisions adopted by **Contracting Parties** pursuant to Article 27, final customers shall be informed about their rights regarding universal service.

11. Suppliers shall provide household customers with adequate information on alternative measures to disconnection sufficiently in advance of any planned disconnection. Such alternative measures may refer to sources of support to avoid disconnection, prepayment systems, energy audits, energy consultancy services, alternative payment plans, debt management advice or disconnection moratoria and not constitute an extra cost to the customers facing disconnection.

12. Suppliers shall provide final customers with a final closure account after any switch of supplier no later than six weeks after such a switch has taken place.

Article 11

Entitlement to a dynamic electricity price contract

1. **Contracting Parties** shall ensure that the national regulatory framework enables suppliers to offer dynamic electricity price contracts. **Contracting Parties** shall ensure that final customers who have a smart meter installed can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier that has more than 200 000 final customers.

2. **Contracting Parties** shall ensure that final customers are fully informed by the suppliers of the opportunities, costs and risks of such dynamic electricity price contracts, and shall ensure that suppliers are required to provide information to the final customers accordingly, including with regard to the need to have an adequate electricity meter installed. Regulatory authorities shall monitor the market developments and assess the risks that the new products and services may entail and deal with abusive practices.

3. Suppliers shall obtain each final customer's consent before that customer is switched to a dynamic electricity price contract.

4. For at least a ten-year period after dynamic electricity price contracts become available, **Contracting Parties** or their regulatory authorities shall monitor, and shall publish an annual report on the main developments of such contracts, including market offers and the impact on consumers' bills, and specifically the level of price volatility.

Article 12

Right to switch and rules on switching-related fees

1. Switching supplier or market participant engaged in aggregation shall be carried out within the shortest possible time. **Contracting Parties** shall ensure that a customer wishing to switch suppliers or market participants engaged in aggregation, while respecting contractual conditions, is entitled to such a switch within a maximum of three weeks from the date of the request. By no later than 2026, the technical process of switching supplier shall take no longer than 24 hours and shall be possible on any working day.

2. **Contracting Parties** shall ensure that at least household customers and small enterprises are not charged any switching-related fees.

3. By way of derogation from paragraph 2, **Contracting Parties** may permit suppliers or market participants engaged in aggregation to charge customers contract termination fees where those customers voluntarily terminate fixed-term, fixed-price electricity supply contracts before their maturity, provided that such fees are part of a contract that the customer has voluntarily entered into and that such fees are clearly communicated to the customer before the contract is entered into. Such fees shall be proportionate and shall not exceed the direct economic loss to the supplier or the market participant engaged in aggregation resulting from the customer's termination of the contract, including the costs of any bundled investments or services that have already been provided to the customer as part of the contract. The burden of proving the direct economic loss shall be on the supplier or market participant engaged in aggregation, and the permissibility of contract termination fees shall be monitored by the regulatory authority, or by another competent national authority.

4. **Contracting Parties** shall ensure that the right to switch supplier or market participants engaged in aggregation is granted to customers in a non-discriminatory manner as regards cost, effort and time.

5. Household customers shall be entitled to participate in collective switching schemes. **Contracting Parties** shall remove all regulatory or administrative barriers for collective switching, while providing a framework that ensures the utmost consumer protection to avoid any abusive practices.

Article 13

Aggregation contract

1. **Contracting Parties** shall ensure that all customers are free to purchase and sell electricity services, including aggregation, other than supply, independently from their electricity supply contract and from an electricity undertaking of their choice.

2. **Contracting Parties** shall ensure that, where a final customer wishes to conclude an aggregation contract, the final customer is entitled to do so without the consent of the final customer's electricity undertakings.

Contracting Parties shall ensure that market participants engaged in aggregation fully inform customers of the terms and conditions of the contracts that they offer to them.

3. **Contracting Parties** shall ensure that final customers are entitled to receive all relevant demand response data or data on supplied and sold electricity free of charge at least once every billing period if requested by the customer.

4. **Contracting Parties** shall ensure that the rights referred to in paragraphs 2 and 3 are granted to final customers in a non-discriminatory manner as regards cost, effort or time. In particular, **Contracting Parties** shall ensure that customers are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.

Article 14

Comparison tools

1. **Contracting Parties** shall ensure that at least household customers, and microenterprises with an expected yearly consumption of below 100 000 kWh, have access, free of charge, to at least one tool comparing the offers of suppliers, including offers for dynamic electricity price contracts. Customers shall be informed of the availability of such tools in or together with their bills or by other means. The tools shall meet at least the following requirements:

(a) they shall be independent from market participants and ensure that electricity undertakings are given equal treatment in search results;

(b) they shall clearly disclose their owners and the natural or legal person operating and controlling the tools, as well as information on how the tools are financed;

(c) they shall set out clear and objective criteria on which the comparison is to be based, including services,

and disclose them;

(d) they shall use plain and unambiguous language;

(e) they shall provide accurate and up-to-date information and state the time of the last update;

(f) they shall be accessible to persons with disabilities, by being perceivable, operable, understandable and robust;

(g) they shall provide an effective procedure for reporting incorrect information on published offers; and

(h) they shall perform comparisons, while limiting the personal data requested to that strictly necessary for the comparison. **Contracting Parties** shall ensure that at least one tool covers the entire market. Where multiple tools cover the market, those tools shall include, as complete as practicable, a range of electricity offers covering a significant part of the market and, where those tools do not completely cover the market, a clear statement to that effect, before displaying results.

2. The tools referred to in paragraph 1 may be operated by any entity, including private companies and public authorities or bodies.

3. **Contracting Parties** shall appoint a competent authority to be responsible for issuing trust marks for comparison tools that meet the requirements set out in paragraph 1, and for ensuring that comparison tools bearing a trust mark continue to meet the requirements set out in paragraph 1. That authority shall be independent of any market participants and comparison tool operators.

4. **Contracting Parties** may require comparison tools referred to in paragraph 1 to include comparative criteria relating to the nature of the services offered by the suppliers.

5. Any tool comparing the offers of market participants shall be eligible to apply for a trust mark in accordance with this Article on a voluntary and non-discriminatory basis.

6. By way of derogation from paragraphs 3 and 5, **Contracting Parties** may choose not to provide for the issuance of trust marks to comparison tools if a public authority or body provides a comparison tool that meets the requirements set out in paragraph 1.

Article 15

Active customers

1. **Contracting Parties** shall ensure that final customers are entitled to act as active customers without being subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective.

2. **Contracting Parties** shall ensure that active customers are:

(a) entitled to operate either directly or through aggregation;

(b) entitled to sell self-generated electricity, including through power purchase agreements;

(c) entitled to participate in flexibility schemes and energy efficiency schemes;

(d) entitled to delegate to a third party the management of the installations required for their activities, including installation, operation, data handling and maintenance, without that third party being considered to be an active customer;

(e) subject to cost-reflective, transparent and non-discriminatory network charges that account separately

for the electricity fed into the grid and the electricity consumed from the grid, in accordance with Article 59(9) of this Directive and **Article 18 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system;

(f) financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.

3. **Contracting Parties** may have different provisions applicable to individual and jointly-acting active customers in their national law, provided that all rights and obligations under this Article apply to all active customers. Any difference in the treatment of jointly-acting active customers shall be proportionate and duly justified.

4. **Contracting Parties** that have existing schemes that do not account separately for the electricity fed into the grid and the electricity consumed from the grid, shall not grant new rights under such schemes after 31 December **2026**. In any event, customers subject to existing schemes shall have the possibility at any time to opt for a new scheme that accounts separately for the electricity fed into the grid and the electricity consumed from the grid as the basis for calculating network charges.

5. **Contracting Parties** shall ensure that active customers that own an energy storage facility:

(a) have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled;

(b) are not subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators;

(c) are not subject to disproportionate licensing requirements or fees;

(d) are allowed to provide several services simultaneously, if technically feasible.

Article 16

Citizen energy communities

1. **Contracting Parties** shall provide an enabling regulatory framework for citizen energy communities ensuring that:

(a) participation in a citizen energy community is open and voluntary;

(b) members or shareholders of a citizen energy community are entitled to leave the community, in which case Article 12 applies;

(c) members or shareholders of a citizen energy community do not lose their rights and obligations as household customers or active customers;

(d) subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities;

(e) citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discrimi-

natory and cost-reflective network charges in accordance with **Article 18 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system.

2. **Contracting Parties** may provide in the enabling regulatory framework that citizen energy communities:

(a) are open to cross-border participation;

(b) are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them subject to conditions set out in paragraph 4 of this Article;

(c) are subject to the exemptions provided for in Article 38(2).

3. **Contracting Parties** shall ensure that citizen energy communities:

(a) are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner;

(b) are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation;

(c) are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with **Article 5 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(d) with regard to consumption of self-generated electricity, citizen energy communities are treated like active customers in accordance with point (e) of Article 15(2);

(e) are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers. For the purposes of point (e) of the first subparagraph, where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority.

4. **Contracting Parties** may decide to grant citizen energy communities the right to manage distribution networks in their area of operation and establish the relevant procedures, without prejudice to Chapter IV or to other rules and regulations applying to distribution system operators. If such a right is granted, **Contracting Parties** shall ensure that citizen energy communities:

(a) are entitled to conclude an agreement on the operation of their network with the relevant distribution system operator or transmission system operator to which their network is connected;

(b) are subject to appropriate network charges at the connection points between their network and the distribution network outside the citizen energy community and that such network charges account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the citizen energy community in accordance with Article 59(7);

(c) do not discriminate or harm customers who remain connected to the distribution system.

Article 17

Demand response through aggregation

1. **Contracting Parties** shall allow and foster participation of demand response through aggregation. **Contracting Parties** shall allow final customers, including those offering demand response through aggregation, to participate alongside producers in a non-discriminatory manner in all electricity markets.

2. **Contracting Parties** shall ensure that transmission system operators and distribution system operators, when procuring ancillary services, treat market participants engaged in the aggregation of demand response in a non-discriminatory manner alongside producers on the basis of their technical capabilities.

3. **Contracting Parties** shall ensure that their relevant regulatory framework contains at least the following elements:

(a) the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants;

(b) non-discriminatory and transparent rules that clearly assign roles and responsibilities to all electricity undertakings and customers;

(c) non-discriminatory and transparent rules and procedures for the exchange of data between market participants engaged in aggregation and other electricity undertakings that ensure easy access to data on equal and non-discriminatory terms while fully protecting commercially sensitive information and customers' personal data;

(d) an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with **Article 5 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(e) provision for final customers who have a contract with independent aggregators not to be subject to undue payments, penalties or other undue contractual restrictions by their suppliers;

(f) a conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances.

4. **Contracting Parties** may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation. Such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility. In such cases, the financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred. The calculation method shall be subject to approval by the regulatory authority or by another competent national authority.

5. **Contracting Parties** shall ensure that regulatory authorities or, where their national legal system so requires, transmission system operators and distribution system operators, acting in close cooperation with

market participants and final customers, establish the technical requirements for participation of demand response in all electricity markets on the basis of the technical characteristics of those markets and the capabilities of demand response. Such requirements shall cover participation involving aggregated loads.

Article 18

Bills and billing information

1. **Contracting Parties** shall ensure that bills and billing information are accurate, easy to understand, clear, concise, user-friendly and presented in a manner that facilitates comparison by final customers. On request, final customers shall receive a clear and understandable explanation of how their bill was derived, especially where bills are not based on actual consumption.

2. **Contracting Parties** shall ensure that final customers receive all their bills and billing information free of charge.

3. **Contracting Parties** shall ensure that final customers are offered the option of electronic bills and billing information and are offered flexible arrangements for the actual payment of the bills.

4. If the contract provides for a future change of the product or price, or a discount, this shall be indicated on the bill together with the date on which the change takes place.

5. **Contracting Parties** shall consult consumer organisations when they consider changes to the requirements for the content of bills.

6. **Contracting Parties** shall ensure that bills and billing information fulfil the minimum requirements set out in Annex I.

Article 19

Smart metering systems

1. In order to promote energy efficiency and to empower final customers, **Contracting Parties** or, where a **Contracting Party** has so provided, the regulatory authority shall strongly recommend that electricity undertakings and other market participants optimise the use of electricity, inter alia, by providing energy management services, developing innovative pricing formulas, and introducing smart metering systems that are interoperable, in particular with consumer energy management systems and with smart grids, in accordance with the applicable **< … >** data protection rules.

2. **Contracting Parties** shall ensure the deployment in their territories of smart metering systems that assist the active participation of customers in the electricity market. Such deployment may be subject to a cost-benefit assessment which shall be undertaken in accordance with the principles laid down in Annex II.

3. **Contracting Parties** that proceed with the deployment of smart metering systems shall adopt and publish the minimum functional and technical requirements for the smart metering systems to be deployed in their territories, in accordance with Article 20 and Annex II. **Contracting Parties** shall ensure the interoperability of those smart metering systems, as well as their ability to provide output for consumer energy management systems. In that respect, **Contracting Parties** shall have due regard to the use of the relevant available standards, including those enabling interoperability, to best practices and to the

importance of the development of smart grids and the development of the internal market for electricity.

4. **Contracting Parties** that proceed with the deployment of smart metering systems shall ensure that final customers contribute to the associated costs of the deployment in a transparent and non-discriminatory manner, while taking into account the long-term benefits to the whole value chain. **The extent of such contribution shall be decided by the national regulatory authorities of each Contracting Party. Contracting Parties** or, where a **Contracting Party** has so provided, the designated competent authorities, shall regularly monitor such deployment in their territories to track the delivery of benefits to consumers.

5. Where the deployment of smart metering systems has been negatively assessed as a result of the cost-benefit assessment referred to in paragraph 2, **Contracting Parties** shall ensure that this assessment is revised at least every four years, or more frequently, in response to significant changes in the underlying assumptions and in response to technological and market developments. **Contracting Parties** shall notify to the **Energy Community Secretariat** the outcome of their updated cost-benefit assessment as it becomes available.

6. The provisions in this Directive concerning smart metering systems shall apply to future installations and to installations that replace older smart meters. Smart metering systems that have already been installed, or for which the 'start of works' began, before **the date of entry into force of this Directive in the Energy Community**, may remain in operation over their lifetime but, in the case of smart metering systems that do not meet the requirements of Article 20 and Annex II, shall not remain in operation after 5 July 2031.

For the purpose of this paragraph, 'start of works' means either the start of construction works on the investment or the first firm commitment to order equipment or other commitment that makes the investment irreversible, whichever is the first in time. Buying of land and preparatory works such as obtaining permits and conducting preliminary feasibility studies are not considered as start of works. For take-overs, 'start of works' means the moment of acquiring the assets directly linked to the acquired establishment.

Article 20

Functionalities of smart metering systems

Where the deployment of smart metering systems is positively assessed as a result of the cost-benefit assessment referred to in Article 19(2), or where smart metering systems are systematically deployed after **the date of entry into force of this Directive in the Energy Community**, **Contracting Parties** shall deploy smart metering systems in accordance with European standards, Annex II and the following requirements:

(a) the smart metering systems shall accurately measure actual electricity consumption and shall be capable of providing to final customers information on actual time of use. Validated historical consumption data shall be made easily and securely available and visualised to final customers on request and at no additional cost. Non-validated near real-time consumption data shall also be made easily and securely available to final customers at no additional cost, through a standardised interface or through remote access, in order to support automated energy efficiency programmes, demand response and other services;

(b) the security of the smart metering systems and data communication shall comply with relevant **applicable** security rules, having due regard of the best available techniques for ensuring the highest level of

cybersecurity protection while bearing in mind the costs and the principle of proportionality;

(c) the privacy of final customers and the protection of their data shall comply with relevant **applicable** data protection and privacy rules;

(d) meter operators shall ensure that the meters of active customers who feed electricity into the grid can account for electricity fed into the grid from the active customers' premises;

(e) if final customers request it, data on the electricity they fed into the grid and their electricity consumption data shall be made available to them, in accordance with the implementing acts adopted pursuant to Article 24, through a standardised communication interface or through remote access, or to a third party acting on their behalf, in an easily understandable format allowing them to compare offers on a like-for-like basis;

(f) appropriate advice and information shall be given to final customers prior to or at the time of installation of smart meters, in particular concerning their full potential with regard to the management of meter reading and the monitoring of energy consumption, and concerning the collection and processing of personal data in accordance with the applicable **< … >** data protection rules;

(g) smart metering systems shall enable final customers to be metered and settled at the same time resolution as the imbalance settlement period in the national market. For the purposes of point (e) of the first subparagraph, it shall be possible for final customers to retrieve their metering data or transmit them to another party at no additional cost and in accordance with their right to data portability under **applicable** data protection rules.

Article 21

Entitlement to a smart meter

1. Where the deployment of smart metering systems has been negatively assessed as a result of the cost-benefit assessment referred to in Article 19(2) and where smart metering systems are not systematically deployed, **Contracting Parties** shall ensure that every final customer is entitled on request, while bearing the associated costs, to have installed or, where applicable, to have upgraded, under fair, reasonable and cost-effective conditions, a smart meter that:

(a) is equipped, where technically feasible, with the functionalities referred to in Article 20, or with a minimum set of functionalities to be defined and published by **Contracting Parties** at national level in accordance with Annex II;

(b) is interoperable and able to deliver the desired connectivity of the metering infrastructure with consumer energy management systems in near real-time. 2. In the context of a customer request for a smart meter pursuant to paragraph 1, **Contracting Parties** or, where a **Contracting Party** has so provided, the designated competent authorities shall:

(a) ensure that the offer to the final customer requesting the installation of a smart meter explicitly states and clearly describes:

(i) the functions and interoperability that can be supported by the smart meter and the services that are feasible as well as the benefits that can be realistically attained by having that smart meter at that moment in time;

(ii) any associated costs to be borne by the final customer;

(b) ensure that it is installed within a reasonable time, no later than four months after the customer's request;

(c) regularly, and at least every two years, review and make publicly available the associated costs, and trace the evolution of those costs as a result of technology developments and potential metering system upgrades.

Article 22

Conventional meters

1. Where final customers do not have smart meters, **Contracting Parties** shall ensure that final customers are provided with individual conventional meters that accurately measure their actual consumption.

2. **Contracting Parties** shall ensure that final customers are able to easily read their conventional meters, either directly or indirectly through an online interface or through another appropriate interface.

Article 23

Data management

1. When laying down the rules regarding the management and exchange of data, **Contracting Parties** or, where a **Contracting Party** has so provided, the designated competent authorities shall specify the rules on the access to data of the final customer by eligible parties in accordance with this Article and the applicable **< … >** legal framework. For the purpose of this Directive, data shall be understood to include metering and consumption data as well as data required for customer switching, demand response and other services.

2. **Contracting Parties** shall organise the management of data in order to ensure efficient and secure data access and exchange, as well as data protection and data security.

Independently of the data management model applied in each **Contracting Party**, the parties responsible for data management shall provide access to the data of the final customer to any eligible party, in accordance with paragraph 1. Eligible parties shall have the requested data at their disposal in a non-discriminatory manner and simultaneously. Access to data shall be easy and the relevant procedures for obtaining access to data shall be made publicly available.

3. The rules on access to data and data storage for the purpose of this Directive shall comply with the relevant **applicable data protection rules**.

The processing of personal data within the framework of this Directive shall be carried out in accordance with **applicable data protection rules**.

4. **Contracting Parties** or, where a **Contracting Party** has so provided, the designated competent authorities, shall authorise and certify or, where applicable, supervise the parties responsible for the data management, in order to ensure that they comply with the requirements of this Directive.

Without prejudice to the tasks of the data protection officers under **applicable data protection rules**, **Contracting Parties** may decide to require that parties responsible for the data management appoint compliance officers who are to be responsible for monitoring the implementation of measures taken by those

parties to ensure non-discriminatory access to data and compliance with the requirements of this Directive.

Contracting Parties may appoint compliance officers or bodies referred to in point (d) of Article 35(2) of this Directive to fulfil the obligations under this paragraph.

5. No additional costs shall be charged to final customers for access to their data or for a request to make their data available.

Contracting Parties shall be responsible for setting the relevant charges for access to data by eligible parties.

Contracting Parties or, where a **Contracting Party** has so provided, the designated competent authorities shall ensure that any charges imposed by regulated entities that provide data services are reasonable and duly justified.

Article 24

Interoperability requirements and procedures for access to data

1. In order to promote competition in the retail market and to avoid excessive administrative costs for the eligible parties, **Contracting Parties** shall facilitate the full interoperability of energy services within the **Energy Community**.

2. **< … >**

3. **Contracting Parties** shall ensure that electricity undertakings apply the interoperability requirements and procedures for access to data referred to in paragraph 2. Those requirements and procedures shall be based on existing national practices.

Article 25

Single points of contact

Contracting Parties shall ensure the provision of single points of contact, to provide customers with all necessary information concerning their rights, the applicable law and dispute settlement mechanisms available to them in the event of a dispute. Such single points of contact may be part of general consumer information points.

Article 26

Right to out-of-court dispute settlement

1. **Contracting Parties** shall ensure that final customers have access to simple, fair, transparent, independent, effective and efficient out-of-court mechanisms for the settlement of disputes concerning rights and obligations established under this Directive, through an independent mechanism such as an energy ombudsman or a consumer body, or through a regulatory authority. Where the final customer is a consumer within the meaning of **applicable law**, such out-of-court dispute settlement mechanisms shall comply with the quality requirements of **applicable law** and shall provide, where warranted, for systems

of reimbursement and compensation.

2. Where necessary, **Contracting Parties** shall ensure that alternative dispute resolution entities cooperate to provide simple, fair, transparent, independent, effective and efficient out-of-court dispute settlement mechanisms for any dispute that arises from products or services that are tied to, or bundled with, any product or service falling under the scope of this Directive.

3. The participation of electricity undertakings in out-of-court dispute settlement mechanisms for household customers shall be mandatory unless the **Contracting Party** demonstrates to the **Energy Community Secretariat** that other mechanisms are equally effective.

Article 27

Universal service

1. **Contracting Parties** shall ensure that all household customers, and, where **Contracting Parties** deem it to be appropriate, small enterprises, enjoy universal service, namely the right to be supplied with electricity of a specified quality within their territory at competitive, easily and clearly comparable, transparent and non-discriminatory prices. To ensure the provision of universal service, **Contracting Parties** may appoint a supplier of last resort. **Contracting Parties** shall impose on distribution system operators an obligation to connect customers to their network under terms, conditions and tariffs set in accordance with the procedure laid down in Article 59(7). This Directive does not prevent **Contracting Parties** from strengthening the market position of the household customers and small and medium-sized non-household customers by promoting the possibilities for the voluntary aggregation of representation for that class of customers.

2. Paragraph 1 shall be implemented in a transparent and non-discriminatory way, and shall not impede the free choice of supplier provided for in Article 4.

Article 28

Vulnerable customers

1. **Contracting Parties** shall take appropriate measures to protect customers and shall ensure, in particular, that there are adequate safeguards to protect vulnerable customers. In this context, each **Contracting Party** shall define the concept of vulnerable customers which may refer to energy poverty and, inter alia, to the prohibition of disconnection of electricity to such customers in critical times. The concept of vulnerable customers may include income levels, the share of energy expenditure of disposable income, the energy efficiency of homes, critical dependence on electrical equipment for health reasons, age or other criteria. **Contracting Parties** shall ensure that rights and obligations linked to vulnerable customers are applied. In particular, they shall take measures to protect customers in remote areas. They shall ensure high levels of consumer protection, particularly with respect to transparency regarding contractual terms and conditions, general information and dispute settlement mechanisms.

2. **Contracting Parties** shall take appropriate measures, such as providing benefits by means of their social security systems to ensure the necessary supply to vulnerable customers, or providing for support for energy efficiency improvements, to address energy poverty where identified pursuant to point (d) of

Article 3(3) of Regulation (EU) 2018/1999 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**, including in the broader context of poverty. Such measures shall not impede the effective opening of the market set out in Article 4 or market functioning and shall be notified to the **Energy Community Secretariat**, where relevant, in accordance with Article 9(4). Such notifications may also include measures taken within the general social security system.

Article 29

Energy poverty

When assessing the number of households in energy poverty pursuant to point (d) of Article 3(3) of Regulation (EU) 2018/1999 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**, **Contracting Parties** shall establish and publish a set of criteria, which may include low income, high expenditure of disposable income on energy and poor energy efficiency.

The **Energy Community Secretariat** shall provide guidance on the definition of 'significant number of households in energy poverty' in this context and in the context of Article 5(5), starting from the premise that any proportion of households in energy poverty can be considered to be significant.

CHAPTER IV
DISTRIBUTION SYSTEM OPERATION

Article 30

Designation of distribution system operators

Contracting Parties shall designate or shall require undertakings that own or are responsible for distribution systems to designate one or more distribution system operators for a period of time to be determined by the **Contracting Parties**, having regard to considerations of efficiency and economic balance.

Article 31

Tasks of distribution system operators

1. The distribution system operator shall be responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity, for operating, maintaining and developing under economic conditions a secure, reliable and efficient electricity distribution system in its area with due regard for the environment and energy efficiency.

2. In any event, the distribution system operator shall not discriminate between system users or classes of system users, particularly in favour of its related undertakings.

3. The distribution system operator shall provide system users with the information they need for efficient access to, including use of, the system.

4. A **Contracting Party** may require the distribution system operator, when dispatching generating installations, to give priority to generating installations using renewable sources or using high-efficiency cogeneration, in accordance with **Article 12 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

5. Each distribution system operator shall act as a neutral market facilitator in procuring the energy it uses to cover energy losses in its system in accordance with transparent, non-discriminatory and market-based procedures, where it has such a function.

6. Where a distribution system operator is responsible for the procurement of products and services necessary for the efficient, reliable and secure operation of the distribution system, rules adopted by the distribution system operator for that purpose shall be objective, transparent and non-discriminatory, and shall be developed in coordination with transmission system operators and other relevant market participants. The terms and conditions, including rules and tariffs, where applicable, for the provision of such products and services to distribution system operators shall be established in accordance with Article 59(7) in a non-discriminatory and cost-reflective way and shall be published.

7. In performing the tasks referred to in paragraph 6, the distribution system operator shall procure the non-frequency ancillary services needed for its system in accordance with transparent, non-discriminatory and market-based procedures, unless the regulatory authority has assessed that the market-based provision of non-frequency ancillary services is economically not efficient and has granted a derogation. The obligation to procure non-frequency ancillary services does not apply to fully integrated network components.

8. The procurement of the products and services referred to in paragraph 6 shall ensure the effective participation of all qualified market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation, in particular by requiring regulatory authorities and distribution system operators in close cooperation with all market participants, as well as transmission system operators, to establish the technical requirements for participation in those markets on the basis of the technical characteristics of those markets and the capabilities of all market participants.

9. Distribution system operators shall cooperate with transmission system operators for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets. Delivery of balancing services stemming from resources located in the distribution system shall be agreed with the relevant transmission system operator in accordance with **Article 57 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC and** Article 182 of Regulation (EU) 2017/1485 **as adapted and adopted by the Ministerial Council Decision 2022/03/MC-EnC**.

10. **Contracting Parties** or their designated competent authorities may allow distribution system operators to perform activities other than those provided for in this Directive and in **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, where such activities are necessary for the distribution system operators to fulfil their obligations under this Directive or **in Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, provided that the regulatory authority has assessed the necessity of such a derogation. This paragraph shall be without prejudice to the right of the distribution system operators to own, develop, manage or operate networks other than electricity networks where the **Contracting Party** or the designated competent authority has granted such a right.

Article 32

Incentives for the use of flexibility in distribution networks

1. **Contracting Parties** shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system. In particular, the regulatory framework shall ensure that distribution system operators are able to procure such services from providers of distributed generation, demand response or energy storage and shall promote the uptake of energy efficiency measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system. Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.

2. Distribution system operators, subject to approval by the regulatory authority, or the regulatory authority itself, shall, in a transparent and participatory process that includes all relevant system users and transmission system operators, establish the specifications for the flexibility services procured and, where appropriate, standardised market products for such services at least at national level. The specifications shall ensure the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation. Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development. Distribution system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs.

3. The development of a distribution system shall be based on a transparent network development plan that the distribution system operator shall publish at least every two years and shall submit to the regulatory authority. The network development plan shall provide transparency on the medium and long-term flexibility services needed, and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.

4. The distribution system operator shall consult all relevant system users and the relevant transmission system operators on the network development plan. The distribution system operator shall publish the results of the consultation process along with the network development plan, and submit the results of the consultation and the network development plan to the regulatory authority. The regulatory authority may request amendments to the plan.

5. **Contracting Parties** may decide not to apply the obligation set out in paragraph 3 to integrated electricity undertakings which serve less than 100 000 connected customers or which serve small isolated systems.

Article 33

Integration of electromobility into the electricity network

1. **< … > Contracting Parties** shall provide the necessary regulatory framework to facilitate the connection of publicly accessible and private recharging points to the distribution networks. **Contracting Parties** shall ensure that distribution system operators cooperate on a non-discriminatory basis with any undertaking that owns, develops, operates or manages recharging points for electric vehicles, including with regard to connection to the grid.

2. Distribution system operators shall not own, develop, manage or operate recharging points for electric vehicles, except where distribution system operators own private recharging points solely for their own use.

3. By way of derogation from paragraph 2, **Contracting Parties** may allow distribution system operators to own, develop, manage or operate recharging points for electric vehicles, provided that all of the following conditions are fulfilled:

(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate recharging points for electric vehicles, or could not deliver those services at a reasonable cost and in a timely manner;

(b) the regulatory authority has carried out an *ex ante* review of the conditions of the tendering procedure under point (a) and has granted its approval;

(c) the distribution system operator operates the recharging points on the basis of third-party access in accordance with Article 6 and does not discriminate between system users or classes of system users, and in particular in favour of its related undertakings. The regulatory authority may draw up guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure.

4. Where **Contracting Parties** have implemented the conditions set out in paragraph 3, **Contracting Parties** or their designated competent authorities shall perform, at regular intervals or at least every five years, a public consultation in order to re-assess the potential interest of other parties in owning, developing, operating or managing recharging points for electric vehicles. Where the public consultation indicates that other parties are able to own, develop, operate or manage such points, **Contracting Parties** shall ensure that distribution system operators' activities in this regard are phased-out, subject to the successful completion of the tendering procedure referred to in point (a) of paragraph 3. As part of the conditions of that procedure, regulatory authorities may allow the distribution system operator to recover the residual value of its investment in recharging infrastructure.

Article 34

Tasks of distribution system operators in data management

Contracting Parties shall ensure that all eligible parties have non-discriminatory access to data under clear and equal terms, in accordance with the relevant data protection rules. In **Contracting Parties** where smart metering systems have been deployed in accordance with Article 19 and where distribution system operators are involved in data management, the compliance programmes referred to in point (d) of Article

35(2) shall include specific measures in order to exclude discriminatory access to data from eligible parties as provided for in Article 23. Where distribution system operators are not subject to Article 35(1), (2) or (3), **Contracting Parties** shall take all necessary measures to ensure that vertically integrated undertakings do not have privileged access to data for the conduct of their supply activities.

Article 35

Unbundling of distribution system operators

1. Where the distribution system operator is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organisation and decision-making from other activities not relating to distribution. Those rules shall not create an obligation to separate the ownership of assets of the distribution system operator from the vertically integrated undertaking.

2. In addition to the requirements under paragraph 1, where the distribution system operator is part of a vertically integrated undertaking, it shall be independent in terms of its organisation and decision-making from the other activities not related to distribution. In order to achieve this, the following minimum criteria shall apply:

(a) the persons responsible for the management of the distribution system operator must not participate in company structures of the integrated electricity undertaking responsible, directly or indirectly, for the day-to-day operation of the generation, transmission or supply of electricity;

(b) appropriate measures must be taken to ensure that the professional interests of the persons responsible for the management of the distribution system operator are taken into account in a manner that ensures that they are capable of acting independently;

(c) the distribution system operator must have effective decision-making rights, independent from the integrated electricity undertaking, with respect to assets necessary to operate, maintain or develop the network. In order to fulfil those tasks, the distribution system operator shall have at its disposal the necessary resources including human, technical, physical and financial resources. This should not prevent the existence of appropriate coordination mechanisms to ensure that the economic and management supervision rights of the parent company in respect of return on assets, regulated indirectly in accordance with Article 59(7), in a subsidiary are protected. In particular, this shall enable the parent company to approve the annual financial plan, or any equivalent instrument, of the distribution system operator and to set global limits on the levels of indebtedness of its subsidiary. It shall not permit the parent company to give instructions regarding day-to-day operations, nor with respect to individual decisions concerning the construction or upgrading of distribution lines, that do not exceed the terms of the approved financial plan, or any equivalent instrument; and

(d) the distribution system operator must establish a compliance programme, which sets out measures taken to ensure that discriminatory conduct is excluded, and ensure that observance of it is adequately monitored. The compliance programme shall set out the specific obligations of employees to meet that objective. An annual report, setting out the measures taken, shall be submitted by the person or body responsible for monitoring the compliance programme, the compliance officer of the distribution system operator, to the regulatory authority referred to in Article 57(1) and shall be published. The compliance officer of the distribution system operator shall be fully independent and shall have access to all the nec-

essary information of the distribution system operator and any affiliated undertaking to fulfil its task. 3. Where the distribution system operator is part of a vertically integrated undertaking, the **Contracting Parties** shall ensure that the activities of the distribution system operator are monitored by regulatory authorities or other competent bodies so that it cannot take advantage of its vertical integration to distort competition. In particular, vertically integrated distribution system operators shall not, in their communication and branding, create confusion with respect to the separate identity of the supply branch of the vertically integrated undertaking.

4. **Contracting Parties** may decide not to apply paragraphs 1, 2 and 3 to integrated electricity undertakings which serve less than 100 000 connected customers, or serving small isolated systems.

Article 36

Ownership of energy storage facilities by distribution system operators

1. Distribution system operators shall not own, develop, manage or operate energy storage facilities.

2. By way of derogation from paragraph 1, **Contracting Parties** may allow distribution system operators to own, develop, manage or operate energy storage facilities, where they are fully integrated network components and the regulatory authority has granted its approval, or where all of the following conditions are fulfilled:

(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate such facilities, or could not deliver those services at a reasonable cost and in a timely manner;

(b) such facilities are necessary for the distribution system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the distribution system and the facilities are not used to buy or sell electricity in the electricity markets; and

(c) the regulatory authority has assessed the necessity of such a derogation and has carried out an assessment of the tendering procedure, including the conditions of the tendering procedure, and has granted its approval. The regulatory authority may draw up guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure.

3. The regulatory authorities shall perform, at regular intervals or at least every five years, a public consultation on the existing energy storage facilities in order to assess the potential availability and interest in investing in such facilities. Where the public consultation, as assessed by the regulatory authority, indicates that third parties are able to own, develop, operate or manage such facilities in a cost-effective manner, the regulatory authority shall ensure that the distribution system operators' activities in this regard are phased out within 18 months. As part of the conditions of that procedure, regulatory authorities may allow the distribution system operators to receive reasonable compensation, in particular to recover the residual value of their investment in the energy storage facilities.

4. Paragraph 3 shall not apply to fully integrated network components or for the usual depreciation period of new battery storage facilities with a final investment decision until **the date of entry into force of this Directive in the Energy Community**, provided that such battery storage facilities are:

(a) connected to the grid at the latest two years thereafter;

(b) integrated into the distribution system;

(c) used only for the reactive instantaneous restoration of network security in the case of network contingencies where such restoration measure starts immediately and ends when regular re-dispatch can solve the issue; and

(d) not used to buy or sell electricity in the electricity markets, including balancing.

Article 37

Confidentiality obligation of distribution system operators

Without prejudice to Article 55 or another legal requirement to disclose information, the distribution system operator shall preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its business, and shall prevent information about its own activities which may be commercially advantageous from being disclosed in a discriminatory manner.

Article 38

Closed distribution systems

1. **Contracting Parties** may provide for regulatory authorities or other competent authorities to classify a system which distributes electricity within a geographically confined industrial, commercial or shared services site and does not, without prejudice to paragraph 4, supply household customers, as a closed distribution system if:

(a) for specific technical or safety reasons, the operations or the production process of the users of that system are integrated; or

(b) that system distributes electricity primarily to the owner or operator of the system or their related undertakings.

2. Closed distribution systems shall be considered to be distribution systems for the purposes of this Directive. **Contracting Parties** may provide for regulatory authorities to exempt the operator of a closed distribution system from:

(a) the requirement under Article 31(5) and (7) to procure the energy it uses to cover energy losses and the non-frequency ancillary services in its system in accordance with transparent, non-discriminatory and market-based procedures;

(b) the requirement under Article 6(1) that tariffs, or the methodologies underlying their calculation, are approved in accordance with Article 59(1) prior to their entry into force;

(c) the requirements under Article 32(1) to procure flexibility services and under Article 32(3) to develop the operator's system on the basis of network development plans;

(d) the requirement under Article 33(2) not to own, develop, manage or operate recharging points for electric vehicles; and

(e) the requirement under Article 36(1) not to own, develop, manage or operate energy storage facilities.

3. Where an exemption is granted under paragraph 2, the applicable tariffs, or the methodologies under-

lying their calculation, shall be reviewed and approved in accordance with Article 59(1) upon request by a user of the closed distribution system.

4. Incidental use by a small number of households with employment or similar associations with the owner of the distribution system and located within the area served by a closed distribution system shall not preclude an exemption under paragraph 2 being granted.

Article 39

Combined operator

Article 35(1) shall not prevent the operation of a combined transmission and distribution system operator, provided that the operator complies with Article 43(1), Articles 44 and 45, or Section 3 of Chapter VI, or that the operator falls under Article 66(3).

CHAPTER V
GENERAL RULES APPLICABLE TO TRANSMISSION SYSTEM OPERATORS

Article 40

Tasks of transmission system operators

1. Each transmission system operator shall be responsible for:

(a) ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity, operating, maintaining and developing under economic conditions secure, reliable and efficient transmission system with due regard to the environment, in close cooperation with neighbouring transmission system operators and distribution system operators;

(b) ensuring adequate means to meet its obligations;

(c) contributing to security of supply through adequate transmission capacity and system reliability;

(d) managing electricity flows on the system, taking into account exchanges with other interconnected systems. To that end, the transmission system operator shall be responsible for ensuring a secure, reliable and efficient electricity system and, in that context, for ensuring the availability of all necessary ancillary services, including those provided by demand response and energy storage facilities, insofar as such availability is independent from any other transmission systems with which its system is interconnected;

(e) providing to the operator of other systems with which its system is interconnected sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system;

(f) ensuring non-discrimination as between system users or classes of system users, particularly in favour of its related undertakings;

(g) providing system users with the information they need for efficient access to the system;

(h) collecting congestion rents and payments under the inter-transmission system operator compensation

mechanism, in accordance with Article 49 of Regulation (EU) 2019/943, granting and managing third-party access and giving reasoned explanations when it denies such access, which shall be monitored by the regulatory authorities; in carrying out their tasks under this Article transmission system operators shall primarily facilitate market integration;

(i) procuring ancillary services to ensure operational security;

(j) adopting a framework for cooperation and coordination between the regional coordination centres;

(k) participating in the establishment of the European and national resource adequacy assessments pursuant to Chapter IV of Regulation (EU) 2019/943;

(l) the digitalisation of transmission systems;

(m) data management, including the development of data management systems, cybersecurity and data protection, subject to the applicable rules, and without prejudice to the competence of other authorities. 2. **Contracting Parties** may provide that one or several responsibilities listed in paragraph 1 of this Article be assigned to a transmission system operator other than the one which owns the transmission system to which the responsibilities concerned would otherwise be applicable. The transmission system operator to which the tasks are assigned shall be certified under the ownership unbundling, the independent system operator or the independent transmission system operator model, and fulfil the requirements provided for in Article 43, but shall not be required to own the transmission system it is responsible for.

The transmission system operator which owns the transmission system shall fulfil the requirements provided for in Chapter VI and be certified in accordance with Article 43. This shall be without prejudice to the possibility for transmission system operators which are certified under the ownership unbundling, the independent system operator or the independent transmission system operator model to delegate, on their own initiative and under their supervision, certain tasks to other transmission system operators which are certified under the ownership unbundling, the independent system operator or the independent transmission system operator model where that delegation of tasks does not endanger the effective and independent decision-making rights of the delegating transmission system operator.

3. In performing the tasks referred to in paragraph 1, transmission system operators shall take into account the recommendations issued by the regional coordination centres. 4. In performing the task referred to in point (i) of paragraph 1, transmission system operators shall procure balancing services subject to the following:

(a) transparent, non-discriminatory and market-based procedures;

(b) the participation of all qualified electricity undertakings and market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation.

For the purpose of point (b) of the first subparagraph, regulatory authorities and transmission system operators shall, in close cooperation with all market participants, establish technical requirements for participation in those markets, on the basis of the technical characteristics of those markets.

5. Paragraph 4 shall apply to the provision of non-frequency ancillary services by transmission system operators, unless the regulatory authority has assessed that the market-based provision of non-frequency ancillary services is economically not efficient and has granted a derogation. In particular, the regulatory framework shall ensure that transmission system operators are able to procure such services from providers of demand response or energy storage and shall promote the uptake of energy efficiency measures, where

such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the transmission system.

6. Transmission system operators, subject to approval by the regulatory authority, or the regulatory authority itself, shall, in a transparent and participatory process that includes all relevant system users and the distribution system operators, establish the specifications for the **< … >** ancillary services procured and, where appropriate, standardised market products for such services at least at national level. The specifications shall ensure the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation. Transmission system operators shall exchange all necessary information and shall coordinate with distribution system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development. Transmission system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least the reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs.

7. The obligation to procure non-frequency ancillary services referred to in paragraph 5 does not apply to fully integrated network components.

8. **Contracting Parties** or their designated competent authorities may allow transmission system operators to perform activities other than those provided for in this Directive and in **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** where such activities are necessary for the transmission system operators to fulfil their obligations under this Directive or **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, provided that the regulatory authority has assessed the necessity of such a derogation. This paragraph shall be without prejudice to the right of the transmission system operators to own, develop, manage or operate networks other than electricity networks where the **Contracting Party** or the designated competent authority has granted such a right.

Article 41

Confidentiality and transparency requirements for transmission system operators and transmission system owners

1. Without prejudice to Article 55 or another legal duty to disclose information, each transmission system operator and each transmission system owner shall preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its activities, and shall prevent information about its own activities which may be commercially advantageous from being disclosed in a discriminatory manner. In particular it shall not disclose any commercially sensitive information to the remaining parts of the undertaking, unless such disclosure is necessary for carrying out a business transaction. In order to ensure the full respect of the rules on information unbundling, **Contracting Parties** shall ensure that the transmission system owner and the remaining part of the undertaking do not use joint services, such as joint legal services, apart from purely administrative or IT functions.

2. Transmission system operators shall not, in the context of sales or purchases of electricity by related undertakings, misuse commercially sensitive information obtained from third parties in the context of providing or negotiating access to the system.

3. Information necessary for effective competition and the efficient functioning of the market shall be made public. That obligation shall be without prejudice to preserving the confidentiality of commercially sensitive information.

Article 42

Decision-making powers regarding the connection of new generating installations and energy storage facilities to the transmission system

1. The transmission system operator shall establish and publish transparent and efficient procedures for non-discriminatory connection of new generating installations and energy storage facilities to the transmission system. Those procedures shall be subject to approval by the regulatory authorities.

2. The transmission system operator shall not be entitled to refuse the connection of a new generating installation or energy storage facility on the grounds of possible future limitations to available network capacities, such as congestion in distant parts of the transmission system. The transmission system operator shall supply necessary information.

The first subparagraph shall be without prejudice to the possibility for transmission system operators to limit the guaranteed connection capacity or to offer connections subject to operational limitations, in order to ensure economic efficiency regarding new generating installations or energy storage facilities, provided that such limitations have been approved by the regulatory authority. The regulatory authority shall ensure that any limitations in guaranteed connection capacity or operational limitations are introduced on the basis of transparent and non-discriminatory procedures and do not create undue barriers to market entry. Where the generating installation or energy storage facility bears the costs related to ensuring unlimited connection, no limitation shall apply.

3. The transmission system operator shall not be entitled to refuse a new connection point, on the ground that it would lead to additional costs resulting from the necessary capacity increase of system elements in the close-up range to the connection point.

CHAPTER VI
UNBUNDLING OF TRANSMISSION SYSTEM OPERATORS

Section 1
Ownership unbundling

Article 43

Ownership unbundling of transmission systems and transmission system operators

1. **Contracting Parties** shall ensure that:

(a) each undertaking which owns a transmission system acts as a transmission system operator;

(b) the same person or persons are not entitled either:

(i) directly or indirectly to exercise control over an undertaking performing any of the functions of generation or supply, and directly or indirectly to exercise control or exercise any right over a transmission system operator or over a transmission system; or

(ii) directly or indirectly to exercise control over a transmission system operator or over a transmission system, and directly or indirectly to exercise control or exercise any right over an undertaking performing any of the functions of generation or supply;

(c) the same person or persons are not entitled to appoint members of the supervisory board, the administrative board or bodies legally representing the undertaking, of a transmission system operator or a transmission system, and directly or indirectly to exercise control or exercise any right over an undertaking performing any of the functions of generation or supply; and

(d) the same person is not entitled to be a member of the supervisory board, the administrative board or bodies legally representing the undertaking, of both an undertaking performing any of the functions of generation or supply and a transmission system operator or a transmission system.

2. The rights referred to in points (b) and (c) of paragraph 1 shall include, in particular:

(a) the power to exercise voting rights;

(b) the power to appoint members of the supervisory board, the administrative board or bodies legally representing the undertaking; or

(c) the holding of a majority share.

3. For the purpose of point (b) of paragraph 1, the notion 'undertaking performing any of the functions of generation or supply' shall include 'undertaking performing any of the functions of production and supply' within the meaning of Directive 2009/73/EC, and the terms 'transmission system operator' and 'transmission system' shall include 'transmission system operator' and 'transmission system' within the meaning of that Directive.

4. The obligation set out in point (a) of paragraph 1 shall be deemed to be fulfilled in a situation where two or more undertakings which own transmission systems have created a joint venture which acts as a transmission system operator in two or more **Contracting Parties** for the transmission systems concerned. No other undertaking may be part of the joint venture, unless it has been approved under Article 44 as an independent system operator or as an independent transmission operator for the purposes of Section 3.

5. For the implementation of this Article, where the person referred to in points (b), (c) and (d) of paragraph 1 is the **Contracting Party** or another public body, two separate public bodies exercising control over a transmission system operator or over a transmission system on the one hand, and over an undertaking performing any of the functions of generation or supply on the other, shall be deemed not to be the same person or persons.

6. **Contracting Parties** shall ensure that neither commercially sensitive information referred to in Article 41 held by a transmission system operator which was part of a vertically integrated undertaking, nor the staff of such a transmission system operator, is transferred to undertakings performing any of the functions of generation and supply.

7. Where on **6 October 2011**, the transmission system belongs to a vertically integrated undertaking a **Contracting Party** may decide not to apply paragraph 1.

In such case, the **Contracting Party** concerned shall either:

(a) designate an independent system operator in accordance with Article 44; or

(b) comply with Section 3.

8. Where, on **6 October 2011**, the transmission system belongs to a vertically integrated undertaking and there are arrangements in place which guarantee more effective independence of the transmission system operator than Section 3, a **Contracting Party** may decide not to apply paragraph 1.

9. Before an undertaking is approved and designated as a transmission system operator under paragraph 8 of this Article, it shall be certified in accordance with the procedures laid down in Article 52(4), (5), and (6) of this Directive and in **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, pursuant to which the **Energy Community Secretariat** shall verify that the arrangements in place clearly guarantee more effective independence of the transmission system operator than Section 3 of this Chapter.

10. Vertically integrated undertakings which own a transmission system shall not in any event be prevented from taking steps to comply with paragraph 1.

11. Undertakings performing any of the functions of generation or supply shall not in any event be able to directly or indirectly take control over or exercise any right over unbundled transmission system operators in **Contracting Parties** which apply paragraph 1.

Section 2
Independent system operator

Article 44
Independent system operator

1. Where the transmission system belongs to a vertically integrated undertaking on 3 September 2009, **Contracting Parties** may decide not to apply Article 43(1) and designate an independent system operator upon a proposal from the transmission system owner. Such designation shall be subject to **opinion of** the **Energy Community Secretariat**.

2. The **Contracting Party** may approve and designate an independent system operator provided that:

(a) the candidate operator has demonstrated that it complies with the requirements laid down in points (b), (c) and (d) of Article 43(1);

(b) the candidate operator has demonstrated that it has at its disposal the required financial, technical, physical and human resources to carry out its tasks under Article 40;

(c) the candidate operator has undertaken to comply with a ten-year network development plan monitored by the regulatory authority;

(d) the transmission system owner has demonstrated its ability to comply with its obligations under paragraph 5. To that end, it shall provide all the draft contractual arrangements with the candidate operator and any other relevant entity; and

(e) the candidate operator has demonstrated its ability to comply with its obligations under **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**,

including the cooperation of transmission system operators at European and regional level.

3. Undertakings which have been certified by the regulatory authority as having complied with the requirements of Article 53 and paragraph 2 of this Article shall be approved and designated as independent system operators by **Contracting Parties**. The certification procedure in either Article 52 of this Directive and **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** or in Article 53 of this Directive shall be applicable.

4. Each independent system operator shall be responsible for granting and managing third-party access, including the collection of access charges, congestion charges, and payments under the inter-transmission system operator compensation mechanism in accordance with **Article 49 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, as well as for operating, maintaining and developing the transmission system, and for ensuring the long-term ability of the system to meet reasonable demand through investment planning. When developing the transmission system, the independent system operator shall be responsible for planning (including authorisation procedure), construction and commissioning of the new infrastructure. For this purpose, the independent system operator shall act as a transmission system operator in accordance with this Section. The transmission system owner shall not be responsible for granting and managing third-party access, nor for investment planning.

5. Where an independent system operator has been designated, the transmission system owner shall:

(a) provide all the relevant cooperation and support to the independent system operator for the fulfilment of its tasks, including in particular all relevant information;

(b) finance the investments decided by the independent system operator and approved by the regulatory authority, or give its agreement to financing by any interested party including the independent system operator. The relevant financing arrangements shall be subject to approval by the regulatory authority. Prior to such approval, the regulatory authority shall consult the transmission system owner together with the other interested parties;

(c) provide for the coverage of liability relating to the network assets, excluding the liability relating to the tasks of the independent system operator; and

(d) provide guarantees to facilitate financing any network expansions with the exception of those investments where, pursuant to point (b), it has given its agreement to financing by any interested party including the independent system operator. 6. In close cooperation with the regulatory authority, the relevant national competition authority shall be granted all relevant powers to effectively monitor compliance of the transmission system owner with its obligations under paragraph 5.

Article 45

Unbundling of transmission system owners

1. A transmission system owner, where an independent system operator has been appointed, which is part of a vertically integrated undertaking shall be independent at least in terms of its legal form, organisation and decision-making from other activities not relating to transmission.

2. In order to ensure the independence of the transmission system owner referred to in paragraph 1, the following minimum criteria shall apply:

(a) persons responsible for the management of the transmission system owner shall not participate in

company structures of the integrated electricity undertaking responsible, directly or indirectly, for the day-to-day operation of the generation, distribution and supply of electricity;

(b) appropriate measures shall be taken to ensure that the professional interests of persons responsible for the management of the transmission system owner are taken into account in a manner that ensures that they are capable of acting independently; and

(c) the transmission system owner shall establish a compliance programme, which sets out measures taken to ensure that discriminatory conduct is excluded, and ensure that observance of it is adequately monitored. The compliance programme shall set out the specific obligations of employees to meet those objectives. An annual report, setting out the measures taken, shall be submitted by the person or body responsible for monitoring the compliance programme to the regulatory authority and shall be published.

Section 3
Independent transmission operators

Article 46
Assets, equipment, staff and identity

1. Transmission system operators shall be equipped with all human, technical, physical and financial resources necessary for fulfilling their obligations under this Directive and carrying out the activity of electricity transmission, in particular:

(a) assets that are necessary for the activity of electricity transmission, including the transmission system, shall be owned by the transmission system operator;

(b) personnel, necessary for the activity of electricity transmission, including the performance of all corporate tasks, shall be employed by the transmission system operator;

(c) leasing of personnel and rendering of services, to and from other parts of the vertically integrated undertaking shall be prohibited. A transmission system operator may, however, render services to the vertically integrated undertaking, provided that:

(i) the provision of those services does not discriminate between system users, is available to all system users on the same terms and conditions and does not restrict, distort or prevent competition in generation or supply; and

(ii) the terms and conditions of the provision of those services are approved by the regulatory authority;

(d) without prejudice to the decisions of the Supervisory Body under Article 49, appropriate financial resources for future investment projects and/or for the replacement of existing assets shall be made available to the transmission system operator in due time by the vertically integrated undertaking after an appropriate request from the transmission system operator.

2. The activity of electricity transmission shall include at least the following tasks in addition to those listed in Article 40:

(a) the representation of the transmission system operator and contacts to third parties and the regulatory authorities;

(b) the representation of the transmission system operator within the ENTSO for Electricity;

(c) granting and managing third-party access on a non-discriminatory basis between system users or classes of system users;

(d) the collection of all the transmission system related charges including access charges, energy for losses and ancillary services charges;

(e) the operation, maintenance and development of a secure, efficient and economic transmission system;

(f) investment planning ensuring the long-term ability of the system to meet reasonable demand and guaranteeing security of supply;

(g) the setting up of appropriate joint ventures, including with one or more transmission system operators, power exchanges, and the other relevant actors pursuing the objectives to develop the creation of regional markets or to facilitate the liberalisation process; and

(h) all corporate services, including legal services, accountancy and IT services. 3. Transmission system operators shall be organised in a legal form as referred to in Annex I to Directive (EU) 2017/1132 of the European Parliament and of the Council.

4. The transmission system operator shall not, in its corporate identity, communication, branding and premises, create confusion with respect to the separate identity of the vertically integrated undertaking or any part thereof.

5. The transmission system operator shall not share IT systems or equipment, physical premises and security access systems with any part of the vertically integrated undertaking nor use the same consultants or external contractors for IT systems or equipment, and security access systems.

6. The accounts of transmission system operators shall be audited by an auditor other than the one auditing the vertically integrated undertaking or any part thereof.

Article 47

Independence of the transmission system operator

1. Without prejudice to the decisions of the Supervisory Body under Article 49, the transmission system operator shall have:

(a) effective decision-making rights, independent from the vertically integrated undertaking, with respect to assets necessary to operate, maintain or develop the transmission system; and

(b) the power to raise money on the capital market in particular through borrowing and capital increase. 2. The transmission system operator shall at all times act so as to ensure it has the resources it needs in order to carry out the activity of transmission properly and efficiently and develop and maintain an efficient, secure and economic transmission system.

3. Subsidiaries of the vertically integrated undertaking performing functions of generation or supply shall not have any direct or indirect shareholding in the transmission system operator. The transmission system operator shall neither have any direct or indirect shareholding in any subsidiary of the vertically integrated undertaking performing functions of generation or supply, nor receive dividends or other financial benefits from that subsidiary.

4. The overall management structure and the corporate statutes of the transmission system operator shall ensure effective independence of the transmission system operator in accordance with this Section. The vertically integrated undertaking shall not determine, directly or indirectly, the competitive behaviour of the transmission system operator in relation to the day-to-day activities of the transmission system operator and management of the network, or in relation to activities necessary for the preparation of the ten-year network development plan developed pursuant to Article 51.

5. In fulfilling their tasks in Article 40 and Article 46(2) of this Directive, and in complying with obligations set out in **Articles 16, 18, 19 and 50 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, transmission system operators shall not discriminate against different persons or entities and shall not restrict, distort or prevent competition in generation or supply.

6. Any commercial and financial relations between the vertically integrated undertaking and the transmission system operator, including loans from the transmission system operator to the vertically integrated undertaking, shall comply with market conditions. The transmission system operator shall keep detailed records of such commercial and financial relations and make them available to the regulatory authority upon request.

7. The transmission system operator shall submit for approval by the regulatory authority all commercial and financial agreements with the vertically integrated undertaking.

8. The transmission system operator shall inform the regulatory authority of the financial resources, referred to in point (d) of Article 46(1), available for future investment projects and/or for the replacement of existing assets.

9. The vertically integrated undertaking shall refrain from any action impeding or prejudicing the transmission system operator from complying with its obligations in this Chapter and shall not require the transmission system operator to seek permission from the vertically integrated undertaking in fulfilling those obligations.

10. An undertaking which has been certified by the regulatory authority as being in accordance with the requirements of this Chapter shall be approved and designated as a transmission system operator by the **Contracting Party** concerned. The certification procedure in either Article 52 of this Directive and **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** or in Article 53 of this Directive shall apply.

Article 48

Independence of the staff and the management of the transmission system operator

1. Decisions regarding the appointment and renewal, working conditions including remuneration, and termination of the term of office of the persons responsible for the management and/or members of the administrative bodies of the transmission system operator shall be taken by the Supervisory Body of the transmission system operator appointed in accordance with Article 49.

2. The identity and the conditions governing the term, the duration and the termination of office of the persons nominated by the Supervisory Body for appointment or renewal as persons responsible for the executive management and/or as members of the administrative bodies of the transmission system operator, and the reasons for any proposed decision terminating such term of office, shall be notified to the

regulatory authority. Those conditions and the decisions referred to in paragraph 1 shall become binding only if the regulatory authority has raised no objections within three weeks of notification.

The regulatory authority may object to the decisions referred to in paragraph 1 where:

(a) doubts arise as to the professional independence of a nominated person responsible for the management and/or member of the administrative bodies; or

(b) in the case of premature termination of a term of office, doubts exist regarding the justification of such premature termination. 3. No professional position or responsibility, interest or business relationship, directly or indirectly, with the vertically integrated undertaking or any part of it or its controlling shareholders other than the transmission system operator shall be exercised for a period of three years before the appointment of the persons responsible for the management and/or members of the administrative bodies of the transmission system operator who are subject to this paragraph.

4. The persons responsible for the management and/or members of the administrative bodies, and employees of the transmission system operator shall have no other professional position or responsibility, interest or business relationship, directly or indirectly, with another part of the vertically integrated undertaking or with its controlling shareholders.

5. The persons responsible for the management and/or members of the administrative bodies, and employees of the transmission system operator shall hold no interest in or receive any financial benefit, directly or indirectly, from any part of the vertically integrated undertaking other than the transmission system operator. Their remuneration shall not depend on activities or results of the vertically integrated undertaking other than those of the transmission system operator.

6. Effective rights of appeal to the regulatory authority shall be guaranteed for any complaints by the persons responsible for the management and/or members of the administrative bodies of the transmission system operator against premature terminations of their term of office.

7. After termination of their term of office in the transmission system operator, the persons responsible for its management and/or members of its administrative bodies shall have no professional position or responsibility, interest or business relationship with any part of the vertically integrated undertaking other than the transmission system operator, or with its controlling shareholders for a period of not less than four years.

8. Paragraph 3 shall apply to the majority of the persons responsible for the management and/or members of the administrative bodies of the transmission system operator.

The persons responsible for the management and/or members of the administrative bodies of the transmission system operator who are not subject to paragraph 3 shall have exercised no management or other relevant activity in the vertically integrated undertaking for a period of at least six months before their appointment.

The first subparagraph of this paragraph and paragraphs 4 to 7 shall be applicable to all the persons belonging to the executive management and to those directly reporting to them on matters related to the operation, maintenance or development of the network.

Article 49

Supervisory Body

1. The transmission system operator shall have a Supervisory Body which shall be in charge of taking decisions which may have a significant impact on the value of the assets of the shareholders within the transmission system operator, in particular decisions regarding the approval of the annual and longer-term financial plans, the level of indebtedness of the transmission system operator and the amount of dividends distributed to shareholders. The decisions falling under the remit of the Supervisory Body shall exclude those that are related to the day-to-day activities of the transmission system operator and management of the network, and to activities necessary for the preparation of the ten-year network development plan developed pursuant to Article 51.

2. The Supervisory Body shall be composed of members representing the vertically integrated undertaking, members representing third-party shareholders and, where the relevant national law so provides, members representing other interested parties such as employees of the transmission system operator.

3. The first subparagraph of Article 48(2) and Article 48(3) to (7) shall apply to at least half of the members of the Supervisory Body minus one.

Point (b) of the second subparagraph of Article 48(2) shall apply to all the members of the Supervisory Body.

Article 50

Compliance programme and compliance officer

1. **Contracting Parties** shall ensure that transmission system operators establish and implement a compliance programme which sets out the measures taken in order to ensure that discriminatory conduct is excluded, and ensure that the compliance with that programme is adequately monitored. The compliance programme shall set out the specific obligations of employees to meet those objectives. It shall be subject to approval by the regulatory authority. Without prejudice to the powers of the regulatory authority, compliance with the programme shall be independently monitored by a compliance officer.

2. The compliance officer shall be appointed by the Supervisory Body, subject to approval by the regulatory authority. The regulatory authority may refuse the approval of the compliance officer only for reasons of lack of independence or professional capacity. The compliance officer may be a natural or legal person. Article 48(2) to (8) shall apply to the compliance officer.

3. The compliance officer shall be in charge of:

(a) monitoring the implementation of the compliance programme;

(b) elaborating an annual report, setting out the measures taken in order to implement the compliance programme and submitting it to the regulatory authority;

(c) reporting to the Supervisory Body and issuing recommendations on the compliance programme and its implementation;

(d) notifying the regulatory authority on any substantial breaches with regard to the implementation of the compliance programme; and

(e) reporting to the regulatory authority on any commercial and financial relations between the vertically integrated undertaking and the transmission system operator. 4. The compliance officer shall submit the proposed decisions on the investment plan or on individual investments in the network to the regulatory authority. This shall occur at the latest when the management and/or the competent administrative body of the transmission system operator submits them to the Supervisory Body.

5. Where the vertically integrated undertaking, in the general assembly or through the vote of the members of the Supervisory Body it has appointed, has prevented the adoption of a decision with the effect of preventing or delaying investments, which under the ten-year network development plan was to be executed in the following three years, the compliance officer shall report this to the regulatory authority, which then shall act in accordance with Article 51.

6. The conditions governing the mandate or the employment conditions of the compliance officer, including the duration of its mandate, shall be subject to approval by the regulatory authority. Those conditions shall ensure the independence of the compliance officer, including by providing all the resources necessary for fulfilling the compliance officer's duties. During his or her mandate, the compliance officer shall have no other professional position, responsibility or interest, directly or indirectly, in or with any part of the vertically integrated undertaking or with its controlling shareholders.

7. The compliance officer shall report regularly, either orally or in writing, to the regulatory authority and shall have the right to report regularly, either orally or in writing, to the Supervisory Body of the transmission system operator.

8. The compliance officer may attend all meetings of the management or administrative bodies of the transmission system operator, and those of the Supervisory Body and the general assembly. The compliance officer shall attend all meetings that address the following matters:

(a) conditions for access to the network, as laid down in **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, in particular regarding tariffs, third-party access services, capacity allocation and congestion management, transparency, ancillary services and secondary markets;

(b) projects undertaken in order to operate, maintain and develop the transmission system, including interconnection and connection investments;

(c) energy purchases or sales necessary for the operation of the transmission system. 9. The compliance officer shall monitor the compliance of the transmission system operator with Article 41.

10. The compliance officer shall have access to all relevant data and to the offices of the transmission system operator and to all the information necessary for the fulfilment of his task.

11. The compliance officer shall have access to the offices of the transmission system operator without prior announcement.

12. After prior approval by the regulatory authority, the Supervisory Body may dismiss the compliance officer. It shall dismiss the compliance officer for reasons of lack of independence or professional capacity upon request of the regulatory authority.

Article 51

Network development and powers to make investment decisions

1. At least every two years, transmission system operators shall submit to the regulatory authority a ten-year network development plan based on existing and forecast supply and demand after having consulted all the relevant stakeholders. That network development plan shall contain efficient measures in order to guarantee the adequacy of the system and the security of supply. The transmission system operator shall publish the ten-year network development plan on its website.

2. The ten-year network development plan shall in particular:

(a) indicate to market participants the main transmission infrastructure that needs to be built or upgraded over the next ten years;

(b) contain all the investments already decided and identify new investments which have to be executed in the next three years; and

(c) provide for a time frame for all investment projects.

3. When elaborating the ten-year network development plan, the transmission system operator shall fully take into account the potential for the use of demand response, energy storage facilities or other resources as alternatives to system expansion, as well as expected consumption, trade with other countries and investment plans for **Energy Community**-wide and regional networks**, as applicable**.

4. The regulatory authority shall consult all actual or potential system users on the ten-year network development plan in an open and transparent manner. Persons or undertakings claiming to be potential system users may be required to substantiate such claims. The regulatory authority shall publish the result of the consultation process, in particular possible needs for investments.

5. The regulatory authority shall examine whether the ten-year network development plan covers all investment needs identified during the consultation process, and whether it is consistent with the non-binding Union-wide ten-year network development plan ('Union-wide network development plan') **referred to in Article 48 of the Regulation (EU) 2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. If any doubt arises as to the consistency with the Union-wide network development plan, the regulatory authority shall consult ACER. The regulatory authority may require the transmission system operator to amend its ten-year network development plan.

The competent national authorities shall examine the consistency of the ten-year network development plan with the national energy and climate plan submitted in accordance with Regulation (EU) 2018/1999 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**.

6. The regulatory authority shall monitor and evaluate the implementation of the ten-year network development plan.

7. In circumstances where the transmission system operator, other than for overriding reasons beyond its control, does not execute an investment, which, under the ten-year network development plan, was to be executed in the following three years, **Contracting Parties** shall ensure that the regulatory authority is required to take at least one of the following measures to ensure that the investment in question is made if such investment is still relevant on the basis of the most recent ten-year network development plan:

(a) to require the transmission system operator to execute the investments in question;

(b) to organise a tender procedure open to any investors for the investment in question; or

(c) to oblige the transmission system operator to accept a capital increase to finance the necessary investments and allow independent investors to participate in the capital.

8. Where the regulatory authority has made use of its powers under point (b) of paragraph 7, it may oblige the transmission system operator to agree to one or more of the following:

(a) financing by any third party;

(b) construction by any third party;

(c) building the new assets concerned itself;

(d) operating the new asset concerned itself. The transmission system operator shall provide the investors with all information needed to realise the investment, shall connect new assets to the transmission network and shall generally make its best efforts to facilitate the implementation of the investment project.

The relevant financial arrangements shall be subject to approval by the regulatory authority.

9. Where the regulatory authority has made use of its powers under paragraph 7, the relevant tariff regulations shall cover the costs of the investments in question.

Section 4
Designation and certification of transmission system operators

Article 52
Designation and certification of transmission system operators

1. Before an undertaking is approved and designated as transmission system operator, it shall be certified in accordance with the procedures laid down in paragraphs 4, 5 and 6 of this Article and in **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

2. Undertakings which have been certified by the regulatory authority as having complied with the requirements of Article 43 pursuant to the certification procedure below, shall be approved and designated as transmission system operators by **Contracting Parties**. The designation of transmission system operators shall be notified to the **Energy Community Secretariat** and published in the ***Website of the Energy Community***.

3. Transmission system operators shall notify to the regulatory authority any planned transaction which may require a reassessment of their compliance with the requirements of Article 43.

4. Regulatory authorities shall monitor the continuing compliance of transmission system operators with the requirements of Article 43. They shall open a certification procedure to ensure such compliance:

(a) upon notification by the transmission system operator pursuant to paragraph 3;

(b) on their own initiative where they have knowledge that a planned change in rights or influence over transmission system owners or transmission system operators may lead to an infringement of Article 43, or where they have reason to believe that such an infringement may have occurred; or

(c) upon a reasoned request from the **Energy Community Secretariat**.

5. The regulatory authorities shall adopt a decision on the certification of a transmission system operator within four months of the date of the notification by the transmission system operator or from the date of the **Energy Community Secretariat** request. After expiry of that period, the certification shall be deemed to be granted. The explicit or tacit decision of the regulatory authority shall become effective only after conclusion of the procedure set out in paragraph 6.

6. The explicit or tacit decision on the certification of a transmission system operator shall be notified without delay to the **Energy Community Secretariat** by the regulatory authority, together with all the relevant information with respect to that decision. The **Energy Community Secretariat** shall act in accordance with the procedure laid down in **Article 51 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

7. The regulatory authorities and the **Energy Community Secretariat** may request from transmission system operators and undertakings performing any of the functions of generation or supply any information relevant for the fulfilment of their tasks under this Article.

8. Regulatory authorities and the **Energy Community Secretariat** shall preserve the confidentiality of commercially sensitive information.

Article 53

Certification in relation to third countries

1. Where certification is requested by a transmission system owner or a transmission system operator which is controlled by a person or persons from a third country or third countries, the regulatory authority shall notify the **Energy Community Secretariat**.

The regulatory authority shall also notify to the **Energy Community Secretariat** without delay any circumstances that would result in a person or persons from a third country or third countries acquiring control of a transmission system or a transmission system operator.

2. The transmission system operator shall notify to the regulatory authority any circumstances that would result in a person or persons from a third country or third countries acquiring control of the transmission system or the transmission system operator.

3. The regulatory authority shall adopt a draft decision on the certification of a transmission system operator within four months of the date of notification by the transmission system operator. It shall refuse the certification if it has not been demonstrated:

(a) that the entity concerned complies with the requirements of Article 43; and

(b) to the regulatory authority or to another competent national authority designated by the **Contracting Party** that granting certification will not put at risk the security of energy supply of the **Contracting Party** and the **Energy Community**. In considering that question the regulatory authority or other competent national authority shall take into account:

(i) the rights and obligations of the **Energy Community** with respect to that third country arising under international law, including any agreement concluded with one or more third countries to which the **Energy Community** is a party and which addresses the issues of security of energy supply;

(ii) the rights and obligations of the **Contracting Party** with respect to that third country arising under agreements concluded with it, insofar as they comply with **Energy Community** law; and

(iii) other specific facts and circumstances of the case and the third country concerned.

4. The regulatory authority shall notify the decision to the **Energy Community Secretariat** without delay, together with all the relevant information with respect to that decision.

5. **Contracting Parties** shall provide for the regulatory authority or the designated competent authority referred to in point (b) of paragraph 3, before the regulatory authority adopts a decision on the certification, to request an opinion from the **Energy Community Secretariat** on whether:

(a) the entity concerned complies with the requirements of Article 43; and

(b) granting certification will not put at risk the security of energy supply to the **Energy Community**.

6. The **Energy Community Secretariat** shall examine the request referred to in paragraph 5 as soon as it is received. Within two months of receiving the request, it shall deliver its opinion to the regulatory authority or, if the request was made by the designated competent authority, to that authority.

In preparing the opinion, the **Energy Community Secretariat** may request the views of **the Energy Community Regulatory Board**, the **Contracting Party** concerned, and interested parties. In the event that the **Energy Community Secretariat** makes such a request, the two-month period shall be extended by two months.

In the absence of an opinion by the **Energy Community Secretariat** within the period referred to in the first and second subparagraphs, the **Energy Community Secretariat** shall be deemed not to raise objections to the decision of the regulatory authority.

7. When assessing whether the control by a person or persons from a third country or third countries will put at risk the security of energy supply to the **Energy Community**, the **Energy Community Secretariat** shall take into account:

(a) the specific facts of the case and the third country or third countries concerned; and

(b) the rights and obligations of the **Energy Community** with respect to that third country or third countries arising under international law, including an agreement concluded with one or more third countries to which the **Energy Community** is a party and which addresses the issues of security of supply.

8. The regulatory authority shall, within two months of the expiry of the period referred to in paragraph 6, adopt its final decision on the certification. In adopting its final decision the regulatory authority shall take utmost account of the **Energy Community Secretariat**'s opinion. In any event **Contracting Parties** shall have the right to refuse certification where granting certification puts at risk the **Contracting Party**'s security of energy supply or the security of energy supply of another **Contracting Party**. Where the **Contracting Party** has designated another competent national authority to make the assessment referred to in point (b) of paragraph 3, it may require the regulatory authority to adopt its final decision in accordance with the assessment of that competent national authority. The regulatory authority's final decision and the **Energy Community Secretariat**'s opinion shall be published together. Where the final decision diverges from the **Energy Community Secretariat**'s opinion, the **Contracting Party** concerned shall provide and publish, together with that decision, the reasoning underlying such decision.

9. Nothing in this Article shall affect the right of **Contracting Parties** to exercise, in accordance with **Energy Community** law, national legal controls to protect legitimate public security interests.

10. **< ... >**

Article 54

Ownership of energy storage facilities by transmission system operators

1. Transmission system operators shall not own, develop, manage or operate energy storage facilities.

2. By way of derogation from paragraph 1, **Contracting Parties** may allow transmission system operators to own, develop, manage or operate energy storage facilities, where they are fully integrated network components and the regulatory authority has granted its approval, or where all of the following conditions are fulfilled:

(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate such facilities, or could not deliver those services at a reasonable cost and in a timely manner;

(b) such facilities or non-frequency ancillary services are necessary for the transmission system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the transmission system and they are not used to buy or sell electricity in the electricity markets; and

(c) the regulatory authority has assessed the necessity of such a derogation, has carried out an *ex ante* review of the applicability of a tendering procedure, including the conditions of the tendering procedure, and has granted its approval. The regulatory authority may draw up guidelines or procurement clauses to help transmission system operators ensure a fair tendering procedure.

3. The decision to grant a derogation shall be notified to the **Energy Community Secretariat** and **Energy Community Regulatory Board** together with relevant information about the request and the reasons for granting the derogation.

4. The regulatory authorities shall perform, at regular intervals or at least every five years, a public consultation on the existing energy storage facilities in order to assess the potential availability and interest of other parties in investing in such facilities. Where the public consultation, as assessed by the regulatory authority, indicates that other parties are able to own, develop, operate or manage such facilities in a cost-effective manner, the regulatory authority shall ensure that transmission system operators' activities in this regard are phased-out within 18 months. As part of the conditions of that procedure, regulatory authorities may allow the transmission system operators to receive reasonable compensation, in particular to recover the residual value of their investment in the energy storage facilities.

5. Paragraph 4 shall not apply to fully integrated network components or for the usual depreciation period of new battery storage facilities with a final investment decision until **2026**, provided that such battery storage facilities are:

(a) connected to the grid at the latest two years thereafter;

(b) integrated into the transmission system;

(c) used only for the reactive instantaneous restoration of network security in the case of network contingencies where such restoration measure starts immediately and ends when regular re-dispatch can solve the issue; and

(d) not used to buy or sell electricity in the electricity markets, including balancing.

Section 5
Unbundling and transparency of accounts

Article 55
Right of access to accounts

1. **Contracting Parties** or any competent authority that they designate, including the regulatory authorities referred to in Article 57, shall, insofar as necessary to carry out their functions, have right of access to the accounts of electricity undertakings as set out in Article 56.

2. **Contracting Parties** and any designated competent authority, including the regulatory authorities, shall preserve the confidentiality of commercially sensitive information. **Contracting Parties** may provide for the disclosure of such information where such disclosure is necessary in order for the competent authorities to carry out their functions.

Article 56
Unbundling of accounts

1. **Contracting Parties** shall take the necessary steps to ensure that the accounts of electricity undertakings are kept in accordance with paragraphs 2 and 3.

2. Electricity undertakings, whatever their system of ownership or legal form, shall draw up, submit to audit and publish their annual accounts in accordance with the rules of national law concerning the annual accounts of limited liability companies **< ... >**.

Undertakings which are not legally obliged to publish their annual accounts shall keep a copy of these at the disposal of the public in their head office.

3. Electricity undertakings shall, in their internal accounting, keep separate accounts for each of their transmission and distribution activities as they would be required to do if the activities in question were carried out by separate undertakings, with a view to avoiding discrimination, cross-subsidisation and distortion of competition. They shall also keep accounts, which may be consolidated, for other electricity activities not relating to transmission or distribution. Revenue from ownership of the transmission or distribution system shall be specified in the accounts. Where appropriate, they shall keep consolidated accounts for other, non-electricity activities. The internal accounts shall include a balance sheet and a profit and loss account for each activity.

4. The audit referred to in paragraph 2 shall, in particular, verify that the obligation to avoid discrimination and cross-subsidisation referred to in paragraph 3 is respected.

CHAPTER VII
REGULATORY AUTHORITIES

Article 57

Designation and independence of regulatory authorities

1. Each **Contracting Party** shall designate a single regulatory authority at national level.

2. Paragraph 1 shall be without prejudice to the designation of other regulatory authorities at regional level within **Contracting Parties**, provided that there is one senior representative for representation and contact purposes at **Energy Community** level within **Energy Community Regulatory Board**.

3. By way of derogation from paragraph 1, a **Contracting Party** may designate regulatory authorities for small systems in a geographically separate region whose consumption, in 2008, accounted for less than 3 % of the total consumption of the **Contracting Party** of which it is part. That derogation shall be without prejudice to the appointment of one senior representative for representation and contact purposes at **Energy Community** level within **Energy Community Regulatory Board**.

4. **Contracting Parties** shall guarantee the independence of the regulatory authority and shall ensure that it exercises its powers impartially and transparently. For that purpose, **Contracting Parties** shall ensure that, when carrying out the regulatory tasks conferred upon it by this Directive and related legislation, the regulatory authority:

(a) is legally distinct and functionally independent from other public or private entities;

(b) ensures that its staff and the persons responsible for its management:

(i) act independently from any market interest; and

(ii) do not seek or take direct instructions from any government or other public or private entity when carrying out the regulatory tasks. That requirement is without prejudice to close cooperation, as appropriate, with other relevant national authorities or to general policy guidelines issued by the government not related to the regulatory powers and duties under Article 59.

5. In order to protect the independence of the regulatory authority, **Contracting Parties** shall in particular ensure that:

(a) the regulatory authority can take autonomous decisions, independently from any political body;

(b) the regulatory authority has all the necessary human and financial resources it needs to carry out its duties and exercise its powers in an effective and efficient manner;

(c) the regulatory authority has a separate annual budget allocation and autonomy in the implementation of the allocated budget;

(d) the members of the board of the regulatory authority or, in the absence of a board, the regulatory authority's top management are appointed for a fixed term of five up to seven years, renewable once;

(e) the members of the board of the regulatory authority or, in the absence of a board, the regulatory authority's top management are appointed based on objective, transparent and published criteria, in an independent and impartial procedure, which ensures that the candidates have the necessary skills and experience for the relevant position in the regulatory authority;

(f) conflict of interest provisions are in place and confidentiality obligations extend beyond the end of the mandate of the members of the board of the regulatory authority or, in the absence of a board, the end of the mandate of the regulatory authority's top management;

(g) the members of the board of the regulatory authority or, in the absence of a board, the regulatory authority's top management can be dismissed only based on transparent criteria in place. In regard to point (d) of the first subparagraph, **Contracting Parties** shall ensure an appropriate rotation scheme for the board or the top management. The members of the board or, in the absence of a board, members of the top management may be relieved from office during their term only if they no longer fulfil the conditions set out in this Article or have been guilty of misconduct under national law.

6. **Contracting Parties** may provide for the *ex post* control of the regulatory authorities› annual accounts by an independent auditor.

7. By 5 July 2022 and every four years thereafter, the **Energy Community Secretariat** shall submit a report to the **Ministerial Council** on the compliance of national authorities with the principle of independence set out in this Article.

Article 58

General objectives of the regulatory authority

In carrying out the regulatory tasks specified in this Directive, the regulatory authority shall take all reasonable measures in pursuit of the following objectives within the framework of its duties and powers as laid down in Article 59, in close consultation with other relevant national authorities, including competition authorities, as well as authorities, including regulatory authorities, from neighbouring **Contracting Parties** and neighbouring third countries, as appropriate, and without prejudice to their competence:

(a) promoting, in close cooperation with regulatory authorities of other **Contracting Parties**, the **Energy Community Secretariat** and **Energy Community Regulatory Board** , a competitive, flexible, secure and environmentally sustainable internal market for electricity within the **Energy Community**, and effective market opening for all customers and suppliers in the **Energy Community**, and ensuring appropriate conditions for the effective and reliable operation of electricity networks, taking into account long-term objectives;

(b) developing competitive and properly functioning regional cross-border markets within the **Energy Community** with a view to achieving the objectives referred to in point (a);

(c) eliminating restrictions on trade in electricity between **Contracting Parties**, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows across the **Energy Community**;

(d) helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer-oriented, and promoting system adequacy and, in accordance with general energy policy objectives, energy efficiency, as well as the integration of large and small-scale production of electricity from renewable sources and distributed generation in both transmission and distribution networks, and facilitating their operation in relation to other energy networks of gas or heat;

(e) facilitating access to the network for new generation capacity and energy storage facilities, in particular removing barriers that could prevent access for new market entrants and of electricity from renewable sources;

(f) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies, especially energy efficiency, in system performance and to

foster market integration;

(g) ensuring that customers benefit through the efficient functioning of their national market, promoting effective competition and helping to ensure a high level of consumer protection, in close cooperation with relevant consumer protection authorities;

(h) helping to achieve high standards of universal service and of public service in electricity supply, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for customer switching.

Article 59

Duties and powers of the regulatory authorities

1. The regulatory authority shall have the following duties:

(a) fixing or approving, in accordance with transparent criteria, transmission or distribution tariffs or their methodologies, or both;

(b) ensuring the compliance of transmission system operators and distribution system operators and, where relevant, system owners, as well as the compliance of any electricity undertakings and other market participants, with their obligations under this Directive, **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, the network codes and the guidelines adopted pursuant to Article **58 of Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** and other relevant **Energy Community** law, including as regards cross-border issues, as well as with **Energy Community Regulatory Board** 's decisions;

(c) **< … >**

(d) approving products and procurement process for **< … >** ancillary services;

(e) implementing the network codes and guidelines adopted pursuant to Articles **6 and 7 of Regulation (EC) 714/2009 as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC of 6 October 2011** through national measures or, where so required, coordinated regional or **Energy Community**-wide measures;

(f) cooperating in regard to cross-border issues with the regulatory authority or authorities of the **Contracting Parties** concerned and with **the Energy Community Regulatory Board < … >**;

(g) complying with, and implementing, any relevant legally binding decisions of the **Energy Community Secretariat** and of **Energy Community Regulatory Board**;

(h) ensuring that transmission system operators make available interconnector capacities to the utmost extent pursuant to **Article 16 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-En**C;

(i) reporting annually on its activity and the fulfilment of its duties to the relevant authorities of the **Contracting Parties**, the **Energy Community Secretariat** and **Energy Community Regulatory Board**, including on the steps taken and the results obtained as regards each of the tasks listed in this Article;

(j) ensuring that there is no cross-subsidisation between transmission, distribution and supply activities or other electricity or non-electricity activities;

(k) monitoring investment plans of the transmission system operators and providing in its annual report an assessment of the investment plans of the transmission system operators **< … >**; such assessment may include recommendations to amend those investment plans;

(l) monitoring and assessing the performance of transmission system operators and distribution system operators in relation to the development of a smart grid that promotes energy efficiency and the integration of energy from renewable sources, based on a limited set of indicators, and publish a national report every two years, including recommendations;

(m) setting or approving standards and requirements for quality of service and quality of supply or contributing thereto together with other competent authorities and monitoring compliance with and reviewing the past performance of network security and reliability rules;

(n) monitoring the level of transparency, including of wholesale prices, and ensuring compliance of electricity undertakings with transparency obligations;

(o) monitoring the level and effectiveness of market opening and competition at wholesale and retail levels, including on electricity exchanges, prices for household customers including prepayment systems, the impact of dynamic electricity price contracts and of the use of smart metering systems, switching rates, disconnection rates, charges for maintenance services, the execution of maintenance services, the relationship between household and wholesale prices, the evolution of grid tariffs and levies, and complaints by household customers, as well as any distortion or restriction of competition, including by providing any relevant information, and bringing any relevant cases to the relevant competition authorities;

(p) monitoring the occurrence of restrictive contractual practices, including exclusivity clauses which may prevent customers from contracting simultaneously with more than one supplier or restrict their choice to do so, and, where appropriate, informing the national competition authorities of such practices;

(q) monitoring the time taken by transmission system operators and distribution system operators to make connections and repairs;

(r) helping to ensure, together with other relevant authorities, that the consumer protection measures are effective and enforced;

(s) publishing recommendations, at least annually, in relation to compliance of supply prices with Article 5, and providing those recommendations to the competition authorities, where appropriate;

(t) ensuring non-discriminatory access to customer consumption data, the provision, for optional use, of an easily understandable harmonised format at national level for consumption data, and prompt access for all customers to such data pursuant to Articles 23 and 24;

(u) monitoring the implementation of rules relating to the roles and responsibilities of transmission system operators, distribution system operators, suppliers, customers and other market participants pursuant to **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(v) monitoring investment in generation and storage capacities in relation to security of supply;

(w) monitoring technical cooperation between **Energy Community** and third-country transmission system operators;

(x) contributing to the compatibility of data exchange processes for the most important market processes at regional level;

(y) monitoring the availability of comparison tools that meet the requirements set out in Article 14;

(z) monitoring the removal of unjustified obstacles to and restrictions on the development of consumption of self-generated electricity and citizen energy communities.

2. Where a **Contracting Party** has so provided, the monitoring duties set out in paragraph 1 may be carried out by other authorities than the regulatory authority. In such a case, the information resulting from such monitoring shall be made available to the regulatory authority as soon as possible.

While preserving their independence, without prejudice to their own specific competence and consistent with the principles of better regulation, the regulatory authority shall, as appropriate, consult transmission system operators and, as appropriate, closely cooperate with other relevant national authorities when carrying out the duties set out in paragraph 1.

Any approvals given by a regulatory authority or **Energy Community Regulatory Board** under this Directive are without prejudice to any duly justified future use of its powers by the regulatory authority under this Article or to any penalties imposed by other relevant authorities **< … >**.

3. **Contracting Parties** shall ensure that regulatory authorities are granted the powers enabling them to carry out the duties referred to in this Article in an efficient and expeditious manner. For this purpose, the regulatory authority shall have at least the following powers:

(a) to issue binding decisions on electricity undertakings;

(b) to carry out investigations into the functioning of the electricity markets, and to decide upon and impose any necessary and proportionate measures to promote effective competition and ensure the proper functioning of the market. Where appropriate, the regulatory authority shall also have the power to cooperate with the national competition authority and the financial market regulators or the **Energy Community Secretariat** in conducting an investigation relating to competition law;

(c) to require any information from electricity undertakings relevant for the fulfilment of its tasks, including the justification for any refusal to grant third-party access, and any information on measures necessary to reinforce the network;

(d) to impose effective, proportionate and dissuasive penalties on electricity undertakings not complying with their obligations under this Directive, **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** or any relevant legally binding decisions of the regulatory authority or of **Energy Community Regulatory Board**, or to propose that a competent court impose such penalties, including the power to impose or propose the imposition of penalties of up to 10 % of the annual turnover of the transmission system operator on the transmission system operator or of up to 10 % of the annual turnover of the vertically integrated undertaking on the vertically integrated undertaking, as the case may be, for non-compliance with their respective obligations pursuant to this Directive; and

(e) appropriate rights of investigation and relevant powers of instruction for dispute settlement under Article 60(2) and (3).

4. **< … >**

5. In addition to the duties conferred upon it under paragraphs 1 and 3 of this Article, when an independent system operator has been designated under Article 44, the regulatory authority shall:

(a) monitor the transmission system owner's and the independent system operator's compliance with their obligations under this Article, and issue penalties for non-compliance in accordance with point (d) of paragraph 3;

(b) monitor the relations and communications between the independent system operator and the transmission system owner so as to ensure compliance of the independent system operator with its obligations, and in particular approve contracts and act as a dispute settlement authority between the independent system operator and the transmission system owner with respect to any complaint submitted by either party pursuant to Article 60(2);

(c) without prejudice to the procedure under point (c) of Article 44(2), for the first ten-year network development plan, approve the investments planning and the multi-annual network development plan submitted at least every two years by the independent system operator;

(d) ensure that network access tariffs collected by the independent system operator include remuneration for the network owner or network owners, which provides for adequate remuneration of the network assets and of any new investments made therein, provided they are economically and efficiently incurred;

(e) have the powers to carry out inspections, including unannounced inspections, at the premises of transmission system owner and independent system operator; and

(f) monitor the use of congestion charges collected by the independent system operator in accordance with **Article 19(2) of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

6. In addition to the duties and powers conferred on it under paragraphs 1 and 3 of this Article, when a transmission system operator has been designated in accordance with Section 3 of Chapter VI, the regulatory authority shall be granted at least the following duties and powers:

(a) to impose penalties in accordance with point (d) of paragraph 3 for discriminatory behaviour in favour of the vertically integrated undertaking;

(b) to monitor communications between the transmission system operator and the vertically integrated undertaking so as to ensure compliance of the transmission system operator with its obligations;

(c) to act as dispute settlement authority between the vertically integrated undertaking and the transmission system operator with respect to any complaint submitted pursuant to Article 60(2);

(d) to monitor commercial and financial relations including loans between the vertically integrated undertaking and the transmission system operator;

(e) to approve all commercial and financial agreements between the vertically integrated undertaking and the transmission system operator on the condition that they comply with market conditions;

(f) to request a justification from the vertically integrated undertaking when notified by the compliance officer in accordance with Article 50(4), such justification including, in particular, evidence demonstrating that no discriminatory behaviour to the advantage of the vertically integrated undertaking has occurred;

(g) to carry out inspections, including unannounced ones, on the premises of the vertically integrated undertaking and the transmission system operator; and

(h) to assign all or specific tasks of the transmission system operator to an independent system operator appointed in accordance with Article 44 in the case of a persistent breach by the transmission system operator of its obligations under this Directive, in particular in the case of repeated discriminatory behaviour to the benefit of the vertically integrated undertaking.

7. The regulatory authorities, except where **Energy Community Regulatory Board** is competent to fix and approve the terms and conditions or methodologies for the implementation of network codes and guidelines under **Chapter VII of Regulation (EU) 2019/943 as adopted and adapted by Ministerial**

Council Decision 2022/03/MC-EnC because of their coordinated nature, shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the national methodologies used to calculate or establish the terms and conditions for:

(a) connection and access to national networks, including transmission and distribution tariffs or their methodologies, those tariffs or methodologies shall allow the necessary investments in the networks to be carried out in a manner allowing those investments to ensure the viability of the networks;

(b) the provision of ancillary services which shall be performed in the most economic manner possible and provide appropriate incentives for network users to balance their input and off-takes, such ancillary services shall be provided in a fair and non-discriminatory manner and be based on objective criteria; and

(c) access to cross-border infrastructures, including the procedures for the allocation of capacity and congestion management.

8. The methodologies or the terms and conditions referred to in paragraph 7 shall be published.

9. With a view to increasing transparency in the market and providing all interested parties with all necessary information and decisions or proposals for decisions concerning transmission and distribution tariffs as referred in Article 60(3), regulatory authorities shall make publicly available the detailed methodology and underlying costs used for the calculation of the relevant network tariffs, while preserving the confidentiality of commercially sensitive information.

10. The regulatory authorities shall monitor congestion management of national electricity systems including interconnectors, and the implementation of congestion management rules. To that end, transmission system operators or market operators shall submit their congestion management rules, including capacity allocation, to the regulatory authorities. Regulatory authorities may request amendments to those rules.

Article 60

Decisions and complaints

1. Regulatory authorities shall have the authority to require transmission system operators and distribution system operators, if necessary, to modify the terms and conditions, including tariffs or methodologies referred to Article 59 of this Directive, to ensure that they are proportionate and applied in a non-discriminatory manner, in accordance with **Article 18 of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**. In the event of delay in the fixing of transmission and distribution tariffs, regulatory authorities shall have the power to fix or approve provisional transmission and distribution tariffs or methodologies and to decide on the appropriate compensatory measures if the final transmission and distribution tariffs or methodologies deviate from those provisional tariffs or methodologies.

2. Any party having a complaint against a transmission or distribution system operator in relation to that operator's obligations under this Directive may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months of receipt of the complaint. That period may be extended by two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall have binding effect unless and until overruled on appeal.

3. Any party who is affected and who has a right to complain concerning a decision on methodologies

taken pursuant to Article 59 or, where the regulatory authority has a duty to consult, concerning the proposed tariffs or methodologies, may, within two months, or within a shorter period as provided for by **Contracting Parties**, after publication of the decision or proposal for a decision, submit a complaint for review. Such a complaint shall not have suspensive effect.

4. **Contracting Parties** shall create appropriate and efficient mechanisms for regulation, control and transparency so as to avoid any abuse of a dominant position, in particular to the detriment of consumers, and any predatory behaviour. Those mechanisms shall take account of the provisions of the **Energy Community Treaty**, and in particular Article **18(1)(b)** thereof.

5. **Contracting Parties** shall ensure that the appropriate measures are taken, including administrative action or criminal proceedings in conformity with their national law, against the natural or legal persons responsible where confidentiality rules imposed by this Directive have not been respected.

6. Complaints referred to in paragraphs 2 and 3 shall be without prejudice to the exercise of rights of appeal under **Energy Community** or national law.

7. Decisions taken by regulatory authorities shall be fully reasoned and justified to allow for judicial review. The decisions shall be available to the public while preserving the confidentiality of commercially sensitive information.

8. **Contracting Parties** shall ensure that suitable mechanisms exist at national level under which a party affected by a decision of a regulatory authority has a right of appeal to a body independent of the parties involved and of any government.

Article 61

Regional cooperation between regulatory authorities on cross-border issues

1. Regulatory authorities shall closely consult and cooperate with each other, in particular within **Energy Community Regulatory Board**, and shall provide each other and **the Energy Community Regulatory Board** with any information necessary for the fulfilment of their tasks under this Directive. With respect to the information exchanged, the receiving authority shall ensure the same level of confidentiality as that required of the originating authority.

2. Regulatory authorities shall cooperate at least at a regional level to:

(a) foster the creation of operational arrangements in order to enable an optimal management of the network, promote joint electricity exchanges and the allocation of cross-border capacity, and to enable an adequate level of interconnection capacity, including through new interconnection, within the region and between regions to allow for development of effective competition and improvement of security of supply, without discriminating between suppliers in different **Contracting Parties**;

(b) coordinate the joint oversight of entities performing functions at regional level;

(c) coordinate, in cooperation with other involved authorities, the joint oversight of national, regional and European resource adequacy assessments;

(d) coordinate the development of all network codes and guidelines for the relevant transmission system operators and other market actors; and

(e) coordinate the development of the rules governing the management of congestion.

3. Regulatory authorities shall have the right to enter into cooperative arrangements with each other to foster regulatory cooperation.

4. The actions referred to in paragraph 2 shall be carried out, as appropriate, in close consultation with other relevant national authorities and without prejudice to their specific competence.

5. **< ... >**

Article 62

Duties and powers of regulatory authorities with respect to regional coordination centres

1. The regional regulatory authorities of the system operation region in which a regional coordination centre is established shall, in close coordination with each other:

(a) approve the proposal for the establishment of regional coordination centres in accordance with Annex IV of Regulation (EU) 2019/943 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**,

(b) approve the costs related to the activities of the regional coordination centres, which are to be borne by the transmission system operators and to be taken into account in the calculation of tariffs, provided that they are reasonable and appropriate;

(c) approve the cooperative decision-making process;

(d) ensure that the regional coordination centres are equipped with all the necessary human, technical, physical and financial resources for fulfilling their obligations under this Directive and carrying out their tasks independently and impartially;

(e) propose jointly with other regulatory authorities of a system operation region possible additional tasks and additional powers to be assigned to the regional coordination centres by the **Contracting Parties or** Member States of the system operation region;

(f) ensure compliance with the obligations under this Directive and other relevant **Energy Community** law, in particular as regards cross-border issues, and jointly identify non-compliance of the regional coordination centres with their respective obligations; where the regulatory authorities have not been able to reach an agreement within a period of four months after the start of consultations for the purpose of jointly identifying non-compliance, the matter shall be referred to **Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**;

(g) monitor the performance of system coordination and report annually to **Energy Community Regulatory Board, and to the extent that Member States are involved, to the** Agency **for the Cooperation of Energy Regulators** in this respect in accordance with Article 46 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC.**

2. **Contracting Parties** shall ensure that regulatory authorities are granted the powers enabling them to carry out the duties referred to in paragraph 1 in an efficient and expeditious manner. For this purpose, the regulatory authorities shall have at least the following powers:

(a) to request information from the regional coordination centres;

(b) to carry out inspections, including unannounced inspections, at the premises of the regional coordi-

nation centres;

(c) to issue joint binding decisions on the regional coordination centres.

3. The regulatory authority located in the **Contracting Party** in which a regional coordination centre has its seat shall have the power to impose effective, proportionate and dissuasive penalties on the regional coordination centre where it does not comply with its obligations under this Directive, Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** or any relevant legally binding decisions of the regulatory authority or of **Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, or shall have the power to propose that a competent court impose such penalties.

Article 63

Compliance with the network codes and guidelines

1. Any regulatory authority and the **Energy Community Secretariat** may request the opinion of **Energy Community Regulatory Board** on the compliance of a decision taken by a regulatory authority with the network codes and guidelines referred to in this Directive or in **Chapter VII of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

2. **The Energy Community Regulatory Board** shall provide its opinion to the regulatory authority which has requested it or to the **Energy Community Secretariat**, respectively, and to the regulatory authority which has taken the decision in question within three months of the date of receipt of the request.

3. Where the regulatory authority which has taken the decision does not comply with **Energy Community Regulatory Board**'s opinion within four months of the date of receipt of that opinion, **the Energy Community Regulatory Board** shall inform the **Energy Community Secretariat** accordingly.

4. Any regulatory authority may inform the **Energy Community Secretariat** where it considers that a decision relevant for cross-border trade taken by another regulatory authority does not comply with the network codes and guidelines referred to in this Directive or in **Chapter VII of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** within two months of the date of that decision.

5. Where the **Energy Community Secretariat**, within two months of having been informed by **the Energy Community Regulatory Board** in accordance with paragraph 3, or by a regulatory authority in accordance with paragraph 4, or, on its own initiative, within three months of the date of the decision, finds that the decision of a regulatory authority raises serious doubts as to its compatibility with the network codes and guidelines referred to in this Directive or in **Chapter VII of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**, the **Energy Community Secretariat** may **< … >** examine the case further. In such a case, it shall invite the regulatory authority and the parties to the proceedings before the regulatory authority to submit observations.

6. Where the **Energy Community Secretariat < … > examines** the case further, it shall, within four months of the date of such decision, issue a final decision:

(a) not to raise objections against the decision of the regulatory authority; or

(b) to **invite** the regulatory authority concerned to withdraw its decision on the basis that network codes and guidelines have not been complied with.

7. **In the absence of an opinion by paragraph 6, the Energy Community Secretariat shall be deemed not to raise objections to the decision of the regulatory authority**.

8. The regulatory authority shall **take into upmost account** the **Energy Community Secretariat's** decision requiring it to withdraw its decision within two months and shall inform the **Energy Community Secretariat** accordingly.

9. **< ... >**

Article 64

Record keeping

1. **Contracting Parties** shall require suppliers to keep at the disposal of the national authorities, including the regulatory authority, the national competition authorities and the **Energy Community Secretariat**, for the fulfilment of their tasks, for at least five years, the relevant data relating to all transactions in electricity supply contracts and electricity derivatives with wholesale customers and transmission system operators.

2. The data shall include details on the characteristics of the relevant transactions such as duration, delivery and settlement rules, the quantity, the dates and times of execution and the transaction prices and means of identifying the wholesale customer concerned, as well as specified details of all unsettled electricity supply contracts and electricity derivatives.

3. The regulatory authority may decide to make available to market participants elements of that information provided that commercially sensitive information on individual market players or individual transactions is not released. This paragraph shall not apply to information about financial instruments which fall within the scope of Directive 2014/65/EU.

4. This Article shall not create additional obligations towards the authorities referred to in paragraph 1 for entities falling within the scope of Directive 2014/65/EU.

5. In the event that the authorities referred to in paragraph 1 need access to data kept by entities falling within the scope of Directive 2014/65/EU, the authorities responsible under that Directive shall provide them with the required data.

CHAPTER VIII
FINAL PROVISIONS

Article 65

Level playing field

1. Measures that the **Contracting Parties** may take pursuant to this Directive in order to ensure a level playing field shall be compatible with the **Energy Community Treaty**, in particular **Article 41** thereof, and with **Energy Community** law.

2. The measures referred to in paragraph 1 shall be proportionate, non-discriminatory and transparent. Those measures may be put into effect only following the notification to and approval by the **Energy Community Secretariat**.

3. The **Energy Community Secretariat** shall act on the notification referred to in paragraph 2 within two months of the receipt of the notification. That period shall begin on the day after receipt of the complete information. In the event that the **Energy Community Secretariat** has not acted within that two-month period, it shall be deemed not to have raised objections to the notified measures.

Article 66

Derogations

1. **< … >**

2. **< … >**

3. **< … >** For the purposes of point (b) of Article 43(1), the notion 'undertaking performing any of the functions of generation or supply' shall not include final customers who perform any of the functions of generation and/or supply of electricity, either directly or via undertakings over which they exercise control, either individually or jointly, provided that the final customers including their shares of the electricity produced in controlled undertakings are, on an annual average, net consumers of electricity and provided that the economic value of the electricity they sell to third parties is insignificant in proportion to their other business operations.

4. **< … >**

5. **< … >**

Article 67

Exercise of the delegation

< … >

Article 68

Committee procedure

< … >

Article 69

Energy Community Secretariat monitoring, reviewing and reporting

1. The **Energy Community Secretariat** shall monitor and review the implementation of this Directive and shall submit a progress report to the **Ministerial Council** as an annex to the State of the Energy Union Report referred to in Article 35 of Regulation (EU) 2018/1999 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC.**

2. By 31 December 2025, the **Energy Community Secretariat** shall review the implementation of this Directive and shall submit a report to the **Ministerial Council**. **< … >**

The **Energy Community Secretariat**'s review shall, in particular, assess whether customers, especially those who are vulnerable or in energy poverty, are adequately protected under this Directive.

Article 70

Amendments to Directive 2012/27/EU

< … >

Article 71

Transposition

1. **Contracting Parties** shall bring into force the laws, regulations and administrative provisions necessary to comply with Articles 2 to 5, Article 6(2) and (3), Article 7(1), point (j) and (l) of Article 8(2), Article 9(2), Article 10(2) to (12), Articles 11 to 24, Articles 26, 28 and 29, Articles 31 to 34 and 36, Article 38(2), Articles 40 and 42, point (d) of Article 46(2), Articles 51 and 54, Articles 57 to 59, Articles 61 to 63, points (1) to (3), (5)(b) and (6) of Article 70 and Annexes I and II by 31 December **2023**. They shall immediately communicate the text of those provisions to the **Energy Community Secretariat**.

However, **Contracting Parties** shall bring into force the laws, regulations and administrative provisions necessary to comply with:

(a) point (5)(a) of Article 70 by **30 June 2023**;

(b) point (4) of Article 70 by **31 December 2023**. When **Contracting Parties** adopt those measures, they shall contain a reference to this Directive or be accompanied by such a reference on the occasion of their official publication. They shall also include a statement that references in existing laws, regulations and administrative provisions to the Directive repealed by this Directive shall be construed as references to this Directive. **Contracting Parties** shall determine how such reference is to be made and how that statement is to be formulated.

2. **Contracting Parties** shall communicate to the **Energy Community Secretariat** the text of the main provisions of national law which they adopt in the field covered by this Directive.

Article 72

Repeal

< … >

Article 73

Entry into force

This Directive enters into force on the day of adoption of Ministerial Council Decision 2021/13/MC-ENC. <…>

Article 74

Addressees

This Directive is addressed to **the Parties and institutions of the Energy Community.**

ANNEX I
MINIMUM REQUIREMENTS FOR BILLING AND BILLING INFORMATION

1. Minimum information to be contained on the bill and in the billing information

1.1. The following key information shall be prominently displayed to final customers in their bills, distinctly separate from other parts of the bill:

(a) the price to be paid and a breakdown of the price where possible, together with a clear statement that all energy sources may also benefit from incentives that were not financed through the levies indicated in the breakdown of the price;

(b) the date on which payment is due.

1.2. The following key information shall be prominently displayed to final customers in their bills and billing information, distinctly separate from other parts of the bill and billing information:

(a) electricity consumption for the billing period;

(b) the name and contact details of the supplier, including a consumer support hotline and email address;

(c) the tariff name;

(d) the end date of the contract, if applicable;

(e) the information on the availability and benefits of switching;

(f) the final customer's switching code or unique identification code for the final customer's supply point;

(g) information on final customers' rights as regards out-of-court dispute settlement, including the contact details of the entity responsible pursuant to Article 26;

(h) the single point of contact referred to in Article 25;

(i) a link or reference to where comparison tools referred to in Article 14 can be found.

1.3. Where bills are based on actual consumption or remote reading by the operator, the following information shall be made available to final customers in, with or signposted to within their bills and periodic settlement bills:

(a) comparisons of the final customer's current electricity consumption with the final customer's consumption for the same period in the previous year in graphic form;

(b) contact information for consumer organisations, energy agencies or similar bodies, including website addresses, from which information may be obtained on available energy efficiency improvement measures for energy-using equipment;

(c) comparisons with an average normalised or benchmarked final customer in the same user category.

2. Frequency of billing and the provision of billing information:

(a) billing on the basis of actual consumption shall take place at least once a year;

(b) where the final customer does not have a meter that allows remote reading by the operator, or where the final customer has actively chosen to disable remote reading in accordance with national law, accurate billing information based on actual consumption shall be made available to the final customer at least every six months, or once every three months, if requested or where the final customer has opted to

receive electronic billing;

(c) where the final customer does not have a meter that allows remote reading by the operator, or where the final customer has actively chosen to disable remote reading in accordance with national law, the obligations in points (a) and (b) may be fulfilled by means of a system of regular self-reading by the final customer, whereby the final customer communicates readings from the meter to the operator; billing or billing information may be based on estimated consumption or a flat rate only where the final customer has not provided a meter reading for a given billing interval;

(d) where the final customer has a meter that allows remote reading by the operator, accurate billing information based on actual consumption shall be provided at least every month; such information may also be made available via the internet, and shall be updated as frequently as allowed by the measurement devices and systems used.

3. Breakdown of the final customer's price

The customer's price is the sum of the following three components: the energy and supply component, the network component (transmission and distribution) and the component comprising taxes, levies, fees and charges.

Where a breakdown of the final customer's price is presented in bills, the common definitions of the three components in that breakdown established under Regulation (EU) 2016/1952 of the European Parliament and of the Council shall be used throughout the **Energy Community**.

4. Access to complementary information on historical consumption

Contracting Parties shall require that, to the extent that complementary information on historical consumption is available, such information is made available, at the request of the final customer, to the supplier or service provider designated by the final customer.

Where the final customer has a meter that allows remote reading by the operator installed, the final customer shall have easy access to complementary information on historical consumption allowing detailed self-checks.

Complementary information on historical consumption shall include:

(a) cumulative data for at least the three previous years or the period since the start of the electricity supply contract, if that period is shorter. The data shall correspond to the intervals for which frequent billing information has been produced; and

(b) detailed data according to the time of use for any day, week, month and year, which is made available to the final customer without undue delay via the internet or the meter interface, covering the period of at least the previous 24 months or the period since the start of the electricity supply contract, if that period is shorter.

5. Disclosure of energy sources

Suppliers shall specify in bills the contribution of each energy source to the electricity purchased by the final customer in accordance with the electricity supply contract (product level disclosure).

The following information shall be made available to final customers in, with, or signposted to within their

bills and billing information:

(a) the contribution of each energy source to the overall energy mix of the supplier (at national level, namely in the **Contracting Party** in which the electricity supply contract has been concluded, as well as at the level of the supplier if the supplier is active in several **Contracting Parties**) over the preceding year in a comprehensible and clearly comparable manner;

(b) information on the environmental impact, in at least terms of CO_2 emissions and the radioactive waste resulting from the electricity produced by the overall energy mix of the supplier over the preceding year. As regards point (a) of the second subparagraph, with respect to electricity obtained via an electricity exchange or imported from an undertaking situated outside the **Energy Community**, aggregate figures provided by the exchange or the undertaking in question over the preceding year may be used.

For the disclosure of electricity from high efficiency cogeneration, guarantees of origin issued under Article 14(10) of Directive 2012/27/EU may be used. The disclosure of electricity from renewable sources shall be done by using guarantees of origin, except in the cases referred to in points (a) and (b) of Article 19(8) of Directive (EU) 2018/2001 **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC**.

The regulatory authority or another competent national authority shall take the necessary steps to ensure that the information provided by suppliers to final customers pursuant to this point is reliable and is provided at a national level in a clearly comparable manner.

ANNEX II
SMART METERING SYSTEMS

1. **Contracting Parties** shall ensure the deployment of smart metering systems in their territories that may be subject to an economic assessment of all of the long-term costs and benefits to the market and the individual consumer or which form of smart metering is economically reasonable and cost-effective and which time frame is feasible for their distribution.

2. Such assessment shall take into consideration the methodology for the cost-benefit analysis and the minimum functionalities for smart metering systems provided for in Commission Recommendation 2012/148/EU as well as the best available techniques for ensuring the highest level of cybersecurity and data protection.

3. Subject to that assessment, **Contracting Parties** or, where a **Contracting Party** has so provided, the designated competent authority, shall prepare a timetable with a target of up to ten years for the deployment of smart metering systems. Where the deployment of smart metering systems is assessed positively, at least 80 % of final customers shall be equipped with smart meters either within seven years of the date of the positive assessment or by 2024 for those **Contracting Parties** that have initiated the systematic deployment of smart metering systems before **the date of entry into force of this Directive in the Energy Community**.

REGULATION (EU) 2019/943 of 5 June 2019 on the internal market for electricity

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in ***bold and blue****.*

CHAPTER I
SUBJECT MATTER, SCOPE AND DEFINITIONS

Article 1
Subject matter and scope

This Regulation aims to:

(a) set the basis for an efficient achievement of the objectives of the **Energy Community** and in particular the climate and energy framework for 2030 by enabling market signals to be delivered for increased efficiency, higher share of renewable energy sources, security of supply, flexibility, sustainability, decarbonisation and innovation;

(b) set fundamental principles for well-functioning, integrated electricity markets, which allow all resource providers and electricity customers non-discriminatory market access, empower consumers, ensure competitiveness on the global market as well as demand response, energy storage and energy efficiency, and facilitate aggregation of distributed demand and supply, and enable market and sectoral integration and market-based remuneration of electricity generated from renewable sources;

(c) set fair rules for cross-border exchanges in electricity, thus enhancing competition within the internal market for electricity, taking into account the particular characteristics of national and regional markets, including the establishment of a compensation mechanism for cross-border flows of electricity, the setting of harmonised principles on cross-border transmission charges and the allocation of available capacities of interconnections between national transmission systems;

(d) facilitate the emergence of a well-functioning and transparent wholesale market, contributing to a high level of security of electricity supply, and provide for mechanisms to harmonise the rules for cross-border exchanges in electricity.

Article 2
Definitions

The following definitions apply:

(1) 'interconnector' means a transmission line which crosses or spans a border between **Contracting Parties of the Energy Community or between Contracting Parties and Member States of the European Union** and which connects the national transmission systems of the **Contracting Parties of the Energy Community or of the Contracting Parties of the Energy Community and the Member States of the European Union**;

(2) 'regulatory authority' means a regulatory authority designated by each **Contracting Party** pursuant to Article 57(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC;**

(3) 'cross-border flow' means a physical flow of electricity on a transmission network of a **Party to the Energy Community** that results from the impact of the activity of producers, customers, or both, outside that **Party to the Energy Community** on its transmission network;

(4) 'congestion' means a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows;

(5) 'new interconnector' means an interconnector not completed by **1 July 2007**;

(6) 'structural congestion' means congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions;

(7) 'market operator' means an entity that provides a service whereby the offers to sell electricity are matched with bids to buy electricity;

(8) 'nominated electricity market operator' or 'NEMO' means a market operator designated by the competent authority to carry out tasks related to single day-ahead or single intraday coupling;

(9) 'value of lost load' means an estimation in euro/MWh, of the maximum electricity price that customers are willing to pay to avoid an outage;

(10) 'balancing' means all actions and processes, in all timelines, through which transmission system operators ensure, in an ongoing manner, maintenance of the system frequency within a predefined stability range and compliance with the amount of reserves needed with respect to the required quality;

(11) 'balancing energy' means energy used by transmission system operators to carry out balancing;

(12) 'balancing service provider' means a market participant providing either or both balancing energy and balancing capacity to transmission system operators;

(13) 'balancing capacity' means a volume of capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the transmission system operator for the duration of the contract;

(14) 'balance responsible party' means a market participant or its chosen representative responsible for its imbalances in the electricity market;

(15) 'imbalance settlement period' means the time unit for which the imbalance of the balance responsible parties is calculated;

(16) 'imbalance price' means the price, be it positive, zero or negative, in each imbalance settlement period for an imbalance in each direction;

(17) 'imbalance price area' means the area in which an imbalance price is calculated;

(18) 'prequalification process' means the process to verify the compliance of a provider of balancing capacity with the requirements set by the transmission system operators;

(19) 'reserve capacity' means the amount of frequency containment reserves, frequency restoration reserves or replacement reserves that needs to be available to the transmission system operator;

(20) 'priority dispatch' means, with regard to the self-dispatch model, the dispatch of power plants on the basis of criteria which are different from the economic order of bids and, with regard to the central dispatch model, the dispatch of power plants on the basis of criteria which are different from the economic order of bids and from network constraints, giving priority to the dispatch of particular generation technologies;

(21) 'capacity calculation region' means the geographic area in which the coordinated capacity calculation is applied;

(22) 'capacity mechanism' means a temporary measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management;

(23) 'high-efficiency cogeneration' means cogeneration which meets the criteria laid down in Annex II to Directive 2012/27/EU of the European Parliament and of the Council, **as adapted by Ministerial Council Decision 2015/08/MC-EnC;**

(24) 'demonstration project' means a project which demonstrates a technology as a first of its kind in the **Energy Community** and represents a significant innovation that goes well beyond the state of the art;

(25) 'market participant' means a natural or legal person who buys, sells or generates electricity, who is engaged in aggregation or who is an operator of demand response or energy storage services, including through the placing of orders to trade, in one or more electricity markets, including in balancing energy markets;

(26) 'redispatching' means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security;

(27) 'countertrading' means a cross-zonal exchange initiated by system operators between two bidding zones to relieve physical congestion;

(28) 'power-generating facility' means a facility that converts primary energy into electrical energy and which consists of one or more power-generating modules connected to a network;

(29) 'central dispatching model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power-generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a transmission system operator within an integrated scheduling process;

(30) 'self-dispatch model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power-generating facilities and demand facilities are determined by the scheduling agents of those facilities;

(31) 'standard balancing product' means a harmonised balancing product defined by all transmission system operators for the exchange of balancing services;

(32) 'specific balancing product' means a balancing product different from a standard balancing product;

(33) 'delegated operator' means an entity to whom specific tasks or obligations entrusted to a transmission system operator or nominated electricity market operator under this Regulation or other **Energy Community** legal acts have been delegated by that transmission system operator or NEMO or have been assigned by a **Party to the Energy Community** or regulatory authority;

(34) 'customer' means a customer as defined in point (1) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC;**

(35) 'final customer' means final customer as defined in point (3) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**;

(36) 'wholesale customer' means a wholesale customer as defined in point (2) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(37) 'household customer' means household customer as defined in point (4) of Article 2 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC;

(38) 'small enterprise' means small enterprise as defined in point (7) of Article 2 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC

(39) 'active customer' means active customer as defined in point (8) of Article 2 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC;

(40) 'electricity markets' means electricity markets as defined in point (9) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**

(41) 'supply' means supply as defined in point (12) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(42) 'electricity supply contract' means electricity supply contract as defined in point (13) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(43) 'aggregation' means aggregation as defined in point (18) of Article 2 of Directive (EU) 2019/944. **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**

(44) 'demand response' means demand response as defined in point (20) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**

(45) 'smart metering system' means smart metering system as defined in point (23) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(46) 'interoperability' means interoperability as defined in point (24) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(47) 'distribution' means distribution as defined in point (28) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(48) 'distribution system operator' means distribution system operator as defined in point (29) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(49) 'energy efficiency' means energy efficiency as defined in point (30) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC;**

(50) ''energy from renewable sources' or 'renewable energy' means energy from renewable sources as defined in point (31) of Article 2 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC

(51) 'distributed generation' means distributed generation as defined in point (32) of Article 2 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC

(52) 'transmission' means transmission as defined in point (34) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**;

(53) 'transmission system operator' means transmission system operator as defined in point (35) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(54) 'system user' means system user as defined in point (36) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**

(55) 'generation' means generation as defined in point (37) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**;

(56) 'producer' means producer as defined in point (38) of Article 2 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(57) 'interconnected system' means interconnected system as defined in point (40) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(58) 'small isolated system' means small isolated system as defined in point (42) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(59) 'small connected system' means small connected system as defined in point (43) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(60) 'ancillary service' means ancillary service as defined in point (48) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**

(61) 'non-frequency ancillary service' means non-frequency ancillary service as defined in point (49) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(62) 'energy storage' means energy storage as defined in point (59) of Article 2 of Directive (EU) 2019/944;

(63) 'regional coordination centre' means regional coordination centre established pursuant to Article 35 to this Regulation;

(64) 'wholesale energy market' means wholesale energy market as defined in point (6) of Article 2 of Regulation (EU) No 1227/2011 of the European Parliament and of the Council **as adapted and adopted by Ministerial Council Decision 2018/10/MC-EnC**;

(65) 'bidding zone' means the largest geographical area within which market participants are able to exchange energy without capacity allocation;

(66) 'capacity allocation' means the attribution of cross-zonal capacity;

(67) 'control area' means a coherent part of the interconnected system, operated by a single system operator and shall include connected physical loads and/or generation units if any;

(68) 'coordinated net transmission capacity' means a capacity calculation method based on the principle of assessing and defining *ex ante* a maximum energy exchange between adjacent bidding zones;

(69) 'critical network element' means a network element either within a bidding zone or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be

exchanged;

(70) 'cross-zonal capacity' means the capability of the interconnected system to accommodate energy transfer between bidding zones;

(71) 'generation unit' means a single electricity generator belonging to a production unit;

(72) 'Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

CHAPTER II
GENERAL RULES FOR THE ELECTRICITY MARKET

Article 3

Principles regarding the operation of electricity markets

Contracting Parties, regulatory authorities, transmission system operators, distribution system operators, market operators and delegated operators shall ensure that electricity markets are operated in accordance with the following principles:

(a) prices shall be formed on the basis of demand and supply;

(b) market rules shall encourage free price formation and shall avoid actions which prevent price formation on the basis of demand and supply;

(c) market rules shall facilitate the development of more flexible generation, sustainable low carbon generation, and more flexible demand;

(d) customers shall be enabled to benefit from market opportunities and increased competition on retail markets and shall be empowered to act as market participants in the energy market and the energy transition;

(e) market participation of final customers and small enterprises shall be enabled by aggregation of generation from multiple power-generating facilities or load from multiple demand response facilities to provide joint offers on the electricity market and be jointly operated in the electricity system, in accordance with **Energy Community** competition law;

(f) market rules shall enable the decarbonisation of the electricity system and thus the economy, including by enabling the integration of electricity from renewable energy sources and by providing incentives for energy efficiency;

(g) market rules shall deliver appropriate investment incentives for generation, in particular for long-term investments in a decarbonised and sustainable electricity system, energy storage, energy efficiency and demand response to meet market needs, and shall facilitate fair competition thus ensuring security of supply;

(h) barriers to cross-border electricity flows between bidding zones or **Parties to the Energy Community** and cross-border transactions on electricity markets and related services markets shall be progressively removed;

(i) market rules shall provide for regional cooperation where effective;

(j) safe and sustainable generation, energy storage and demand response shall participate on equal footing in the market, under the requirements provided for in the Union law;

(k) all producers shall be directly or indirectly responsible for selling the electricity they generate;

(l) market rules shall allow for the development of demonstration projects into sustainable, secure and low-carbon energy sources, technologies or systems which are to be realised and used to the benefit of society;

(m) market rules shall enable the efficient dispatch of generation assets, energy storage and demand response;

(n) market rules shall allow for entry and exit of electricity generation, energy storage and electricity supply undertakings based on those undertakings' assessment of the economic and financial viability of their operations;

(o) in order to allow market participants to be protected against price volatility risks on a market basis, and mitigate uncertainty on future returns on investment, long-term hedging products shall be tradable on exchanges in a transparent manner and long-term electricity supply contracts shall be negotiable over the counter, subject to compliance with **Energy Community** competition law;

(p) market rules shall facilitate trade of products across the **Energy Community** and regulatory changes shall take into account effects on both short-term and long-term forward and futures markets and products;

(q) market participants shall have a right to obtain access to the transmission networks and distribution networks on objective, transparent and non-discriminatory terms.

Article 4

Just transition

The **Energy Community Secretariat** shall support **Contracting Parties** that put in place a national strategy for the progressive reduction of existing coal and other solid fossil fuel generation and mining capacity through all available means to enable a just transition in regions affected by structural change. The **Energy Community Secretariat** shall assist **Contracting Parties** in addressing the social and economic impacts of the clean energy transition.

The **Energy Community Secretariat** shall work in close partnership with the stakeholders in coal and carbon-intensive regions, shall facilitate the access to and use of available funds and programmes, and shall encourage the exchange of good practices, including discussions on industrial roadmaps and reskilling needs.

Article 5

Balance responsibility

1. All market participants shall be responsible for the imbalances they cause in the system ('balance responsibility'). To that end, market participants shall either be balance responsible parties or shall contractually delegate their responsibility to a balance responsible party of their choice. Each balance responsible party shall be financially responsible for its imbalances and shall strive to be balanced or shall help the electricity system to be balanced.

2. **Contracting Parties** may provide derogations from balance responsibility only for:

(a) demonstration projects for innovative technologies, subject to approval by the regulatory authority, provided that those derogations are limited to the time and extent necessary for achieving the demonstration purposes;

(b) power-generating facilities using renewable energy sources with an installed electricity capacity of less than 400 kW;

(c) installations benefitting from support approved by **the competent authorities** under **Energy Community** State aid rules pursuant to **Articles 18 and 19 of Energy Community Treaty**, and commissioned **before the date of entry into force of this Regulation**.

Contracting Parties may, without prejudice to **Annex III of Energy Community Treaty**, provide incentives to market participants which are fully or partly exempted from balancing responsibility to accept full balancing responsibility.

3. When a **Contracting Party** provides a derogation in accordance with paragraph 2, it shall ensure that the financial responsibility for imbalances is fulfilled by another market participant.

4. For power-generating facilities commissioned from 1 January 2026, point (b) of paragraph 2 shall apply only to generating installations using renewable energy sources with an installed electricity capacity of less than 200 kW.

Article 6

Balancing market

1. Balancing markets, including prequalification processes, shall be organised in such a way as to:

(a) ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response;

(b) ensure that services are defined in a transparent and technologically neutral manner and are procured in a transparent, market-based manner;

(c) ensure non-discriminatory access to all market participants, individually or through aggregation, including for electricity generated from variable renewable energy sources, demand response and energy storage;

(d) respect the need to accommodate the increasing share of variable generation, increased demand responsiveness and the advent of new technologies.

2. The price of balancing energy shall not be pre-determined in contracts for balancing capacity. Procurement processes shall be transparent in accordance with Article 40(4) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** while protecting the confidentiality of commercially sensitive information.

3. Balancing markets shall ensure operational security whilst allowing for maximum use and efficient allocation of cross-zonal capacity across timeframes in accordance with Article 17.

4. The settlement of balancing energy for standard balancing products and specific balancing products shall be based on marginal pricing (pay-as-cleared) unless all regulatory authorities approve an alternative

pricing method on the basis of a joint proposal by all transmission system operators following an analysis demonstrating that that alternative pricing method is more efficient.

Market participants shall be allowed to bid as close to real time as possible, and balancing energy gate closure times shall not be before the intraday cross-zonal gate closure time.

Transmission system operators applying a central dispatching model may establish additional rules in accordance with **Regulation (EU) 2017/2195, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

5. The imbalances shall be settled at a price that reflects the real-time value of energy.

6. Each imbalance price area shall be equal to a bidding zone, except in the case of a central dispatching model where an imbalance price area may constitute a part of a bidding zone.

7. The dimensioning of reserve capacity shall be performed by the transmission system operators and shall be facilitated at regional level.

8. The procurement of balancing capacity shall be performed by the transmission system operator and may be facilitated at a regional level. Reservation of cross-border capacity to that end may be limited. The procurement of balancing capacity shall be market-based and organised in such a way as to be non-discriminatory between market participants in the prequalification process in accordance with Article 40(4) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** whether market participants participate individually or through aggregation.

Procurement of balancing capacity shall be based on a primary market unless and to the extent that the regulatory authority has provided for a derogation to allow the use of other forms of market- based procurement on the grounds of a lack of competition in the market for balancing services. Derogations from the obligation to base the procurement of balancing capacity on use of primary markets shall be reviewed every three years.

9. The procurement of upward balancing capacity and downward balancing capacity shall be carried out separately, unless the regulatory authority approves a derogation from this principle on the basis that this would result in higher economic efficiency as demonstrated by an evaluation performed by the transmission system operator. Contracts for balancing capacity shall not be concluded more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day, unless and to the extent that the regulatory authority has approved the earlier contracting or longer contracting periods to ensure the security of supply or to improve economic efficiency.

Where a derogation is granted, for at least 40 % of the standard balancing products and a minimum of 30 % of all products used for balancing capacity, contracts for the balancing capacity shall be concluded for no more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day. The contracting of the remaining part of the balancing capacity shall be performed for a maximum of one month in advance of the provision of balancing capacity and shall have a maximum contractual period of one month.

10. At the request of the transmission system operator, the regulatory authority may decide to extend the contractual period of the remaining part of balancing capacity referred to in paragraph 9 to a maximum period of twelve months provided that such a decision is limited in time, and the positive effects in terms of lowering of costs for final customers exceed the negative impacts on the market. The request shall include:

(a) the specific period during which the exemption would apply;

(b) the specific volume of balancing capacity to which the exemption would apply;

(c) an analysis of the impact of the exemption on the participation of balancing resources; and

(d) a justification for the exemption demonstrating that such an exemption would lead to lower costs to final customers.

11. Notwithstanding paragraph 10, from 1 January 2026 contract periods shall not be longer than six months.

12. By 1 January 2028, regulatory authorities shall report to the **Energy Community Secretariat and the Energy Community Regulatory Board** on the share of the total capacity covered by contracts with a duration or a procurement period of longer than one day.

13. Transmission system operators or their delegated operators shall publish, as close to real time as possible but with a delay after delivery of no more than 30 minutes, the current system balance of their scheduling areas, the estimated imbalance prices and the estimated balancing energy prices.

14. Transmission system operators may, where standard balancing products are not sufficient to ensure operational security or where some balancing resources cannot participate in the balancing market through standard balancing products, propose, and the regulatory authorities may approve, derogations from paragraphs 2 and 4 for specific balancing products which are activated locally without exchanging them with other transmission system operators.

Proposals for derogations shall include a description of measures proposed to minimise the use of specific products, subject to economic efficiency, a demonstration that the specific products do not create significant inefficiencies and distortions in the balancing market either inside or outside the scheduling area, as well as, where applicable, the rules and information for the process for converting the balancing energy bids from specific balancing products into balancing energy bids from standard balancing products.

Article 7

Day-ahead and intraday markets

1. Transmission system operators and NEMOs shall jointly organise the management of the integrated day-ahead and intraday markets in accordance with Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Transmission system operators and NEMOs shall cooperate at **Energy Community** level or, where more appropriate, at a regional level in order to maximise the efficiency and effectiveness of **Energy Community** electricity day-ahead and intraday trading. The obligation to cooperate shall be without prejudice to the application of competition law. In their functions relating to electricity trading, transmission system operators and NEMOs shall be subject to regulatory oversight by the regulatory authorities pursuant to Article 59 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC, and the Energy Community Regulatory Board <…>.**

2. Day-ahead and intraday markets shall:

(a) be organised in such a way as to be non-discriminatory;

(b) maximise the ability of all market participants to manage imbalances;

(c) maximise the opportunities for all market participants to participate in cross-zonal trade in as close as

possible to real time across all bidding zones;

(d) provide prices that reflect market fundamentals, including the real time value of energy, on which market participants are able to rely when agreeing on longer-term hedging products;

(e) ensure operational security while allowing for maximum use of transmission capacity;

(f) be transparent while at the same time protecting the confidentiality of commercially sensitive information and ensuring trading occurs in an anonymous manner;

(g) make no distinction between trades made within a bidding zone and across bidding zones; and

(h) be organised in such a way as to ensure that all markets participants are able to access the market individually or through aggregation.

Article 8

Trade on day-ahead and intraday markets

1. **Once designated in accordance with Articles 4 to 6 of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** NEMOs shall allow market participants to trade energy as close to real time as possible and at least up to the intraday cross-zonal gate closure time.

2. NEMOs shall provide market participants with the opportunity to trade in energy in time intervals which are at least as short as the imbalance settlement period for both day-ahead and intraday markets.

3. NEMOs shall provide products for trading in day-ahead and intraday markets which are sufficiently small in size, with minimum bid sizes of 500 kW or less, to allow for the effective participation of demand-side response, energy storage and small-scale renewables including direct participation by customers.

4. By 1 January **2023,** the imbalance settlement period shall be 15 minutes in all scheduling areas, unless regulatory authorities have granted a derogation or an exemption. Derogations may be granted only until 31 December **2024**.

From 1 January **2027**, the imbalance settlement period shall not exceed 30 minutes where an exemption has been granted by all the regulatory authorities within a synchronous area.

Article 9

Forward markets

1. In accordance with Regulation (EU) 2016/1719**, as adapted and adopted Ministerial Council Decision 2022/03/MC-EnC,** transmission system operators shall issue long-term transmission rights or have equivalent measures in place to allow for market participants, including owners of power-generating facilities using renewable energy sources, to hedge price risks across bidding zone borders, unless an assessment of the forward market on the bidding zone borders performed by the competent regulatory authorities shows that there are sufficient hedging opportunities in the concerned bidding zones.

2. Long-term transmission rights shall be allocated in a transparent, market based and non- discriminatory manner through a single allocation platform **in accordance with Article 2(4) and chapter IV of**

Regulation (**EU) 2016/1719, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

3. Subject to compliance with **Energy Community** competition law, market operators shall be free to develop forward hedging products, including long-term forward hedging products, to provide market participants, including owners of power-generating facilities using renewable energy sources, with appropriate possibilities for hedging financial risks against price fluctuations. **Contracting Parties** shall not require that such hedging activity be limited to trades within a **Contracting Party** or bidding zone.

Article 10

Technical bidding limits

1. There shall be neither a maximum nor a minimum limit to the wholesale electricity price. This provision shall apply, inter alia, to bidding and clearing in all timeframes and shall include balancing energy and imbalance prices, without prejudice to the technical price limits which may be applied in the balancing timeframe and in the day-ahead and intraday timeframes in accordance with paragraph 2.

2. NEMOs may apply harmonised limits on maximum and minimum clearing prices for day- ahead and intraday timeframes. Those limits shall be sufficiently high so as not to unnecessarily restrict trade, shall be harmonised for the internal market and shall take into account the maximum value of lost load. NEMOs shall implement a transparent mechanism to adjust automatically the technical bidding limits in due time in the event that the set limits are expected to be reached. The adjusted higher limits shall remain applicable until further increases under that mechanism are required.

3. Transmission system operators shall not take any measures for the purpose of changing wholesale prices.

4. Regulatory authorities or, where a **Contracting Party** has designated another competent authority for that purpose, such designated competent authorities, shall identify policies and measures applied within their territory that could contribute to indirectly restricting wholesale price formation, including limiting bids relating to the activation of balancing energy, capacity mechanisms, measures by the transmission system operators, measures intended to challenge market outcomes, or to prevent the abuse of dominant positions or inefficiently defined bidding zones.

5. Where a regulatory authority or designated competent authority has identified a policy or measure which could serve to restrict wholesale price formation it shall take all appropriate actions to eliminate or, if not possible, to mitigate the impact of that policy or measure on bidding behaviour. **Contracting Parties** shall provide a report to the **Energy Community Secretariat** by 5 January **2023** detailing the measures and actions they have taken or intend to take.

Article 11

Value of lost load

1. By 5 July **2023** where required for the purpose of setting a reliability standard in accordance with Article 25 regulatory authorities or, where a **Contracting Party** has designated another competent authority for that purpose, such designated competent authorities shall determine a single estimate of the value

of lost load for their territory. That estimate shall be made publically available. Regulatory authorities or other designated competent authorities may determine different estimates per bidding zone if they have more than one bidding zone in their territory. Where a bidding zone consists of territories of more than one **Contracting Party**, the concerned regulatory authorities or other designated competent authorities shall determine a single estimate of the value of lost load for that bidding zone. In determining the single estimate of the value of lost load, regulatory authorities or other designated competent authorities shall apply the methodology **referred to in** Article 23(6) **of Regulation (EU) 2019/943**.

2. Regulatory authorities and designated competent authorities shall update their estimate of the value of lost load at least every five years, or earlier where they observe a significant change.

Article 12

Dispatching of generation and demand response

1. The dispatching of power-generating facilities and demand response shall be non- discriminatory, transparent and, unless otherwise provided under paragraphs 2 to 6, market based.

2. Without prejudice to **Articles 18 and 19 of Energy Community Treaty**, **Contracting Parties** shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources to the extent permitted by the secure operation of the national electricity system, based on transparent and non-discriminatory criteria and where such power-generating facilities are either:

(a) power-generating facilities that use renewable energy sources and have an installed electricity capacity of less than 400 kW; or

(b) demonstration projects for innovative technologies, subject to approval by the regulatory authority, provided that such priority is limited to the time and extent necessary for achieving the demonstration purposes.

3. A **Contracting Party** may decide not to apply priority dispatch to power-generating facilities as referred to in point (a) of paragraph 2 with a start of operation at least six months after that decision, or to apply a lower minimum capacity than that set out under point (a) of paragraph 2, provided that:

(i) it has well-functioning intraday and other wholesale and balancing markets and that those markets are fully accessible to all market participants in accordance with this Regulation;

(j) redispatching rules and congestion management are transparent to all market participants;

(k) the national contribution of the **Contracting Party** towards the **Contracting Parties' economy-wide target of the relevant share of renewable energy in 2030 <…>** under Article 3(2) of Directive (EU) 2018/2001 of the European Parliament and of the Council and point (a)(2) of Article 4 of Regulation (EU) 2018/1999 of the European Parliament and of the Council, **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC,** is **not lower than the share to be adopted by Ministerial Council Decision,** or alternatively, the **Contracting Party**'s share of energy from renewable sources in gross final electricity consumption is at least 50 %;

(l) the **Contracting Party** has notified the planned derogation to the **Energy Community Secretariat** setting out in detail how the conditions set out under points (a), (b) and (c) are fulfilled; and

(m) the **Contracting Party** has published the planned derogation, including the detailed reasoning for the

granting of that derogation, taking due account of the protection of commercially sensitive information where required.

Any derogation shall avoid retroactive changes that affect generating installations already benefiting from priority dispatch, notwithstanding any agreement between a **Contracting Party** and the operator of a generating installation on a voluntary basis.

Without prejudice to **Articles 18 and 19 of the Energy Community Treaty**, **Contracting Parties** may provide incentives to installations eligible for priority dispatch to voluntarily give up priority dispatch.

4. Without prejudice to **Articles 18 and 19 of the Energy Community Treaty**, **Contracting Parties** may provide for priority dispatch for electricity generated in power-generating facilities using high-efficiency cogeneration with an installed electricity capacity of less than 400 kW.

5. For power-generating facilities commissioned as from 1 January 2026, point (a) of paragraph 2 shall apply only to power-generating facilities that use renewable energy sources and have an installed electricity capacity of less than 200 kW.

6. Without prejudice to contracts concluded before **the date of entry into force of this Regulation**, power-generating facilities that use renewable energy sources or high-efficiency cogeneration and were commissioned before **the date of entry into force of this Regulation** and, when commissioned, were subject to priority dispatch under Article 15(5) of Directive 2012/27/EU **as adapted and adopted by Ministerial Council Decision 2015/08/MC-EnC** or Article 16(2) of Directive 2009/28/EC **as adapted and adopted by Ministerial Council Decision 2018/02/MC-EnC,** shall continue to benefit from priority dispatch. Priority dispatch shall no longer apply to such power-generating facilities from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased.

7. Priority dispatch shall not endanger the secure operation of the electricity system, shall not be used as a justification for curtailment of cross-zonal capacities beyond what is provided for in Article 16 and shall be based on transparent and non-discriminatory criteria.

Article 13

Redispatching

1. The redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria. It shall be open to all generation technologies, all energy storage and all demand response, including those located in other Member States **or Contracting Parties** unless technically not feasible.

2. The resources that are redispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms and shall be financially compensated. Balancing energy bids used for redispatching shall not set the balancing energy price.

3. Non-market-based redispatching of generation, energy storage and demand response may only be used where:

(a) no market-based alternative is available;

(b) all available market-based resources have been used;

(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 Contracting Party 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).

4. The transmission system operators and distribution system operators shall report at least annually to the competent regulatory authority, on:

(a) the level of development and effectiveness of market-based redispatching mechanisms for power generating, energy storage and demand response facilities;

(b) the reasons, volumes in MWh and type of generation source subject to redispatching;

(c) the measures taken to reduce the need for the downward redispatching of generating installations using renewable energy sources or high-efficiency cogeneration in the future including investments in digitalisation of the grid infrastructure and in services that increase flexibility.

The regulatory authority shall submit the report to **the Energy Community Regulatory Board** and shall publish a summary of the data referred to in points (a), (b) and (c) of the first subparagraph together with recommendations for improvement where necessary.

5. Subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria established by the regulatory authorities, transmission system operators and distribution system operators shall:

(a) guarantee the capability of transmission networks and distribution networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching, which shall not prevent network planning from taking into account limited redispatching where the transmission system operator or distribution system operator is able to demonstrate in a transparent way that doing so is more economically efficient and does not exceed 5 % of the annual generated electricity in installations which use renewable energy sources and which are directly connected to their respective grid, unless otherwise provided by a **Contracting Party** in which electricity from power-generating facilities using renewable energy sources or high-efficiency cogeneration represents more than 50 % of the annual gross final consumption of electricity;

(b) take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from renewable energy sources or from high- efficiency cogeneration;

(c) ensure that their networks are sufficiently flexible so that they are able to manage them.

6. Where non-market-based downward redispatching is used, the following principles shall apply:

(a) power-generating facilities using renewable energy sources shall only be subject to downward redispatching if no other alternative exists or if other solutions would result in significantly disproportionate costs or severe risks to network security;

(b) electricity generated in a high-efficiency cogeneration process shall only be subject to downward redispatching if, other than downward redispatching of power-generating facilities using renewable energy

sources, no other alternative exists or if other solutions would result in disproportionate costs or severe risks to network security;

(c) self-generated electricity from generating installations using renewable energy sources or high- efficiency cogeneration which is not fed into the transmission or distribution network shall not be subject to downward redispatching unless no other solution would resolve network security issues;

(d) downward redispatching under points (a), (b) and (c)shall be duly and transparently justified. The justification shall be included in the report under paragraph 3.

7. Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy. Such financial compensation shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:

(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;

(b) net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.

CHAPTER III
NETWORK ACCESS AND CONGESTION MANAGEMENT

SECTION 1
Capacity Allocation

Article 14
Bidding zone review

1. **Contracting Parties** shall take all appropriate measures to address congestions. Bidding zone borders shall be based on long-term, structural congestions in the transmission network. Bidding zones shall not contain such structural congestions unless they have no impact on neighbouring bidding zones, or, as a temporary exemption, their impact on neighbouring bidding zones is mitigated through the use of remedial actions and those structural congestions do not lead to reductions of cross-zonal trading capacity in accordance with the requirements of Article 16. The configuration of bidding zones shall be designed in such a way as to maximise economic efficiency and to maximise cross-zonal trading opportunities in accordance with Article 16 **for bidding zones in the same capacity calculation region established in accordance with Article 15 of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial**

Council Decision 2022/03/MC-EnC, while maintaining security of supply.

2. **When reporting** on structural congestions and other major physical congestions between and within bidding zones, including the location and frequency of such congestions, in accordance with **Regulation (EU) 2015/1222 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC, the ENTSO for Electricity, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC, shall extend this report to include the Contracting Parties. To the extent the report covers bidding zones located outside the Continental Europe synchronous area, the Energy Community Secretariat shall <…> coordinate the contributions by the transmission system operators concerned to the report.**

3. In order to ensure an optimal configuration of bidding zones, a bidding zone review shall be carried out **for the Contracting Parties for bidding zones in the same capacity calculation region established in accordance with Article 15 of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC, at the latest six months following the first report by the ENTSO for Electricity in accordance with paragraph 2, but not later than 31 December 2025.** That review shall identify all structural congestions and shall include an analysis of different configurations of bidding zones in a coordinated manner with the involvement of affected stakeholders from all relevant **Contracting Parties and Member States**, in accordance with **Articles 32 and 33 of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC. Before performing any of its tasks pursuant to those provisions, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC, shall consult the Energy Community Regulatory Board. <….>**

4. **<….>**

5. **The bidding zone review shall take into account the methodology and assumptions developed pursuant to Article 14 paragraph 5 of Regulation (EU) 2019/943. <….>**

6. **<….>**

7. Where structural congestion has been identified in the report pursuant to paragraph 2 of this Article or in the bidding zone review pursuant to this Article or by one or more transmission system operators in their control areas in a report approved by the competent regulatory authority, the **Contracting Party** with identified structural congestion shall, in cooperation with its transmission system operators, decide, within six months of receipt of the report, either to establish national or multinational action plans pursuant to Article 15, or to review and amend its bidding zone configuration. Those decisions shall be immediately notified to the **Energy Community Secretariat** and to **the Energy Community Regulatory Board**.

8. For those **Contracting Parties** that have opted to amend the bidding zone configuration pursuant to paragraph 7, the relevant **Contracting Parties in the same capacity calculation region established in accordance with Article 15 of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** shall reach a unanimous decision within six months of the notification referred to in paragraph 7. Other Members States **and Contracting Parties in the same capacity calculation region** may submit comments to the relevant **Contracting Parties**, who should take account of those comments when reaching their decision. The decision shall be reasoned and shall be notified to **the Energy Community Secretariat** and **the Energy Community Regulatory Board**. In the event that the relevant **Contracting Parties** fail to reach a unanimous decision within those six months, they shall immediately notify the **Energy Community Regulatory Board** thereof. As a measure

of last resort, the **Energy Community Regulatory Board and** after consulting **the Energy Community Secretariat,** shall adopt a decision whether to amend or maintain the bidding zone configuration in and between those **Contracting Parties** by six months after receipt of such a notification.

9. **Contracting Parties and the Energy Community Regulatory Board** shall consult relevant stakeholders before adopting a decision under this Article.

10. Any decision adopted under this Article shall specify the date of implementation of any changes. That implementation date shall balance the need for expeditiousness with practical considerations, including forward trade of electricity. The decision may establish appropriate transitional arrangements.

11. **<....>**

Article 15

Action plans

1. Following the adoption of a decision pursuant to Article 14(7), the **Contracting Party** with identified structural congestion shall develop an action plan in cooperation with its regulatory authority. That action plan shall contain a concrete timetable for adopting measures to reduce the structural congestions identified within four years of the adoption of the decision pursuant to Article 14(7).

2. Irrespective of the concrete progress of the action plan, **Contracting Parties** shall ensure that without prejudice to derogations granted under Article 16(9) or deviations under Article 16(3), the cross-zonal trade capacity is increased on an annual basis until the minimum capacity provided for in Article 16(8) is reached. That minimum capacity shall be reached by **31 December 2027**.

Those annual increases shall be achieved by means of a linear trajectory. The starting point of that trajectory shall be either the capacity allocated at the border or on a critical network element in the year before adoption of the action plan or the average during the three years before adoption of the action plan, whichever is higher. **Contracting Parties** shall ensure that, during the implementation of their action plans the capacity made available for cross-zonal trade to be compliant with Article 16(8) is at least equal to the values of the linear trajectory, including by use of remedial actions in the capacity calculation region.

3. The cost of the remedial actions necessary to achieve the linear trajectory referred to in paragraph 2 or make available cross-zonal capacity at the borders or on critical network elements concerned by the action plan shall be borne by the **Contracting Party** or **Contracting Parties** implementing the action plan.

4. On an annual basis, during the implementation of the action plan and within six months of its expiry, the relevant transmission system operators shall assess for the previous 12 months whether the available cross-border capacity has reached the linear trajectory or, from **1 January 2028**, the minimum capacities provided for in Article 16(8) have been achieved. They shall submit their assessments to the **Energy Community Regulatory Board** and to the relevant regulatory authorities. Before drafting the report, each transmission system operator shall submit its contribution to the report, including all the relevant data, to its regulatory authority for approval.

5. For those **Contracting Parties** for which the assessments referred to in paragraph 4 demonstrate that a transmission system operator has not complied with the linear trajectory, the relevant **Contracting Parties** shall, within six months of receipt of the assessment report referred to in paragraph 4, decide unanimously whether to amend or maintain the bidding zone configuration within and between those

Contracting Parties. In their decision, the relevant **Contracting Parties** should take account of any comments submitted by other Member States or **Contracting Parties**. The relevant **Contracting Parties**' decision shall be substantiated and shall be notified to the **Energy Community Secretariat** and the **Energy Community Regulatory Board**.

The relevant **Contracting Parties** shall notify the **Energy Community Secretariat** immediately if they fail to reach a unanimous decision within the timeframe laid down. Within six months of receipt of such notification, the **Energy Community Secretariat**, as a last resort and after consulting **the Agency for the Cooperation of Energy Regulators, the Energy Community Regulatory Board** and the relevant stakeholders shall adopt a decision whether to amend or maintain the bidding zone configuration in and between those **Contracting Parties**.

6. Six months before the expiry of the action plan, the **Contracting Parties** with identified structural congestion shall decide whether to address remaining congestion by amending its bidding zone or whether to address remaining internal congestion with remedial actions for which it shall cover the costs.

7. Where no action plan is established within six months of identification of structural congestion pursuant to Article 14(7), the relevant transmission system operators shall, within 12 months of identification of such structural congestion, assess whether the available cross-border capacity has reached the minimum capacities provided for in Article 16(8) during the previous 12 months and shall submit an assessment report to the relevant regulatory authorities and to **the Energy Community Regulatory Board**.

Before drafting the report, each transmission system operator shall send its contribution to the report, including all relevant data, to its national regulatory authority for approval. Where the assessment demonstrates that a transmission system operator has not complied with the minimum capacity, the decision-making process laid down in paragraph 5 of this Article shall apply.

Article 16

General principles of capacity allocation and congestion management

1. Network congestion problems **between the Parties to the Energy Community** shall be addressed with non-discriminatory market-based solutions which give efficient economic signals to the market participants and transmission system operators involved. Network congestion problems shall be solved by means of non-transaction-based methods, namely methods that do not involve a selection between the contracts of individual market participants. When taking operational measures to ensure that its transmission system remains in the normal state, the transmission system operator shall take into account the effect of those measures on neighbouring control areas and coordinate such measures with other affected transmission system operators as provided for in Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

2. Transaction curtailment procedures shall be used only in emergency situations, namely where the transmission system operator must act in an expeditious manner and redispatching or countertrading is not possible. Any such procedure shall be applied in a non-discriminatory manner. Except in cases of force majeure, market participants that have been allocated capacity shall be compensated for any such curtailment.

3. Regional coordination centres shall carry out coordinated capacity calculation in accordance with paragraphs 4 and 8 of this Article, as provided for in point (a) of Article 37(1) and in Article 42(1).

Regional coordination centres shall calculate cross-zonal capacities respecting operational security limits using data from transmission system operators including data on the technical availability of remedial actions, not including load shedding. Where regional coordination centres conclude that those available remedial actions in the capacity calculation region or between capacity calculation regions are not sufficient to reach the linear trajectory pursuant to Article 15(2) or the minimum capacities provided for in paragraph 8 of this Article while respecting operational security limits, they may, as a measure of last resort, set out coordinated actions reducing the cross- zonal capacities accordingly. Transmission system operators may deviate from coordinated actions in respect of coordinated capacity calculation and coordinated security analysis only in accordance with Article 42(2).

By 3 months after the entry into operation of the regional coordination centres pursuant to Article 35 of this Regulation and every three months thereafter, the regional coordination centres shall submit a report, **corresponding to the reports submitted pursuant to Article 16(3) of the Regulation (EU) 2019/943**, to the relevant regulatory authorities, to the **Energy Community Regulatory Board and, to the extent Member States are affected, to the Agency for the Cooperation of Energy Regulators** on any reduction of capacity or deviation from coordinated actions pursuant to the second subparagraph and shall assess the incidences and make recommendations, if necessary, on how to avoid such deviations in the future. **If the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC, or the Energy Community Regulatory Board** concludes that the prerequisites for a deviation pursuant to this paragraph are not fulfilled or are of a structural nature, **the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC, or the Energy Community Regulatory Board** shall submit an opinion to the relevant regulatory authorities, **to the European Commission and to the Energy Community Secretariat. Before issuing an opinion, the Energy Community Regulatory Board and the Agency for the Cooperation of Energy Regulators shall consult each other.** The competent regulatory authorities shall take appropriate action against transmission system operators or regional coordination centres pursuant to Article 59 or 62 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** if the prerequisites for a deviation pursuant to this paragraph were not fulfilled.

Deviations of a structural nature shall be addressed in an action plan referred to in Article 14(7) or in an update of an existing action plan.

4. The maximum level of capacity of the interconnections and the transmission networks affected by cross-border capacity **between Parties to the Energy Community** shall be made available to market participants complying with the safety standards of secure network operation. Counter- trading and redispatch, including cross-border redispatch, shall be used to maximise available capacities to reach the minimum capacity provided for in paragraph 8. A coordinated and non- discriminatory process for cross-border remedial actions shall be applied to enable such maximisation, following the implementation of a redispatching and counter-trading cost-sharing methodology.

5. Capacity shall be allocated by means of explicit capacity auctions or implicit auctions including both capacity and energy. Both methods may coexist on the same interconnection. For intraday trade, continuous trading, which may be complemented by auctions, shall be used.

6. In the case of congestion, the valid highest value bids for network capacity, whether implicit or explicit, offering the highest value for the scarce transmission capacity in a given timeframe, shall be successful. Other than in the case of new interconnectors which benefit from an exemption under Article 7 of Reg-

ulation (EC) No 1228/2003, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC,** Article 17 of Regulation (EC) No 714/2009, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC,** or Article 63 of this Regulation, establishing reserve prices in capacity-allocation methods shall be prohibited.

7. Capacity shall be freely tradable on a secondary basis, provided that the transmission system operator is informed sufficiently in advance. Where a transmission system operator refuses any secondary trade (transaction), this shall be clearly and transparently communicated and explained to all the market participants by that transmission system operator and notified to the regulatory authority.

8. Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones. Without prejudice to the application of the derogations under paragraphs 3 and 9 of this Article and to the application of Article 15(2), this paragraph shall be considered to be complied with where the following minimum levels of available capacity for cross-zonal trade are reached:

(a) for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70 % of the transmission capacity respecting operational security limits after deduction of contingencies, as determined in accordance with **Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC;**

(b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross- zonal critical network elements, taking into account contingencies, as determined in accordance with **Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

The total amount of 30 % can be used for the reliability margins, loop flows and internal flows on each critical network element.

9. At the request of the transmission system operators in a capacity calculation region, the relevant regulatory authorities may grant a derogation from paragraph 8 on foreseeable grounds where necessary for maintaining operational security. Such derogations, which shall not relate to the curtailment of capacities already allocated pursuant to paragraph 2, shall be granted for no more than one-year at a time, or, provided that the extent of the derogation decreases significantly after the first year, up to a maximum of two years. The extent of such derogations shall be strictly limited to what is necessary to maintain operational security and they shall avoid discrimination between internal and cross-zonal exchanges.

Before granting a derogation, the relevant regulatory authority shall consult the regulatory authorities of other Member States **and Contracting Parties** forming part of the affected capacity calculation regions. Where a regulatory authority disagrees with the proposed derogation, the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators**, **acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** shall decide whether it should be granted pursuant to **Article 62(1)(f) of Directive (EU) 2019/944, including as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC.** The justification and reasons for the derogation shall be published. **Before taking a decision, the Energy Community Regulatory Board and the Agency for the Cooperation of Energy Regulators shall consult each other.**

Where a derogation is granted, the relevant transmission system operators shall develop and publish a methodology and projects that shall provide a long-term solution to the issue that the derogation seeks to address. The derogation shall expire when the time limit for the derogation is reached or when the solution is applied, whichever is earlier.

10. Market participants shall inform the transmission system operators concerned within a reasonable period in advance of the relevant operational period whether they intend to use allocated capacity. Any allocated capacity that is not going to be used shall be made available again to the market, in an open, transparent and non-discriminatory manner.

11. As far as technically possible, transmission system operators shall net the capacity requirements of any power flows in opposite directions over the congested interconnection line in order to use that line to its maximum capacity. Having full regard to network security, transactions that relieve the congestion shall not be refused.

12. The financial consequences of a failure to honour obligations associated with the allocation of capacity shall be attributed to the transmission system operators or NEMOs who are responsible for such a failure. Where market participants fail to use the capacity that they have committed to use, or, in the case of explicitly auctioned capacity, fail to trade capacity on a secondary basis or give the capacity back in due time, those market participants shall lose the rights to such capacity and shall pay a cost-reflective charge. Any cost-reflective charges for the failure to use capacity shall be justified and proportionate. If a transmission system operator does not fulfil its obligation of providing firm transmission capacity, it shall be liable to compensate the market participant for the loss of capacity rights. Consequential losses shall not be taken into account for that purpose. The key concepts and methods for the determination of liabilities that accrue upon failure to honour obligations shall be set out in advance in respect of the financial consequences, and shall be subject to review by the relevant regulatory authority.

13. When allocating costs of remedial actions between transmission system operators, regulatory authorities shall analyse to what extent flows resulting from transactions internal to bidding zones contribute to the congestion between two bidding zones observed, and allocate the costs based on the contribution to the congestion to the transmission system operators of the bidding zones creating such flows except for costs induced by flows resulting from transactions internal to bidding zones that are below the level that could be expected without structural congestion in a bidding zone.

That level shall be jointly analysed and defined by all transmission system operators in a capacity calculation region for each individual bidding zone border, and shall be subject to the approval of all regulatory authorities in the capacity calculation region.

Article 17

Allocation of cross-zonal capacity across timeframes

1. Transmission system operators of Member States **and Contracting Parties** shall recalculate available cross-zonal capacity at least after day-ahead gate closure times and after intraday cross- zonal gate closure times. Transmission system operators shall allocate the available cross-zonal capacity plus any remaining cross-zonal capacity not previously allocated and any cross-zonal capacity released by physical transmission right holders from previous allocations in the following cross-zonal capacity allocation process.

2. Transmission system operators shall propose an appropriate structure for the allocation of cross-zonal capacity across timeframes, including day-ahead, intraday and balancing. That allocation structure shall be subject to review by the relevant regulatory authorities. In drawing up their proposal, the transmission system operators shall take into account:

(a) the characteristics of the markets;

(b) the operational conditions of the electricity system, such as the implications of netting firmly declared schedules;

(c) the level of harmonisation of the percentages allocated to different timeframes and the timeframes adopted for the different cross-zonal capacity allocation mechanisms that are already in place

3. Where cross-zonal capacity is available after the intraday cross-zonal gate closure time, transmission system operators shall use the cross-zonal capacity for the exchange of balancing energy or for the operation of the imbalance netting process.

4. Where cross-zonal capacity is allocated for the exchange of balancing capacity or sharing of reserves pursuant to Article 6(8) of this Regulation, transmission system operators shall use the methodologies developed in **accordance with Regulation (EU) 2017/2195, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

5. Transmission system operators shall not increase the reliability margin calculated pursuant to Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** due to the exchange of balancing capacity or sharing of reserves.

SECTION 2

Network charges and congestion income

Article 18

Charges for access to networks, use of networks and reinforcement

1. Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. Those charges shall not include unrelated costs supporting unrelated policy objectives.

Without prejudice to Article 15(1) and (6) of Directive 2012/27/EU, **as adopted and adapted by Ministerial Council Decision 2015/08/MC-EnC,** and the criteria in Annex XI to that Directive the method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level. The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response. Without prejudice to paragraph 3 of this Article,

those charges shall not be distance-related.

2. Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.

3. Where appropriate, the level of the tariffs applied to producers or final customers, or both shall provide locational signals at **Energy Community** level and take into account the amount of network losses and congestion caused, and investment costs for infrastructure.

4. When setting the charges for network access, the following shall be taken into account:

(a) payments and receipts resulting from the inter-transmission system operator compensation mechanism;

(b) actual payments made and received as well as payments expected for future periods, estimated on the basis of previous periods.

5. Setting the charges for network access under this Article shall be without prejudice to charges resulting from congestion management referred to in Article 16.

6. There shall be no specific network charge on individual transactions for cross-zonal trading of electricity.

7. Distribution tariffs shall be cost-reflective taking into account the use of the distribution network by system users including active customers. Distribution tariffs may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles. Where **Contracting Parties** have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** and, where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer.

8. Distribution tariff methodologies shall provide incentives to distribution system operators for the most cost-efficient operation and development of their networks including through the procurement of services. For that purpose regulatory authorities shall recognise relevant costs as eligible, shall include those costs in distribution tariffs, and may introduce performance targets in order to provide incentives to distribution system operators to increase efficiencies in their networks, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems.

9. By **5 October 2023** in order to mitigate the risk of market fragmentation **the Energy Community Regulatory Board** shall provide a best practice report on transmission and distribution tariff methodologies while taking account of national specificities. That best practice report shall address at least:

(a) the ratio of tariffs applied to producers and tariffs applied to final customers;

(b) the costs to be recovered by tariffs;

(c) time-differentiated network tariffs;

(d) locational signals;

(e) the relationship between transmission tariffs and distribution tariffs;

(f) methods to ensure transparency in the setting and structure of tariffs;

(g) groups of network users subject to tariffs including, where applicable, the characteristics of those groups, forms of consumption, and any tariff exemptions;

(h) losses in high, medium and low-voltage grids.

The Energy Community Regulatory Board shall take into account the best practice report developed by the Agency for the Cooperation of Energy Regulators for that purpose. The Energy Community Regulatory Board shall update the best practice report at least once every two years.

10. Regulatory authorities shall duly take the best practice report into consideration when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC.**

Article 19

Congestion income

1. Congestion-management procedures associated with a pre-specified timeframe may generate revenue only in the event of congestion which arises for that timeframe, except in the case of new interconnectors which benefit from an exemption under Article 63 of this Regulation, Article 17 of Regulation (EC) No 714/2009, **as adapted by Ministerial Council Decision 2011/02/MC- EnC** or Article 7 of Regulation (EC) No 1228/2003, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC**. The procedure for the distribution of those revenues shall be subject to review by the regulatory authorities and shall neither distort the allocation process in favour of any party requesting capacity or energy nor provide a disincentive to reduce congestion.

2. The following objectives shall have priority with the respect to the allocation of any revenues resulting from the allocation of cross-zonal capacity:

(a) guaranteeing the actual availability of the allocated capacity including firmness compensation; or

(b) maintaining or increasing cross-zonal capacities through optimization of the usage of existing interconnectors by means of coordinated remedial actions, where applicable, or covering costs resulting from network investments that are relevant to reduce interconnector congestion

3. Where the priority objectives set out in paragraph 2 have been adequately fulfilled, the revenues may be used as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs or fixing network tariffs, or both. The residual revenues shall be placed on a separate internal account line until such a time as it can be spent for the purposes set out in paragraph 2.

4. The use of revenues in accordance with point (a) or (b) of paragraph 2 shall be subject to **the** methodology **adopted by the Agency for the Cooperation of Energy Regulators in accordance with Article 19(4) of Regulation (EU) 2019/943**. **<…>**[1]

5. Transmission system operators shall clearly establish, in advance, how any congestion income will be used, and shall report to the regulatory authorities on the actual use of that income. By 1 March each year, the regulatory authorities shall inform **the Energy Community Regulatory Board** and shall publish a report setting out:

1 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

(a) the amount of revenue collected for the 12-month period ending on 31 December of the previous year;

(b) how that revenue was used pursuant to paragraph 2, including the specific projects the income has been used for, and the amount placed on a separate account line;

(c) the amount that was used when calculating network tariffs; and;

(d) verification that the amount referred to in point (c) complies with this Regulation and the methodology developed pursuant to paragraphs 3 and 4.

Where some of the congestion revenues are used when calculating network tariffs, the report shall set out how the transmission system operators fulfilled the priority objectives set out in paragraph 2 where applicable.

CHAPTER IV
RESOURCE ADEQUACY

Article 20
Resource adequacy in the internal market for electricity

1. **Contracting Parties** shall monitor resource adequacy within their territory on the basis of the European resource adequacy assessment referred to in Article 23. For the purpose of complementing the European resource adequacy assessment, **Contracting Parties** may also carry out national resource adequacy assessments pursuant to Article 24.

2. Where the European resource adequacy assessment referred to in Article 23 or national resource adequacy assessment referred to in Article 24 identifies a resource adequacy concern, the **Contracting Parties** concerned shall identify any regulatory distortions or market failures that caused or contributed to the emergence of the concern.

3. **Contracting Parties** with identified resource adequacy concerns shall develop and publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures **and submit it to the competent national State aid authority when notifying a capacity mechanism for the purpose of Article 21(8), as well as to the Energy Community Secretariat.** When addressing resource adequacy concerns, the **Contracting Parties** shall in particular take into account the principles set out in Article 3 and shall consider:

(a) removing regulatory distortions;

(b) removing price caps in accordance with Article 10;

(c) introducing a shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation (EU) 2017/2195 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(d) increasing interconnection and internal grid capacity with a view to reaching at least their interconnection targets as referred in point (d)(1) of Article 4 of Regulation (EU) 2018/1999, **as adapted and adopted by Ministerial Council Decision 2021/14/MC-EnC;**

(e) enabling self-generation, energy storage, demand side measures and energy efficiency by adopting measures to eliminate any identified regulatory distortions;

(f) ensuring cost-efficient and market-based procurement of balancing and ancillary services;

(g) removing regulated prices where required by Article 5 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC.**

4. The **Contracting Parties** concerned shall submit their implementation plans to the **Energy Community Secretariat** for review.

5. Within four months of receipt of the implementation plan, the **Energy Community Secretariat** shall issue an opinion on whether the measures are sufficient to eliminate the regulatory distortions or market failures that were identified pursuant to paragraph 2, and may invite the **Contracting Parties** to amend their implementation plans accordingly.

6. The **Contracting Parties** concerned shall monitor the application of their implementation plans and shall publish the results of the monitoring in an annual report and shall submit that report to the **Energy Community Secretariat**.

7. The **Energy Community Secretariat** shall issue an opinion on whether the implementation plans have been sufficiently implemented and whether the resource adequacy concern has been resolved.

8. **Contracting Parties** shall continue to adhere to the implementation plan after the identified resource adequacy concern has been resolved.

Article 21

General principles for capacity mechanisms

1. To eliminate residual resource adequacy concerns, **Contracting Parties** may, as a last resort while implementing the measures referred to in Article 20(3) of this Regulation in accordance with **Articles 18 and 19 of the Treaty** introduce capacity mechanisms.

2. Before introducing capacity mechanisms, the **Contracting Parties** concerned shall conduct a comprehensive study of the possible effects of such mechanisms on the neighbouring Member States **and Contracting Parties** by consulting at least its neighbouring Member States **and Contracting Parties** to which they have a direct network connection and the stakeholders of those Member States **and Contracting Parties**.

3. **Contracting Parties** shall assess whether a capacity mechanism in the form of strategic reserve is capable of addressing the resource adequacy concerns. Where this is not the case, **Contracting Parties** may implement a different type of capacity mechanism.

4. **Contracting Parties** shall not introduce capacity mechanisms where both European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern.

5. **Contracting Parties** shall not introduce capacity mechanisms before the implementation plan as referred to in Article 20(3) has received an opinion by the **Energy Community Secretariat** as referred to in Article 20(5).

6. Where a **Contracting Party** applies a capacity mechanism, it shall review that capacity mechanism and shall ensure that no new contracts are concluded under that mechanism where both the European

resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern or the implementation plan as referred to in Article 20(3) has not received an opinion by the **Energy Community Secretariat** as referred to in Article 20(5).

7. When designing capacity mechanisms **Contracting Parties** shall include a provision allowing for an efficient administrative phase-out of the capacity mechanism where no new contracts are concluded under paragraph 6 during three consecutive years.

8. Capacity mechanisms shall be temporary. They shall be approved by the **competent national State aid authority upon informing the Energy Community Secretariat,** no longer than 10 years. They shall be phased out or the amount of the committed capacities shall be reduced on the basis of the implementation plans referred to in Article 20. **Contracting Parties** shall continue to apply the implementation plan after the introduction of the capacity mechanism.

Article 22

Design principles for capacity mechanisms

1. Any capacity mechanism shall:

(a) be temporary;

(b) not create undue market distortions and not limit cross-zonal trade;

(c) not go beyond what is necessary to address the adequacy concerns referred to in Article 20;

(d) select capacity providers by means of a transparent, non-discriminatory and competitive process;

(e) provide incentives for capacity providers to be available in times of expected system stress;

(f) ensure that the remuneration is determined through the competitive process;

(g) set out the technical conditions for the participation of capacity providers in advance of the selection process;

(h) be open to participation of all resources that are capable of providing the required technical performance, including energy storage and demand side management;

(i) apply appropriate penalties to capacity providers that are not available in times of system stress.

2. The design of strategic reserves shall meet the following requirements:

(a) where a capacity mechanism has been designed as a strategic reserve, the resources thereof are to be dispatched only if the transmission system operators are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;

(b) during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher;

(c) the output of the strategic reserve following dispatch is to be attributed to balance responsible parties through the imbalance settlement mechanism;

(d) the resources taking part in the strategic reserve are not to receive remuneration from the wholesale electricity markets or from the balancing markets;

(e) the resources in the strategic reserve are to be held outside the market for at least the duration of the contractual period.

The requirement referred to in point (a) of the first subparagraph shall be without prejudice to the activation of resources before actual dispatch in order to respect the ramping constraints and operating requirements of the resources. The output of the strategic reserve during activation shall not be attributed to balance groups through wholesale markets and shall not change their imbalances.

3. In addition to the requirements laid down in paragraph 1, capacity mechanisms other than strategic reserves shall:

(a) be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded;

(b) remunerate the participating resources only for their availability and ensure that the remuneration does not affect decisions of the capacity provider on whether or not to generate;

(c) ensure that capacity obligations are transferable between eligible capacity providers.

4. Capacity mechanisms shall incorporate the following requirements regarding CO2 emission limits:

(a) from **the date of entry into force of this Regulation** at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;

(b) from 1 July 2025 at the latest, generation capacity that started commercial production before **the date of entry into force of this Regulation** and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity and more than 350 kg CO2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism.

The emission limit of 550 g CO2 of fossil fuel origin per kWh of electricity and the limit of 350 kg CO2 of fossil fuel origin on average per year per installed kWe referred to in points (a) and (b) of the first subparagraph shall be calculated on the basis of the design efficiency of the generation

unit meaning the net efficiency at nominal capacity under the relevant standards provided for by the International Organization for Standardization.

For the purpose of implementing the first subparagraph, Contracting Parties shall take into account the opinion providing technical guidance published by the Agency for the Cooperation of Energy Regulators in accordance with Article 22(4) of Regulation (EU) 2019/943.

5. **Contracting Parties** that apply capacity mechanisms on **the date of entry into force of this Regulation** shall adapt their mechanisms to comply with Chapter 4 without prejudice to commitments or contracts concluded by 31 December 20**22**.

Article 23

European resource adequacy assessment

1. The European resource adequacy assessment shall identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demands for electricity at European level, at the level of the Member States **and Contracting Parties**, and at the level of individual

bidding zones, where relevant. The European resource adequacy assessment shall cover each year within a period of 10 years from the date of that assessment.

2. The **ENTSO for Electricity, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC, shall include the Contracting Parties in the European resource adequacy assessment based on Article 23 of Regulation (EU) No 2019/943. Before conducting the European resource adequacy assessment, the ENTSO for Electricity shall consult the transmission system operators of the Contracting Parties and the Energy Community Secretariat.**

Transmission system operators shall provide the ENTSO for Electricity the data it needs to carry out the resource adequacy assessment. Producers and other market participants shall provide transmission system operators with data regarding expected utilisation of the generation resources, taking into account the availability of primary resources and appropriate scenarios of projected demand and supply.

3. **<…>**

4. **<…>**.

5. **<…>**

6. **<…>**

7. The results of the **Energy Community and** European resource adequacy assessment under paragraph **2** shall be subject to the prior consultation of **Contracting Parties**, **the Security of Supply Group for Electricity** and relevant stakeholders **in the Energy Community <…>.**

Article 24

National resource adequacy assessments

1. National resource adequacy assessments shall have a regional scope and shall be based on the methodology referred in **<…>** Article 23(5) **of Regulation (EU) 2019/943**.

National resource adequacy assessments shall contain the reference central scenarios as referred to in point (b) of Article 23(5).

National resource adequacy assessments may take into account additional sensitivities to those referred in point (b) of Article 23(5). In such cases, national resource adequacy assessments may:

(a) make assumptions taking into account the particularities of national electricity demand and supply;

(b) use tools and consistent recent data that are complementary to those used by the ENTSO for Electricity for the European resource adequacy assessment.

In addition, the national resource adequacy assessments, in assessing the contribution of capacity providers located in another Member State **or Contracting Party** to the security of supply of the bidding zones that they cover, shall use the methodology **developed by the ENTSO for Electricity in accordance with** point (a) of Article 26(11) **of Regulation (EU) 2019/943 and approved by the Agency for the Cooperation of Energy Regulators**.

2. National resource adequacy assessments and, where applicable, the European resource adequacy assessment and the opinion of **the Energy Community Regulatory Board** pursuant to paragraph 3 shall be made publicly available.

3. Where the national resource adequacy assessment identifies an adequacy concern with regard to a bidding zone that was not identified in the European resource adequacy assessment, the national resource adequacy assessment shall include the reasons for the divergence between the two resource adequacy assessments, including details of the sensitivities used and the underlying assumptions. **Contracting Parties** shall publish that assessment and submit it to the **Energy Community Secretariat**.

Within **four** months of the date of the receipt of the report, **the Energy Community Secretariat** shall provide an opinion on whether the differences between the national resource adequacy assessment and the European resource adequacy assessment are justified. **When preparing its opinion, the Energy Community Secretariat shall request the Energy Community Regulatory Board to provide its opinion on the report and shall consult the Agency for Cooperation of Energy Regulators.**

The body that is responsible for the national resource adequacy assessment shall take due account of **the Energy Community Secretariat's** opinion, and where necessary shall amend its assessment. Where it decides not to take **the Energy Community Secretariat's** opinion fully into account, the body that is responsible for the national resource adequacy assessment shall publish a report with detailed reasons.

Article 25

Reliability standard

1. When applying capacity mechanisms **Contracting Parties** shall have a reliability standard in place. A reliability standard shall indicate the necessary level of security of supply of the **Contracting Parties** in a transparent manner. In the case of cross-border bidding zones, such reliability standards shall be established jointly by the relevant authorities.

2. The reliability standard shall be set by the **Contracting Party** or by a competent authority designated by the **Contracting Party**, following a proposal by the regulatory authority. The reliability standard shall be based on the methodology **developed by the ENTSO for Electricity in accordance with** Article 23(6) **of Regulation (EU) 2019/943 and approved by the Agency for the Cooperation of Energy Regulators**.

3. The reliability standard shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe and shall be expressed as 'expected energy not served' and 'loss of load expectation'.

4. When applying capacity mechanisms, the parameters determining the amount of capacity procured in the capacity mechanism shall be approved by the **Contracting Party** or by a competent authority designated by the **Contracting Party**, on the basis of a proposal of the regulatory authority.

Article 26

Cross-border participation in capacity mechanisms

1. Capacity mechanisms other than strategic reserves and where technically feasible, strategic reserves shall be open to direct cross-border participation of capacity providers located in another Member State **or Contracting Party**, subject to the conditions laid down in this Article.

2. Member States **and Contracting Parties** shall ensure that foreign capacity capable of providing

equivalent technical performance to domestic capacities has the opportunity to participate in the same competitive process as domestic capacity. In the case of capacity mechanisms in operation on **the date of entry into force of this Regulation,** Member States **and Contracting Parties** may allow interconnectors to participate directly in the same competitive process as foreign capacity for a maximum of **four** years from **the date of entry into force of this Regulation**.

Contracting Parties may require foreign capacity to be located in a Member State **or Contracting Party** that has a direct network connection with the **Contracting Party** applying the mechanism.

3. Member States **and Contracting Parties** shall not prevent capacity which is located in their territory from participating in capacity mechanisms of other Member States **or Contracting Parties**.

4. Cross-border participation in capacity mechanisms shall not change, alter or otherwise affect cross-zonal schedules or physical flows between Member States **or Contracting Parties**. Those schedules and flows shall be determined solely by the outcome of capacity allocation pursuant to Article 16.

5. Capacity providers shall be able to participate in more than one capacity mechanism.

Where capacity providers participate in more than one capacity mechanism for the same delivery period, they shall participate up to the expected availability of interconnection and the likely concurrence of system stress between the system where the mechanism is applied and the system in which the foreign capacity is located, in accordance with the methodology **developed by the ENTSO for Electricity in accordance with** point (a) of Article 26(11) **of Regulation (EU) 2019/943 and approved by the Agency for the Cooperation of Energy Regulators**.

6. Capacity providers shall be required to make non-availability payments where their capacity is not available.

Where capacity providers participate in more than one capacity mechanism for the same delivery period, they shall be required to make multiple non-availability payments where they are unable to fulfil multiple commitments.

7. For the purposes of providing a recommendation to transmission system operators, regional coordination centres established pursuant to Article 35 shall calculate on an annual basis the maximum entry capacity available for the participation of foreign capacity. That calculation shall take into account the expected availability of interconnection and the likely concurrence of system stress in the system where the mechanism is applied and the system in which the foreign capacity is located. Such a calculation shall be required for each bidding zone border.

Transmission system operators shall set the maximum entry capacity available for the participation of foreign capacity based on the recommendation of the regional coordination centre on an annual basis.

8. **Contracting Parties** shall ensure that the entry capacity referred to in paragraph 7 is allocated to eligible capacity providers in a transparent, non-discriminatory and market-based manner.

9. Where capacity mechanisms allow for cross-border participation in two neighbouring Member States **or Contracting Parties**, any revenues arising through the allocation referred to in paragraph 8 shall accrue to the transmission system operators concerned and shall be shared between them in accordance with the methodology **developed by the ENTSO for Electricity in accordance with** point (b) of Article 26(11) **of Regulation (EU) 2019/943 and approved by the Agency for the Cooperation of Energy Regulators**, or in accordance with a common methodology approved by both relevant regulatory authorities. If the neighbouring Member State **or Contracting Party** does not apply a capacity mechanism or

applies a capacity mechanism which is not open to cross-border participation, the share of revenues shall be approved by the competent national authority of the Member State **o**r **Contracting Party** in which the capacity mechanism is implemented after having sought the opinion of the regulatory authorities of the neighbouring Member States **or Contracting Parties**. Transmission system operators shall use such revenues for the purposes set out in Article 19(2).

10. The transmission system operator where the foreign capacity is located shall:

(a) establish whether interested capacity providers can provide the technical performance as required by the capacity mechanism in which the capacity provider intends to participate, and register that capacity provider as an eligible capacity provider in a registry set up for that purpose **by the ENTSO for Electricity in accordance with Article 26 of Regulation (EU) 2019/943**;

(b) carry out availability checks;

(c) notify the transmission system operator in the Member State **or Contracting Party** applying the capacity mechanism of the information it acquires under points (a) and (b) of this subparagraph and the second subparagraph.

The relevant capacity provider shall notify the transmission system operator of its participation in a foreign capacity mechanism without delay.

11. **< … >**

12. The regulatory authorities concerned shall verify whether the capacities have been calculated in accordance with the methodology **developed by the ENTSO for Electricity in accordance with** point (a) **of Article 26(11) of Regulation (EU) 2019/943 and approved by the Agency for the Cooperation of Energy Regulators**.

13. Regulatory authorities shall ensure that cross-border participation in capacity mechanisms is organised in an effective and non-discriminatory manner. They shall in particular provide for adequate administrative arrangements for the enforcement of non-availability payments across borders.

14. The capacities allocated in accordance with paragraph 8 shall be transferable between eligible capacity providers. Eligible capacity providers shall notify the registry as referred to in point (a) of paragraph 10 of any such transfer.

15. **<…>** The registry referred to in point (a) of paragraph 10 **<…>** shall be open to all eligible capacity providers, the systems implementing capacity mechanisms and their transmission system operators.

Article 27

Approval procedure

< … >

CHAPTER V
TRANSMISSION SYSTEM OPERATION

Article 28

European network of transmission system operators for electricity

1. Transmission system operators shall cooperate at **Energy Community** level through the ENTSO for Electricity, in order to promote the completion and functioning of the internal market for electricity and cross-zonal trade and to ensure the optimal management, coordinated operation and sound technical evolution of the European electricity transmission network.

2. **< … > Transmission system operators which are not members of the ENTSO for Electricity shall enter into agreements with the ENTSO for Electricity, to cover the additional costs resulting from the extension of the tasks of the ENTSO for Electricity to these transmission system operators.**

Article 29

The ENTSO for Electricity

< …>

Article 30

Tasks of the ENTSO for Electricity

< … >

Article 31

Consultations

< … >

Article 32

Monitoring by ACER

< … >

Article 33

Costs

The costs related to the activities of the ENTSO for Electricity referred to in Articles 4 to 12, as well as the costs referred to in Article 28, shall be borne by the transmission system operators and shall be taken into account in the calculation of tariffs. Regulatory authorities shall approve those costs only if they are reasonable and proportionate.

Article 34

Regional cooperation of transmission system operators

1. Transmission system operators shall establish regional cooperation, **to the extent possible,** within the ENTSO for Electricity **<...>**. In particular, they shall publish a regional investment plan biennially, and may take investment decisions based on that regional investment plan. **<...>**

2. Transmission system operators shall promote operational arrangements in order to ensure the optimum management of the network and shall promote the development of energy exchanges, the coordinated allocation of cross-border capacity through non-discriminatory market-based solutions, paying due attention to the specific merits of implicit auctions for short-term allocations, and the integration of balancing and reserve power mechanisms.

3. For the purposes of achieving the goals set in paragraphs 1 and 2, the geographical area covered by each regional cooperation structure **<...> is defined by Annex IV**. Each **Contracting Party** may promote cooperation in more than one geographical area.

<...>

Article 35

Establishment and mission of regional coordination centres

1. **<...>**

2. **<...>** The regional coordination centres shall replace the regional security coordinators established pursuant to the system operation guideline adopted on the basis of Article 18 of Regulation (EC) No 714/2009 and shall enter into operation **in accordance with Annex IV.**

3. Regional coordination centres shall have a legal form referred to in Annex II to Directive (EU) 2017/1132 of the European Parliament and of the Council.

4. In performing their tasks under **Energy Community and** Union law, regional coordination centres shall act independently of individual national interests and independently of the interests of transmission system operators.

5. Regional coordination centres shall complement the role of transmission system operators by performing the tasks of regional relevance assigned to them in accordance with Article 37. Transmission system operators shall be responsible for managing electricity flows and ensuring a secure, reliable and efficient electricity system in accordance with point (d) of Article 40(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC.**

Article 36

Geographical scope of regional coordination centres

1. **The system operation regions defined by Annex V shall cover** transmission system operators, bidding zones, bidding zone borders, capacity calculation regions and outage coordination regions **<...>**

2. **Within six months upon the establishment of a system operation region in line with Annex V, each transmission system operator shall participate in any of the regional coordination centres defined by Annex IV.** In exceptional circumstances, where the control area of a transmission system operator is part of various synchronous areas, the transmission system operator may participate in two regional coordination centres. **<…>. <…>** Where the activities of two **or more** regional coordination centres may overlap in a system operation region, the transmission system operators of that system operation region shall decide to either designate a single regional coordination centre in that region or that the two **or more** regional coordination centres carry out some or all of the tasks of regional relevance in the entire system operation region on a rotational basis **in coordination**, while other tasks are carried out by a single designated regional coordination centre.

3. **<…>**

4. **<…>**

Article 37

Tasks of regional coordination centres

1. Each regional coordination centre shall carry out at least all the following tasks of regional relevance in the system operation region **for which** it is established **and cooperate with regional coordination centres carrying out tasks in the same system operation regions**:

(a) carrying out the coordinated capacity calculation in accordance with the methodologies developed pursuant to **Regulation (EU) 2015/1222, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(b) carrying out the coordinated security analysis in accordance with the methodologies developed pursuant to **Regulation (EU) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(c) creating common grid models in accordance with the methodologies and procedures developed pursuant to **Regulation (EU) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(d) supporting the consistency assessment of transmission system operators' defence plans and restoration plans in accordance with the procedure set out in **Regulation (EU) 2017/2196, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(e) carrying out regional week ahead to at least day-ahead system adequacy forecasts and preparation of risk reducing actions in accordance with the methodology set out in Article 8 of Regulation (EU) 2019/941, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** and the procedures set out in **Regulation (EU) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(f) carrying out regional outage planning coordination in accordance with the procedures and methodologies set out in **Regulation (EU) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC;**

(g) training and certification of staff working for regional coordination centres;

(h) supporting the coordination and optimisation of regional restoration as requested by transmission system operators;

(i) carrying out post-operation and post-disturbances analysis and reporting;

(j) regional sizing of reserve capacity;

(k) facilitating the regional procurement of balancing capacity;

(l) supporting transmission system operators, at their request, in the optimisation of inter- transmission system operators settlements;

(m) carrying out tasks related to the identification of regional electricity crisis scenarios if and to the extent they are delegated to the regional coordination centres pursuant to Article 6(1) of Regulation (EU) 2019/941**, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(n) carrying out tasks related to the seasonal adequacy assessments if and to the extent that they are delegated to the regional coordination centres pursuant to Article 9(2) of Regulation (EU) 2019/941, **as adapted and adopted by Ministerial Council Decision 2021/13/MC- EnC**;

(o) calculating the value for the maximum entry capacity available for the participation of foreign capacity in capacity mechanisms for the purposes of issuing a recommendation pursuant to Article 26(7);

(p) carrying out tasks related to supporting transmission system operators in the identification of needs for new transmission capacity, for upgrade of existing transmission capacity or their alternatives, to be submitted to the regional groups established pursuant to Regulation (EU) No 347/2013, **as adapted and adopted by Ministerial Council Decision 2015/09-EnC-MC** and included in the ten-year network development plan referred to in Article 51 of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

The tasks referred to in the first subparagraph are set out in more detail in Annex I. 2.

2. **<...>**

3. Transmission system operators shall provide their regional coordination centres with the information necessary to carry out its tasks.

4. Regional coordination centres shall provide transmission system operators of the system operation region with all information necessary to implement the coordinated actions and recommendations issued by regional coordination centres.

5. **The tasks set out in this Article and not already covered by the relevant network codes or guidelines shall be performed by the regional coordination centres on the basis of the decision adopted by the Agency for the Cooperation of Energy Regulators pursuant to Article 37(5) of Regulation (EU) 2019/943.**

Article 38

Cooperation within and between regional coordination centres

The day-to-day coordination within and between regional coordination centres shall be managed through cooperative processes among the transmission system operators of the region, including arrangements for coordination between regional coordination centres where relevant. The cooperative process shall be

based on:

(a) working arrangements to address planning and operational aspects relevant to the tasks referred to in Article 37;

(b) a procedure for sharing analysis and consulting on regional coordination centres' proposals with the transmission system operators in the system operation region and relevant stakeholders and with other regional coordination centres, in an efficient and inclusive manner, in the exercise of the operational duties and tasks, in accordance with Article 40;

(c) a procedure for the adoption of coordinated actions and recommendations in accordance with Article 42.

Article 39

Working arrangements

1. Regional coordination centres shall develop working arrangements that are efficient, inclusive, transparent and facilitate consensus, in order to address planning and operational aspects related to the tasks to be carried out, taking into account, in particular, the specificities and requirements of those tasks as specified in Annex I. Regional coordination centres shall also develop a process for the revision of those working arrangements.

2. Regional coordination centres shall ensure that the working arrangements referred to in paragraph 1 contain rules for the notification of parties concerned.

Article 40

Consultation procedure

1. Regional coordination centres shall develop a procedure to organised, in the exercise of their daily operational duties and tasks, the appropriate and regular consultation of transmission system operators in the system operation region, other regional coordination centres and of relevant stakeholders. In order to ensure that regulatory issues can be addressed, regulatory authorities shall be involved when required.

2. Regional coordination centres shall consult the Member States **and Contracting Parties** in the system operation region and, where there is a regional forum, their regional forums on matters of political relevance excluding the day-to-day activities of regional coordination centres and the implementation of their tasks. Regional coordination centres shall take due account of the recommendations of the Member States **and Contracting Parties** and where applicable, of their regional forums.

Article 41

Transparency

1. Regional coordination centres shall develop a process for stakeholder involvement and shall organise regular meetings with stakeholders to discuss matters relating to the efficient, secure and reliable operation of the interconnected system and to identify shortcomings and propose improvements.

2. The **<….>** regional coordination centres shall operate in full transparency towards stakeholders and the general public. They shall publish all relevant documentation on their respective websites.

Article 42

Adoption and review of coordinated actions and recommendations

1. The transmission system operators in a system operation region **defined by Annex V** shall develop a procedure for the adoption and revision of coordinated actions and recommendations issued by regional coordination centres in accordance with the criteria set out in paragraphs 2, 3, and 4.

2. Regional coordination centres shall issue coordinated actions to the transmission system operators in respect of the tasks referred to in points (a) and (b) of Article 37(1). Transmission system operators shall implement the coordinated actions except where the implementation of the coordinated actions would result in a violation of the operational security limits defined by each transmission system operator in accordance with **Regulation (EC) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC.**

Where a transmission system operator decides not to implement a coordinated action for the reasons set out in this paragraph, it shall transparently report the detailed reasons to the regional coordination centre and the transmission system operators of the system operation region without undue delay. In such cases, the regional coordination centre shall assess the impact of that decision on the other transmission system operators of the system operation region and may propose a different set of coordinated actions subject to the procedure set out in paragraph 1.

3. Regional coordination centres shall issue recommendations to the transmission system operators in relation to the tasks listed in points (c) to (p) of Article 37(1) or assigned in accordance with Article 37(2).

Where a transmission system operator decides to deviate from a recommendation as referred to in paragraph 1, it shall submit a justification for its decision to regional coordination centres and to the other transmission system operators of the system operation region without undue delay.

4. The review of coordinated actions or a recommendation shall be triggered at the request of one or more of the transmission system operators of the system operation region. Following the review of the coordinated action or recommendation, regional coordination centres shall confirm or modify the measure.

5. Where a coordinated action is subject to review in accordance with paragraph 4 of this Article, the request for review shall not suspend the coordinated action except where the implementation of the coordinated action would result in a violation of the operational security limits defined by each individual transmission system operator in accordance with **Regulation (EC) 2017/1485 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**.

6. Upon the proposal of a Member State **or Contracting Party in a system operation region defined by Annex V, <…>**, the Member States **or Contracting Parties** in a system operation region may jointly decide to grant the competence to issue coordinated actions to their regional coordination centre for one or more of the tasks provided for in points (c) to (p) of Article 37(1) of this Regulation.

Article 43

Management board of regional coordination centres

1. In order to adopt measures related to their governance and to monitor their performance, the regional coordination centres shall establish a management board.

2. The management board shall be composed of members representing all the transmission system operators that participate in the relevant regional coordination centre.

3. The management board shall be responsible for:

(a) drafting and endorsing the statutes and rules of procedure of regional coordination centres;

(b) deciding upon and implementing the organisational structure;

(c) preparing and endorsing the annual budget;

(d) developing and endorsing the cooperative processes in accordance with Article 38.

4. The competences of the management board shall exclude those that are related to the day-to- day activities of regional coordination centres and the performance of its tasks.

Article 44

Organisational structure

1. The transmission system operators of a system operation region shall establish the organisational structure of regional coordination centres that supports the safety of their tasks.

Their organisational structure shall specify:

(a) the powers, duties and responsibilities of the personnel;

(b) the relationship and reporting lines between different parts and processes of the organisation.

2. Regional coordination centres may establish regional desks to address sub-regional specificities or establish back-up regional coordination centres for the efficient and reliable exercise of their tasks where proven to be strictly necessary.

Article 45

Equipment and staff

Regional coordination centres shall be equipped with all human, technical, physical and financial resources necessary for fulfilling their obligations under this Regulation and carrying out their tasks independently and impartially.

Article 46

Monitoring and reporting

1. Regional coordination centres shall establish a process for the continuous monitoring of at least:

(a) their operational performance;

(b) the coordinated actions and recommendations issued, the extent to which the coordinated actions and recommendations have been implemented by the transmission system operators and the outcome achieved;

(c) the effectiveness and efficiency of each of the tasks for which they are responsible and, where applicable, the rotation of those tasks.

2. Regional coordination centres shall account for their costs in a transparent manner and report them to the **Energy Community Regulatory Board**, **and to the extent that Member States are involved,** to the **Agency for the Cooperation of Energy Regulators,** and to the regulatory authorities in the system operation region.

3. Regional coordination centres shall submit an annual report on the outcome of the monitoring provided for in paragraph 1 and information on their performance to the ENTSO for Electricity, the **Agency for the Cooperation of Energy Regulators, the Energy Community Regulatory Board**, the regulatory authorities in the system operation region and the **Security of Supply** Group.

4. Regional coordination centres shall report any shortcomings that they identify in the monitoring process under paragraph 1 to the ENTSO for Electricity, the regulatory authorities in the system operation region, the **Agency for the Cooperation of Energy Regulators, the Energy Community Regulatory Board,** the **Security of Supply Group** and the other competent authorities of Member States **and Contracting Parties** responsible for the prevention and management of crisis situations. On the basis of that report, the relevant regulatory authorities of the system operation region may propose measures to address the shortcomings to the regional coordination centres.

5. Without prejudice to the need to protect security and the confidentiality of commercially sensitive information, regional coordination centres shall make public the reports referred to in paragraphs 3 and 4.

Article 47

Liability

In proposals for the establishment of regional coordination centres in accordance with Article 35, the transmission system operators in the system operation region shall include the necessary steps to cover liability related to the execution of regional coordination centres' tasks. The method employed to provide the cover shall take into account the legal status of regional coordination centres and the level of commercial insurance cover available.

Article 48

Ten-year network development plan

<...>

The Contracting Parties shall be included in the ten-year network development plan modelling of the integrated network, scenario development and an assessment of the resilience of the system pursuant to

Article 48 of Regulation 2019/943.

Article 49

Inter-transmission system operator compensation mechanism

1. Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks.

2. The compensation referred to in paragraph 1 shall be paid by the operators of national transmission systems from which cross-border flows originate and the systems where those flows end.

3. Compensation payments shall be made on a regular basis with regard to a given period in the past. Ex-post adjustments of compensation paid shall be made where necessary, to reflect costs actually incurred.[2]

<...>

4. **<...>**

5. The magnitude of cross-border flows hosted and the magnitude of cross-border flows designated as originating or ending in national transmission systems shall be determined on the basis of the physical flows of electricity actually measured during a given period.

6. The costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward-looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, in so far as such infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. When establishing the costs incurred, recognised standard-costing methodologies shall be used. Benefits that a network incurs as a result of hosting cross-border flows shall be taken into account to reduce the compensation received.

7. For the purpose of the inter-transmission system operator compensation mechanism only, where transmission networks of two or more Member States **or Contracting Parties** form part, in whole or in part, of a single control block, the control block as a whole shall be considered as forming part of the transmission network of one of the Member States or **Contracting Parties** concerned, in order to avoid flows within control blocks being considered as cross-border flows under point (b) of Article 2(2) and giving rise to compensation payments under paragraph 1 of this Article. The regulatory authorities of the Member States **or Contracting Parties** concerned may decide which of the Member States **or Contracting Parties** concerned shall be that of which the control block as a whole is to be considered to form part.

Article 50

Provision of information

1. Transmission system operators shall put in place coordination and information exchange mechanisms to ensure the security of the networks in the context of congestion management.

2. The safety, operational and planning standards used by transmission system operators shall be made public. The information published shall include a general scheme for the calculation of the total transfer

2 There is a clerical error in the Ministerial Council Decision D2022/03/MC-EnC.

capacity and the transmission reliability margin based upon the electrical and physical features of the network. Such schemes shall be subject to approval by the regulatory authorities.

3. Transmission system operators shall publish estimates of available transfer capacity for each day, indicating any available transfer capacity already reserved. Those publications shall be made at specified intervals before the day of transport and shall include, in any event, week-ahead and month-ahead estimates, as well as a quantitative indication of the expected reliability of the available capacity.

4. Transmission system operators shall publish relevant data on aggregated forecast and actual demand, on availability and actual use of generation and load assets, on availability and use of the networks and interconnections, on balancing power and reserve capacity and on the availability of flexibility. For the availability and actual use of small generation and load assets, aggregated estimate data may be used.

5. The market participants concerned shall provide the transmission system operators with the relevant data.

6. Generation undertakings which own or operate generation assets, where at least one generation asset has an installed capacity of at least 250 MW, or which have a portfolio comprising at least 400 MW of generation assets, shall keep at the disposal of the regulatory authority, the national competition authority and the **Energy Community Secretariat**, for five years all hourly data per plant that is necessary to verify all operational dispatching decisions and the bidding behaviour at power exchanges, interconnection auctions, reserve markets and over-the-counter- markets. The per-plant and per hour information to be stored shall include, but shall not be limited to, data on available generation capacity and committed reserves, including allocation of those committed reserves on a per-plant level, at the times the bidding is carried out and when production takes place.

7. Transmission system operators shall exchange regularly a set of sufficiently accurate network and load flow data in order to enable load flow calculations for each transmission system operator in its relevant area. The same set of data shall be made available to the regulatory authorities, and to the **Energy Community Secretariat,** Member States **and Contracting Parties** upon request. The regulatory authorities, Member State **and Contracting Parties** and the **Energy Community Secretariat** shall treat that set of data confidentially, and shall ensure that confidential treatment is also given by any consultant carrying out analytical work on their request, on the basis of those data.

Article 51

Certification of transmission system operators

1. The **Energy Community Secretariat** shall examine any notification of a decision on the certification of a transmission system operator as laid down in Article 52(6) of Directive (EU) 2019/944, **as adopted and adapted by Ministerial Council Decision 2021/13/MC-EnC** as soon as it is received. Within two months of receipt of such notification, the **Energy Community Secretariat** shall deliver its opinion to the relevant regulatory authority as to its compatibility with Article 43 and either Article 52(2) or Article 53 of Directive (EU) 2019/944.

When preparing the opinion referred to in the first subparagraph, the **Energy Community Secretariat** may request **the Energy Community Regulatory Board** to provide its opinion on the regulatory authority's decision. In such a case, the two-month period referred to in the first subparagraph shall be extended by two further months.

In the absence of an opinion by the **Energy Community Secretariat** within the periods referred to in the first and second subparagraphs, the **Energy Community Secretariat** shall be considered not to raise objections to the regulatory authority's decision.

2. Within two months of receipt of an opinion of the **Energy Community Secretariat**, the regulatory authority shall adopt its final decision regarding the certification of the transmission system operator, taking the utmost account of that opinion. The regulatory authority's decision and the **Energy Community Secretariat**'s opinion shall be published together.

3. At any time during the procedure, regulatory authorities or the **Energy Community Secretariat** may request from a transmission system operator or an undertaking performing any of the functions of generation or supply any information relevant to the fulfilment of their tasks under this Article.

4. Regulatory authorities and the **Energy Community Secretariat** shall protect the confidentiality of commercially sensitive information.

5. Where the **Energy Community Secretariat** has received notification of the certification of a transmission system operator under Article 43(9) of Directive (EU) 2019/944, **as adapted and adopted by the Ministerial Council Decision 2021/13/MC-EnC, the Energy Community Secretariat shall issue an opinion relating to certification. The regulatory authority shall take the utmost account of that opinion. Where the final decision diverges from the Secretariat's opinion the regulatory authority concerned shall provide and publish, together with that decision, the reasoning underlying its decision. Diverting decisions shall be included in the agenda of the first meeting of the Ministerial Council following the date of the decision, for information and discussion.**

CHAPTER VI
DISTRIBUTION SYSTEM OPERATION

Article 52

Coordination Group of the Energy Community Distribution System Operators

1. Distribution system operators shall cooperate at **Contracting Party** level through the **Coordination Group of the Energy Community Distribution System Operators established by Procedural Act No 2018/01/MC-EnC** in order to promote the completion and functioning of the **single** market for electricity, and to promote optimal management and a coordinated operation of distribution and transmission systems, **and in accordance with the tasks and terms of reference adopted by Procedural Act No 2018/01/MC-EnC**. **Energy Community Distribution System Operators shall be represented by the Energy Community Secretariat in all activities aimed to enhance cooperation with the EU DSO entity established in accordance with Regulation (EU) 943/2019. This is without prejudice to distribution system operators joining the EU DSO entity individually based on common agreement.**

2. **<...>** As an expert entity working for the common **Energy Community** interest, the **Coordination Group of the Energy Community Distribution System Operators** shall neither represent particular interests nor seek to influence the decision-making process to promote specific interests.

3. <...>

Article 53

Establishment of the EU DSO entity

<...>

Article 54

Principal rules and procedures for the EU DSO entity

<...>

Article 55

Tasks of the EU DSO entity

<...>

Article 56

Consultations in the network code development process

<...>

Article 57

Cooperation between distribution system operators and transmission system operators

1. Distribution system operators and transmission system operators shall cooperate with each other in planning and operating their networks. In particular, distribution system operators and transmission system operators shall exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks.

2. Distribution system operators and transmission system operators shall cooperate with each other in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system operators and the transmission system operators.

CHAPTER VII
NETWORK CODES AND GUIDELINES

Article 58

Adoption of network codes and guidelines

The Energy Community shall transpose and implement the network codes and guidelines developed at European Union level and as adapted by the Ministerial Council.

Article 59

Establishment of network codes

<…>

Article 60

Amendments of network codes

<…>

Article 61

Guidelines

<…>

Article 62

Right of Contracting Parties to provide for more detailed measures

This Regulation shall be without prejudice to the rights of **Contracting Parties** to maintain or introduce measures that contain more detailed provisions than those set out in this Regulation, in the guidelines referred to in Article 61 or in the network codes referred to in Article 59, provided that those measures are compatible with **Energy Community** law.

CHAPTER VIII
FINAL PROVISIONS

Article 63

New interconnectors

1. New direct current interconnectors may, upon request, be exempted, for a limited period, from Article 19(2) and (3) of this Regulation and from Articles 6 and 43, Article 59(7) and Article 60(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** provided that the following conditions are met:

(a) the investment enhances competition in electricity supply;

(b) the level of risk attached to the investment is such that the investment would not take place unless an exemption is granted;

(c) the interconnector is owned by a natural or legal person which is separate, at least in terms of its legal form, from the system operators in whose systems that interconnector is to be built;

(d) charges are levied on users of that interconnector;

(e) since **1 July 2007**, no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector; and

(f) an exemption would not be to the detriment of competition or the effective functioning of the internal market for electricity, or the efficient functioning of the regulated system to which the interconnector is linked.

2. Paragraph 1 shall also apply, in exceptional cases, to alternating current interconnectors provided that the costs and risks of the investment in question are particularly high when compared with the costs and risks normally incurred when connecting two neighbouring national transmission systems by an alternating current interconnector.

3. Paragraph 1 shall also apply to significant increases of capacity in existing interconnectors.

4. The decision granting an exemption as referred to in paragraphs 1, 2 and 3 shall be taken on a case-by-case basis by the regulatory authorities of the Member States **and Contracting Parties** concerned. An exemption may cover all or part of the capacity of the new interconnector, or of the existing interconnector with significantly increased capacity.

Within two months of receipt of the request for exemption by the last of the regulatory authorities concerned, **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** may provide those regulatory authorities with an opinion. The regulatory authorities may base their decision on that opinion.

In deciding to grant an exemption, regulatory authorities shall take into consideration, on a case- by-case basis, the need to impose conditions regarding the duration of the exemption and non- discriminatory access to the interconnector. When deciding on those conditions, regulatory authorities shall, in particular, take account of additional capacity to be built or the modification of existing capacity, the time-frame of the project and national circumstances.

Before granting an exemption, the regulatory authorities of the **Contracting Parties and Member States** concerned shall decide on the rules and mechanisms for management and allocation of capacity. Those congestion-management rules shall include the obligation to offer unused capacity on the market and users of the facility shall be entitled to trade their contracted capacities on the secondary market. In the assessment of the criteria referred to in points (a), (b) and (f) of paragraph 1, the results of the capacity-allocation procedure shall be taken into account.

Where all the regulatory authorities concerned have reached agreement on the exemption decision within six months of receipt of the request, they shall inform the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators** of that decision.

The exemption decision, including any conditions referred to in the third subparagraph of this paragraph,

shall be duly reasoned and published.

5. The decision referred to in paragraph 4 shall be taken by the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,**:

(a) where the regulatory authorities concerned have not been able to reach an agreement within six months from the date on which the last of those regulatory authorities received the exemption request; or

(b) upon a joint request from the regulatory authorities concerned.

Before taking such a decision, the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** shall consult the regulatory authorities concerned and the applicants.

6. Notwithstanding paragraphs 4 and 5, **Contracting Parties** may provide for the regulatory authority or the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators**, as the case may be, to submit, for a formal decision, to the relevant body in the **Contracting Parties**, its opinion on the request for an exemption. That opinion shall be published together with the decision.

7. A copy of every request for exemption shall be transmitted for information without delay by the regulatory authorities to the **Energy Community Secretariat** and **Energy Community Regulatory Board, and to the extent Member States are affected to the European Commission and the Agency for the Cooperation of Energy Regulators** on receipt. The decision shall be notified, without delay, by the regulatory authorities concerned or by **Energy Community Regulatory Board and, to the extent Member States are affected, by the Agency for the Cooperation of Energy Regulators** (the notifying bodies), to the **Energy Community Secretariat and, to the extent Member States are affected, to the European Commission**, together with all the relevant information with respect to the decision. That information may be submitted to the **Energy Community Secretariat, and to the extent Member States are affected, to the European Commission** in aggregate form, enabling the **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** to reach a well-founded decision. In particular, the information shall contain:

(a) the detailed reasons on the basis of which the exemption was granted or refused, including the financial information justifying the need for the exemption;

(b) the analysis undertaken of the effect on competition and the effective functioning of the internal market for electricity resulting from the grant of the exemption;

(c) the reasons for the time period and the share of the total capacity of the interconnector in question for which the exemption is granted; and

(d) the result of the consultation of the regulatory authorities concerned.

8. Within 50 working days of the day following that of receipt of the notification under paragraph 7, the **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** may **issue an opinion inviting** the notifying bodies to amend or withdraw the decision to grant an exemption. That period may be extended by an additional 50 working days where further information is requested by the **Energy Community Secretariat or, to the extent Member States are affected, the European Commission**. The additional period shall begin on the day following receipt of

the complete information. The initial period may also be extended by consent of both the **Energy Community Secretariat, or, to the extent Member States are affected, the European Commission** and the notifying bodies.

Where the requested information is not provided within the period set out in the **Energy Community Secretariat**'s, **or, to the extent Member States are affected, the European Commission's** request, the notification shall be deemed to be withdrawn unless, before the expiry of that period, either the period is extended by consent of both the **Energy Community Secretariat, or, to the extent Member States are affected, the European Commission** and the notifying bodies, or the notifying bodies, in a duly reasoned statement, inform the **Energy Community Secretariat and, to the extent Member States are affected, the European Commission** that they consider the notification to be complete.

The notifying bodies shall take the utmost account of a Secretariat's or, to the extent Member States are affected, the European Commission's opinion that recommends to amend or withdraw the exemption decision. Where the final decision diverges from the Secretariat's, or, to the extent Member States are affected, the European Commission's opinion, the regulatory authority concerned shall provide and publish, together with that decision, the reasoning underlying its decision. Diverting decisions shall be included in the agenda of the first meeting of the Ministerial Council following the date of the decision, for information and discussion.

The **Energy Community Secretariat and the European Commission** shall protect the confidentiality of commercially sensitive information.

The **Energy Community Secretariat's or, to the extent Member States are affected, the European Commission's opinion on** an exemption decision shall expire two years after the date of its adoption in the event that construction of the interconnector has not started by that date, and five years after the date of its adoption if the interconnector has not become operational by that date, unless the **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** decides, on the basis of a reasoned request by the notifying bodies, that any delay is due to major obstacles beyond the control of the person to whom the exemption has been granted.

9. Where the regulatory authorities of the **Contracting Parties and Member States** concerned decide to modify an exemption decision, they shall notify their decision to the **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** without delay, together with all the relevant information with respect to the decision. Paragraphs 1 to 8 shall apply to the decision to modify an exemption decision, taking into account the particularities of the existing exemption.

10. The **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** may, on request or on its own initiative, reopen proceedings relating to an exemption request where:

(a) taking due account of the legitimate expectations of the parties and of the economic balance- achieved in the original exemption decision, there has been a material change in any of the facts on which the decision was based;

(b) the undertakings concerned act contrary to their commitments; or

(c) the decision was based on incomplete, incorrect or misleading information, which was provided by the parties.

11. **<...>**

Article 64

Derogations

<…>

Article 65

Provision of information and confidentiality

1. **Contracting Parties** and the regulatory authorities shall, on request, provide the **Energy Community Secretariat** with all the information necessary for the purposes of enforcing this Regulation.

The **Energy Community Secretariat** shall set a reasonable time limit within which the information is to be provided, taking into account the complexity and urgency of the information required.

2. If the **Contracting Party** or the regulatory authority concerned does not provide the information referred to in paragraph 1 within the time limit referred to in paragraph 1 the **Energy Community Secretariat** may request all the information necessary for the purpose of enforcing this Regulation directly from the undertakings concerned.

When sending a request for information to an undertaking, the **Energy Community Secretariat** shall, at the same time, forward a copy of the request to the regulatory authorities of the **Contracting Parties** in whose territory the seat of the undertaking is situated.

3. In its request for information under paragraph 1, the **Energy Community Secretariat** shall state the legal basis of the request, the time limit within which the information is to be provided, the purpose of the request, and the penalties provided for in Article 66(2) for supplying incorrect, incomplete or misleading information.

4. The owners of the undertakings or their representatives and, in the case of legal persons, the natural persons authorised to represent the undertaking by law or by their instrument of incorporation, shall supply the information requested. Where lawyers are authorised to supply the information on behalf of their client, the client shall remain fully responsible in the event that the information supplied is incomplete, incorrect or misleading.

5. Where an undertaking does not provide the information requested within the time limit set by the **Energy Community Secretariat** or supplies incomplete information, the **Energy Community Secretariat** may request **the Contracting Party** concerned to require the information to be provided. That request shall specify what information is required and set an appropriate time limit within which it is to be supplied. It shall indicate an appropriate proposal for penalties provided for in Article 66. **<…>**

6. The information referred to in paragraphs 1 and 2 shall be used only for the purposes of enforcing this Regulation.

The **Energy Community Secretariat** shall not disclose information acquired pursuant to this Regulation where that information is covered by the obligation of professional secrecy.

Article 66

Penalties

1. Contracting Parties shall lay down rules on penalties applicable to infringements of the provisions of this Regulation and shall take all measures necessary to ensure that those provisions are implemented. The penalties provided for must be effective, proportionate and dissuasive. Contracting Parties shall notify these rules and measures to the Energy Community Secretariat and shall notify the Energy Community Secretariat without delay of any subsequent amendment affecting them.

2. **<...>**

3. The penalties provided for pursuant to paragraph 1 **<...>** shall not be of a criminal law nature.

Article 67

Committee procedure

<...>

Article 68

Exercise of the delegation

<...>

Article 69

Commission reviews and reports

<...>

Article 70

Repeal

Ministerial Council Decision 2011/02/EnC-MC adapting and adopting Regulation (EC) No 714/2009 is repealed. References to Regulation (EC) No 714/2009 shall be construed as references to this Regulation and shall be read in accordance with the correlation table set out in Annex III.

Article 71

Entry into force

This Decision 2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[3]

3 The text displayed here corresponds to Article 13 of Decision D/2022/03/MC-EnC.

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with <…>, Regulation (EU) 2019/943, <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

ANNEX I
TASKS OF REGIONAL COORDINATION CENTRES

1. Coordinated capacity calculation

1.1 Regional coordination centres shall carry out the coordinated calculation of cross-zonal capacities.

1.2 Coordinated capacity calculation shall be performed for the day-ahead and intraday timeframes.

1.3 Coordinated capacity calculation shall be performed on the basis of the methodologies developed pursuant to the guideline on capacity allocation and congestion management adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009.

1.4 Coordinated capacity calculation shall be performed based on a common grid model in accordance with point 3.

1.5 Coordinated capacity calculation shall ensure an efficient congestion management in accordance with the principles of congestion management defined in this Regulation.

2. Coordinated security analysis

2.1 Regional coordination centres shall carry out a coordinated security analysis aiming to ensure secure system operation.

2.2 Security analysis shall be performed for all operational planning timeframes, between the year-ahead and intraday timeframes, using the common grid models.

2.3 Coordinated security analysis shall be performed on the basis of the methodologies developed pursuant to the system operation guideline adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009.

2.4 Regional coordination centres shall share the results of the coordinated security analysis with at least the transmission system operators in the system operation region.

2.5 When as a result of the coordinated security analysis a regional coordination centre detects a 2.5possible constraint, it shall design remedial actions maximising effectiveness and economic efficiency.

3. Creation of common grid models

3.1 Regional coordination centres shall set up efficient processes for the creation of a common 3.1grid model for each operational planning timeframe between the year-ahead and intraday timeframes.

3.2 Transmission system operators shall appoint one regional coordination centre to build the Union-wide common grid models.

3.3 Common grid models shall be performed in accordance with the methodologies developed pursuant to **Regulation (EC) 2017/1485**.

3.4 Common grid models shall include relevant data for efficient operational planning and capacity calculation in all operational planning timeframes between the year-ahead and intraday timeframes.

3.5 Common grid models shall be made available to all regional coordination centres, transmission system operators, ENTSO for Electricity and, upon request, to the **Energy Community Regulatory Board**.

4. Support for transmission system operators' defence and restoration plans with regard to the consistency assessment

4.1 Regional coordination centres shall support the transmission system operators in the system operation

region in carrying out the consistency assessment of transmission system operators' defence plans and restoration plans pursuant to **Regulation (EC) 2017/2195, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC.**

4.2 All transmission system operators shall agree on a threshold above which the impact of actions of one or more transmission system operators in the emergency, blackout or restoration states is considered significant for other transmission system operators synchronously or non-synchronously interconnected.

4.3 In providing support to the transmission system operators, the regional coordination centre shall:

(a) identify potential incompatibilities;

(b) propose mitigation actions.

4.4 Transmission system operators shall assess and take into account the proposed mitigation actions.

5. Support the coordination and optimisation of regional restoration

5.1 Each relevant regional coordination centre shall support the transmission system operators appointed as frequency leaders and the resynchronisation leaders pursuant to **Regulation (EU) 2017/2196,[4] as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**. The transmission system operators in the system operation region shall establish the role of the regional coordination centre relating to the support to the coordination and optimisation of regional restoration.

5.2 Transmission system operators may request assistance from regional coordination centres if their system is in a blackout or restoration state.

5.3 Regional coordination centres shall be equipped with the close to real time supervisory control and data acquisition systems with the observability defined by applying the threshold referred to in point 4.2.

6. Post-operation and post-disturbances analysis and reporting

6.1 Regional coordination centres shall investigate and prepare a report on any incident above the threshold referred to in point 4.2. The regulatory authorities in the system operation region **as defined by Annex V** may be involved in the investigation upon their request. The report shall contain recommendations aiming to prevent similar incidents in future.

6.2 Regional coordination centres shall publish the report. **The Energy Community Regulatory Board, or the extent Member States are affected, the Agency for Cooperation of European Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** may issue recommendations aiming to prevent similar incidents in future.

7. Regional sizing of reserve capacity

7.1 Regional coordination centres shall calculate the reserve capacity requirements for the system operation region. The determination of reserve capacity requirements shall:

(a) pursue the general objective to maintain operational security in the most cost effective manner;

(b) be performed at the day-ahead or intraday timeframe, or both;

(c) calculate the overall amount of required reserve capacity for the system operation region;

(d) determine minimum reserve capacity requirements for each type of reserve capacity;

(e) take into account possible substitutions between different types of reserve capacity with the aim to minimise the costs of procurement;

4 There is a clerical error in the Ministerial Council Decision D2022/03/MC-EnC.

(f) set out the necessary requirements for the geographical distribution of required reserve capacity, if any.

8. Facilitation of the regional procurement of balancing capacity

8.1 Regional coordination centres shall support the transmission system operators in the system operation region in determining the amount of balancing capacity that needs to be procured. The determination of the amount of balancing capacity shall: (a) be performed at the day-ahead or intraday timeframe, or both;

(b) take into account possible substitutions between different types of reserve capacity with the aim to minimise the costs of procurement;

(c) take into account the volumes of required reserve capacity that are expected to be provided by balancing energy bids, which are not submitted based on a contract for balancing capacity.

8.2 Regional coordination centres shall support the transmission system operators of the system operation region in procuring the required amount of balancing capacity determined in accordance with point 8.1. The procurement of balancing capacity shall: (a) be performed at the day-ahead or intraday timeframe, or both;

(b) take into account possible substitutions between different types of reserve capacity with the aim to minimise the costs of procurement.

9. Week-ahead to at least day-ahead regional system adequacy assessments and preparation of risk reducing actions

9.1 Regional coordination centres shall carry out week-ahead to at least day-ahead regional adequacy assessments in accordance with the procedures set out in Regulation (EU) 2017/1485, **as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** and on the basis of the methodology developed pursuant Article 8 of Regulation (EU) 2019/941**, as adopted and adapted by Ministerial Council Decision 2021/13/MC- EnC.**

9.2 Regional coordination centres shall base the short-term regional adequacy assessments on the information provided by the transmission system operators of system operation region withthe aim of detecting situations where a lack of adequacy is expected in any of the control areas or at regional level. Regional coordination centres shall take into account possible cross- zonal exchanges and operational security limits in all relevant operational planning timeframes.

9.3 When performing a regional system adequacy assessment, each regional coordination centre shall coordinate with other regional coordination centres to:

(a) verify the underlying assumptions and forecasts;

(b) detect possible cross-regional lack of adequacy situations.

9.4 Each regional coordination centre shall deliver the results of the regional system adequacy assessments together with the actions it proposes to reduce risks of lack of adequacy to the transmission system operators in the system operation region and to other regional coordination centres.

10. Regional outage planning coordination

10.1 Each Regional coordination centre shall carry out regional outage coordination in accordance with **Regulation (EU) 2017/1485, as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC** in order to monitor the availability status of the relevant assets and coordinate their availability plans to ensure the operational security of the transmission system, while maximising the capacity of the interconnectors and the transmission systems affecting cross-zonal flows.

10.2 Each Regional coordination centre shall maintain a single list of relevant grid elements, power gener-

ating modules and demand facilities of the system operation region **as defined by Annex V** and make it available on the ENTSO for Electricity operational planning data environment.

10.3 Each Regional coordination centre shall carry out the following activities related to outage coordination in the system operation region:

(a) assess outage planning compatibility using all transmission system operators' year-ahead availability plans;

(b) provide the transmission system operators in the system operation region with a list of detected planning incompatibilities and the solutions it proposes to solve the incompatibilities.

11. Optimisation of inter-transmission system operator compensation mechanisms

11.1 The transmission system operators in the system operation region may jointly decide to receive support from the regional coordination centre in administering the financial flows related to settlements between transmission system operators involving more than two transmission system operators, such as redispatching costs, congestion income, unintentional deviations or reserve procurement costs.

12. Training and certification of staff working for regional coordination centre

12.1 Regional coordination centres shall prepare and carry out training and certification programmes focusing on regional system operation for the personnel working for regional coordination centres.

12.2 The training programs shall cover all the relevant components of system operation, where the regional coordination centre performs tasks including scenarios of regional crisis.

13. Identification of regional electricity crisis scenarios

13.1 If the ENTSO for Electricity delegates this function, regional coordination centres shall identify regional electricity crisis scenarios in accordance with the criteria set out in Article 6(1) of Regulation (EU) 2019/941, **as adopted and adapted by Ministerial Council Decision 2021/13/MC-EnC**.

The identification of regional electricity crisis scenarios shall be performed in accordance with the methodology set out in Article 5 of Regulation (EU) 2019/941, **as adopted and adapted by Ministerial Council Decision 2021/13/MC-EnC**.

13.2 Regional coordination centres shall support the competent authorities of each system operation region upon their request in the preparation and carrying out of biennial crisis simulation in accordance with Article 12(3) of Regulation (EU) 2019/941, **as adopted and adapted by Ministerial Council Decision 2021/13/MC-EnC**.

14. Identification of needs for new transmission capacity, for upgrade of existing transmission capacity or their alternatives

14.1 Regional coordination centres shall support transmission system operators in the identification of needs for new transmission capacity, for an upgrade of existing transmission capacity or for their alternatives, to be submitted to the regional groups established pursuant to Regulation (EU) No 347/2013, **as adopted by Ministerial Council Decision 2015/09/MC-EnC** and to be included in the ten-year network development plan referred to in Article 51 of Directive (EU) 2019/944, **as adopted by Ministerial Council Decision 2021/13/MC-EnC.**

15. Calculation of the maximum entry capacity available for the participation of foreign capacity in capacity mechanisms

15.1 Regional coordination centres shall support transmission system operator in calculating the maximum

entry capacity available for the participation of foreign capacity in capacity mechanisms taking into account the expected availability of interconnection and the likely concurrence of system stress between the system where the mechanism is applied and the system in which the foreign capacity is located.

15.2 The calculation shall be performed in accordance with the methodology developed by the **ENTSO for Electricity and approved by the Agency for the Cooperation of Energy Regulators**.

15.3 Regional coordination centres shall provide a calculation for each bidding zone border covered by the system operation region.

16. Preparation of seasonal adequacy assessments

16.1 If the ENTSO for Electricity delegates this function pursuant to Article 9 of Regulation (EU) 2019/941, regional coordination centres shall carry out regional seasonal adequacy assessments.

16.2 The preparation of seasonal adequacy assessments shall be carried out on the basis of the methodology developed pursuant to Article 8 of Regulation (EU) 2019/941, **as adopted and adapted by Ministerial Council Decision 2021/13/MC-EnC**.

ANNEX II

<...>

ANNEX III

<...>

ANNEX IV
REGIONAL COORDINATION CENTRES FOR THE SYSTEM OPERATION REGIONS

Article 1

Subject matter and scope

1. Regional Coordination Centres seated in a Contracting Party defined by Articles 2 to 4 of this Annex are mandated to perform the tasks and mission in line with Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.

2. Regional Coordination Centres seated in a Member State defined by Articles 2 to 4 of this Annex are mandated to perform the tasks and mission in line with Regulation (EU) 2019/943.

Article 2

Regional Coordination Centres for the Shadow SEE SOR

1. For the bidding zone borders between Contracting Parties, the Regional Coordination Centres located in the EU or in a Contracting Party shall assume the roles of Regional Coordination Centres in the Shadow South-East Europe System Operation Region (Shadow SEE SOR).

2. For the bidding zone borders between Member States and Contracting Parties, the Regional Coordination Centres in Thessaloniki (Greece) or Munich (Germany) shall assume the roles of Regional Coordination Centres in the Shadow South-East Europe System Operation Region (Shadow SEE SOR) unless all concerned neighbouring transmission system operators of the European Union agree to a Regional Coordination Centre located in a Contracting Party.

3. Paragraphs 1 and 2 of this Article shall not apply if and to the extent a decision is adopted in accordance with the procedure stipulated in Article 35(1) of Regulation (EU) 2019/943 before the expiry of the deadline stipulated in Article 2 of Ministerial Council Decision 2022/03/MC-EnC. In this case, the decision shall include Regional Coordination Centres located in the European Union for the bidding zone borders between Member States and Contracting Parties unless all concerned neighbouring transmission system operators of the European Union agree to a Regional Coordination Centre located in a Contracting Party.

Article 3

Regional Coordination Centres for the EE SOR

Upon agreement of the shareholders of the respective Regional Coordination Centres, the Regional Coordination Centres for the Eastern Europe System Operation Region (EE SOR) shall be the Regional Coordination Centre for the Central Europe SOR.

Article 4

Adjustments to the Regional Coordination Centres

Adjustments to the configuration of Regional Coordination Centres listed in this Annex shall be subject to a proposal of all transmission system operators of a system operation region defined in this Annex and the approval procedures pursuant to Article 35 of Regulation (EU) 2019/943. The proposal shall include Regional Coordination Centres located in the European Union for the bidding zone borders between Member States and Contracting Parties unless all concerned neighbouring transmission system operators of the European Union agree to a Regional Coordination Centre located in a Contracting Party.

Article 5

Implementation and monitoring

Within 6 months upon their establishment the Regional Coordination Centres defined by Articles 2 to 4 of this Annex shall present to the regulatory authorities concerned:

(a) the organisational, financial and operational arrangements necessary to ensure the efficient, ecure and reliable operation of the interconnected transmission system;

(b) an implementation plan for the entry into operation of the regional coordination centres;

(c) the statutes and rules of procedure of the regional coordination centres;

(d) a description of cooperative processes in accordance with Article 38 of this Regulation;

(e) a description of the arrangements concerning the liability of the regional coordination centres in accordance with Article 47 of this Regulation.

ANNEX V
SYSTEM OPERATION REGIONS IN THE ENERGY COMMUNITY

Article 1

Subject matter and scope

1. This Annex specifies the transmission system operators (TSOs), bidding zones (BZ), bidding zone borders, capacity calculation regions (CCR) as defined according to Article 15 of Regulation 2015/1222 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC, and outage coordination regions (OCR) that are covered by the individual system operation regions (SOR) established in line with this Regulation, reflecting interdependency of the electricity system in terms of flows, as well as geographic system operation regions already established within the EU process.

2. This Annex also defines how the coordination between regional coordination centres shall take place for bidding zone borders adjacent to SORs.

Article 2

System Operation Regions

1. SORs include TSOs that have been designated or assigned with responsibilities which are relevant for system operation, such as, but not limited to: calculation of capacity, assessment of needed remedial actions to ensure security of the whole system, coordination of all the outages to ensure security and efficiency, adequacy assessment and tasks related to the provision of system balancing.

2. TSOs from SORs in the Energy Community should cooperate with TSOs from regions established under Regulation (EU) 2019/943 and consult in particular with those TSOs where system operation regions overlap with capacity calculation regions.

3. When consulting the relevant stakeholders, the TSOs of each SOR shall take the utmost account of the views expressed by the TSOs included in a CCR but not incorporated in the SOR of the mentioned CCR.

4. In case of amendments to the capacity calculation regions, the list of bidding zones, bidding zone borders and TSOs in system operation regions defined pursuant to paragraph 5 shall automatically reflect the changes to the capacity calculation regions.

5. In case of amendments to the determination of Capacity Calculation Regions pursuant to Article 15 of the Commission Regulation (EU) 2015/1222 and until such amendments are incorporated in this document, the list of bidding zones, bidding zone borders and transmission system operators in system operation regions defined pursuant to paragraph 5 shall be understood as reflecting the changes to the determination of Capacity Calculation Regions. This is without prejudice to the relevant transmission system operators' right under Article 36(4) of Regulation 2019/943 to submit a proposal to ACER for amendments."

6. When developing procedures for the adoption and revision of coordinated actions and recommendations, in line with Article 42 of the Regulation 2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC, TSOs of Shadow SEE SOR shall consult with the relevant TSOs of adjacent SORs where the bidding zone borders listed in paragraph 1 are concerned. In doing so, the TSOs of the Shadow SEE

SOR shall take the utmost account of the views expressed by the relevant TSOs of adjacent SORs.

7. The system operation regions shall be defined as follows:

	CCR	TSOs	BZs	BZ borders
Shadow South-east Europe System Operation Region (Shadow SEE SOR)	Shadow SEE CCR	Operatori i Sistemit te Transmetimit sh.a. (OST) Nezavisni operator sistema u Bosni i Hercegovini (NOS BiH) Operator sistemi, transmisioni dhe tregu Sh.A. (KOSTT) Crnogorski elektroprenosni sistem AD (CGES) Makedonski Elektroprenosen Sistem Operator AD (MEPSO)	Albania (AL) Bosnia and Hercegovina (BA) Kosovo* (KS) Montenegro (ME) North Macedonia (MK) Serbia (RS)	Shadow SEE CCR bidding zone borders ITME CCR bidding zone borders
		Elektromreza Srbije AD (EMS)		
Eastern Europe System Operation Region	EE CCR	Ukrenergo NPC SE (Ukrenergo) I.S. Moldelectrica (Moldeelctrica)	Ukraine (UA) Moldova (MD)	EE CCR bidding zone borders
(EE SOR)				

Article 3

Coordination of the bidding zone borders adjacent to the Shadow SEE SOR

1. The bidding zone borders adjacent to Shadow SEE SOR:

- Croatia – Bosnia and Hercegovina (HR - BA), Croatian Transmission System Operator Ltd. (HOPS) and Nezavisni operator sistema u Bosni i Hercegovini (NOS BiH)

- Croatia – Serbia (HR - RS), Croatian Transmission System Operator Ltd. (HOPS) and Elektromreza Srbije AD (EMS)

- Hungary – Serbia (HU - RS), Hungarian Independent Transmission Operator Company Ltd (MAVIR) and Elektromreza Srbije AD (EMS)

- Romania – Serbia (RO - RS), Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A. and Elektromreza Srbije AD (EMS)

- Bulgaria – Serbia (BG - RS), Elektroenergien Sistemen Operator EAD (ESO) and Elektromreza Srbije AD (EMS)

- Bulgaria – North Macedonia (BG - MK), Elektroenergien Sistemen Operator EAD (ESO) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)

- Greece – North Macedonia (BG - MK), Independent Power Transmission Operator S.A. (IPTO) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)

- Greece – Albania (GR - AL), Independent Power Transmission Operator S.A. (IPTO) and Operatori i Sistemit te Transmetimit sh.a. (OST)

- Italy – Montenegro (IT-ME), TERNA Rete Elettrica Nazionale S.p.A (TERNA) and Crnogorski elektroprenosni sistem AD (CGES).

2. The regional coordination centres (RCCs) defined in Annex IV for the Shadow SEE SOR shall coordinate the bidding zone borders listed in paragraph 1 in accordance with applicable terms, conditions and methodologies, and its mission as set out in this Regulation or Regulation (EU) 2019/943 in case the RCC is seated in a Member State.

3. TSOs listed in paragraph 1 that are part of the SORs defined by the Agency for the Cooperation of Energy Regulators, shall participate in the coordination of the borders through the RCC defined by the TSOs from the SEE Shadow SOR.

4. RCCs defined by the TSOs from the SEE Shadow SOR shall have agreements with RCCs defined for the neighbouring SORs defined by the Agency for the Cooperation of Energy Regulators; the Central Europe SOR and the SEE SOR.

Article 4

Coordination of the bidding zone borders adjacent to the EE SOR

1. The bidding zone borders adjacent to EE SOR are:

- Ukraine - Poland (UA - PL), Ukrenergo NPC SE (Ukrenergo) and PSE S.A. (PSE)

- Ukraine- Slovakia (UA - SL), Ukrenergo NPC SE (Ukrenergo) and Slovenská elektrizaná prenosová süstava, a.s. (SEPS)

- Ukraine - Hungary (UA - HU), Ukrenergo NPC SE (Ukrenergo) and Hungarian Independent Transmission Operator Company Ltd (MAVIR)

- Ukraine - Romania (UA - RO), Ukrenergo NPC SE (Ukrenergo) and Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A. (TEL)

- Moldova - Romania (MD - RO), I.S. Moldelectrica (MED) and Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A. (TEL).

2. The RCC mandated for EE SOR according to Annex IV shall coordinate the bidding zone borders listed in paragraph 1 in accordance with applicable terms, conditions and methodologies, and its mission as set out in this Regulation or Regulation (EU) 2019/943. in case the RCC's seat is in a Member State.

3. TSOs listed in paragraph 1 that are part of the SORs defined by the Agency for the Cooperation of Energy Regulators, shall participate in the coordination of the borders through the RCC defined by the TSOs from the EE SOR.

4. RCC defined by the TSOs from the EE SOR shall have agreements with RCCs defined for the neighboring SORs defined by the Agency for the Cooperation of Energy Regulators; the Central Europe SOR and the SEE SOR.

Article 5

Deviations and Adaptations

1. Article 2 shall not apply if and to the extent a decision is adopted in accordance with the procedure stipulated in Article 36(1) of Regulation (EU) 2019/943 before the expiry of the deadline stipulated in Article 2 of Ministerial Council Decision 2022/03/MC-EnC. In this case, the decision shall also specify the manner of coordination between regional coordination centres concerning the bidding zone borders adjacent to the SORs established.

2. Adjustments of the configuration of System Operation Regions listed in this Annex shall be subject to a proposal of ENTSO for Electricity and the decision of the Agency for the Cooperation of Energy Regulators pursuant to Article 36(1) of Regulation (EU) 2019/943.

REGULATION (EU) 2019/942 of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

*The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in **bold and blue**.*

Chapter I
Objectives and tasks

Article 1
Establishment and objectives

This Regulation **stipulates the tasks of the** European Union Agency for the Cooperation of Energy Regulators **(ACER) in the Energy Community in situations affecting at least one Contracting Party and one Member State of the European Union, limited to the application of the provisions of Directive (EU) 2019/944, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196 and Regulation (EU) 2017/1485, covering the territories referred to in Article 27 of the Treaty, and in particular the energy sector stakeholders of those Contracting Parties and Member States as defined by Article 1(1) of Procedural Act 2022/01/MC-EnC.**

Article 2
Type of acts of ACER

ACER shall:

(a) issue opinions and recommendations addressed to transmission system operators, **<…>** regional coordination centres and nominated electricity market operators;

(b) issue opinions and recommendations addressed to regulatory authorities;

(c) **<…>**;

(d) issue individual decisions on the provision of information in accordance with Article 3(2) **and** point (b) of Article 7(2); on approving the methodologies, terms and conditions in accordance with Article 4(4), Article 5 **<…>** (3) and (4); **<…>** on technical issues as referred to in Article 6(1); on arbitration between regulators in accordance with Article 6(10); related to regional coordination centres as referred to in point (a) of Article 7(2); **<…>**; on exemptions as referred to in Article 10; **<…>.**

(e) **<…>**

Article 3

General tasks

1. **<…>**

2. At ACER's request, the regulatory authorities, the ENTSO for Electricity, the ENTSO for Gas, the regional coordination centres, **the Coordination Group of the Energy Community Distribution System Operators established by Procedural Act No 2018/01/MC-EnC,** the transmission system operators and the nominated electricity market operators shall provide to ACER the information necessary for the purpose of carrying out ACER's tasks under this Regulation, unless ACER has already requested and received such information.

For the purpose of information requests as referred to in the first subparagraph, ACER shall have the power to issue decisions. In its decisions, ACER shall specify the purpose of its request, shall make a reference to the legal basis under which the information is requested, and shall state a time limit within which the information is to be provided. That time limit shall be proportionate to the request.

ACER shall use confidential information received pursuant to this Regulation only for the purpose of carrying out the tasks assigned to it in this Regulation. ACER shall ensure the appropriate data protection of the information pursuant to Article 41 **of Regulation (EU) 2019/942**.

Article 4

Tasks of ACER as regards the cooperation of transmission system operators and distribution system operators

1. **<…>**

2. **<…>**

3. **<…>**

4. ACER, where appropriate, after requesting updates to the drafts submitted by transmission system operators, shall approve the methodology regarding the use of revenues from congestion income pursuant to Article 19(4) of Regulation (EU) 2019/943**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

5. **<…>**

6. The relevant regulatory authorities shall coordinate in order to jointly identify whether there is non-compliance of **<…>** regional coordination centres with their obligations under **Energy Community** law and shall take appropriate action in accordance with point (c) of Article 59(1) and point (f) of Article 62(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

At the request of one or more regulatory authorities or at its own initiative, ACER shall issue a reasoned opinion as well as a recommendation to **<…>** regional coordination centres with regard to compliance with their obligations.

7. Where a reasoned opinion of ACER identifies a case of potential non-compliance of **<…>** a regional

coordination centre with their respective obligations, the regulatory authorities concerned shall unanimously take coordinated decisions establishing whether there is non-compliance with the relevant obligations and, where applicable, determining the measures to be taken by the **<…>** regional coordination centre to remedy that non-compliance. Where the regulatory authorities fail to take such coordinated decisions unanimously within four months of the date of receipt of ACER's reasoned opinion, the matter shall be referred to ACER for a decision pursuant to Article 6(10).

8. **<…>**

Article 5

Tasks of ACER as regards the development and implementation of network codes and guidelines

1.**<…>**

2. **<…>**

3. Where a **Decision adopted by the Ministerial Council under both Title II and Title III of the Treaty** provides for the development of proposals for terms and conditions or methodologies for the implementation of network codes and guidelines which require the approval of all the regulatory authorities of the region concerned, those regulatory authorities shall agree unanimously on the common terms and conditions or methodologies to be approved by each of those regulatory authorities: **<…>.**

The proposals referred to in the first subparagraph shall be notified to ACER within one week of their submission to those regulatory authorities. The regulatory authorities may refer the proposals to ACER for approval pursuant to point (b) of the second subparagraph of Article 6(10) and shall do so pursuant to point (a) of the second subparagraph of Article 6(10) where there is no unanimous agreement as referred to in the first subparagraph.

The Director or the Board of Regulators, acting on its own initiative or on a proposal from one or more of its members, may require the regulatory authorities of the region concerned to refer the proposal to ACER for approval. Such a request shall be limited to cases in which the regionally agreed proposal would have a tangible impact on the internal energy market or on security of supply beyond the region.

4. Without prejudice to paragraph **<…>** 3, ACER shall be competent to take a decision pursuant to Article 6(10) where the competent regulatory authorities fail to agree on terms and conditions or methodologies for the implementation of new network codes and guidelines adopted after **the expiry of the deadline for transposition of Ministerial Council Decision**, where those terms and conditions or methodologies require the approval of **<…>** all the regulatory authorities of the region concerned.

5. **<…>**

6. Before approving the terms and conditions or methodologies referred to in paragraph **<…>** 3, the regulatory authorities, or, where competent, ACER, shall revise them where necessary, after consulting **the Energy Community Regulatory Board**, the ENTSO for Electricity, the ENTSO for Gas, **the Coordination Group of the Energy Community Distribution System Operators established by Procedural Act 2018/01/MC-EnC** or the EU DSO entity, in order to ensure that they are in line with the purpose of the network code or guideline and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market. ACER shall take a decision on the approval within the period

specified in the relevant network codes and guidelines. That period shall begin on the day following that on which the proposal was referred to ACER.

7. **<…>**

8. ACER shall monitor the regional cooperation of transmission system operators referred to in Article 34 of Regulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and Article 12 of Regulation (EC) No 715/2009**, as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC** and shall take into account the outcome of that cooperation when formulating its opinions, recommendations and decisions.

Article 6

Tasks of ACER as regards the regulatory authorities

1. ACER shall adopt individual decisions on technical issues where those decisions are provided for in Regulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** Regulation (EC) No 715/2009, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC,** Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** or Directive 2009/73/EC, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC**.

2. ACER may, in accordance with its work programme, at the request of the **Energy Community Secretariat, the European** Commission or on its own initiative, make recommendations to assist regulatory authorities and market participants in sharing good practices.

3. **<…>**

4. **<…>**

5. **<…>**

6. **<…>**

7. **<…>**

8. **<…>**

9. ACER shall submit opinions to the relevant regulatory authority and to the **Energy Community Secretariat and the European** Commission pursuant to Article 16(3) of Regulation (EU) 2019/943 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

10. ACER shall be competent to adopt individual decisions on regulatory issues having effects on cross-border trade or cross-border system security which require a joint decision by at least two regulatory authorities, where such competences have been conferred on the regulatory authorities under **a Decision adopted by the Ministerial Council under both Title II and Title III of the Treaty**: **<…>**

ACER shall be competent to adopt individual decisions as specified in the first subparagraph in the following situations:

(a) where the competent regulatory authorities have not been able to reach an agreement within six months of referral of the case to the last of those regulatory authorities, or within four months in cases under Article 4(7) of this Regulation or under point (c) of Article (59)(1) or point (f) of Article 62(1) of Directive

(EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**; or

(b) on the basis of a joint request from the competent regulatory authorities.

The competent regulatory authorities may jointly request that the period referred to in point (a) of the second subparagraph of this paragraph be extended by a period of up to six months, except in cases under Article 4(7) of this Regulation or under point (c) of Article 59(1) or point (f) of Article 62(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

Where the competences to decide on cross-border issues referred to in the first subparagraph have been conferred on the regulatory authorities in new network codes or guidelines adopted **<…>** after **15 December 2022**, ACER shall only be competent on a voluntary basis pursuant to point (b) of the second subparagraph of this paragraph, upon a request from at least 60 % of the competent regulatory authorities. Where only two regulatory authorities are involved, either one may refer the case to ACER.

<…>

11. When preparing its decision pursuant to paragraph 10, ACER shall consult the regulatory authorities and transmission system operators concerned and shall be informed of the proposals and observations of all the transmission system operators concerned.

12. Where a case has been referred to ACER under paragraph 10, ACER:

(a) shall issue a decision within six months of the date of referral, or within four months thereof in cases pursuant to Article 4(7) of this Regulation or point (c) of Article (59)(1) or point (f) of Article 62(1) of Directive (EU) 2019/944, **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**; and

(b) may, if necessary, provide an interim decision to ensure that security of supply or operational security is protected.

13. Where the regulatory issues referred to in paragraph 10 include exemptions within the meaning of Article 63 of Regulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, or Article 36 of Directive 2009/73/EC, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC** the deadlines provided for in this Regulation shall not be cumulative with the deadlines provided for in those provisions.

Article 7

Tasks of ACER as regards regional coordination centres

1. ACER, in close cooperation with the regulatory authorities and the ENTSO for Electricity, shall monitor and analyse the performance of regional coordination centres, taking into account the reports provided for in Article 46(3) of Regulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. To carry out the tasks referred to in paragraph 1 in an efficient and expeditious manner, ACER shall in particular:

(a) decide on the configuration of system operation regions pursuant to **Annex V[1] of Regulation (EU) 2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(b) request information from regional coordination centres where appropriate pursuant to Article 46 of Reg-

1 There is a clerical error in the Ministerial Council Decision D2022/03/MC-EnC.

ulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(c) issue opinions and recommendations to the **Ministerial Council, the Permanent High Level Group, the Energy Community Regulatory Board, the Energy Community Secretariat** and the European Commission;

(d) issue opinions and recommendations to regional coordination centres.

Article 8

Tasks of ACER as regards nominated electricity market operators

<...>

Article 9

Tasks of ACER as regards generation adequacy and risk preparedness

<...>

Article 10

Tasks of ACER as regards exemptions

ACER shall decide on exemptions, as provided for in Article 63(5) of Regulation (EU) 2019/943, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. ACER shall also decide on exemptions as provided for in Article 36(4) of Directive 2009/73/EC, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC**, where the infrastructure concerned is located in the territory of **at least** one **Contracting Party and** a Member State.

Article 11

Tasks of ACER as regards infrastructure

<...>

Article 12

Tasks of ACER as regards wholesale market integrity and transparency

<...>

Article 13

Commissioning of new tasks to ACER

<...>

Article 14

Consultations, transparency and procedural safeguards

1. In carrying out its tasks **under Article 1 of this Regulation**, ACER shall, extensively consult at an early stage **the Energy Community Regulatory Board**, market participants, transmission system operators, consumers, end-users and, where relevant, competition authorities, without prejudice to their respective competence, in an open and transparent manner, in particular when its tasks concern transmission system operators.

2. ACER shall ensure that the public and any interested parties are, where appropriate, given objective, reliable and easily accessible information, in particular with regard to the results of its work.

<…>

3. **<…>**

4. ACER shall make public, on its own website, at least the agenda, the background documents and, where appropriate, the minutes of the meetings of the Administrative Board, of the Board of Regulators and of the Board of Appeal.

5. **<…>**

6. Before taking any individual decision as provided for in this Regulation, ACER shall inform any party concerned of its intention to adopt that decision, and shall set a time limit within which the party concerned may express its views on the matter, taking full account of the urgency, complexity and potential consequences of the matter.

7. Individual decisions of ACER shall state the reasons on which they are based for the purpose of allowing an appeal on the merits.

8. The parties concerned by individual decisions shall be informed of the legal remedies available under this Regulation.

Article 15

Monitoring and reporting on the electricity and natural gas sectors

<…>

Chapter II
Organisation of ACER

Article 16

Legal status

<…>

Article 17

Administrative and Management Structure

<...>

Article 18

Composition of the Administrative Board

<...>

Article 19

Functions of the Administrative Board

<...>

Article 20

Annual and multi-annual programming

<...>

Article 21

Composition of the Board of Regulators

<...>

Article 22

Functions of the Board of Regulators

<...>

Article 23

Director

<...>

Article 24

Tasks of the Director

<...>

Article 25

Creation and composition of the Board of Appeal

<...>

Article 26

Members of the Board of Appeal

<...>

Article 27

Exclusion and objection in the Board of Appeal

<...>

Article 28

Decisions subject to appeal

1. Any natural or legal person, including the regulatory authorities, may appeal against a decision referred to in point (d) of Article 2 which is addressed to that person, or against a decision which, although in the form of a decision addressed to another person, is of direct and individual concern to that person.

2. The appeal shall include a statement of the grounds for appeal and shall be filed in writing at ACER within two months of the notification of the decision to the person concerned, or, in the absence thereof, within two months of the date on which ACER published its decision. The Board of Appeal shall decide upon the appeal within four months of the lodging of the appeal.

3. An appeal lodged pursuant to paragraph 1 shall not have suspensory effect. The Board of Appeal may, however, if it considers that circumstances so require, suspend the application of the contested decision.

4. If the appeal is admissible, the Board of Appeal shall examine whether it is well-founded. It shall invite the parties to the appeal proceedings as often as necessary to file observations on notifications issued by itself or on communications from the other parties to the appeal proceedings, within specified time limits. Parties to the appeal proceedings shall be entitled to make an oral presentation.

5. The Board of Appeal may confirm the decision, or it may remit the case to the competent body of ACER. The latter shall be bound by the decision of the Board of Appeal.

6. ACER shall publish the decisions taken by the Board of Appeal.

Article 29

Actions before the Court of Justice

Actions for the annulment of a decision issued by ACER pursuant to this Regulation and actions for failure to act within the applicable time limits may be brought before the Court of Justice only after the exhaustion of the appeal procedure referred to in Article 28. ACER shall take the necessary measures to comply with the judgments of the Court of Justice.

Article 30

Working groups

<…>

Chapter III
Establishment and structure of the budget

Article 31

Structure of the budget

<…>

Article 32

Fees

<…>

Article 33

Establishment of the budget

<…>

Article 34

Implementation and control of the budget

<…>

Article 35

Presentation of accounts and discharge

<…>

Article 36

Financial rules

<…>

Article 37

Combating fraud

<…>

Chapter IV
General and final provisions

Article 38

Privileges and immunities and Headquarters Agreement

<...>

Article 39

Staff

<...>

Article 40

Liability of ACER

<...>

Article 41

Transparency and communication

<...>

Article 42

Protection of classified and sensitive non-classified information

<...>

Article 43

Cooperation agreements

<...>

Article 44

Language arrangements

<...>

Article 45

Evaluation

<...>

Article 46

Repeal

<…>

Article 47

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[2]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with Regulation (EU) 2019/942 <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

2 The text displayed here corresponds to Article 13 of Decision 2022/03/MC-EnC.

REGULATION (EU) 2019/941 of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC

Incorporated and adapted by the Decision of the Ministerial Council of the Energy Community 2021/13/MC-EnC of 30 November 2021 amending Annex I to the Treaty Establishing the Energy Community (Energy Community Treaty) and incorporating Directive (EU) 2019/944 and Regulation (EU) 2019/941 in the Energy Community acquis communautaire and amended by Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

*The adaptations made by the Ministerial Council Decisions 2021/13/MC-EnC and 2022/03/MC-EnC are highlighted in **bold and blue**.*

CHAPTER I
General Provisions

Article 1
Subject matter

This Regulation lays down rules for cooperation between **Contracting Parties** with a view to preventing, preparing for and managing electricity crises in a spirit of solidarity and transparency and in full regard for the requirements of a competitive internal market for electricity.

Article 2
Definitions

For the purposes of this Regulation, the following definitions apply:

(1) 'security of electricity supply' means the ability of an electricity system to guarantee the supply of electricity to customers with a clearly established level of performance, as determined by the **Contracting Parties** concerned;

(2) 'transmission system operator' means transmission system operator as defined in point (35) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(3) 'distribution' means distribution as defined in point (28) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(4) 'cross-border flow' means cross-border flow as defined in point (3) of Article 2 of Regulation (EU) 2019/943 **as adopted and adapted by Ministerial Council Decision 2022/03/MC-En**C;

(5) 'cross zonal capacity' means the capability of the interconnected system to accommodate energy transfer between bidding zones;

(6) 'customer' means customer as defined in point (1) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(7) 'distribution system operator' means distribution system operator as defined in point (29) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(8) 'generation' means generation as defined in point (37) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(9) 'electricity crisis' means a present or imminent situation in which there is a significant electricity shortage, as determined by the **Contracting Parties** and described in their risk-preparedness plans, or in which it is impossible to supply electricity to customers;

(10) 'simultaneous electricity crisis' means an electricity crisis affecting more than one **Contracting Party** at the same time;

(11) 'competent authority' means a national governmental authority or a regulatory authority designated by a **Contracting Party** in accordance with Article 3;

(12) 'regulatory authorities' means regulatory authorities referred to in Article 57(1) of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(13) 'crisis coordinator' means a person, a group of persons, a team composed of the relevant national electricity crisis managers or an institution tasked with acting as a contact point and coordinating the information flow during an electricity crisis;

(14) 'non-market-based measure' means any supply- or demand-side measure that deviates from market rules or commercial agreements, the purpose of which is to mitigate an electricity crisis;

(15) 'producer' means producer as defined in point (38) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(16) 'region' means a group of **Contracting Parties** whose transmission system operators share[1] the same regional coordination centre as referred to in **Annex IV of** Regulation (EU) 2019/94**3 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**;

(17) 'subgroup' means a group of **Contracting Parties**, within a region, which have the technical ability to provide each other assistance in accordance with Article 15;

(18) 'early warning' means a provision of concrete, serious, reliable information indicating that an event may occur which is likely to result in a significant deterioration of the electricity supply situation and is likely to lead to electricity crisis;

(19) 'transmission' means transmission as defined in point (34) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

(20) 'electricity undertaking' means electricity undertaking as defined in point (57) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021**;

1 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

(21) 'capacity allocation' means the attribution of cross zonal capacity;

(22) 'energy from renewable sources' means energy from renewable sources or renewable energy as defined in point (31) of Article 2 of Directive (EU) 2019/944 **as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC of 30 November 2021;**

(23) 'Security of Supply Coordination Group' is the group established by Procedural Act 2008/02/MC-EnC of 11 December 2008, as amended by Procedural Act 2021/03/MC-EnC of 30 November 2021.

Article 3

Competent authority

1. As soon as possible and in any event by 5 January **2023**, each **Contracting Party** shall designate a national governmental or regulatory authority as its competent authority. The competent authorities shall be responsible for, and shall cooperate with each other for the purposes of, carrying out the tasks provided for in this Regulation. Where appropriate, until the competent authority has been designated, the national entities responsible for the security of electricity supply shall carry out the tasks of the competent authority in accordance with this Regulation.

2. **Contracting Parties** shall, without delay, notify the **Energy Community Secretariat** and the **Security of Supply Coordination Group** and make public the name and the contact details of their competent authorities designated pursuant to paragraph 1 and any changes to their name or contact details.

3. **Contracting Parties** may allow the competent authority to delegate the operational tasks regarding risk-preparedness planning and risk management set out in this Regulation to other bodies. Delegated tasks shall be performed under the supervision of the competent authority and shall be specified in the risk-preparedness plan in accordance with point (b) of Article 11(1).

CHAPTER II
Risk assessment

Article 4

Assessment of risks to security of electricity supply

Each competent authority shall ensure that all relevant risks relating to security of electricity supply are assessed in accordance with the rules laid down in this Regulation and in **Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC**. To that end, it shall cooperate with transmission system operators, distribution system operators, regulatory authorities, the ENTSO for Electricity, regional coordination centres and other relevant stakeholders, as required.

Article 5

Methodology for identifying regional electricity crisis scenarios

< ... >

Article 6

Identification of regional electricity crisis scenarios

1. **Based on the regional crisis scenarios identified according to Article 6 of Regulation (EU) 2019/941, within six months of the adoption of Ministerial Council Decision 2021/13/MC-EnC, the ENTSO for Electricity shall, on the basis of the methodology developed pursuant to Article 5 of Regulation (EU) 2019/941 and in close cooperation with the Security of Supply Coordination Group, competent authorities and regulatory authorities, identify the most relevant electricity crisis scenarios for each region**.

2. The ENTSO for Electricity shall submit the regional electricity crisis scenarios to the relevant transmission system operators, regional coordination centres, competent authorities and regulatory authorities **of the Contracting Parties** as well as to the **Security of Supply Coordination Group**. The **Security of Supply Coordination Group** may recommend amendments.

3. The ENTSO for Electricity shall update the regional electricity crisis scenarios **when updating the regional crisis scenarios pursuant to Article 6(3) of Regulation (EU) 2019/941**.

Article 7

Identification of national electricity crisis scenarios

1. Within four months of the identification of the regional electricity crisis scenarios in accordance with Article 6(1), the competent authority shall identify the most relevant national electricity crisis scenarios.

2. In identifying the national electricity crisis scenarios, the competent authority shall consult the transmission system operators, the distribution system operators that the competent authority considers to be relevant, the relevant producers or their trade bodies, and the regulatory authority where it is not the competent authority.

3. The national electricity crisis scenarios shall be identified on the basis of at least the risks referred to in Article 5(2) **of Regulation (EU) 2019/941** and shall be consistent with the regional electricity crisis scenarios identified in accordance with Article 6(1). **Contracting Parties** shall update the national electricity crisis scenarios every four years, unless circumstances warrant more frequent updates.

4. Within four months of identification of regional electricity crisis scenarios in accordance with Article 6(1), **Contracting Parties** shall inform the **Security of Supply Coordination Group** and the **Energy Community Secretariat** of their assessment of the risks in relation to the ownership of infrastructure relevant for security of electricity supply, and any measures taken to prevent or mitigate such risks, with an indication of why such measures are considered necessary and proportionate.

Article 8

Methodology for short-term and seasonal adequacy assessments

< ... >

Article 9

Short-term and seasonal adequacy assessments

1. **All short-term adequacy assessments, whether carried out at national or regional level, shall be carried out in accordance with the methodology developed pursuant to Article 8 of Regulation (EU) 2019/941**.

2. The ENTSO for Electricity shall carry out seasonal adequacy assessments in accordance with the methodology developed pursuant to Article 8. It shall publish the results for the winter adequacy assessment by 1 December each year and for the summer adequacy assessment by 1 June each year. It may delegate tasks relating to the adequacy assessments to regional coordination centres. It shall present the adequacy assessment at a meeting of the **Security of Supply Coordination Group**, which may make recommendations where appropriate.

3. The regional coordination centres shall carry out week-ahead to at least day ahead adequacy assessments in accordance with Regulation (EU) 2017/1485 on the basis of the methodology adopted pursuant to Article 8 of this Regulation.

CHAPTER III
Risk-preparedness plans

Article 10

Establishment of risk-preparedness plans

1. On the basis of the regional and national electricity crisis scenarios identified pursuant to Articles 6 and 7, the competent authority of each **Contracting Party** shall establish a risk-preparedness plan, after consulting distribution system operators considered relevant by the competent authority, the transmission system operators, the relevant producers or their trade bodies, the electricity and natural gas undertakings, the relevant organisations that represent the interests of industrial and non-industrial electricity customers, and the regulatory authority where it is not the competent authority.

2. The risk-preparedness plan shall consist of national measures, regional and, where applicable, bilateral measures as provided for in Articles 11 and 12. In accordance with Article 16, all measures that are planned or taken to prevent, prepare for and mitigate electricity crises shall fully comply with the rules governing the internal electricity market and system operation. Those measures shall be clearly defined, transparent, proportionate and non-discriminatory.

3. The risk-preparedness plan shall be developed in accordance with Articles 11 and 12 and with the template set out in the Annex. If necessary, **Contracting Parties** may include additional information in

the risk-preparedness plan.

4. In order to ensure consistency of risk-preparedness plans, competent authorities shall, before adopting their risk-preparedness plans, submit the draft plans, for consultation, to the competent authorities of the relevant **Contracting Parties** in the region and, where they are not in the same region, to the competent authorities of directly connected **Contracting Parties**, as well as to the S**ecurity of Supply Coordination Group**.

5. Within six months of receipt of the draft risk-preparedness plans, the competent authorities referred to in paragraph 4 and the **Security of Supply Coordination Group** may issue recommendations relating to the draft plans submitted pursuant to paragraph 4.

6. Within nine months of submitting their draft plans, the competent authorities concerned shall adopt their risk-preparedness plans, taking into account the results of the consultation pursuant to paragraph 4 and any recommendations issued pursuant to paragraph 5. They shall notify their risk-preparedness plans to the **Energy Community Secretariat** without delay.

7. The competent authorities and the **Energy Community Secretariat** shall publish the risk-preparedness plans on their websites, while ensuring confidentiality of sensitive information, in particular information on measures relating to the prevention or mitigation of consequences of malicious attacks. The protection of the confidentiality of sensitive information shall be based on the principles determined pursuant to Article 19.

8. The competent authorities shall adopt and publish their first risk-preparedness plans by 5 January **2025**. They shall update them every four years thereafter, unless circumstances warrant more frequent updates.

Article 11

Content of risk-preparedness plans as regards national measures

1. The risk-preparedness plan of each **Contracting Party** shall set out all national measures that are planned or taken to prevent, prepare for and mitigate electricity crises as identified pursuant to Articles 6 and 7. It shall at least:

(a) contain a summary of the electricity crisis scenarios defined for the relevant **Contracting Party** and region, in accordance with the procedures laid down in Articles 6 and 7;

(b) establish the role and responsibilities of the competent authority and describe which tasks, if any, have been delegated to other bodies;

(c) describe the national measures designed to prevent or prepare for the risks identified pursuant to Articles 6 and 7;

(d) designate a national crisis coordinator and establish its tasks;

(e) establish detailed procedures to be followed in electricity crises, including the corresponding schemes on information flows;

(f) identify the contribution of market-based measures in coping with electricity crises, in particular demand-side and supply-side measures;

(g) identify possible non-market-based measures to be implemented in electricity crises, specifying the triggers, conditions and procedures for their implementation, and indicating how they comply with the

requirements laid down in Article 16 and with regional and bilateral measures;

(h) provide a framework for manual load shedding, stipulating the circumstances in which loads are to be shed and, with regard to public safety and personal security, specifying which categories of electricity users are, in accordance with national law, entitled to receive special protection against disconnection, justifying the need for such protection, and specifying how the transmission system operators and distribution system operators of the **Contracting Parties** concerned are to decrease consumption;

(i) describe the mechanisms used to inform the public about electricity crises;

(j) describe the national measures necessary to implement and enforce the regional and, where applicable, bilateral measures agreed pursuant to Article 12;

(k) include information on related and necessary plans for developing the future grid that will help to cope with the consequences of identified electricity crisis scenarios.

2. National measures shall take full account of the regional and, where applicable, bilateral measures agreed pursuant to Article 12 and shall endanger neither the operational security or safety of the transmission system, nor the security of electricity supply of other **Contracting Parties**.

Article 12

Content of risk-preparedness plans as regards regional and bilateral measures

1. In addition to the national measures referred to in Article 11, the risk-preparedness plan of each **Contracting Party** shall include regional and, where applicable, bilateral measures to ensure that electricity crises with a cross-border impact are properly prevented or managed. Regional measures shall be agreed within the region concerned between **Contracting Parties** that have the technical ability to provide each other assistance in accordance with Article 15. For that purpose, **Contracting Parties** may also form subgroups within a region. Bilateral measures shall be agreed between **Contracting Parties** which are directly connected but are not within the same region. **Contracting Parties** shall ensure consistency between regional and bilateral measures. Regional and bilateral measures shall include at least:

(a) the designation of a crisis coordinator;

(b) mechanisms to share information and cooperate;

(c) coordinated measures to mitigate the impact of an electricity crisis, including a simultaneous electricity crisis, for the purpose of assistance in accordance with Article 15;

(d) procedures for carrying out annual or biennial tests of the risk-preparedness plans;

(e) the trigger mechanisms of non-market-based measures that are to be activated in accordance with Article 16(2).

2. The **Contracting Parties** concerned shall agree the regional and bilateral measures to be included in the risk-preparedness plan after consulting the relevant regional coordination centres. The **Energy Community Secretariat** may have a facilitating role in the preparation of the agreement on regional and bilateral measures. The **Energy Community Secretariat** may request **the Energy Community Regulatory Board** and the ENTSO for Electricity to provide technical assistance to **Contracting Parties** with a view to facilitating such an agreement. At least eight months before the deadline for the adoption or the updating of the risk-preparedness plan, the competent authorities shall report on the agreements

reached to the **Security of Supply Coordination Group**. If the **Contracting Parties** are not able to reach an agreement, the competent authorities concerned shall inform the **Energy Community Secretariat** of the reasons for such disagreement. In such a case the **Energy Community Secretariat** shall propose measures including a cooperation mechanism **among Contracting Parties** for the conclusion of an agreement on regional and bilateral measures.

3. With the involvement of relevant stakeholders, the competent authorities of the **Contracting Parties** of each region shall periodically test the effectiveness of the procedures developed in risk-preparedness plans for preventing electricity crises, including the mechanisms referred to in point (b) of paragraph 1, and carry out biennial simulations of electricity crises, in particular testing those mechanisms.

Article 13

Energy Community Secretariat assessment of the risk-preparedness plans

1. Within four months of the notification of the adopted risk-preparedness plan by the competent authority, the **Energy Community Secretariat** shall assess the plan taking duly into account the views expressed by the **Security of Supply Coordination Group**.

2. The **Energy Community Secretariat** shall, after consulting the **Security of Supply Coordination Group**, issue a non-binding opinion, setting out detailed reasons, and submit it to the competent authority, with a recommendation to review its risk-preparedness plan where that plan:

(a) is not effective to mitigate the risks identified in the electricity crisis scenarios;

(b) is inconsistent with the electricity crisis scenarios identified or with the risk-preparedness plan of another **Contracting Party**;

(c) does not comply with the requirements laid down in Article 10(2);

(d) sets out measures that are likely to jeopardise the security of electricity supply of other **Contracting Parties**;

(e) unduly distorts competition or the effective functioning of the internal market; or

(f) does not comply with the provisions of this Regulation or other provisions of **Energy Community** law.

3. Within three months of receipt of the **Energy Community Secretariat**'s opinion referred to in paragraph 2, the competent authority concerned shall take full account of the **Energy Community Secretariat**'s recommendation and shall either notify the amended risk-preparedness plan to the **Energy Community Secretariat** or notify the **Energy Community Secretariat** of the reasons why it objects to the recommendation.

4. In the event that the competent authority objects to the **Energy Community Secretariat**'s recommendation, the **Energy Community Secretariat** may, within four months of receipt of the notification of the competent authority's reasons for objection, withdraw its recommendation or convene a meeting with the competent authority and, where the **Energy Community Secretariat** considers it to be necessary, the **Security of Supply Coordination Group**, in order to assess the issue. The **Energy Community Secretariat** shall set out detailed reasons for requesting any modifications to the risk-preparedness plan. Where the final position of the competent authority concerned diverges from the **Energy Community Secretariat**'s detailed reasons, that competent authority shall provide the **Energy Community**

Secretariat with the reasons for its position within two months of receipt of the **Energy Community Secretariat**'s detailed reasons.

CHAPTER IV
Managing electricity crises

Article 14

Early warning and declaration of an electricity crisis

1. Where a seasonal adequacy assessment or other qualified source provides concrete, serious and reliable information that an electricity crisis may occur in a **Contracting Party**, the competent authority of that **Contracting Party** shall, without undue delay, issue an early warning to the **Energy Community Secretariat**, the competent authorities of the **Contracting Parties** within the same region and, where they are not in the same region, the competent authorities of the directly connected **Contracting Parties**. The competent authority concerned shall also provide information on the causes of the possible electricity crisis, on measures planned or taken to prevent an electricity crisis and on the possible need for assistance from other **Contracting Parties**. The information shall include the possible impacts of the measures on the **neighbouring** electricity market. The **Energy Community Secretariat** shall provide that information to the **Security of Supply Coordination Group**.

2. When confronted with an electricity crisis, the competent authority shall, after consulting the transmission system operator concerned, declare an electricity crisis and inform the competent authorities of the **Contracting Parties** within the same region and, where they are not in the same region, the competent authorities of directly connected **Contracting Parties**, as well as the **Energy Community Secretariat**, without undue delay. That information shall include the causes of the deterioration of the electricity supply situation, the reasons for declaring an electricity crisis, the measures planned or taken to mitigate it and the need for any assistance from other **Contracting Parties**.

3. Where they consider the information provided pursuant to paragraph 1 or 2 to be insufficient, the **Energy Community Secretariat**, the **Security of Supply Coordination Group** or the competent authorities of the **Contracting Parties** within the same region and, where they are not in the same region, the competent authorities of directly connected **Contracting Parties** may request the **Contracting Party** concerned to provide additional information.

4. Where a competent authority issues an early warning or declares an electricity crisis, the measures set out in the risk-preparedness plan shall be followed to the fullest extent possible.

Article 15

Cooperation and assistance among Contracting Parties

1. **Contracting Parties** shall act and cooperate in a spirit of solidarity in order to prevent or manage electricity crises.

2. Where they have the necessary technical ability, **Contracting Parties** shall offer each other assistance

by means of regional or bilateral measures that have been agreed pursuant to this Article and to Article 12 before that assistance is provided. To that end, and with the purpose of protecting public safety and personal security, **Contracting Parties** shall agree on regional or bilateral measures of their choice in order to deliver electricity in a coordinated manner.

3. **Contracting Parties** shall agree on the necessary technical, legal and financial arrangements for the implementation of the regional or bilateral measures before assistance is offered. Such arrangements shall specify, inter alia, the maximum quantity of electricity to be delivered at regional or bilateral level, the trigger for any assistance and for suspension of assistance, how the electricity will be delivered, and provisions on fair compensation between **Contracting Parties** in accordance with paragraphs 4, 5 and 6.

4. Assistance shall be subject to a prior agreement between the **Contracting Parties** concerned with regard to fair compensation, which shall cover at least:

(a) the cost of the electricity delivered into the territory of the **Contracting Party** requesting assistance as well as the associated transmission costs; and

(b) any other reasonable costs incurred by the **Contracting Party** providing assistance, including as regards reimbursement for assistance prepared without effective activation, as well as any costs resulting from judicial proceedings, arbitration proceedings or similar proceedings and settlements.

5. Fair compensation pursuant to paragraph 4 shall include, inter alia, all reasonable costs that the **Contracting Party** providing assistance incurs from an obligation to pay compensation by virtue of fundamental rights guaranteed by **Energy Community** law and by virtue of the applicable international obligations when implementing the provisions of this Regulation on assistance and further reasonable costs incurred from the payment of compensation pursuant to national compensation rules.

6. **The Contracting Party requesting assistance shall promptly pay, or ensure the prompt payment of fair compensation to the Contracting Party providing assistance. The Commission Recommendation 2020/775 shall be applied as non-binding guidance.**

7. **< … >**

8. In the event of an electricity crisis in which **Contracting Parties** have not yet agreed on regional or bilateral measures and technical, legal and financial arrangements pursuant to this Article, **Contracting Parties** shall agree on ad hoc measures and arrangements in order to apply this Article, including as regards fair compensation pursuant to paragraphs 4, 5 and 6. Where a **Contracting Party** requests assistance before such ad hoc measures and arrangements have been agreed, it shall undertake, prior to receiving assistance, to pay fair compensation in accordance with paragraphs 4, 5 and 6.

9. **Contracting Parties** shall ensure that the provisions of this Regulation on assistance are implemented in accordance with the **Energy Community Treaty < … >** and other applicable international obligations. They shall take the necessary measures to that end.

Article 16

Compliance with market rules

1. Measures taken to prevent or mitigate electricity crises shall comply with the rules governing the internal electricity market and system operation.

2. Non-market-based measures shall be activated in an electricity crisis only as a last resort if all options provided by the market have been exhausted or where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation. Non-market-based measures shall not unduly distort competition and the effective functioning of the internal electricity market. They shall be necessary, proportionate, non-discriminatory and temporary. The competent authority shall inform relevant stakeholders in its **Contracting Party** of the application of any non-market-based measures.

3. Transaction curtailment including curtailment of already allocated cross zonal capacity, limitation of provision of cross zonal capacity for capacity allocation or limitation of provision of schedules shall be initiated only in accordance with **Article 16(2) of Regulation (EU) 2019/943 as adopted and adapted by Ministerial Council Decision 2022/03/MC-EnC, and the rules adopted to implement that provision**.

CHAPTER V
Evaluation and monitoring

Article 17
Ex post *evaluation*

1. As soon as possible and in any event three months after the end of an electricity crisis, the competent authority of the **Contracting Party** that declared the electricity crisis shall provide the **Security of Supply Coordination Group** and the **Energy Community Secretariat** with an *ex post* evaluation report, after having consulted the regulatory authority, where the regulatory authority is not the competent authority.

2. The *ex post* evaluation report shall include at least:

(a) a description of the event that triggered the electricity crisis;

(b) a description of any preventive, preparatory and mitigating measures taken and an assessment of their proportionality and effectiveness;

(c) an assessment of the cross-border impact of the measures taken;

(d) an account of the assistance prepared, with or without effective activation, provided to or received from neighbouring **Contracting Parties** and third countries;

(e) the economic impact of the electricity crisis and the impact of the measures taken on the electricity sector to an extent allowed by data available at the time of the assessment, in particular the volumes of energy non-served and the level of manual demand disconnection (including a comparison between the level of voluntary and forced demand disconnection);

(f) reasons justifying the application of any non-market-based measures;

(g) any possible improvements or proposed improvements to the risk-preparedness plan;

(h) an overview of possible improvements to grid development in cases where insufficient network development caused or contributed to the electricity crisis.

3. Where they consider the information provided in the *ex post* evaluation report to be insufficient, the **Security of Supply Coordination Group** and the **Energy Community Secretariat** may request the

competent authority concerned to provide additional information.

4. The competent authority concerned shall present the results of the *ex post* evaluation at a meeting of the **Security of Supply Coordination Group**. Those results shall be reflected in the updated risk-preparedness plan.

Article 18

Monitoring

1. In addition to carrying out other tasks set out in this Regulation, the **Security of Supply Coordination Group** shall discuss:

(a) the results of the 10-year network development plan in electricity prepared by the ENTSO for Electricity;

(b) the coherence of the risk-preparedness plans, adopted by the competent authorities following the procedure referred to in Article 10;

(c) the results of the European resource adequacy assessments carried out by the ENTSO for Electricity as referred to in Article 23(4) of Regulation (EU) 2019/943;

(d) the performance of **Contracting Parties** in the area of security of electricity supply taking into account at least the indicators calculated in the European resource adequacy assessment, namely the expected energy non-served and loss of load expectation;

(e) the results of the seasonal adequacy assessments referred to in Article 9(2);

(f) the information received from the **Contracting Parties** pursuant to Article 7(4);

(g) the results of the *ex post* evaluation referred to in Article 17(4);

(h) the methodology for short-term adequacy assessment referred to in Article 8 **of Regulation (EU) 2019/941**;

(i) the methodology for identifying regional electricity crisis scenarios referred to in Article 5 **of Regulation (EU) 2019/941**[18].

2. The **Security of Supply Coordination Group** may issue recommendations to the **Contracting Parties** as well as to the ENTSO for Electricity related to the matters referred to in paragraph 1.

3. **The Energy Community Regulatory Board** shall, on an ongoing basis, monitor the security of electricity supply measures and shall report regularly to the **Security of Supply Coordination Group**.

4. By 1 September **2028**, the **Energy Community Secretariat** shall, on the basis of the experience gained in the application of this Regulation, evaluate the possible means by which to enhance security of electricity supply at **Energy Community** level and submit a report to the **Ministerial Council** on the application of this Regulation, including, where necessary, legislative proposals to amend this Regulation.

Article 19

Treatment of confidential information

1. **Contracting Parties** and competent authorities shall implement the procedures referred to in this

Regulation in accordance with the applicable rules, including national rules relating to the handling of confidential information and processes. If the implementation of those rules results in information not being disclosed, inter alia as part of risk-preparedness plans, the **Contracting Party** or authority may provide a non-confidential summary thereof, and shall do so upon request.

2. The **Energy Community Secretariat**, **the Energy Community Regulatory Board**, the **Security of Supply Coordination Group**, the ENTSO for Electricity, **Contracting Parties**, competent authorities, regulatory authorities and other relevant bodies, entities or persons, which receive confidential information pursuant to this Regulation, shall ensure the confidentiality of sensitive information.

CHAPTER VI
Final provisions

Article 20

Cooperation between Contracting Parties and Member States

Where the Contracting Parties and the Member States cooperate in the area of security of electricity supply, such cooperation may include defining an electricity crisis, the process of the identification of electricity crisis scenarios and the establishment of risk-preparedness plans so that no measures are taken that endanger the security of electricity supply of the Contracting Parties, the Member States, the Energy Community or the Union. In that respect, the European Commission and the Member States may participate in the Security of Supply Coordination Group with regard to all matters with which they are concerned.< … >

Article 21

Derogation

Until Georgia is directly connected with another Contracting Parties, Article 6, Article 12 and paragraphs 2 to 9 of Article 15 shall not apply between Georgia and other Contracting Parties. Georgia and relevant other Contracting Parties may develop, with the support of the Energy Community Secretariat, measures and procedures alternative to those provided for in Article 12, provided that such alternative measures and procedures do not affect the effective application of this Regulation between the other Contracting Parties. < … >

Article 22

Transitional provision pending the establishment of regional coordination centres

< … >

Article 23

Repeal

< … >

Article 24

Entry into force

< … >

ANNEX
TEMPLATE FOR RISK-PREPAREDNESS PLAN

The following template shall be completed in English.

General information

— Name of the competent authority responsible for the preparation of this plan

— **Contracting Parties** in the region

1. SUMMARY OF THE ELECTRICITY CRISIS SCENARIOS

Describe briefly the electricity crisis scenarios identified at regional and national level in accordance with the procedure laid down in Articles 6 and 7, including the description of the assumptions applied.

2. ROLES AND RESPONSIBILITIES OF THE COMPETENT AUTHORITY

Define the role and responsibilities of the competent authority and the bodies to which tasks have been delegated.

Describe which tasks, if any, have been delegated to other bodies.

3. PROCEDURES AND MEASURES IN THE ELECTRICITY CRISIS

3.1. National procedures and measures

(a) Describe procedures to be followed in the cases of an electricity crisis, including the corresponding schemes on information flows;

(b) Describe preventive and preparatory measures;

(c) Describe measures to mitigate electricity crises, in particular demand-side and supply-side measures, whilst indicating in which circumstances such measures can be used especially the trigger of each measure. Where non-market-based measures are considered, they must be duly justified in light of the requirements laid down in Article 16 and must comply with regional and, where applicable, bilateral measures;

(d) Provide a framework for manual load shedding, stipulating under which circumstances loads are to be shed. Specify with regard to public safety and personal security which categories of electricity users are entitled to receive special protection against disconnection, and justify the need for such protection. Specify how the transmission system operators and the distribution system operators should act in order to decrease the consumption;

(e) Describe the mechanisms used to inform the public about the electricity crisis.

3.2. Regional and bilateral procedures and measures

(a) Describe the agreed mechanisms for cooperation within the region and for ensuring appropriate coordination before and during the electricity crisis, including the decision-making procedures for appropriate reaction at regional level;

(b) Describe any regional and bilateral measures that have been agreed, including any necessary technical, legal and financial arrangements for the implementation of those measures. When describing such arrangements, provide information on, inter alia, the maximum quantities of electricity to be delivered at regional or bilateral level, the trigger for the assistance and possibility to request its suspension, how the electricity will be delivered, and the provisions on fair compensation between **Contracting Parties**. Describe the national measures necessary to implement and enforce the regional and bilateral measures agreed;

(c) Describe the mechanisms in place for cooperation and for coordinating actions, before and during the electricity crisis, with other **Contracting Parties** outside of the region as well as with third countries within the relevant synchronous area.

4. CRISIS COORDINATOR

Indicate and define the role of the crisis coordinator. Specify the contact details.

5. STAKEHOLDER CONSULTATIONS

In accordance with Article 10(1), describe the mechanism used for and the results of the consultations carried out, for the development of this plan, with:

(a) relevant electricity and natural gas undertakings, including relevant producers or their trade bodies;

(b) relevant organisations representing the interests of non-industrial electricity customers;

(c) relevant organisations representing the interests of industrial electricity customers;

(d) regulatory authorities;

(e) the transmission system operators;

(f) relevant distribution system operators.

6. EMERGENCY TESTS

(a) Indicate the calendar for the biennial regional (and, if applicable also national) real time response simulations of electricity crises;

(b) In accordance with point (d) of Article 12(1), indicate procedures agreed and the actors involved. For the updates of the plan: briefly describe the tests carried out since the last plan was adopted and the main results. Indicate which measures have been adopted as a result of those tests.

II. PART

ELECTRICITY NETWORK CODES AND GUIDELINES

COMMISSION REGULATION (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

*The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in **bold and blue**.*

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter and scope

1. This Regulation lays down detailed rules on cross-zonal capacity allocation in the forward markets, on the establishment of a common methodology to determine long-term cross-zonal capacity, on the establishment of a single allocation platform **<…>** offering long-term transmission rights, and on the possibility to return long-term transmission rights for subsequent forward capacity allocation or transfer long-term transmission rights between market participants.

2. This Regulation shall apply to all transmission systems and interconnections in the **Energy Community,** except the transmission systems **<…>** which are not connected with other transmission systems via interconnectors.

3. In **Contracting Parties** where more than one TSO exists, this Regulation shall apply to all TSOs within that **Contracting Party**. Where a TSO does not have a function relevant to one or more obligations under this Regulation, **Contracting Parties** may provide that the responsibility for complying with those obligations is assigned to one or more different, specific TSOs.

4. **<…>**

5. **<…>**

Article 2
Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) No 543/2013 **as adapted and adopted by Ministerial Council**

Decision 2015/01/MC-EnC as well as Article 2 of Directive **(EU) 2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** shall apply.

In addition, the following definitions shall apply:

(1) 'forward capacity allocation' means the attribution of long-term cross-zonal capacity through an auction before the day-ahead time frame;

(2) 'long-term transmission right' means a physical transmission right or a FTR — option or a FTR — obligation acquired in the forward capacity allocation;

(3) 'allocation rules' means the rules for forward capacity allocation applied by the single allocation platform;

(4) '**regional** allocation platform' means the **<…>** platform established by **Article 48**;

(5) 'auction' means the process by which long-term cross-zonal capacity is offered and allocated to market participants who submit bids;

(6) 'UIOSI' means the principle according to which the underlying cross-zonal capacity of physical transmission rights purchased and non-nominated is automatically made available for day-ahead capacity allocation and according to which the holder of these physical transmission rights receives remuneration from the TSOs.

(7) 'nomination' means the notification of the use of long-term cross-zonal capacity by a physical transmission rights holder and its counterparty, or an authorised third party, to the respective TSOs;

(8) 'nomination rules' means the rules with regard to the notification of use of long-term cross-zonal capacity by a physical transmission rights holder and their counterparty, or an authorised third party, to the respective TSOs;

(9) 'market spread' means the difference between the hourly day-ahead prices of the two concerned bidding zones for the respective market time unit in a specific direction;

(10) 'compensation rules' means the rules according to which each TSO responsible for the bidding zone border, where long-term transmission rights have been allocated, compensates transmission right holders for curtailing the long-term transmission rights.

(11) 'Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

Article 3

Objectives of forward capacity allocation

This Regulation aims at:

(a) promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants;

(b) optimising the calculation and allocation of long-term cross-zonal capacity;

(c) providing non-discriminatory access to long-term cross-zonal capacity;

(d) ensuring fair and non-discriminatory treatment of TSOs, the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board,** regulatory authorities and market participants;

(e) respecting the need for a fair and orderly forward capacity allocation and orderly price formation;

(f) ensuring and enhancing the transparency and reliability of information on forward capacity allocation;

(g) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the **Energy Community**.

Article 4

Adoption of terms and conditions or methodologies

1. **Where this Regulation requires** TSOs **to** develop the terms and conditions or methodologies **they shall** submit them for approval to the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or the competent regulatory authorities within the respective deadlines set out in this Regulation. **<…>** Where a proposal for terms and conditions or methodologies pursuant to this Regulation needs to be developed and agreed by more than one TSO, the participating TSOs shall closely cooperate. TSOs, with the assistance of the ENTSO for Electricity, shall regularly inform the competent regulatory authorities and the Agency **for the Cooperation of Energy Regulators and the Energy Community Regulatory Board** about the progress of the development of those terms and conditions or methodologies.

2. **<…>**

3. Where TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 are not able to reach an agreement and where regions concerned are composed of more than five **Contracting Parties and/or** Member States, they shall decide by qualified majority voting. A qualified majority for proposals in accordance with paragraph 7 shall require the following majority:

(a) TSOs representing at least 72 % of the **Contracting Parties and/or** Member States concerned; and

(b) TSOs representing **Contracting Parties and/or** Member States comprising at least 65 % of the population of the concerned region.

A blocking minority for decisions on proposals for terms and conditions or methodologies listed in paragraph 7 shall include at least the minimum number of TSOs representing more than 35 % of the population of the participating **Contracting Parties and/or** Member States, plus TSOs representing at least one additional **Contracting Party and/or** Member State concerned, failing of which the qualified majority shall be deemed attained.

TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 in relation to regions composed of five **Contracting Party and/or** Member States or less shall decide by consensus.

For TSO decisions on proposals for terms and conditions or methodologies listed in paragraph 7, one vote shall be attributed per **Contracting Party or** Member State. If there is more than one TSO in the territory of **a Contracting Party or** a Member State, **the Contracting Party or** the Member State shall allocate the voting powers among the TSOs.

4. If TSOs fail to submit an initial or amended proposal for terms and conditions or methodologies to the competent regulatory authorities or the Agency **for the Cooperation of Energy Regulators** in accordance with paragraph **<…>** 7 or 11 within the deadlines set out in this Regulation, they shall provide the competent regulatory authorities and the Agency **for the Cooperation of Energy Regulators and**

the Energy Community Regulatory Board with the relevant drafts of the proposals for the terms and conditions or methodologies, and explain what has prevented an agreement. The **Energy Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or all competent regulatory authorities jointly, shall take the appropriate steps for the adoption of the required terms and conditions or methodologies in accordance with paragraphs **<…>** 7 respectively, for instance by requesting amendments or revising and completing the drafts pursuant to this paragraph, including where no drafts have been submitted, and approve them.

5. Each regulatory authority or where applicable the **Energy Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, as the case may be, shall be responsible for approving the terms and conditions or methodologies referred to in paragraphs 6 and 7. Before approving the terms and conditions or methodologies, the **Energy Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or the competent regulatory authorities shall revise the proposals where necessary, after consulting the respective TSOs, in order to ensure that they are in line with the purpose of this Regulation and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

6. **TSOs shall apply the following terms and conditions or methodologies,** any amendments thereof shall be subject to approval by the Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**:

(a) the generation and load data provision methodology pursuant to Article 17**(1) of Regulation (EU) 2016/1719**;

(b) the common grid model methodology pursuant to Article 18**(1) of Regulation (EU) 2016/1719**;

(c) the requirements for the single allocation platform pursuant to Article 49 **of Regulation (EU) 2016/1719, subject to Article 48 paragraphs 4 or 6 of the present Regulation**

(d) the harmonised allocation rules pursuant to Article 51 **of Regulation (EU) 2016/1719**;

(e) the congestion income distribution methodology pursuant to Article **57 of Regulation (EU) 2016/1719**;

(f) the methodology for sharing costs of establishing, developing and operating the single allocation platform pursuant to Article 59 **of Regulation (EU) 2016/1719, subject to Article 48 paragraphs 4 or 6 of the present Regulation**;

(g) the methodology for sharing costs incurred to ensure firmness and remuneration of long-term transmission rights pursuant to Article 61 **of Regulation (EU) 2016/1719**.

7. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by all regulatory authorities of the concerned region:

(a) the capacity calculation methodology pursuant to Article 10;

(b) the methodology for splitting cross-zonal capacity pursuant to Article 16;

(c) the regional design of long-term transmission rights pursuant to Article 31;

(d) the establishment of fallback procedures in accordance with Article 42;

(e) the regional requirements of the harmonised allocation rules pursuant to Article 52, including the regional compensation rules pursuant to Article 55;

f.[1] the requirements for the regional allocation platform pursuant to Article 49;

(g) the methodology for sharing costs of establishing, developing and operating the regional allocation platform pursuant to Article 59.

8. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. Proposals for terms and conditions or methodologies subject to the approval by several or all regulatory authorities in accordance with paragraph 7 shall be submitted to the **Energy Community Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** within 1 week of their submission to the regulatory authorities. Upon request by the competent regulatory authorities, the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall issue an opinion within 3 months on the proposals for terms and conditions or methodologies.

9. Where the approval of the terms and conditions or methodologies in accordance with paragraph 7 or the amendment in accordance with paragraph 11 requires a decision by more than one regulatory authority, the competent regulatory authorities shall consult and closely cooperate and coordinate with each other in order to reach an agreement. Where applicable, the competent regulatory authorities shall take into account the opinion of **the Energy Community Regulatory Board or** the Agency **for the Cooperation of Energy Regulators**. Regulatory authorities or, where competent, the Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall take decisions concerning the submitted terms and conditions or methodologies in accordance with paragraph **<…>** 7, within 6 months following the receipt of the terms and conditions or methodologies by the Agency **for the Cooperation of Energy Regulators** or, where applicable, by the last regulatory authority concerned. The period shall begin on the day following that on which the proposal was submitted to the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators <…>** or to the last regulatory authority concerned in accordance with paragraph 7.

10. Where the regulatory authorities have not been able to reach an agreement within the period referred to in paragraph 9, or upon their joint request, **<…> the Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within 6 months **<…>**.

11. In the event that the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or all competent regulatory authorities jointly request an amendment to approve the terms and conditions or methodologies submitted in accordance with paragraph **<…>** 7, the relevant TSOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months following the request from the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for**

1 There is a clerical error in the Ministerial Council Decision D/2022/03/MC-EnC.

the Cooperation of Energy Regulators or the regulatory authorities. The **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or the competent regulatory authorities shall decide on the amended terms and conditions or methodologies within 2 months following their submission. Where the competent regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies pursuant to paragraph 7 within the 2-month deadline, or upon their joint request **the Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the amended terms and conditions or methodologies within 6 months **<…>**. If the relevant TSOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in paragraph 4 shall apply.

12. The **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or the regulatory authorities jointly, where they are responsible for the adoption of terms and conditions or methodologies in accordance with paragraph **<…>** 7, may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the Agency **for the Cooperation of Energy Regulators**.

The proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 6 and approved in accordance with the procedure set out in this Article.

13. TSOs responsible for establishing the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet after approval by the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or the competent regulatory authorities or, if no such approval is required, after their establishment, except where such information is considered as confidential in accordance with Article 7.

Article 5

Stakeholder involvement

The **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, in close cooperation with ENTSO for Electricity, shall organise stakeholder involvement regarding forward capacity allocation and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the operation and development of the forward capacity allocation, including the harmonisation of auction rules. This shall not replace the stakeholder consultations in accordance with Article 6.

Article 6

Consultation

1. TSOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each Member State **and Contracting Party**, on the draft proposals for terms and conditions or methodologies where explicitly set out in this Regulation. The consultation shall last for a period of not less than one month.

2. **<…>** Proposals submitted by the TSOs at regional level shall be submitted to consultation at least at regional level. Parties submitting proposals at bilateral or at multilateral level shall consult at least the Member States **and Contracting Parties** concerned.

3. The entities responsible for the proposal for terms and conditions or methodologies shall duly consider the views of stakeholders resulting from the consultations undertaken in accordance with paragraph 1, prior to its submission for regulatory approval if required in accordance with Article 4 or prior to publication in all other cases. In all cases, a clear and robust justification for including or not the views resulting from the consultation shall be developed and published in a timely manner before or simultaneously with the publication of the proposal for terms and conditions or methodologies.

Article 7

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons subject to the provisions of this Regulation.

3. Confidential information received by the persons referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **national or Energy Community** legislation.

4. Without prejudice to cases covered by national law **<…>**, regulatory authorities, bodies or persons which receive confidential information pursuant to this Regulation may use it only for the purpose of the performance of their functions under this Regulation.

TITLE II
REQUIREMENTS FOR TERMS, CONDITIONS AND METHODOLOGIES

CHAPTER 1
Forward capacity calculation

Section 1
General requirements

Article 8

Capacity calculation regions

For the purposes of this Regulation the capacity calculation regions shall be those established pursuant to Article 15 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

Article 9

Capacity calculation time frames

All TSOs in each capacity calculation region shall ensure that long-term cross-zonal capacity is calculated for each forward capacity allocation and at least on annual and monthly time frames.

Section 2
Capacity calculation methodology

Article 10

Capacity calculation methodology

1. No later than six months after the approval of the common coordinated capacity calculation methodology referred to in Article 9(7) of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, all TSOs in each capacity calculation region shall submit a proposal for a common capacity calculation methodology for long-term time frames within the respective region. The proposal shall be subject to consultation in accordance with Article 6.

2. The approach used in the common capacity calculation methodology shall be either a coordinated net transmission capacity approach or a flow-based approach.

3. The capacity calculation methodology shall be compatible with the capacity calculation methodology established for the day-ahead and intraday time frames pursuant to Article 21(1) of Regulation (EU)

2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

4. The uncertainty associated with long-term capacity calculation time frames shall be taken into account when applying:

(a) a security analysis based on multiple scenarios and using the capacity calculation inputs, the capacity calculation approach referred to in Article 21(1)(b) and the validation of cross-zonal capacity referred to in Article 21(1)(c) of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**; or

(b) a statistical approach based on historical cross-zonal capacity for day-ahead or intraday time frames if it can be demonstrated that this approach may:

(i) increase the efficiency of the capacity calculation methodology;

(ii) better take into account the uncertainties in long-term cross-zonal capacity calculation than the security analysis in accordance with paragraph 4(a);

(iii) increase economic efficiency with the same level of system security.

5. All TSOs in each capacity calculation region may jointly apply the flow-based approach for long-term capacity calculation time frames on the following conditions:

(a) the flow-based approach leads to an increase of economic efficiency in the capacity calculation region with the same level of system security;

(b) the transparency and accuracy of the flow-based results have been confirmed in the capacity calculation region;

(c) the TSOs provide market participants with six months to adapt their processes.

6. Where a security analysis based on multiple scenarios is applied for developing the capacity calculation methodology in a capacity calculation region, the requirements for the capacity calculation inputs, the capacity calculation approach and the validation of cross-zonal capacity as provided for in Article 21(1) of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** except Article 21(1)(a)(iv) where relevant, shall apply.

7. When developing the capacity calculation methodology, the requirements for the fallback procedures and the requirement provided for in Article 21(3) of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** shall be taken into account.

Article 11

Reliability margin methodology

The proposal for a common capacity calculation methodology shall include a reliability margin methodology which shall meet the requirements set out in Article 22 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 12

Methodologies for operational security limits and contingencies

The proposal for a common capacity calculation methodology shall include methodologies for operational security limits and contingencies which shall meet the requirements set out in Article 23(1) and (2) of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 13

Generation shift keys methodology

The proposal for a common capacity calculation methodology shall include a methodology to determine generation shift keys which shall meet the requirements set out in Article 24 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 14

Methodology for remedial actions

If remedial actions are taken into account in the long-term capacity calculation, each TSO shall ensure that those remedial actions are technically available in real time operation and meet the requirements set out in Article 25 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

Article 15

Cross-zonal capacity validation methodology

The proposal for a common capacity calculation methodology shall include a cross-zonal validation methodology which shall meet the requirements set out in Article 26 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 16

Methodology for splitting long-term cross-zonal capacity

1. No later than the submission of the capacity calculation methodology referred to in Article 10, the TSOs of each capacity calculation region shall jointly develop a proposal for a methodology for splitting long-term cross-zonal capacity in a coordinated manner between different long-term time frames within the respective region. The proposal shall be subject to consultation in accordance with Article 6 .

2. The methodology for splitting long-term cross-zonal capacity shall comply with the following conditions:

(a) it shall meet the hedging needs of market participants;

(b) it shall be coherent with the capacity calculation methodology;

(c) it shall not lead to restrictions in competition, in particular for access to long-term transmission rights.

Section 3
Common grid model

Article 17
Generation and load data provision methodology

<...>

Article 18
Common grid model methodology

<...>

Article 19
Scenarios

1. All TSOs in capacity calculation regions, where security analysis based on multiple scenarios pursuant to Article 10 is applied, shall jointly **apply the** common set of scenarios **developed in accordance with Article 18 of Regulation (EU) 2015/1222** to be used in the common grid model for each long-term capacity calculation time frame.

2. **<...>**

Article 20
Individual grid model

When developing the individual grid model for a long-term capacity calculation time frame in capacity calculation regions, where security analysis based on multiple scenarios pursuant to Article 10 is applied, each TSO shall apply the requirements set in Article 19 of Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Section 4
Capacity calculation process

Article 21

General provisions

1. **<…>** No later than six months after the **expiry of the deadline for transposition** of **this Regulation, <…>**, all TSOs in each capacity calculation region shall jointly develop operational rules for long-term capacity calculation time frames supplementing the rules defined for the operation to merge the individual grid models pursuant to Article 27 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. The coordinated capacity calculators established in Article 27 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** shall calculate long-term cross-zonal capacities for their capacity calculation region. For this purpose, no later than six months after the approval of the capacity calculation methodology for long-term time frames referred to in Article 10, all TSOs in each capacity calculation region shall jointly develop operational rules for long-term capacity calculation time frames supplementing the rules defined for the operation of the coordinated capacity calculators pursuant to Article 27 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

3. The relevant requirements set in Article 27 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** shall apply for long-term capacity calculation time frames.

Article 22

Creation of a common grid model

The process and requirements set in Article 28 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** for **merging into** a common grid model shall apply when creating the common grid model for long-term capacity calculation time frames in capacity calculation regions, where security analysis based on multiple scenarios pursuant to Article 10 is applied.

Article 23

Regional calculations of long-term cross-zonal capacities

1. Where TSOs apply the statistical approach pursuant to Article 10, the process for the calculation of long-term cross-zonal capacity shall include at least:

(a) a selection of historical day-ahead or intraday cross-zonal capacity data sets from a single period or a set of periods and order the data into a duration curve;

(b) a calculation of capacity corresponding to the risk level for the selected data set;

(c) a calculation of long-term cross-zonal capacity to be offered to forward capacity allocation taking into account a margin to reflect the difference between historical cross-zonal capacity values and forecasted long-term cross-zonal capacity values;

(d) common rules to take into account available information about planned outages, new infrastructure and generation and load pattern for the long-term capacity calculation time frames.

2. Where TSOs apply the security analysis based on multiple scenarios pursuant to Article 10, the requirements set in Article 29 of Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** except Article 29(4) where relevant, shall apply to long-term capacity calculation time frames in capacity calculation regions.

3. Each coordinated capacity calculator shall split the calculated long-term cross-zonal capacity for each forward capacity allocation by applying the methodology for splitting cross-zonal capacity pursuant to Article 16.

4. Each coordinated capacity calculator shall submit the calculated long-term cross-zonal capacity and the splitting of long-term cross-zonal capacity for validation to each TSO within the relevant capacity calculation region pursuant to Article 24.

Article 24

Validation and delivery of cross-zonal capacity and split cross-zonal capacity

1. Each TSO shall validate the results of the calculation for long-term cross-zonal capacity on its bidding zone borders or critical network elements for each long-term capacity calculation time frame pursuant to Article 15.

2. Each TSO shall validate the results of the calculation for splitting of long-term cross-zonal capacity on its bidding zone borders or critical network elements pursuant to Article 16.

3. Each TSO shall send its capacity validation and validated splitting of this capacity for each forward capacity allocation to the relevant coordinated capacity calculators and to the other TSOs of the relevant capacity calculation regions.

4. Validated splitting of long-term cross-zonal capacity shall be provided by each coordinated capacity calculator for the execution of forward capacity allocation pursuant to Article 29.

5. TSOs shall, upon request, provide to their regulatory authorities a report detailing how the value of long-term cross-zonal capacity for a specific long-term capacity calculation time frame has been obtained.

Article 25

Coordinated curtailment of cross-zonal capacity

1. TSOs shall coordinate curtailments of already allocated long-term cross-zonal capacity, if the curtailments concern a time frame of more than 48 hours ahead of the start of the delivery day. In case of curtailment of long-term transmission rights, including nominations in respect of such rights, within 48 hours ahead of the start of the delivery day, TSOs in each capacity calculation region shall apply the day-ahead and intraday capacity calculation process as referred in Article 29 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. If a TSO needs to curtail already allocated long-term cross-zonal capacity, it shall send a request to the

responsible coordinated capacity calculator to launch the coordinated calculation of necessary curtailments of long-term cross-zonal capacity for the capacity calculation region. The TSO shall support its request with all relevant information.

3. The coordinated capacity calculator shall provide the updated cross-zonal capacity to the relevant TSOs for validation.

4. Each TSO shall validate the updated cross-zonal capacity on its bidding zone borders or critical network elements pursuant to Article 24.

5. The coordinated capacity calculator shall provide the validated updated cross-zonal capacity to the relevant TSOs and single allocation platform to perform curtailment pursuant to Article 53.

Section 5
Biennial report on capacity calculation

Article 26
Biennial report on capacity calculation and allocation

1. No later than two years after the **expiry of the deadline for transposition** of this Regulation, ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC** shall **extend the reports on long-term capacity calculation and allocation drafted in accordance with Article 26(1) and (2) of Regulation (EU) 2016/1719 to include the Contracting Parties <…>. To the extent the report covers TSOs from Contracting Parties not part of the continental synchronized operation or not member of the ENTSO for Electricity, the Secretariat shall coordinate the relevant contributions.**

2. **<…>**

3. For each bidding zone, bidding zone border and capacity calculation region, the report on capacity calculation and allocation shall contain at least:

(a) the capacity calculation approach used;

(b) statistical indicators on reliability margins;

(c) statistical indicators of cross-zonal capacity, where appropriate for each capacity calculation time frame;

(d) quality indicators for the information used for the capacity calculation;

(e) where appropriate, proposed measures to improve capacity calculation;

(f) recommendations for further development of the forward capacity calculation, including further harmonisation of methodologies, processes and governance arrangements.

4. **For the report,** TSOs shall **use** the statistical and quality indicators **agreed in accordance with Article 26 of Regulation (EU) 2016/1719**. The Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** may require the amendment of those indicators **<…>** during their application.

5. **<…>**

CHAPTER 2
Bidding zones

Article 27
General provisions

1. The bidding zones applicable to day-ahead and intraday trading shall apply to forward capacity calculation and allocation.

2. Where a bidding zone border no longer exist, holders of long-term transmission rights on this bidding zone border shall be entitled to reimbursement by the concerned TSOs based on the initial price paid for the long-term transmission rights.

CHAPTER 3
Forward capacity allocation

Section 1
General provisions

Article 28
General principles

The allocation of forward capacity shall take place in a way which:

(a) uses the marginal pricing principle to generate results for each bidding zone border, direction of utilisation and market time unit;

(b) allocates no more than the offered long-term cross-zonal capacity in accordance with Article 39;

(c) is repeatable.

Article 29
Input and results

1. The single allocation platform shall use the following inputs for determining the allocation of forward capacity in accordance with paragraph 2:

(a) validated splitting of long-term cross-zonal capacity submitted by each coordinated capacity calculator and capacities associated with returned long-term transmission rights pursuant to Article 43;

(b) bids submitted by market participants.

2. For each forward capacity allocation, the single allocation platform shall simultaneously determine at

least the following results for each bidding zone border, direction of utilisation and market time unit:

(a) the volume of allocated long-term transmission rights expressed in MW;

(b) the price of long-term transmission rights pursuant to Article 40;

(c) the execution status of bids.

3. The single allocation platform shall ensure that auction results are accurate.

4. Each TSO shall ensure that the auction results are consistent with the inputs provided to the single allocation platform in accordance with paragraph 1.

Section 2
Options for cross-zonal transmission risk hedging

Article 30
Decision on cross-zonal risk hedging opportunities

1. TSOs on a bidding zone border shall issue long-term transmission rights unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border. When adopting their decisions, the competent regulatory authorities of the bidding zone border shall consult the regulatory authorities of the relevant capacity calculation region and take due account of their opinions.

2. Where long-term transmission rights do not exist on a bidding zone border at the entry into force of this Regulation, the competent regulatory authorities of the bidding zone border shall adopt coordinated decisions on the introduction of long-term transmission rights no later than six months after the **expiry of the deadline for transposition** of this Regulation.

3. The decisions pursuant to paragraphs 1 and 2 shall be based on an assessment, which shall identify whether the electricity forward market provides sufficient hedging opportunities in the concerned bidding zones. The assessment shall be carried out in a coordinated manner by the competent regulatory authorities of the bidding zone border and shall include at least:

(a) a consultation with market participants about their needs for cross-zonal risk hedging opportunities on the concerned bidding zone borders;

(b) an evaluation.

4. The evaluation referred to in paragraph 3(b) shall investigate the functioning of wholesale electricity markets and shall be based on transparent criteria which include at least:

(a) an analysis of whether the products or combination of products offered on forward markets represent a hedge against the volatility of the day-ahead price of the concerned bidding zone. Such product or combination of products shall be considered as an appropriate hedge against the risk of change of the day-ahead price of the concerned bidding zone where there is a sufficient correlation between the day-ahead price of the concerned bidding zone and the underlying price against which the product or combination of products are settled;

(b) an analysis of whether the products or combination of products offered on forward markets are efficient.

For this purpose, at least the following indicators shall be assessed:

(i) trading horizon;

(ii) bid-ask spread;

(iii) traded volumes in relation to physical consumption;

(iv) open interest in relation to physical consumption.

5. In case the assessment referred to in paragraph 3 shows that there are insufficient hedging opportunities in one or more bidding zones, the competent regulatory authorities shall request the relevant TSOs:

(a) to issue long-term transmission rights; or

(b) to make sure that other long-term cross-zonal hedging products are made available to support the functioning of wholesale electricity markets.

6. In case the competent regulatory authorities choose to issue a request as referred to in paragraph 5(b), the relevant TSOs shall develop the necessary arrangements and submit them to the competent regulatory authorities' approval no later than six months after the request by the competent regulatory authorities. Those necessary arrangements shall be implemented no later than six months after approval by the competent regulatory authorities. The competent regulatory authorities may extend the implementation time upon request from the relevant TSOs by a period of no more than 6 months.

7. Where regulatory authorities decide that long-term transmission rights shall not be issued by the respective TSOs or that other long-term cross-zonal hedging products shall be made available by the respective TSOs, Articles 16, 28, 29, 31 to 57, 59 and 61 shall not apply to the TSOs of the bidding zone borders.

8. Upon a joint request of the TSOs on a bidding zone border or at their own initiative, and at least every 4 years, the competent regulatory authorities of the bidding zone border shall perform, in cooperation with the **Energy Community Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators**, an assessment pursuant to paragraphs 3 to 5.

Article 31

Regional design of long-term transmission rights

1. Long-term cross-zonal capacity shall be allocated to market participants by the allocation platform in the form of physical transmission rights pursuant to the UIOSI principle or in the form of FTRs — options or FTRs — obligations.

2. All TSOs issuing long-term transmission rights shall offer long-term cross-zonal capacity, through the single allocation platform **referred to in Article 48**, to market participants for at least annual and monthly time frames. All TSOs in each capacity calculation region may jointly propose to offer long-term cross-zonal capacity on additional time frames.

3. No later than six months after the **expiry of the deadline for transposition** of this Regulation, TSOs in each capacity calculation region where long-term transmission rights exist shall jointly develop a proposal for the regional design of long-term transmission rights to be issued on each bidding zone border within the capacity calculation region.

No later than six months after the coordinated decisions of the regulatory authorities of the bidding zone

border to introduce long-term transmission rights pursuant Article 30(2), TSOs of the concerned capacity calculation region, shall jointly develop a proposal for the regional design of long-term transmission rights to be issued on each bidding zone border within the concerned capacity calculation region.

Regulatory authorities of **Contracting Parties and** Member States in which the current regional design of long-term transmission rights is part of a TSO cross-border re-dispatch arrangement for the purpose of ensuring that operation remains within operational security limits may decide to maintain physical long-term transmission rights on its bidding zone borders.

4. The proposals referred to in paragraph 3 shall include a time schedule for implementation and at least the description of the following items specified in the allocation rules:

(a) type of long-term transmission rights;

(b) forward capacity allocation time frames;

(c) form of product (base load, peak load, off-peak load);

(d) the bidding zone borders covered.

5. The proposals shall be subject to consultation in accordance with Article 6. For the proposed long-term transmission rights to be issued, each TSO shall duly consider the result of the consultation.

6. The allocation of physical transmission rights and FTRs — options in parallel at the same bidding zone border is not allowed. The allocation of physical transmission rights and FTRs — obligations in parallel at the same bidding zone border is not allowed.

7. A review of long-term transmission rights offered on a bidding zone border may be launched by:

(a) all regulatory authorities of the bidding zone border, at their own initiative; or

(b) all regulatory authorities of the bidding zone border based upon a recommendation from the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or joint request by all TSOs of the concerned bidding zone border.

8. All TSOs in each capacity calculation region shall be responsible for undertaking the review as provided for in paragraph 9.

9. Each TSO involved in the review of long-term transmission rights shall:

(a) assess the offered long-term transmission rights taking into account the characteristics in paragraph 4;

(b) if considered necessary, propose alternative long-term transmission rights, taking into account the result of the assessment in subparagraph (a);

(c) carry out a consultation in accordance with Article 6 regarding:

(i) the results of the assessment of the offered long-term transmission rights;

(ii) if applicable, the proposal for alternative long-term transmission rights.

10. Following the consultation referred to in paragraph 9(c) and within three months of the issuance of the decision to launch a review, the TSOs of the capacity calculation region concerned shall jointly submit a proposal to the competent regulatory authorities to maintain or amend the type of long-term transmission rights.

Article 32

Physical transmission rights

1. Each physical transmission right holder shall be entitled to nominate all or part of its physical transmission rights pursuant to Article 36.

2. Where the physical transmission rights holders do not make a nomination by the deadline specified in the nomination rules, they shall be entitled to obtain remuneration in accordance with Article 35.

Article 33

Financial transmission rights — options

1. Holders of FTRs — options shall be entitled to obtain remuneration in accordance with Article 35.

2. The implementation of FTRs — options shall be subject to the application of day-ahead price coupling in accordance with Articles 38 to 50 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 34

Financial transmission rights — obligations

1. Holders of FTRs — obligations shall be entitled to receive or obliged to pay the financial remuneration pursuant to Article 35.

2. The implementation of FTRs — obligations shall be subject to the application of day-ahead price coupling according to Articles 38 to 50 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 35

Principles for long-term transmission rights remuneration

1. The relevant TSOs performing the allocation of transmission rights on a bidding zone border through the single allocation platform shall remunerate the long-term transmission rights holders in case the price difference is positive in the direction of the long-term transmission rights.

2. The holders of FTRs — obligations shall remunerate the relevant TSOs through the single allocation platform allocating transmission rights on a bidding zone border in case the price difference is negative in the direction of the FTRs — obligations.

3. The remuneration of long-term transmission rights in paragraphs 1 and 2 shall comply with the following principles:

(a) where the cross-zonal capacity is allocated through implicit allocation or another method resulting from a fallback situation in the day-ahead time frame, the remuneration of long-term transmission rights shall be equal to the market spread;

(b) where the cross-zonal capacity is allocated through explicit auction in the day-ahead time frame, the remuneration of long-term transmission rights shall be equal to the clearing price of the daily auction.

4. In case allocation constraints on interconnections between bidding zones have been included in the day-ahead capacity allocation process in accordance with Article 23(3) of Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** they may be taken into account for the calculation of the remuneration of long-term transmission rights pursuant to paragraph 3.

Section 3
Nomination procedures for physical transmission rights

Article 36
General provisions for physical transmission rights nomination

1. Where TSOs issue and apply physical transmission rights on bidding zone borders, they shall enable physical transmission rights holders and/or their counterparties to nominate their electricity exchange schedules. Physical transmission rights holders may authorise eligible third parties to nominate their electricity exchange schedules on their behalf in line with the nomination rules in accordance with paragraph 3.

2. No later than 12 months after the **expiry of the deadline for transposition** of this Regulation, all TSOs issuing physical transmission rights on a bidding zone border shall submit to the relevant regulatory authorities' approval a proposal for nomination rules for electricity exchange schedules between bidding zones. The proposal shall be subject to consultation in accordance with Article 6. Nomination rules shall contain at least the following information:

(a) the entitlement of a physical transmission rights holder to nominate electricity exchange schedules;

(b) minimum technical requirements to nominate;

(c) description of the nomination process;

(d) nomination timings;

(e) format of nomination and communication.

3. All TSOs shall progressively harmonise the nomination rules on all bidding zone borders on which physical transmission rights are applied.

4. Physical transmission rights holders, their counterparties where applicable or an authorised third party acting on their behalf shall nominate all or part of their physical transmission rights between bidding zones in compliance with the nomination rules.

5. In case allocation constraints on interconnections between bidding zones have been included in the day-ahead capacity allocation process in accordance with Article 23(3) of Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** they shall be taken into account in the proposal for nomination rules referred to in paragraph 2.

Section 4
Processes and operation

Article 37
Terms and conditions for participation in the forward capacity allocation

1. Market participants shall be registered with the single allocation platform **referred to in Article 48** and meet all eligibility requirements under the harmonised allocation rules before being entitled to participate in the auctions or transfer their long-term transmission rights. The eligibility requirements shall comply with the principles of non-discrimination and transparency.

2. Following a market participant's request for registration, the single allocation platform shall notify the market participant whether it fulfils all eligibility requirements and is entitled to participate in the auctions or transfer its long-term transmission rights from a specified date.

3. Market participants shall fully comply with the harmonised allocation rules. They shall keep all information relating to their participation up to date and notify the single allocation platform of any changes to this information without delay.

4. The single allocation platform shall be entitled to suspend or withdraw a market participant's right to participate in the auctions or transfer its long-term transmission rights following a breach of its contractual obligations under the harmonised allocation rules.

5. The suspension or withdrawal of the right of the market participant to participate in the auctions or transfer its long-term transmission right pursuant to the harmonised allocation rules shall not exonerate a market participant or the single allocation platform from their obligations deriving from long-term transmission rights allocated and paid before the suspension or withdrawal.

Article 38
Submission of input data to the single allocation platform

Each TSO shall ensure that validated splitting of long-term cross-zonal capacity is submitted to the single allocation platform prior to the publication of the auction specification in accordance with Article 39.

Article 39
Operation of the forward capacity allocation

1. No later than the time specified in the harmonised allocation rules for each forward capacity allocation, an auction specification containing at least the following information shall be defined and published on the single allocation platform:

(a) date and time of gate opening and gate closure of the auction;

(b) validated splitting of long-term cross-zonal capacity and type of the long-term transmission rights that

will be auctioned;

(c) format of bids;

(d) date and time of publication of auction results;

(e) the period during which auction results can be contested.

2. The published long-term cross-zonal capacity shall not be modified during a period prior to the gate closure of the auction. The harmonised allocation rules shall specify that period.

3. Each market participant shall submit its bids to the single allocation platform prior to the gate closure time and in accordance with the conditions set out in the auction specification.

4. The single allocation platform shall ensure the confidentiality of submitted bids.

Article 40

Pricing of the long-term transmission rights

The price of long-term transmission rights for each bidding zone border, direction of utilisation and market time unit shall be determined based on the marginal price principle and expressed in euro per megawatt. In case the demand for the long-term cross-zonal capacity for a bidding zone border, direction of utilisation and market time unit is lower or equal to the offered long-term cross-zonal capacity, the price shall be zero.

Article 41

Financial requirements and settlement

1. The single allocation platform shall provide invoicing or self-billing procedures for the settlement of debits or credits resulting from the allocation of long-term transmission rights, the return of long-term transmission rights and the remuneration of long-term transmission rights. The harmonised allocation rules shall specify those procedures.

2. In order to participate in the auctions, a market participant shall have sufficient collaterals to secure bids and allocated long-term transmission rights in accordance with the conditions set out in the harmonised allocation rules.

Article 42

Establishment of fallback procedures

1. In the event that forward capacity allocation is unable to produce results, the default fallback procedure shall be the postponement of the forward capacity allocation.

2. All TSOs in each capacity calculation region shall be entitled to implement alternative coordinated fallback solutions. In such cases, all TSOs in each capacity calculation region shall develop a coordinated proposal for reliable fallback procedures.

Article 43

Return of long-term transmission rights

1. Long-term transmission rights holders may return their long-term transmission rights to the relevant TSOs through the single allocation platform for subsequent forward capacity allocation.

2. Long-term transmission rights holders willing to return their long-term transmission rights for subsequent forward capacity allocation shall notify this, directly or indirectly through a third party, to the single allocation platform as set out in the harmonised allocation rules.

3. Long-term transmission rights holders who return their long-term transmission rights shall be remunerated, directly or indirectly through a third party, by the relevant TSOs through the single allocation platform **referred to in Article 48**. Such remuneration shall be equal to the price resulting from the auction where the long-term transmission rights are reallocated.

Article 44

Transfer of long-term transmission rights

1. Long-term transmission rights holders shall be entitled to transfer all or part of their long-term transmission rights to other market participants in accordance with the harmonised allocation rules.

2. The rules on admissibility and a list of market participants registered with the single allocation platform and eligible to transfer long-term transmission rights shall be published on the single allocation platform.

3. Long-term transmission rights holders shall notify the transfer of long-term transmission rights, directly or indirectly through a third party, to the single allocation platform in accordance with the harmonised allocation rules.

4. Market participants acquiring those long-term transmission rights shall confirm, in accordance with the harmonised allocation rules, directly or indirectly through a third party, to the single allocation platform the notification sent by the previous long-term transmission rights holder.

Article 45

Delivery of results

1. The single allocation platform **referred to in Article 48** shall notify the TSOs responsible for the bidding zone border to which the long-term transmission rights are associated, the market participants and the long-term transmission rights holders about the result of the forward capacity allocation within the time frame provided in the auction specification.

2. The single allocation platform shall inform market participants about the execution status and clearing prices of their bids.

Article 46

Initiation of fallback procedures

1. In the event that the single allocation platform is unable to deliver either the auction specification in accordance with Article 39 or part or all of the results of the forward capacity allocation within the time frame specified in the harmonised allocation rules, the TSOs responsible on the bidding zone border shall implement the fallback procedures established pursuant to Article 42.

2. As soon as a failure to deliver the items referred to in paragraph 1 is identified, the single allocation platform shall notify the TSOs responsible on the bidding zone border. The single allocation platform shall notify market participants that fallback procedures may be applied.

Article 47

Publication of market information

1. At least the following information for each bidding zone border and direction of utilisation shall be published on the single allocation platform:

(a) auction specification in accordance with Article 39;

(b) an indicative auction calendar setting out the type of long-term transmission rights to be offered and the dates when those long-term transmission rights shall be offered to market participants;

(c) forward capacity allocation results in accordance with Article 29;

(d) number of market participants in each auction;

(e) list of eligible market participants for the transfer of long-term transmission rights;

(f) the single allocation platform's contact details.

2. The relevant TSOs shall publish, through the single allocation platform, the information required referred to in paragraph 1 in accordance with the timing set out in the auction specification and in Regulation (EU) No 543/2013**, as adapted and adopted by Ministerial Council Decision 2015/01/MC-EnC**.

3. The single allocation platform shall ensure that historical data for a period of not less than five years is made publicly available.

CHAPTER 4
Regional allocation platform[2]

Article 48

Regional allocation platform

1. All TSOs **of Contracting Parties** shall ensure that **a regional** allocation platform is operational and complies with the functional requirements specified in Article 49 within 12 months after the approval of the

2 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

proposal for a common set of requirements and for the establishment of **a regional** allocation platform. The competent regulatory authorities may extend this period upon request from the relevant TSOs due to delays relating to public procurement procedures by a period of no more than 6 months.

2. Forward capacity allocations on Direct Current interconnectors shall take place on **a regional** allocation platform no later than 24 months after the approval as referred to in paragraph 1.

3. The regional allocation platform shall be open to participation of TSOs of Member State and third countries.

4. For interconnections between Contracting Parties and Member States, the respective transmission system operators shall by no later than the expiry of the deadline for transposition of this Regulation conclude a bilateral agreement to determine whether forward capacity allocations for the relevant interconnection shall be performed by the regional allocation platform established in accordance with this Article, or the single allocation platform established in accordance with Article 48 of Regulation 2016/1719.

5. The regional allocation platform shall perform its tasks in close cooperation with the single platform established in accordance with Article 48 of Regulation 2016/1719, and harmonize its operational and allocation rules with those applied by that single platform. For this purpose, the platforms may enter into administrative cooperation agreements.

6. Where the transmission system operators of a Contracting Party and a Member State fail to conclude an agreement referred to in paragraph 4, the tasks of the regional allocation platform related to interconnection between that Contracting Party and Member State shall be integrated into the single allocation platform established in accordance with Article 48 of Regulation 2016/1719 within 18 month after expiry of the deadline for implementation of this Regulation.

Article 49

Functional requirements

1. Within six months after the entry into force of this Regulation, all TSOs shall submit to all regulatory authorities a common proposal for a set of requirements **<…>** of the **regional** allocation platform **serving the TSOs of Contracting Parties**. The proposal shall identify different options for the establishment and governance of the **regional** allocation platform, including the development by TSOs or by third parties on their behalf. The proposal by TSOs shall cover the general tasks of the **regional** allocation platform provided for in Article 50 and the requirements for cost recovery in accordance with Article 59.

2. The functional requirements for the single allocation platform shall at least include:

(a) the expected bidding zone borders to be covered;

(b) the technical availability and reliability of provided services;

(c) the operational processes;

(d) the products to be offered;

(e) the forward capacity allocation time frames;

(f) the allocation methods and algorithms;

(g) the principles of financial settlement and risk management of allocated products;

(h) a harmonised contractual framework with market participants;

(i) the data interfaces.

Article 50

General tasks

The relevant TSOs shall use the **regional** allocation platform, at least, for the following purposes:

(a) the registration of market participants;

(b) providing a single point of contact to market participants;

(c) the operation of auction procedures;

(d) the financial settlement of allocated long-term transmission rights with market participants, including management of collaterals;

(e) the cooperation with a clearing house, if required by the common rules for the implementation of FTRs — obligations pursuant to Article 34;

(f) the organisation of a fallback procedure pursuant to Article 42 and 46;

(g) enabling the return of long-term transmission rights pursuant to Article 43;

(h) facilitating the transfer of long-term transmission rights pursuant to Article 44;

(i) the publication of market information pursuant to Article 47;

(j) providing and operating interfaces for data exchange with market participants.

CHAPTER 5
Harmonised allocation rules

Article 51

Introduction of harmonised allocation rules

1. Within six months after the entry into force of this Regulation, all TSOs shall **apply the** harmonised allocation rules for long-term transmission rights pursuant to Article 52(2) **of Regulation (EU) 2016/1719. <…>**

2. Once the regional requirements have entered into force, they shall prevail over the general requirements defined in the harmonised allocation rules. In case the general requirements of the harmonised allocation rules are amended and submitted to all regulatory authorities' approval, the regional requirements shall also be submitted to regulatory authorities' approval of the concerned capacity calculation region.

Article 52

Requirements for the harmonised allocation rules

Except for interconnections with third countries, the harmonised allocation rules for long-term transmission rights may not deviate from Article 52[3] of Regulation (EU) 2015/1222.

2. **<...>**

3. **<...>**

CHAPTER 6
Firmness of allocated cross-zonal capacity

Article 53

General firmness provisions

1. All TSOs shall be entitled to curtail long-term transmission rights to ensure operation remains within operational security limits prior to the day-ahead firmness deadline. Where TSOs curtail long-term transmission rights, they shall report this to the respective regulatory authorities and also publish the factual reasons that lead to the curtailment.

2. The concerned TSOs on the bidding zone border where long-term transmission rights have been curtailed shall compensate the holders of curtailed long-term transmission rights with the market spread.

Article 54

Definition of caps

1. The concerned TSOs on a bidding zone border may propose a cap on the total compensation to be paid to all holders of curtailed long-term transmission rights in the relevant calendar year or the relevant calendar month in case of Direct Current interconnectors.

2. The cap shall not be lower than the total amount of congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar year. In case of Direct Current interconnectors, TSOs may propose a cap not lower than the total congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar month.

3. In case of several interconnectors operated by different TSOs on the same bidding zone border and subject to different regulatory regimes overseen by regulatory authorities, the total congestion income used for calculation of capped compensation pursuant to paragraph 2 may be dissociated between each interconnector. Such a division shall be proposed by the concerned TSOs and approved by the competent regulatory authorities.

Article 55

3 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

Compensation rules

Where TSOs propose to apply a cap referred to in Article 54, they shall jointly propose a set of compensation rules with regard to the applied cap.

Article 56

Firmness in the event of *force majeure*

1. In the event of *force majeure*, TSOs may curtail long-term transmission rights. Such curtailment shall be undertaken in a coordinated manner following liaison with all TSOs directly affected.

2. The TSO which invokes the *force majeure* shall publish a notification describing the nature of the *force majeure* and its probable duration.

3. In the event of curtailment due to *force majeure* the concerned holders of long-term transmission rights shall receive compensation for the period of that *force majeure* by the TSO which invoked the *force majeure*. In this case, the compensation shall be equal to the amount initially paid for the concerned long-term transmission right during the forward allocation process.

4. The TSO which invokes a *force majeure* shall make every possible effort to limit the consequences and duration of the *force majeure*.

5. Where a **Contracting Party** or Member State has so provided, upon request by the TSO concerned, the national regulatory authority shall assess whether an event qualifies as *force majeure*.

CHAPTER 7
Congestion income distribution

Article 57

Congestion income distribution methodology

<...>

CHAPTER 8
Cost recovery

Article 58

General provisions on cost recovery

1. Costs incurred by TSOs arising from obligations in this Regulation shall be assessed by all regulatory authorities.

2. Costs assessed as reasonable, efficient and proportionate shall be recovered in a timely manner through

network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

3. If requested by regulatory authorities, relevant TSOs shall, within three months of the request, provide information necessary to facilitate the assessment of the costs incurred.

Article 59

Cost of establishing, developing and operating the single allocation platform

All TSOs issuing long-term transmission rights on **a** single allocation platform shall jointly bear the costs related to the establishment and operation of **a** single allocation platform. Within six months of **the expiry of the deadline for transposition** of this regulation, all TSOs shall propose a methodology for sharing these costs, which shall be reasonable, efficient and proportionate, for example on the basis of principles similar to those provided under Article 80 of Regulation (EU) No 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 60

Cost of establishing and operating the coordinated capacity calculation process

1. Each TSO shall individually bear the costs related to the provision of inputs to the capacity calculation.

2. All TSOs shall jointly bear the costs related to the establishment and operation of merging the individual grid models.

3. All TSOs in each capacity calculation region shall bear costs of establishing and operating the coordinated capacity calculators.

Article 61

Cost of ensuring firmness and remuneration of long-term transmission rights

1. The cost of ensuring firmness shall include costs incurred from compensation mechanisms associated with ensuring firmness of cross-zonal capacities as well as the cost of re-dispatching, countertrading and imbalance associated with compensating market participants and be borne by TSOs, to the extent possible in accordance with Article 16(6)(a) of Regulation (EC) No 714/2009**, as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC**.

2.When fixing or approving transmission tariffs or other appropriate mechanism in accordance with Article 37(1)(a) of Directive 2009/72/EC, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC,** and having regard to Article 14(1) of Regulation (EC) No 714/2009, **as adapted and adopted by Ministerial Council Decision 2011/02/MC-EnC,** regulatory authorities shall consider compensation payments as eligible costs provided that they are reasonable, efficient and proportionate.

3.**<...>**

TITLE III
DELEGATION OF TASKS AND MONITORING

Article 62
Delegation of tasks

1. A TSO may delegate all or part of any task assigned to it under this Regulation to one or more third parties in the case the third party can carry out the respective function at least as effectively as the delegating TSO. The delegating TSO shall remain responsible for ensuring compliance with the obligations under this Regulation, including ensuring access to information necessary for monitoring by the regulatory authority.

2. Prior to the delegation, the third party concerned shall have clearly demonstrated to the delegating TSO its ability to meet each of the obligations of this Regulation.

3. In the event that all or part of any task specified in this Regulation is delegated to a third party, the delegating TSO shall ensure that suitable confidentiality agreements in accordance with the confidentiality obligations of the delegating TSO have been put in place prior to delegation.

Article 63
Monitoring

1. **The Energy Community Secretariat** shall monitor the implementation of forward capacity allocation and the establishment of single allocation platform in accordance with **this Regulation.** Monitoring shall cover in particular the following matters

the progress and potential problems with the implementation of forward capacity allocation, including fair and transparent access for market participants to long-term transmission rights;

the effectiveness of the methodologies for splitting long-term cross-zonal capacity in accordance with Article 16;

the report on capacity calculation and allocation in accordance with Article 26;

the effectiveness of the operation of the forward capacity allocation and the single allocation platform.

2. **<…>**

3. **<…>**

4. Market participants and other relevant organisations regarding forward capacity allocation shall, at the joint request of the **ENTSO for Electricity and the Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators**, submit to **the Secretariat** the information required for monitoring in accordance with paragraph 1, except for information already obtained by the regulatory authorities, **the Energy Community Regulatory Board** or the Agency **for the Cooperation of Energy Regulators**. **<…>**

TITLE IV
FINAL PROVISIONS

Article 64

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[4]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with <…>, Regulation (EU) 2016/1719, <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

4 The text displayed here corresponds to Article 13 of Decision D/2022/03/MC-EnC.

COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

*The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in **bold and blue**.*

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter and scope

1. This Regulation lays down detailed guidelines on cross-zonal capacity allocation and congestion management in the day-ahead and intraday markets, including the requirements for the establishment of common methodologies for determining the volumes of capacity simultaneously available between bidding zones, criteria to assess efficiency and a review process for defining bidding zones.

2. This Regulation shall apply to all transmission systems and interconnections in the **Energy Community** except the transmission systems **<...>** which are not connected with other transmission systems via interconnections.

3. In **Contracting Parties** where more than one transmission system operator exists, this Regulation shall apply to all transmission system operators within that **Contracting Party**. Where a transmission system operator does not have a function relevant to one or more obligations under this Regulation, **Contracting Parties** may provide that the responsibility for complying with those obligations is assigned to one or more different, specific transmission system operators.

4. <...>

5. <...>

Article 2
Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No **2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MCEnC,** Article 2 of Commission Regulation (EU) No 543/2013**, as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC,** and Article 2 of Directive (EU) **2019/944** of the European Parliament and of the

Council**, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** shall apply.

In addition, the following definitions shall apply:

1. 'individual grid model' means a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the-common grid model;
2. 'common grid model' means a **<…>** wide data set agreed **in accordance with Article 2 No 2 of Regulation (EU) 2015/1222, and extended to TSOs of Contracting Parties**;
3. 'capacity calculation region' means the geographic area in which coordinated capacity calculation is applied;
4. 'scenario' means the forecasted status of the power system for a given time-frame;
5. 'net position' means the netted sum of electricity exports and imports for each market time unit for a bidding zone;
6. 'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation;
7. 'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits;
8. 'coordinated net transmission capacity approach' means the capacity calculation method based on the principle of assessing and defining *ex ante* a maximum energy exchange between adjacent bidding zones;
9. 'flow-based approach' means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements;
10. 'contingency' means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security;
11. 'coordinated capacity calculator' means the entity or entities with the task of calculating transmission capacity, at regional level or above;
12. 'generation shift key' means a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the common grid model;
13. 'remedial action' means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security;
14. 'reliability margin' means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation;
15. 'market time' means central European summer time or central European time, whichever is in effect;
16. 'congestion income' means the revenues received as a result of capacity allocation;
17. 'market congestion' means a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints;
18. 'physical congestion' means any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system;
19. 'structural congestion' means congestion in the transmission system that can be unambiguously

defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions;

20. 'matching' means the trading mode through which sell orders are assigned to appropriate buy orders to ensure the maximisation of economic surplus for single day-ahead or intraday coupling;

21. 'order' means an intention to purchase or sell energy or capacity expressed by a market participant subject to specified execution conditions;

22. 'matched orders' means all buy and sell orders matched by the price coupling algorithm or the continuous trade matching algorithm;

23. 'nominated electricity market operator (NEMO)' means an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling;

24. 'shared order book' means a module in the continuous intraday coupling system collecting all matchable orders from the NEMOs participating in single intraday coupling and performing continuous matching of those orders;

25. 'trade' means one or more matched orders;

26. 'single day-ahead coupling' means the auctioning process **defined by Article 2 No 26 of Regulation (EU) 2015/1222, and extended to bidding zones from Contracting Parties**;

27. 'single intraday coupling' means the continuous process **defined by Article 2 No 27 of Regulation (EU) 2015/1222, and extended to bidding zones from Contracting Parties**;

28. 'price coupling algorithm' means the algorithm **defined by Article 2 No 28 of Regulation (EU) 2015/1222, and extended to bidding zones from Contracting Parties**;

29. 'continuous trading matching algorithm' means the algorithm **defined by Article 2 No 29 of Regulation (EU) 2015/1222, and extended to bidding zones from Contracting Parties**;

30. 'market coupling operator (MCO) function' means the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities;

31. 'clearing price' means the price determined by matching the highest accepted selling order and the lowest accepted buying order in the electricity market;

32. 'scheduled exchange' means an electricity transfer scheduled between geographic areas, for each market time unit and for a given direction;

33. 'scheduled exchange calculator' means the entity or entities with the task of calculating scheduled exchanges;

34. 'day-ahead market time-frame' means the time-frame of the electricity market until the day-ahead market gate closure time, where, for each market time unit, products are traded the day prior to delivery;

35. 'day-ahead firmness deadline' means the point in time after which cross-zonal capacity becomes firm;

36. 'day-ahead market gate closure time' means the point in time until which orders are accepted in the day-ahead market;

37. 'intraday market time-frame' means the time-frame of the electricity market after intraday cross-zonal gate opening time and before intraday cross-zonal gate closure time, where for each market time unit, products are traded prior to the delivery of the traded products;

38. 'intraday cross-zonal gate opening time' means the point in time when cross-zonal capacity between bidding zones is released for a given market time unit and a given bidding zone border;

39. 'intraday cross-zonal gate closure time' means the point in time where cross-zonal capacity allocation is no longer permitted for a given market time unit;

40. 'capacity management module' means a system containing up-to-date information on available

cross-zonal capacity for the purpose of allocating intra-day cross-zonal capacity;

41. 'non-standard intraday product' means a product for continuous intraday coupling not for constant energy delivery or for a period exceeding one market time unit with specific characteristics designed to reflect system operation practices or market needs, for example orders covering multiple market time units or products reflecting production unit start-up costs;

42. 'central counter party' means the entity or entities with the task of entering into contracts with market participants, by novation of the contracts resulting from the matching process, and of organising the transfer of net positions resulting from capacity allocation with other central counter parties or shipping agents;

43. 'shipping agent' means the entity or entities with the task of transferring net positions between different central counter parties;

44. 'firmness' means a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed;

45. '*force majeure*' means any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation;

46. 'economic surplus for the single day-ahead or intraday coupling' means the sum of (i) the supplier surplus for the single day-ahead or intraday coupling for the relevant time period, (ii) the consumer surplus for the single day-ahead or intraday coupling, (iii) the congestion income and (iv) other related costs and benefits where these increase economic efficiency for the relevant time period, supplier and consumer surplus being the difference between the accepted orders and the clearing price per energy unit multiplied by the volume of energy of the orders.

47. 'Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

Article 3

Objectives of capacity allocation and congestion management cooperation

This Regulation aims at:

(a) promoting effective competition in the generation, trading and supply of electricity;

(b) ensuring optimal use of the transmission infrastructure;

(c) ensuring operational security;

(d) optimising the calculation and allocation of cross-zonal capacity;

(e) ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board,** regulatory authorities and market participants;

(f) ensuring and enhancing the transparency and reliability of information;

(g) contributing to the efficient long-term operation and development of the electricity transmission system

and electricity sector in the **Energy Community**;

(h) respecting the need for a fair and orderly market and fair and orderly price formation;

(i) creating a level playing field for NEMOs;

(j) providing non-discriminatory access to cross-zonal capacity.

Article 4

NEMOs designation and revocation of the designation

1. Each **Contracting Party** electrically connected to a bidding zone in another **Contracting Party or** Member State shall ensure that one or more NEMOs are designated by **six** months after the entry into force of this Regulation to perform the single day-ahead and/or intraday coupling. For that purpose, domestic and non-domestic market operators may be invited to apply to be designated as a NEMO.

2. Each **Contracting Party** concerned shall ensure that at least one NEMO is designated in each bidding zone on its territory. NEMOs shall be designated for an initial term of four years. Except where Article 5(1) applies, **Contracting Parties** shall allow applications for designation at least annually.

3. Unless otherwise provided by **Contracting Parties**, regulatory authorities shall be the designating authority, responsible for NEMO designation, monitoring of compliance with the designation criteria and, in the case of national legal monopolies, the approval of NEMO fees or the methodology to calculate NEMO fees. **Contracting Parties** may provide that authorities other than the regulatory authorities be the designating authority. In these circumstances **Contracting Parties** shall ensure that the designating authority has the same rights and obligations as the regulatory authorities in order to effectively carry out its tasks.

4. The designating authority shall assess whether NEMO candidates meet the criteria set out in Article 6. Those criteria shall apply regardless of whether one or more NEMOs are appointed. When deciding upon NEMO designations, any discrimination between applicants, notably between non-domestic and domestic applicants, shall be avoided. If the designating authority is not the regulatory authority, the regulatory authority shall give an opinion on the extent to which the applicant for designation meets the designation criteria laid down in Article 6. NEMO designations shall only be refused where the designation criteria in Article 6 are not met or in accordance with Article 5(1).

5. A NEMO designated in one **Contracting Party or** Member State shall have the right to offer day-ahead and intraday trading services with delivery in another **Contracting Party or** Member State. The trading rules in the latter **Contracting Party or** Member State shall apply without the need for designation as a NEMO in that **Contracting Party or** Member State. The designating authorities shall monitor all NEMOs performing single day-ahead and/or intra-day coupling within their **Contracting Party or** Member State. In accordance with Article 19 of Regulation (EC) No 714/2009t, the designating authorities shall ensure compliance with this Regulation by all NEMOs performing single day-ahead and/or intra-day coupling within their **Contracting Party**, regardless of where the NEMOs were designated. The authorities in charge of NEMO designation, monitoring and enforcement shall exchange all information necessary for an efficient supervision of NEMO activities.

A designated NEMO must notify the designating authority of another **Contracting Party or** Member State if it proposes to perform single day-ahead or intraday coupling in that **Contracting Party or** Member State two months before commencing operation.

6. By way of exception to paragraph 5 of this Article, a **Contracting Party or** Member State may refuse the trading services by a NEMO designated in another **Contracting Party or** Member State if:

(a) a national legal monopoly for day-ahead and intraday trading services exists in the **Contracting Party or** Member State or bidding zone of the **Contracting Party or** Member State where delivery takes place in accordance with Article 5(1); or

(b) the **Contracting Party or** Member State where delivery takes place can establish that there are technical obstacles to delivery into that **Contracting Party or** Member State of electricity purchased on day-ahead and intraday markets using NEMOs designated in another **Contracting Party or** Member State linked to the need to ensure the objectives of this Regulation are met while maintaining operational security; or

(c) the trading rules in the **Contracting Party or** Member State of delivery are not compatible with the delivery into that **Contracting Party or** Member State of electricity purchased on the basis of day-ahead and intraday trading services provided by a NEMO designated in another **Contracting Party or** Member State; or

(d) the NEMO is a national legal monopoly in accordance with Article 5 in the **Contracting Party or** Member State where it is designated.

7. In case of a decision to refuse day-ahead and/or intraday trading services with delivery in another **Contracting Party or** Member State, the **Contracting Party** of delivery shall notify its decision to the NEMO and to the designating authority of the **Contracting Party or** Member State where the NEMO is designated, as well as to the **Energy Community Secretariat and the Energy Community Regulatory Board and, to the extent Member States are affected, the European Commission and the Agency for the Cooperation of Energy Regulators.** The refusal shall be duly justified. In the cases set out in subparagraphs 6(b) and 6(c), the decision to refuse trading services with delivery in another **Contracting Party or** Member State shall also set out how and by when the technical obstacles to trading can be overcome or the domestic trading rules can be made compatible with trading services with delivery in another **Contracting Party or** Member State. The designating authority of the **Contracting Party** refusing the trading services shall investigate the decision and publish an opinion on how to remove the obstacles to the trading services or how to make the trading services and the trading rules compatible.

8. The **Contracting Party** where the NEMO has been designated shall ensure that designation is revoked if the NEMO fails to maintain compliance with the criteria in Article 6 and is not able to restore compliance within six months of being notified of such failure by the designating authority **from a Member State or Contratcing Party**. If the regulatory authority is not responsible for designation and monitoring, they shall be consulted on the revocation. The designating authority shall also notify the designating authority of the other **Contracting Party or** Member States in which that NEMO is active of its failure to maintain compliance at the same time it notifies the NEMO.

9. If a designating authority of a **Contracting Party** finds that a NEMO active but not designated in its country fails to maintain compliance with the criteria in Article 6 with respect to its activities in this country, it must notify the NEMO of its non-compliance. If the NEMO does not restore compliance within three months of being notified, the designating authority can suspend the right to offer intraday and day-ahead trading services in this **Contracting Party** until such time as the NEMO restores compliance. The designating authority shall notify the designating authority of the **Contracting Party or** Member State in which the NEMO is designated**, as well as the Energy Community Secretariat and the Energy Community Regulatory Board and, to the extent Member States are affected, the European**

Commission and the Agency for the Cooperation of Energy Regulators.

10. The designating authority shall inform the **Energy Community Regulatory Board** of the designation and revocation of NEMOs. The **Energy Community Regulatory Board** shall maintain a list of designated NEMOs **in the Contracting Parties**, their status and where they operate on its website.

Article 5

NEMOs designation in case of a national legal monopoly for trading services

1. If a national legal monopoly for day-ahead and intraday trading services which excludes the designation of more than one NEMO already exists in a **Contracting Party** or **Contracting Party's** bidding zone at the time of the entry into force of this Regulation, the **Contracting Party** concerned must notify the **Energy Community Secretariat** within two months after entry into force of this regulation and may refuse the designation of more than one NEMO per bidding zone.

If there are several applicants to be designated as the only NEMO, the **Contracting Party** concerned shall designate the applicant which best meets the criteria listed in Article 6. If a **Contracting Party** refuses the designation of more than one NEMO per bidding zone, the competent national authority shall fix or approve the NEMO fees for trading in the day-ahead and intraday markets, sufficiently in advance of their entry into force, or specify the methodologies used to calculate them.

In accordance with Article 4(6), the **Contracting Party** concerned may also refuse cross-border trading services offered by a NEMO designated in another **Contracting Party or** Member State; however, the protection of existing power exchanges in that **Contracting Party or** Member State from economic disadvantages through competition is not a valid reason for refusal.

2. For the purposes of this regulation, a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a **Contracting Party** or **Contracting Party's** bidding zone can carry out day-ahead and intraday trading services.

3. **<...>**

Article 6

NEMO designation criteria

1. An applicant shall only be designated as a NEMO if it complies with all of the following requirements:

(a) it has contracted or contracts adequate resources for common, coordinated and compliant operation of single day-ahead and/or intraday coupling, including the resources necessary to fulfil the NEMO functions, financial resources, the necessary information technology, technical infrastructure and operational procedures or it shall provide proof that it is able to make these resources available within a reasonable preparatory period before taking up its tasks in accordance with Article 7;

(b) it shall be able to ensure that market participants have open access to information regarding the NEMO tasks in accordance with Article 7;

(c) it shall be cost-efficient with respect to single day-ahead and intraday coupling and shall in its internal

accounting keep separate accounts for MCO functions and other activities in order to prevent cross-subsidisation;

(d) it shall have an adequate level of business separation from other market participants;

(e) if designated as a national legal monopoly for day-ahead and intraday trading services in a **Contracting Party**, it shall not use the fees in Article 5(1) to finance its day-ahead or intraday activities in a **Contracting Party or Member State** other than the one where these fees are collected;

(f) it shall be able to treat all market participants in a non-discriminatory way;

(g) it shall have appropriate market surveillance arrangements in place;

(h) it shall have in place appropriate transparency and confidentiality agreements with market participants and the TSOs;

(i) it shall be able to provide the necessary clearing and settlement services;

(j) it shall be able to put in place the necessary communication systems and routines for coordinating with the TSOs of the Member State **and Contracting Party**.

2. The designation criteria set out in paragraph 1 shall be applied in such a way that competition between NEMOs is organised in a fair and non-discriminatory manner.

Article 7

NEMO tasks

1. NEMOs shall act as market operators in national or regional markets to perform in cooperation with TSOs single day-ahead and intraday coupling. Their tasks shall include receiving orders from market participants, having overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices and settling and clearing the contracts resulting from the trades according to relevant participant agreements and regulations.

With regard to single day-ahead and intraday coupling, NEMOs shall in particular be responsible for the following tasks:

(a) implementing the MCO functions set out in paragraph 2 in coordination with other NEMOs;

(b) **applying** the requirements for the single day-ahead and intraday coupling, requirements for MCO functions and the price coupling algorithm with respect to all matters related to electricity market functioning in accordance with paragraph 2 of this Article, and Articles 36 **<...>**;

(c) **applying** maximum and minimum prices in accordance with Articles 41 and 54;

making anonymous and sharing the received order information necessary to perform the MCO functions provided for in paragraph 2 of this Article and Articles 40 and 53;

(d) assessing the results calculated by the MCO functions set out in paragraph 2 of this Article allocating the orders based on these results, validating the results as final if they are considered correct and taking responsibility for them in accordance with Articles 48 and 60;

(e) informing the market participants on the results of their orders in accordance with Articles 48 and 60;

(f) acting as central counter parties for clearing and settlement of the exchange of energy resulting from single day-ahead and intraday coupling in accordance with Article 68(3);

(h) **implementing** jointly with relevant NEMOs and TSOs back-up procedures for national or regional market operation in accordance with Article 36(3) if no results are available from the MCO functions in accordance with Article 39(2), taking account of fallback procedures provided for in Article 44;

(i) jointly providing single day-ahead and intraday coupling cost forecasts and cost information to competent regulatory authorities and TSOs where NEMO costs for establishing, amending and operating single day-ahead and intraday coupling are to be covered by the concerned TSOs' contribution in accordance with Articles 75 to 77 and Article 80;

(j) Where applicable, in accordance with Article 45 and 57, coordinate with TSOs to establish arrangements concerning more than one NEMO within a bidding zone and perform single day-ahead and/or intraday coupling in line with the approved arrangements.

2. NEMOs **may** carry out MCO functions jointly with NEMOs **from Member States**. Those functions shall include the following:

(a) Developing**,** maintaining **and applying** the algorithms, systems and procedures for single day-ahead and intraday coupling in accordance with Articles 36 and 51;

(b) processing input data on cross-zonal capacity and allocation constraints provided by coordinated capacity calculators in accordance with Articles 46 and 58;

(c) operating the price coupling and continuous trading matching algorithms in accordance with Articles 48 and 60;

(d) validating and sending single day-ahead and intraday coupling results to the NEMOs in accordance with Articles 48 and 60.

3. By **twelve** months after the entry into force of this Regulation all NEMOs **from Contracting Parties and Member States** shall submit to all regulatory authorities**, the Energy Community Regulatory Board** and the **Agency for the Cooperation of Energy Regulators** a plan **on integration of e NEMOs from Contracting Parties in** the MCO functions set out in paragraph 2, **and in the** agreements between NEMOs and with third parties. The plan shall **be consistent with the plan drafted in accordance with Regulation (EU) 2015/1222 and shall** include a detailed description and the proposed timescale for implementation, **<...>** and a description of the expected impact of **such integration** on the **<...>** performance of the MCO functions in **Article 7 (2) of Regulation (EU) 2015/1222**.

4. Cooperation between NEMOs shall be strictly limited to what is necessary for the efficient and secure design, implementation and operation of single day-ahead and intraday coupling. The joint performance of MCO functions shall be based on the principle of non-discrimination and ensure that no NEMO can benefit from unjustified economic advantages through participation in MCO functions.

5. The **Energy Community Regulatory Board** shall monitor NEMOs' progress in **<...>** performing the MCO functions **pursuant to paragraph 2**, in particular regarding the contractual and regulatory framework and regarding technical preparedness to fulfil the MCO functions. **<...>**

6. **<...>**

Article 8

TSOs' tasks related to single day-ahead and intraday coupling

1. In **Contracting Parties** electrically connected to another **Contracting Party or** Member State all TSOs shall participate in the single day-ahead and intraday coupling.

2. TSOs shall:

(a) jointly **apply** TSO requirements for the price coupling and continuous trading matching algorithms for all aspects related to capacity allocation in accordance with Article 37(1)(a) **of Commission Regulation (EU) 2015/1222**;

(b) **<...>**

(c) establish and perform capacity calculation in accordance with Articles 14 to 30;

(d) where necessary, establish cross zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) calculate and send cross zonal capacities and allocation constraints in accordance with Articles 46 and 58;

(f) verify single day-ahead coupling results in terms of validated cross-zonal capacities and allocation constraints in accordance with Articles 48(2) and 52;

(g) where required, establish scheduled exchange calculators for calculating and publishing scheduled exchanges on borders between bidding zones in accordance with Articles 49 and 56;

(h) respect the results from single day-ahead and intraday coupling calculated in accordance with Article 39 and Article 52;

(i) establish and operate fallback procedures as appropriate for capacity allocation in accordance with Article 44;

(j) **apply** the intraday cross-zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59;

(k) share congestion income in accordance with the methodology **<...>** developed in accordance with Article 73;

(l) where so agreed, act as shipping agents transferring net positions in accordance with Article 68(6).

Article 9

Adoption of terms and conditions or methodologies

1. **Where this Regulation requires** TSOs and NEMOs **to** develop the terms and conditions or methodologies**, they shall** submit them for approval to the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** or the competent regulatory authorities within the respective deadlines set out in this Regulation. In exceptional circumstances, notably in cases where a deadline cannot be met due to circumstances external to the sphere of TSOs or NEMOs, the deadlines for terms and conditions or methodologies may be prolonged **<...>** jointly by all competent regulatory authorities in procedures pursuant to paragraph 7, and by the competent regulatory authority in procedures pursuant to paragraph 8.

Where a proposal for terms and conditions or methodologies pursuant to this Regulation needs to be developed and agreed by more than one TSO or NEMO, the participating TSOs and NEMOs shall closely cooperate. TSOs, with the assistance of the ENTSO for Electricity **where feasible**, and all NEMOs shall regularly inform the competent regulatory authorities**, the Energy Community Regulatory Board and the Agency for the Cooperation of Energy Regulators** about the progress of developing those terms and conditions or methodologies.

2. **<...>**

3. Except for Article 43(1), Article 44, Article 56(1), Article 63 and Article 74(1), where TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph (7) are not able to reach an agreement and where the regions concerned are composed of more than five **Contracting Parties and/or** Member States, they shall decide by qualified majority voting. The qualified majority shall be reached within each of the respective voting classes of TSOs and NEMOs. A qualified majority for proposals for terms and conditions or methodologies listed in paragraph 7 shall require the following majority:

(a) TSOs representing at least 72 % of the **Contracting Parties and/or** Member States concerned; and

(b) TSOs representing **Contracting Parties and/or** Member States comprising at least 65 % of the population of the concerned region.

A blocking minority for decisions on proposals for terms and conditions or methodologies listed in paragraph 7 shall include at least the minimum number of TSOs representing more than 35 % of the population of the participating **Contracting Parties and/or** Member States, plus TSOs representing at least one additional **Contracting Party and/or** Member State concerned, failing of which the qualified majority shall be deemed attained.

TSOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 in relation to regions composed of five **Contracting Parties and/or** Member States or less shall decide by consensus.

For TSO decisions on proposals for terms and conditions or methodologies listed in paragraph 7, one vote shall be attributed per **Contracting Party or** Member State. If there is more than one TSO in the territory of a **Contracting Party or** Member State, the Member State shall allocate the voting powers among the TSOs.

NEMOs deciding on proposals for terms and conditions or methodologies listed in paragraph 7 shall decide by consensus.

4. If TSOs or NEMOs fail to submit an initial or amended proposal for terms and conditions or methodologies to the competent regulatory authorities or the Agency **for the Cooperation of Energy Regulators** in accordance with paragraphs **7,** 8 or 12 within the deadlines set out in this Regulation, they shall provide the competent regulatory authorities, **the Energy Community Regulatory Board and the Agency for the Cooperation of Energy Regulators,** with the relevant drafts of the proposals for the terms and conditions or methodologies, and explain what has prevented an agreement. The **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, all competent regulatory authorities jointly, or the competent regulatory authority shall take the appropriate steps for the adoption of the required terms and conditions or methodologies in accordance with paragraphs 6, 7 and 8 respectively, for instance by requesting amendments or revising and completing the drafts pursuant to this paragraph, including where no drafts have been submitted, and approve them.

5. Each regulatory authority or where applicable **the Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, as the case may be, shall approve the terms and conditions or methodologies used to calculate or set out the single day-ahead and intraday coupling developed by TSOs and NEMOs. They shall be responsible for approving the terms and conditions or methodologies referred to in paragraphs **<...>** 7 and 8. Before approving the terms and conditions or methodologies, the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or the competent regulatory authorities shall revise the proposals where necessary, after consulting the respective TSOs or NEMOs, in order to ensure that they are in line with the purpose of this Regulation **and consistent with Regulation (EU) 2015/1222** and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

6. **TSOs and NEMOs shall apply the** following terms and conditions or methodologies and any amendments thereof shall be subject to approval by the Agency **for the Cooperation of Energy Regulators**:

(a) the plan on joint performance of MCO functions in accordance with Article 7(3);

(b) the capacity calculation regions in accordance with Article 15(1), **when adjusting pursuant to Article 1(2) of the Annex to this Regulation**;

(c) the generation and load data provision methodology in accordance with Article 16(1) **of Regulation (EU) 2015/1222**;

(d) the common grid model methodology in accordance with Article 17(1) **of Regulation (EU) 2015/1222**;

(e) the proposal for a harmonised capacity calculation methodology in accordance with Article**s 9(2), 9(6) and** 21(4) **of Regulation (EU) 2015/1222**;

(f) back-up methodology in accordance with Article 36(3) **of Regulation (EU) 2015/1222**;

(g) the algorithm submitted by NEMOs in accordance with Article 37(5) **of Regulation (EU) 2015/1222**, including the TSOs' and NEMOs' sets of requirements for algorithm development in accordance with Article 37(1) **of Regulation (EU) 2015/1222**;

(h) products that can be taken into account by NEMOs in the single day-ahead and intraday coupling process in accordance with Articles 40**(1)** and 53**(1) of Regulation (EU) 2015/1222**;

(i) the maximum and minimum prices in accordance with Articles 41(1) and 54(2) **of Regulation (EU) 2015/1222**;

(j) the intraday capacity pricing methodology to be developed in accordance with Article**s 9(2), 9(6) and** 55(1) **of Regulation (EU) 2015/1222**;

(k) the intraday cross–zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59(1) **of Regulation (EU) 2015/1222**;

(l) the day-ahead firmness deadline in accordance with Article 69 **of Regulation (EU) 2015/1222**;

(m) the congestion income distribution methodology in accordance with Article 73(1) **of Regulation (EU) 2015/1222**;

7. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by all regulatory authorities of the concerned region:

(a) the common capacity calculation methodology in accordance with Article 20(2);

(b) decisions on the introduction and postponement of flow-based calculation in accordance with Article 20(2) to (6) and on exemptions in accordance with Article 20(7);

(c) the methodology for coordinated redispatching and countertrading in accordance with Article 35(1);

(d) the common methodologies for the calculation of scheduled exchanges in accordance with Articles 43(1) and 56(1);

(e) the fallback procedures in accordance with Article 44;

(f) complementary regional auctions in accordance with Article 63(1);

(g) **<...>**

(h) the redispatching or countertrading cost sharing methodology in accordance with Article 74(1).

8. The following terms and conditions or methodologies and any amendments thereof shall be subject to individual approval by each regulatory authority or other competent authority of the **Contracting Parties** concerned:

(a) where applicable, NEMO designation and revocation or suspension of designation in accordance with Article 4(2), (8) and (9);

(b) if applicable, the fees or the methodologies used to calculate the fees of NEMOs relating to trading in the day-ahead and intraday markets in accordance with Article 5(1);

(c) proposals of individual TSOs for a review of the bidding zone configuration in accordance with Article 32(1)(d);

(d) where applicable, the proposal for cross-zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) capacity allocation and congestion management costs in accordance with Articles 75 to 79;

(f) if applicable, cost sharing of regional costs of single day-ahead and intraday coupling in accordance with Article 80(4).

9. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. Proposals for terms and conditions or methodologies subject to the approval by several regulatory authorities in accordance with paragraph 7 shall be submitted to the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** within 1 week of their submission to regulatory authorities. Proposals for terms and conditions or methodologies subject to the approval by one regulatory authority in accordance with paragraph 8 may be submitted to the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MCEnC,** within 1 month of their submission at the discretion of the regulatory authority while they shall be submitted upon the request **of Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC in case <...>** the proposal **is considered** to have a cross-border impact. Upon request by the competent regulatory authorities, **Energy Community Regulatory Board and, to the extent Member States are affected,**

the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC shall issue an opinion within 3 months on the proposals for terms and conditions or methodologies.

10. Where the approval of the terms and conditions or methodologies in accordance with paragraph 7 or the amendment in accordance with paragraph 12 requires a decision by more than one regulatory authority, the competent regulatory authorities shall consult and closely cooperate and coordinate with each other in order to reach an agreement. Where applicable, the competent regulatory authorities shall take into account the opinion of **the Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**. Regulatory authorities or, where competent, **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall take decisions concerning the submitted terms and conditions or methodologies in accordance with paragraphs **<…>** 7 and 8, within 6 months following the receipt of the terms and conditions or methodologies by **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or the regulatory authority or, where applicable, by the last regulatory authority concerned. The period shall begin on the day following that on which the proposal was submitted **in accordance with paragraph 9** to the last regulatory authority concerned in accordance with paragraph 7 or, where applicable, to the regulatory authority in accordance with paragraph 8.

11. Where the regulatory authorities have not been able to reach agreement within the period referred to in paragraph 10, or upon their joint request, or upon the **request of Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within 6 months **<…>**.

12. In the event that the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators**, or all competent regulatory authorities jointly, or the competent regulatory authority request an amendment to approve the terms and conditions or methodologies submitted in accordance with paragraphs **<…>** 7 and 8 respectively, the relevant TSOs or NEMOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months following the request from the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators** or the competent regulatory authorities or the competent regulatory authority. The **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators** or the competent regulatory authorities or the competent regulatory authority shall decide on the amended terms and conditions or methodologies within 2 months following their submission. Where the competent regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies pursuant to paragraph 7 within the 2-month deadline, or upon their joint request, or upon the **request of the Energy Community Regulatory**

Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators <…>, the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the amended terms and conditions or methodologies within 6 months **<…>**. If the relevant TSOs or NEMOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in paragraph 4 of this Article shall apply.

13. The **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, or all competent regulatory authorities jointly, or the competent regulatory authority, where they are responsible for the adoption of terms and conditions or methodologies in accordance with paragraphs **<…>** 7 and 8, may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs or NEMOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**.

The proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 12 and approved in accordance with the procedure set out in this Article.

14. TSOs and NEMOs responsible for establishing the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet after approval by the **Energy Community Regulatory Board, the Agency for the Cooperation of Energy Regulators** or the competent regulatory authorities or, if no such approval is required, after their establishment, except where such information is considered as confidential in accordance with Article 13.'

Article 10

Day-to-day management of the single day-ahead and intraday coupling

TSOs and NEMOs shall jointly **contribute to organisation of** the day-to-day management of the single day-ahead and intraday coupling. They shall meet regularly to discuss and decide on day-to-day operational issues. TSOs and NEMOs **from Member States acting in accordance with Regulation (EU) 2015/1222** shall invite the **Energy Community Regulatory Board and the Energy Community Secretariat** as observers to these meetings and shall publish summary minutes of the meetings.

Article 11

Stakeholder involvement

The **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, in close cooperation with ENTSO for Electricity **<…>**, shall

organise stakeholder involvement regarding single day-ahead and intraday coupling and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the single day-ahead and intraday coupling. This shall not replace the stakeholder consultations in accordance with Article 12.

Article 12

Consultation

1. TSOs and NEMOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each **Contracting Party and** Member State, on the draft proposals for terms and conditions or methodologies where explicitly set out in this Regulation. The consultation shall last for a period of not less than one month.

2. **<…>** Proposals submitted by the TSOs and NEMOs at regional level shall be submitted to consultation at least at regional level. Parties submitting proposals at bilateral or at multilateral level shall consult at least the **Contracting Parties and** Member States concerned.

3. The entities responsible for the proposal for terms and conditions or methodologies shall duly consider the views of stakeholders resulting from the consultations undertaken in accordance with paragraph 1, prior to its submission for regulatory approval if required in accordance with Article 9 or prior to publication in all other cases. In all cases, a clear and robust justification for including or not the views resulting from the consultation shall be developed in the submission and published in a timely manner before or simultaneously with the publication of the proposal for terms and conditions or methodologies.

Article 13

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any person subject to the provisions of this Regulation.

3. Confidential information received by the persons referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **Energy Community or national** legislation.

4. Without prejudice to cases covered by national law, regulatory authorities, bodies or persons which receive confidential information pursuant to this Regulation may use it only for the purpose of the performance of their functions under this Regulation.

TITLE II

REQUIREMENTS FOR TERMS, CONDITIONS AND METHODOLOGIES CONCERNING CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

CHAPTER 1

Capacity calculation

Section 1

General requirements

Article 14

Capacity calculation time-frames

1. All TSOs shall calculate cross-zonal capacity for at least the following time-frames:

(a) day-ahead, for the day-ahead market;

(b) intraday, for the intraday market.

2. For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated. For the intraday market time-frame, individual values for cross-zonal capacity for each remaining intraday market time unit shall be calculated.

3. For the day-ahead market time-frame, the capacity calculation shall be based on the latest available information. The information update for the day-ahead market time-frame shall not start before 15:00 market time two days before the day of delivery.

4. All TSOs in each capacity calculation region **as defined by Article 15(1)** shall ensure that cross-zonal capacity is recalculated within the intraday market time-frame based on the latest available information. The frequency of this recalculation shall take into consideration efficiency and operational security.

Article 15

Capacity calculation regions

1. **The capacity calculations regions including Contracting Parties and Member States (for their interconnections with Contracting Parties) are established by Annex 1 to this Regulation.**

2. **Annex I**[1] shall define the bidding zone borders attributed to TSOs who are members of each capacity calculation region. The following requirements shall be met:

(a) it shall take into consideration the **capacity calculation** regions **defined in accordance with Article 15(1) of Regulation (EU) 2015/1222**;

(b) each bidding zone border, or two separate bidding zone borders if applicable, through which interconnection between two bidding zones exists, shall be assigned to one capacity calculation region;

1 There is a clerical error in the Ministerial Council Decision D/2022/03/MC-EnC.

(c) at least those TSOs shall be assigned to all capacity calculation regions in which they have bidding zone borders.

3. Capacity calculation regions **as established under this Regulation or in accordance with Article 15(1) of Regulation (EU) 2015/1222** applying a flow-based approach shall be merged into one capacity calculation region if the following cumulative conditions are fulfilled:

(a) their transmission systems are directly linked to each other;

(b) they participate in the same single day-ahead or intraday coupling area;

(c) merging them is more efficient than keeping them separate. The competent regulatory authorities may request a joint cost-benefit analysis from the TSOs concerned to assess the efficiency of the merger.

Section 2
The common grid model

Article 16
Generation and load data provision methodology

1. **<…>**

2. The **<…>** generation and load data provision methodology shall specify which generation units and loads are required to provide information to their respective TSOs for the purposes of capacity calculation.

3. **<…>**

4. The methodology shall specify the deadlines applicable to generation units and loads for providing the information referred to in paragraph 3.

5. **For application of the generation and load data provision methodology** each TSO shall use and share with other TSOs **at least** the **following** information:

(a) information related to their technical characteristics;

(b) information related to the availability of generation units and loads;

(c) information related to the schedules of generation units;

(d) relevant available information relating to how generation units will be dispatched.

The**se** information **<…>** shall be used for capacity calculation purposes only.

6. No later than **eight** months after the **entry into force of this Regulation**, ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC** shall publish **<…>**:

(a) a list of the entities required to provide information to the TSOs;

(b) a list of the information referred to in paragraph 3 to be provided;

(c) deadlines for providing information.

Article 17

Common grid model methodology

<…>

Article 18

Scenarios

1. **<…>** TSOs shall **apply** the common scenarios for each capacity calculation time-frame referred to in Article 14(1)(a) and (b) **developed in line with Article 18(1) of Regulation (EU) 2015/1222**. **<…>**

2. **TSOs shall apply the** common rules **developed in line with Article 18(3) of Regulation (EU) 2015/1222** for determining the net position in each bidding zone and the flow for each direct current line. **<…>**

Article 19

Individual grid model

1. For each bidding zone and for each scenario:

(a) all TSOs in the bidding zone shall jointly provide a single individual grid model which complies with Article 18(3); or

(b) each TSO in the bidding zone shall provide an individual grid model for its control area, including interconnections, provided that the sum of net positions in the control areas, including interconnections, covering the bidding zone complies with Article 18(3).

2. Each individual grid model shall represent the best possible forecast of transmission system conditions for each scenario specified by the TSO(s) at the time when the individual grid model is created.

3. Individual grid models shall cover all network elements of the transmission system that are used in regional operational security analysis for the concerned time-frame.

4. All TSOs shall harmonise to the maximum possible extent the way in which individual grid models are built.

5. Each TSO shall provide all necessary data in the individual grid model to allow active and reactive power flow and voltage analyses in steady state.

6. Where appropriate, and upon agreement between all TSOs within a capacity calculation region, each TSO in that capacity calculation region shall exchange data between each other to enable voltage and dynamic stability analyses.

Section 3
Capacity calculation methodologies

Article 20
Introduction of flow-based capacity calculation methodology

1. For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.

2. No later than **6** months after the **establishment of** a capacity calculation region in accordance with **Annex I,** all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region. The proposal shall be subject to consultation in accordance with Article 12. **The proposal shall be aligned with the capacity calculation methodology applicable in the neighbouring capacity calculation regions. <…>**

3. **<…>**

4. No later than six months after at least all South East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs **from these Contracting Parties together with the TSOs** from at least Croatia, Romania, Bulgaria, **Hungary** and Greece **<…> shall** jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame. The proposal shall provide for an implementation date of the common capacity calculation methodology using the flow-based approach of no longer than two years after the participation of all SEE Energy Community Contracting Parties in the single day-ahead coupling. The TSOs from **Contracting Parties** which have borders with other regions are encouraged to join the initiatives to implement a common flow-based capacity calculation methodology with these regions.

5. At the time when two or more adjacent capacity calculation regions in the same synchronous area implement a capacity calculation methodology using the flow-based approach for the day-ahead or the intraday market time-frame, they shall be considered as one region for this purpose and the TSOs from this region shall submit within six months a proposal for applying a common capacity calculation methodology using the flow-based approach for the day-ahead or intraday market time-frame. The proposal shall provide for an implementation date of the common cross regional capacity calculation methodology of no longer than 12 months after the implementation of the flow-based approach in these regions for the methodology for the day-ahead market time-frame, and 18 months for the methodology for the intraday time-frame. The timelines indicated in this paragraph may be adapted in accordance with paragraph 6.

The methodology in the two capacity calculation regions which have initiated developing a common capacity calculation methodology may be implemented first before developing a common capacity calculation methodology with any further capacity calculation region.

6. If the TSOs concerned are able to demonstrate that the application of common flow-based methodologies in accordance with paragraphs 4 and 5 would not yet be more efficient assuming the same level of operational security, they may jointly request the competent regulatory authorities to postpone the deadlines.

7. TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach in regions and bidding zone borders **<…>**, if the TSOs concerned are able to demon-

strate that the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.

8. To enable market participants to adapt to any change in the capacity calculation approach, the TSOs concerned shall test the new approach alongside the existing approach and involve market participants for at least six months before implementing a proposal for changing their capacity calculation approach.

9. The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones.

Article 21

Capacity calculation methodology

1. The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include at least the following items for each capacity calculation time-frame:

(a) methodologies for the calculation of the inputs to capacity calculation, which shall include the following parameters:

(i) a methodology for determining the reliability margin in accordance with Article 22;

(ii) the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23;

(iii) the methodology for determining the generation shift keys in accordance with Article 24;

(iv) the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25.

(b) a detailed description of the capacity calculation approach which shall include the following:

(i) a mathematical description of the applied capacity calculation approach with different capacity calculation inputs;

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with **Article 16(9) of Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2002/03/MC-EnC**;

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;

(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges

in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.

(c) a methodology for the validation of cross-zonal capacity in accordance with Article 26.

2. For the intraday capacity calculation time-frame, the capacity calculation methodology shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency.

3. The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

4. All TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs. **<...>**

Article 22

Reliability margin methodology

1. The proposal for a common capacity calculation methodology shall include a methodology to determine the reliability margin. The methodology to determine the reliability margin shall consist of two steps. First, the relevant TSOs shall estimate the probability distribution of deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution.

2. The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:

(a) unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;

(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time-frame and real time, for the market time unit being considered.

3. In the methodology to determine the reliability margin, TSOs shall also set out common harmonised principles for deriving the reliability margin from the probability distribution.

4. On the basis of the methodology adopted in accordance with paragraph 1, TSOs shall determine the reliability margin respecting the operational security limits and taking into account uncertainties between the capacity calculation time-frame and real time, and the remedial actions available after capacity calculation.

5. For each capacity calculation time-frame, the TSOs concerned shall determine the reliability margin for critical network elements, where the flow-based approach is applied, and for cross-zonal capacity, where the coordinated net transmission capacity approach is applied.

Article 23

Methodologies for operational security limits, contingencies and allocation constraints

1. Each TSO shall respect the operational security limits and contingencies used in operational security analysis.

2. If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

3. If TSOs apply allocation constraints, they can only be determined using:

(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or

(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling.

Article 24

Generation shift keys methodology

1. The proposal for a common capacity calculation methodology shall include a proposal for a methodology to determine a common generation shift key for each bidding zone and scenario developed in accordance with Article 18.

2. The generation shift keys shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model. That forecast shall notably take into account the information from the generation and load data provision methodology.

Article 25

Methodology for remedial actions in capacity calculation

1. Each TSO within each capacity calculation region shall individually define the available remedial actions to be taken into account in capacity calculation to meet the objectives of this Regulation.

2. Each TSO within each capacity calculation region shall coordinate with the other TSOs in that region the use of remedial actions to be taken into account in capacity calculation and their actual application in real time operation.

3. To enable remedial actions to be taken into account in capacity calculation, all TSOs in each capacity calculation region shall agree on the use of remedial actions that require the action of more than one TSO.

4. Each TSO shall ensure that remedial actions are taken into account in capacity calculation under the condition that the available remedial actions remaining after calculation, taken together with the reliability margin referred to in Article 22, are sufficient to ensure operational security.

5. Each TSO shall take into account remedial actions without costs in capacity calculation.

6. Each TSO shall ensure that the remedial actions to be taken into account in capacity calculation are the same for all capacity calculation time-frames, taking into account their technical availabilities for each capacity calculation time-frame.

Article 26

Cross-zonal capacity validation methodology

1. Each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders or critical network elements provided by the coordinated capacity calculators in accordance with Articles 27 to 31.

2. Where a coordinated net transmission capacity approach is applied, all TSOs in the capacity calculation region shall include in the capacity calculation methodology referred to in Article 21 a rule for splitting the correction of cross-zonal capacity between the different bidding zone borders.

3. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity referred to in paragraph 1 for reasons of operational security.

4. Each coordinated capacity calculator shall coordinate with the neighbouring coordinated capacity calculators during capacity calculation and validation.

5. Each coordinated capacity calculator shall, every three months, report all reductions made during the validation of cross-zonal capacity in accordance with paragraph 3 to all regulatory authorities of the capacity calculation region. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

6. All the regulatory authorities of the capacity calculation region shall decide whether to publish all or part of the report referred to in paragraph 5.

Section 4

The capacity calculation process

Article 27

General provisions

1. **<…>**

2. No later than **six** months after the **establishment of** the capacity calculation **regions** referred to in Article **15(1)**, all the TSOs in each capacity calculation region shall jointly set up the coordinated capacity calculators and establish rules governing their operations.

3. All TSOs of each capacity calculation region shall review the quality of data submitted within the capacity calculation every second year as part of the biennial report on capacity calculation and allocation produced in accordance with Article 31.

4. Using the latest available information, all TSOs shall regularly and at least once a year review and update:

(a) the operational security limits, contingencies and allocation constraints used for capacity calculation;

(b) the probability distribution of the deviations between expected power flows at the time of capacity calculation and realised power flows in real time used for calculation of reliability margins;

(c) the remedial actions taken into account in capacity calculation;

(d) the application of the methodologies for determining generation shift keys, critical network elements and contingencies referred to in Articles 22 to 24.

Article 28

Merging into the common grid model

1. For each capacity calculation time-frame referred to in Article 14(1), each generator or load unit subject to Article 16 shall provide the data specified in the generation and load data provision methodology to the TSO responsible for the respective control area within the specified deadlines.

2. Each generator or load unit providing information pursuant to Article 16(**5**) shall deliver the most reliable set of estimations practicable.

3. For each capacity calculation time-frame, each TSO shall establish the individual grid model for each scenario in accordance with Article 19, in order to merge individual grid models into a common grid model.

4. Each TSO shall deliver to the TSOs responsible for merging the individual grid models into a common grid model the most reliable set of estimations practicable for each individual grid model.

5. For each capacity calculation time-frame a single, **<…>** common grid model **as referred to Article 9(6)(d) is** created **<…>**.

Article 29

Regional calculation of cross-zonal capacity

1. For each capacity calculation time-frame, each TSO shall provide the coordinated capacity calculators and all other TSOs in the capacity calculation region with the following items: operational security limits, generation shift keys, remedial actions, reliability margins, allocation constraints and previously allocated cross-zonal capacity.

2. Each coordinated capacity calculator shall perform an operational security analysis applying operational security limits by using the common grid model created for each scenario in accordance with Article 28(5).

3. When calculating cross-zonal capacity, each coordinated capacity calculator shall:

(a) use generation shift keys to calculate the impact of changes in bidding zone net positions and of flows on direct current lines;

(b) ignore those critical network elements that are not significantly influenced by the changes in bidding zone net positions according to the methodology set out in Article 21; and,

(c) ensure that all sets of bidding zone net positions and flows on direct current lines not exceeding cross-zonal capacity comply with reliability margins and operational security limits in accordance with Article 21(1)(a)(i) and (ii), and take into account previously allocated cross-zonal capacity in accordance with Article 21(1)(b)(iii).

4. Each coordinated capacity calculator shall optimise cross-zonal capacity using available remedial actions taken into account in capacity calculation in accordance with Article 21(1)(a)(iv).

5. Each coordinated capacity calculator shall apply the sharing rules established in accordance with Article 21(1)(b)(vi).

6. Each coordinated capacity calculator shall respect the mathematical description of the applied capacity calculation approach established in accordance with Article 21(1)(b)(i).

7. Each coordinated capacity calculator applying the flow-based approach shall:

(a) use data on operational security limits to calculate the maximum flows on critical network elements;

(b) use the common grid model, generation shift keys and contingencies to calculate the power transfer distribution factors;

(c) use power transfer distribution factors to calculate the flows resulting from previously allocated cross-zonal capacity in the capacity calculation region;

(d) calculate flows on critical network elements for each scenario (taking into account contingencies), and adjust them by assuming no cross-zonal power exchanges within the capacity calculation region, applying the rules for avoiding undue discrimination between internal and cross-zonal power exchanges established in accordance with Article 21(1)(b)(ii);

(e) calculate the available margins on critical network elements, taking into account contingencies, which shall equal the maximum flows reduced by adjusted flows referred to in point (d), reliability margins, and flows resulting from previously allocated cross-zonal capacity;

(f) adjust the available margins on critical network elements or power transfer distribution factors using available remedial actions to be considered in capacity calculation in accordance with Article 25.

8. Each coordinated capacity calculator applying the coordinated net transmission capacity approach shall:

(a) use the common grid model, generation shift keys and contingencies to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;

(b) adjust maximum power exchange using remedial actions taken into account in capacity calculation in accordance with Article 25;

(c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal exchanges in accordance with Article 21(1)(b)(ii);

(d) apply the rules set out in accordance with Article 21(1)(b)(vi) for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(e) calculate cross-zonal capacity, which shall be equal to maximum power exchange adjusted for the reliability margin and previously allocated cross-zonal capacity.

9. Each coordinated capacity calculator shall cooperate with the neighbouring coordinated capacity calculators. Neighbouring TSOs shall ensure such cooperation by exchanging and confirming information on interdependency with the relevant regional coordinated capacity calculators, for the purposes of capacity calculation and validation. Neighbouring TSOs shall provide information on interdependency to the coordinated capacity calculators before capacity calculation. An assessment of the accuracy of this information and corrective measures shall be included in the biennial report drafted in accordance with Article 31, where appropriate.

10. Each coordinated capacity calculator shall set:

(a) flow-based parameters for each bidding zone within the capacity calculation region, if applying the flow-based approach; or

(b) cross-zonal capacity values for each bidding zone border within the capacity calculation region, if applying the coordinated net transmission capacity approach.

11. Each coordinated capacity calculator shall submit the cross-zonal capacity to each TSO within its capacity calculation region for validation in accordance with Article 21(1)(c).

Article 30

Validation and delivery of cross-zonal capacity

1. Each TSO shall validate the results of the regional capacity calculation for its bidding zone borders or critical network elements, in accordance with Article 26.

2. Each TSO shall send its capacity validation and allocation constraints to the relevant coordinated capacity calculators and to the other TSOs of the relevant capacity calculation regions.

3. Each coordinated capacity calculator shall provide the validated cross-zonal capacities and allocation constraints for the purposes of allocating capacity in accordance with Articles 46 and 58.

Section 5

Biennial report on capacity calculation and allocation

Article 31

Biennial report on capacity calculation and allocation

1. **Within three** years after the entry into force of this Regulation, ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC,** shall **include the Contracting Parties' bidding zones in the <…>** report on capacity calculation and allocation **<…> drafted in accordance with Article 31(1) of Regulation (EU) 2015/1222**.

2. **<…>**

3. For each bidding zone, bidding zone border and capacity calculation region, the report on capacity calculation and allocation shall contain at least:

(a) the capacity calculation approach used;

(b) statistical indicators on reliability margins;

(c) statistical indicators of cross-zonal capacity, including allocation constraints where appropriate for each capacity calculation time-frame;

(d) quality indicators for the information used for the capacity calculation;

(e) where appropriate, proposed measures to improve capacity calculation;

(f) for regions where the coordinated net transmission capacity approach is applied, an analysis of whether

the conditions specified in Article 20(7) are still fulfilled;

(g) indicators for assessing and following in the longer term the efficiency of single day-ahead and intraday coupling, including the merging of capacity calculation regions in accordance with Article 15(3) where relevant;

(h) recommendations for further development of single day-ahead and intraday coupling, including further harmonisation of methodologies, processes and governance arrangements.

4. After consulting the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators,** all TSOs shall jointly agree on the statistical and quality indicators for the report. The **Energy Community Regulatory Board and the Agency for the Cooperation of Energy Regulators** may require the amendment of those indicators, prior to the agreement by the TSOs or during their application.

5. **<...>**

CHAPTER 2
Bidding zone configuration

Article 32
Reviewing existing bidding zone configurations

1. A review of an existing bidding zone configuration may be launched by:

(a) the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators,** in accordance with Article 34(7);

(b) several regulatory authorities, pursuant to a recommendation from the **Energy Community Regulatory Board or the Agency for the Cooperation of Energy Regulators** in accordance with Article 34;

(c) TSOs of a capacity calculation region, together with all concerned TSOs whose control areas, including interconnectors, are within the geographic area in which the bidding zone configuration shall be assessed in accordance with paragraph 2(a);

(d) one single regulatory authority or TSO with the approval of its competent regulatory authority, for the bidding zones inside the TSO's control area, if the bidding zone configuration has negligible impact on neighbouring TSOs' control areas, including interconnectors, and the review of bidding zone configuration is necessary to improve efficiency, or to maintain operational security;

(e) Member States **and Contracting Parties** in a capacity calculation region.

2. If a review is launched in accordance with paragraph 1(a),(b), (c) or (e), the entity launching the review shall specify:

(a) the geographic area in which bidding zone configuration shall be assessed and the neighbouring geographic areas for which impacts shall be taken into account;

(b) the participating TSOs;

(c) the participating regulatory authorities.

3. If a review is launched in accordance with paragraph 1(d), the following conditions shall apply:

(a) the geographic area in which bidding zone configuration is assessed shall be limited to the control area of the relevant TSO, including interconnectors;

(b) the TSO of the relevant control area shall be the only TSO participating in the review;

(c) the competent regulatory authority shall be the only regulatory authority participating in the review;

(d) the relevant TSO and regulatory authority, respectively, shall give the neighbouring TSOs and regulatory authorities mutually agreed prior notice of the launch of the review, giving reasons; and

(e) the conditions for the review shall be specified, and the results of the review and proposal for the relevant regulatory authorities shall be published.

4. The review process shall consist of two steps.

(a) In the first step, the TSOs participating in a review of bidding zone configuration shall develop the methodology and assumptions that will be used in the review process and propose alternative bidding zone configurations for the assessment.

The proposal on methodology and assumptions and alternative bidding zone configuration shall be submitted to the participating regulatory authorities, which shall be able to require coordinated amendments within three months.

(b) In the second step, the TSOs participating in a review of bidding zone configuration shall:

(i) assess and compare the current bidding zone configuration and each alternative bidding zone configuration using the criteria specified in Article 33;

(ii) hold a consultation in accordance with Article 12 and a workshop regarding the alternative bidding zone configuration proposals compared to the existing bidding zone configuration, including timescales for implementation, unless the bidding zone configuration has negligible impact on neighbouring TSOs' control areas;

(iii) submit a joint proposal to maintain or amend the bidding zone configuration to the participating **Contracting Parties and** Member States **(for their interconnections with Contracting Parties)** and the participating regulatory authorities within 15 months of the decision to launch a review.

(c) On receiving the joint proposal to maintain or to amend the bidding zone configuration in accordance with point (iii) above, the participating Member States **and Contracting Parties or, where provided by Member States and Contracting Parties**, the regulatory authorities shall within six months reach an agreement on the proposal to maintain or amend the bidding zone configuration.

5. NEMOs or market participants shall, if requested by TSOs, provide the TSOs participating in a review of a bidding zone with information to enable them to assess bidding zone configurations. This information shall be shared only between the participating TSOs for the sole purpose of assessing bidding zone configurations.

6. The initiative for the review of the bidding zones configuration and its results shall be published by ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC,** or if the review was launched in accordance with paragraph 1(d), by the participating TSO.

Article 33

Criteria for reviewing bidding zone configurations

1. If a review of bidding zone configuration is carried out in accordance with Article 32, at least the following criteria shall be considered:

(a) in respect of network security:

(i) the ability of bidding zone configurations to ensure operational security and security of supply;

(ii) the degree of uncertainty in cross–zonal capacity calculation.

(b) in respect of overall market efficiency:

(i) any increase or decrease in economic efficiency arising from the change;

(ii) market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals;

(iii) transaction and transition costs, including the cost of amending existing contractual obligations incurred by market participants, NEMOs and TSOs;

(iv) the cost of building new infrastructure which may relieve existing congestion;

(v) the need to ensure that the market outcome is feasible without the need for extensive application of economically inefficient remedial actions;

(vi) any adverse effects of internal transactions on other bidding zones to ensure compliance with **Article 16(9) of Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2002/03/MC-EnC**;

(vii) the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.

(c) in respect of the stability and robustness of bidding zones:

(i) the need for bidding zones to be sufficiently stable and robust over time;

(ii) the need for bidding zones to be consistent for all capacity calculation time-frames;

(iii) the need for each generation and load unit to belong to only one bidding zone for each market time unit;

(iv) the location and frequency of congestion, if structural congestion influences the delimitation of bidding zones, taking into account any future investment which may relieve existing congestion.

2. A bidding zone review in accordance with Article 32 shall include scenarios which take into account a range of likely infrastructure developments throughout the period of 10 years starting from the year following the year in which the decision to launch the review was taken.

Article 34

Regular reporting on current bidding zone configuration <…>

1. The **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall assess the efficiency of current bidding zone configuration every three years.

They shall:

(a) request ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC and Article 14 of Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** to **extend the** technical report on current bidding zone configuration **drafted in accordance with Article 34(1)(a) of Regulation (EU) 2015/1222 to include the Contracting Parties<…>** and

(b) draft a market report evaluating the impact of current bidding zone configuration on market efficiency.

2. The technical report referred to in paragraph 1 second subparagraph point (a) shall include at least:

(a) a list of structural congestion and other major physical congestion, including locations and frequency;

(b) an analysis of the expected evolution or removal of physical congestion resulting from investment in networks or from significant changes in generation or in consumption patterns;

(c) an analysis of the share of power flows that do not result from the capacity allocation mechanism, for each capacity calculation region, where appropriate;

(d) congestion incomes and firmness costs;

(e) a scenario encompassing a ten year time-frame.

3. Each TSO shall provide data and analysis to allow the technical report on current bidding zone configuration to be produced in a timely manner.

4. ENTSO for Electricity shall deliver to the **Energy Community Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators**, the technical report on current bidding zone configuration no later than nine months after the request by the **Energy Community Regulatory Board or the** Agency **for the Cooperation of Energy Regulators**.

5. **Where feasible, the report under this Regulation shall be aligned with the technical report delivered pursuant to Article 34(3) of Regulation (EU) 2015/1222, and** shall cover the last three full calendar years preceding the request by the **Energy Community Regulatory Board or the** Agency **for the Cooperation of Energy Regulators**.

6. Without prejudice to the confidentiality obligations provided for in Article 13, ENTSO for Electricity shall make the technical report available to the public.

7. If the technical or market report reveals inefficiencies in the current bidding zone configuration, the **Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators,** may request TSOs to launch a review of an existing bidding zone configuration in accordance with Article 32(1).

CHAPTER 3
Redispatching and countertrading

Article 35
Coordinated redispatching and countertrading

1. Within 16 months **upon entry into force of this Regulation**, all the TSOs in each capacity calculation region shall develop a proposal for a common methodology for coordinated redispatching and countertrading. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology for coordinated redispatching and countertrading shall include actions of cross-border relevance and shall enable all TSOs in each capacity calculation region to effectively relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not. The methodology for coordinated redispatching and countertrading shall address the fact that its application may significantly influence flows outside the TSO's control area.

3. Each TSO may redispatch all available generation units and loads in accordance with the appropriate mechanisms and agreements applicable to its control area, including interconnectors.

By 26 months **upon entry into force of this Regulation**, all TSOs in each capacity calculation region shall develop a report, subject to consultation in accordance with Article 12, assessing the progressive coordination and harmonisation of those mechanisms and agreements and including proposals. The report shall be submitted to their respective regulatory authorities for their assessment. The proposals in the report shall prevent these mechanisms and agreements from distorting the market.

4. Each TSO shall abstain from unilateral or uncoordinated redispatching and countertrading measures of cross-border relevance. Each TSO shall coordinate the use of redispatching and countertrading resources taking into account their impact on operational security and economic efficiency.

5. The relevant generation units and loads shall give TSOs the prices of redispatching and countertrading before redispatching and countertrading resources are committed.

Pricing of redispatching and countertrading shall be based on:

(a) prices in the relevant electricity markets for the relevant time-frame; or

(b) the cost of redispatching and countertrading resources calculated transparently on the basis of incurred costs.

6. Generation units and loads shall *ex-ante* provide all information necessary for calculating the redispatching and countertrading cost to the relevant TSOs. This information shall be shared between the relevant TSOs for redispatching and countertrading purposes only.

CHAPTER 4
Algorithm development

Article 36
General provisions

1. All NEMOs shall **apply**:

(a) **the** price coupling algorithm**, and**

(b) **the** continuous trading matching algorithm **developed in accordance with Article 37 of Regulation (EU) 2015/1222**.

2. NEMOs shall ensure that the price coupling algorithm and the continuous trading matching algorithm meet the requirements provided for in Articles 39 and 52 respectively.

3. **Upon integration into the single day-ahead coupling,** NEMOs shall in cooperation with TSOs **apply** back-up methodology **referred to Article 9(6)(f).**

4. Where possible, NEMOs shall use already agreed solutions to efficiently implement the objectives of this Regulation.

Article 37
Algorithm development

<...>

CHAPTER 5
Single day-ahead coupling

Section 1
The price coupling algorithm

Article 38
Objectives of the price coupling algorithm

1. The price coupling algorithm shall produce the results set out in Article 39(2), in a manner which:

(a) aims at maximising economic surplus for single day-ahead coupling for the price-coupled region for the next trading day;

(b) uses the marginal pricing principle according to which all accepted bids will have the same price per bidding zone per market time unit;

(c) facilitates efficient price formation;

(d) respects cross-zonal capacity and allocation constraints;

(e) is repeatable and scalable.

2. The price coupling algorithm shall be developed in such a way that it would be possible to apply it to a larger or smaller number of bidding zones.

Article 39

Inputs and results of the price coupling algorithm

1. In order to produce results, the price coupling algorithm shall use:

(a) allocation constraints established in accordance with Article 23(3);

(b) cross-zonal capacity results validated in accordance with Article 30(c) orders submitted in accordance with Article 40.

2. The price coupling algorithm shall produce at least the following results simultaneously for each market time unit:

(a) a single clearing price for each bidding zone and market time unit in EUR/MWh;

(b) a single net position for each bidding zone and each market time unit;

(c) the information which enables the execution status of orders to be determined.

3. All NEMOs shall ensure the accuracy and efficiency of results produced by the single price coupling algorithm.

4. All TSOs shall verify that the results of the price coupling algorithm are consistent with cross-zonal capacity and allocation constraints.

Article 40

Products accommodated

1. **<…>** NEMOs shall ensure that orders resulting from **the** products **available** to the price coupling algorithm are expressed in euros and make reference to the market time.

2. All NEMOs shall ensure that the price coupling algorithm is able to accommodate orders resulting from these products covering one market time unit and multiple market time units.

3. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult, in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

4. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 3.

Article 41

Maximum and minimum prices

1. **Upon integration into the single day-ahead coupling**, **<…>** NEMOs shall, in cooperation with the relevant TSOs, **apply the** maximum and minimum **<…>** prices **referred to in Article 9(6)(i)**. **<…>**

2. **<…>**

Article 42

Pricing of day-ahead cross-zonal capacity

1. The day-ahead cross-zonal capacity charge shall reflect market congestion and shall amount to the difference between the corresponding day-ahead clearing prices of the relevant bidding zones.

2. No charges, such as imbalance fees or additional fees, shall be applied to day-ahead cross-zonal capacity except for the pricing in accordance with paragraph 1.

Article 43

Methodology for calculating scheduled exchanges resulting from single day-ahead coupling

1. By 16 months after **expiry of the deadline for transposition**, TSOs which intend to calculate scheduled exchanges resulting from single day-ahead coupling shall develop a proposal for a common methodology for this calculation. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and shall list the information which shall be provided by the relevant NEMOs to the scheduled exchange calculator established in accordance with Article 8(2)(g) and the time limits for delivering this information. The time limit for delivering information shall be no later than 15.30 market time day-ahead.

3. The calculation shall be based on net positions for each market time unit.

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, TSOs applying scheduled exchanges shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the methodology shall be reviewed every two years.

Article 44

Establishment of fallback procedures

By 16 months after the entry into force of this Regulation, each TSO, in coordination with all the other TSOs in the capacity calculation region, shall develop a proposal for robust and timely fallback procedures to ensure efficient, transparent and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

The proposal for the establishment of fallback procedures shall be **aligned with the procedure established under Article 44 of Regulation (EU) 2015/1222 and shall be** subject to consultation in accordance with Article 12.

Article 45

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article **51** of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted to the relevant national regulatory authorities for approval within **twelve**[2] months after more than one NEMO has been designated and/or allowed to offer trading services in a bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within **twelve** months after entry into force of this Regulation.

Section 2
The single day-ahead coupling process

Article 46

Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints shall be provided to relevant NEMOs in time to ensure the publication of cross-zonal capacity and of allocation constraints to the market no later than 11.00 market time day-ahead.

2. If a coordinated capacity calculator is unable to provide for cross-zonal capacity and allocation constraints one hour prior to the day-ahead market gate closure time, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall immediately publish a notice for market participants.

In such cases, cross-zonal capacity and allocation constraints shall be provided by the coordinated capacity calculator no later than 30 minutes before the day-ahead market gate closure time.

2 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

Article 47

Operation of single day-ahead coupling

1. The day-ahead market gate opening time shall be at the latest 11:00 market time day-ahead.

2. The day-ahead market gate closure time in each bidding zone shall be noon market time day-ahead. TSOs or NEMOs **<…>** may set a different gate closure time **they have** joined single day-ahead coupling.

3. Market participants shall submit all orders to the relevant NEMOs before day-ahead market gate closure time, in accordance with Articles 39 and 40.

4. Each NEMO shall submit the orders received in accordance with paragraph 3 to perform the MCO functions in accordance with Article 7(2) **in line with the price coupling algorithm applied in accordance with Article 36.**

5. Orders matched in single day-ahead coupling shall be considered firm.

6. MCO functions shall ensure anonymity of submitted orders.

Article 48

Delivery of results

1. **<…>** All NEMOs performing MCO functions shall deliver the single day-ahead coupling results:

(a) to all TSOs, all coordinated capacity calculators and all NEMOs, for the results specified in Article 39(2)(a) and (b);

(b) to all NEMOs, for the results specified in Article 39(2)(c).

2. Each TSO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(b) have been calculated in accordance with the allocation constraints and validated cross-zonal capacity.

3. Each NEMO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(c) have been calculated in accordance with the orders.

4. Each NEMO shall inform market participants on the execution status of their orders without unjustifiable delay.

Article 49

Calculation of scheduled exchanges resulting from single day-ahead coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in Article 43.

2. Each scheduled exchange calculator shall notify relevant NEMOs, central counter parties, shipping agents and TSOs of the agreed scheduled exchanges.

Article 50

Initiation of fallback procedures

1. In the event that all NEMOs performing MCO functions are unable to deliver part or all of the results of the price coupling algorithm **applied in accordance with Article 36**, the fallback procedures established in accordance with Article 44 shall apply.

2. In cases where there is a risk that all NEMOs performing MCO functions are unable to deliver part or all of the results within the deadline, all NEMOs shall notify all TSOs as soon as the risk is identified. All NEMOs performing MCO functions shall immediately publish a notice to market participants that fallback procedures may be applied.

CHAPTER 6
Single intraday coupling

Section 1
Objectives, conditions and results of single intraday coupling

Article 51

Objectives of the continuous trading matching algorithm

1. From the intraday cross-zonal gate opening time until the intraday cross-zonal gate closure time, the continuous trading matching algorithm shall determine which orders to select for matching such that matching:

(a) aims at maximising economic surplus for single intraday coupling per trade for the intraday market time-frame by allocating capacity to orders for which it is feasible to match in accordance with the price and time of submission;

(b) respects the allocation constraints provided in accordance with Article 58(1);

(c) respects the cross-zonal capacity provided in accordance with Article 58(1);

(d) respects the requirements for the delivery of results set out in Article 60;

(e) is repeatable and scalable.

2. The continuous trading matching algorithm shall produce the results provided for in Article 52 and correspond to the product capabilities and functionalities set out in Article 53.

Article 52

Results of the continuous trading matching algorithm

1. All NEMOs, as part of their MCO function, shall ensure that the continuous trading matching algorithm produces at least the following results:

(a) the execution status of orders and prices per trade;

(b) a single net position for each bidding zone and market time unit within the intraday market.

2. All NEMOs shall ensure the accuracy and efficiency of results produced by the continuous trading matching algorithm.

3. All TSOs shall verify that the results of the continuous trading matching algorithm are consistent with cross-zonal capacity and allocation constraints in accordance with Article 58(2).

Article 53

Products accommodated

1. **<…>** NEMOs shall ensure that all orders resulting from **the** products **available** to the MCO functions to be performed in accordance with Article 7 are expressed in euros and make reference to the market time and the market time unit.

2. All NEMOs shall ensure that orders resulting from these products are compatible with the characteristics of cross-zonal capacity, allowing them to be matched simultaneously.

3. All NEMOs shall ensure that the continuous trading matching algorithm is able to accommodate orders covering one market time unit and multiple market time units.

4. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

5. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 4.

Article 54

Maximum and minimum prices

1. **<…>** NEMOs shall, in cooperation with the relevant TSOs, **apply the** maximum and minimum prices **referred to in Article 9(6)(i). <…>**

2. **<…>**

3. **<…>**

Article 55

Pricing of intraday capacity

1. **<…>**

2. **<…>**

3. **<…>** All TSOs shall **apply the** single methodology for pricing intraday cross-zonal capacity **referred to in Article 9(6)(j). <…>**

4. No charges, such as imbalance fees or additional fees, shall be applied to intraday cross-zonal capacity except for the pricing in accordance with paragraphs 1, 2 and 3 **of Regulation (EU) 2015/1222**.

Article 56

Methodology for calculating scheduled exchanges resulting from single intraday coupling

1. By 16 months after the **integration into single intraday coupling**, the TSOs which intend to calculate scheduled exchanges resulting from single intraday coupling shall develop a proposal for a common methodology for this calculation.

The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and, where required, shall list the information which the relevant NEMOs shall provide to the scheduled exchange calculator and the time limits for delivering this information.

3. The calculation of scheduled exchanges shall be based on net positions as specified in Article 52(1)(b).

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, the relevant TSOs shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the TSOs shall review the methodology every two years.

Article 57

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article **51** of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted for approval by the relevant national regulatory authorities within **twelve** months of more than one NEMO being designated and/or allowed to offer trading services in a

bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within **twelve** months after entry into force of this Regulation.

Section 2
The single intraday coupling process

Article 58
Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints are provided to the relevant NEMOs no later than 15 minutes before the intraday cross-zonal gate opening time.

2. If updates to cross-zonal capacity and allocation constraints are required, due to operational changes on the transmission system, each TSO shall notify the coordinated capacity calculators in its capacity calculation region. The coordinated capacity calculators shall then notify the relevant NEMOs.

3. If any coordinated capacity calculator is unable to comply with paragraph 1, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall publish a notice to all market participants without unjustifiable delay.

Article 59
Operation of single intraday coupling

1. **<…>** TSOs shall **apply** the intraday cross-zonal gate opening and intraday cross-zonal gate closure times **referred to in Article 9(6)(k)**. **<…>**

2. The intraday cross-zonal gate closure time shall be set in such a way that it:

(a) maximises market participants' opportunities for adjusting their balances by trading in the intraday market time-frame as close as possible to real time; and

(b) provides TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security.

3. One intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be at most one hour before the start of the relevant market time unit and shall take into account the relevant balancing processes in relation to operational security.

4. The intraday energy trading for a given market time unit for a bidding zone border shall start at the latest at the intraday cross-zonal gate opening time of the relevant bidding zone borders and shall be allowed until the intraday cross-zonal gate closure time.

5. Before the intraday cross-zonal gate closure time, market participants shall submit to relevant NEMOs all the orders for a given market time unit. All NEMOs shall submit the orders for a given market time unit for single matching immediately after the orders have been received from market participants.

6. Orders matched in single intraday coupling shall be considered firm.

7. MCO functions shall ensure the anonymity of orders submitted via the shared order book.

Article 60

Delivery of results

1. All NEMOs performing MCO functions shall deliver the continuous trading matching algorithm results:

(a) to all other NEMOs, for results on the execution status per trade specified in Article 52(1)(a);

(b) to all TSOs and scheduled exchange calculators, for results single net positions specified in Article 52(1)(b).

2. If, in accordance with paragraph 1(a), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all other

NEMOs.

3. If, in accordance with paragraph 1(b), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all TSOs and each scheduled exchange calculator as soon as reasonably practicable. All NEMOs shall notify the market participants concerned.

4. All NEMOs shall send, without undue delay, the necessary information to market participants to ensure that the actions specified in Articles 68 and 73(3) can be undertaken.

Article 61

Calculation of scheduled exchanges resulting from single intraday coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in accordance with Article 56.

2. Each scheduled exchange calculator shall notify the relevant NEMOs, central counter parties, shipping agents, and TSOs of the agreed scheduled exchanges.

Article 62

Publication of market information

1. As soon as the orders are matched, each NEMO shall publish for relevant market participants at least the status of execution of orders and prices per trade produced by the continuous trading matching algorithm in accordance with Article 52(1)(a).

2. Each NEMO shall ensure that information on aggregated executed volumes and prices is made publicly available in an easily accessible format for at least 5 years. **<...>**

Article 63

Complementary regional auctions

1. **<…>** The relevant NEMOs and TSOs on bidding zone borders may jointly submit a common proposal for the design and implementation of complementary regional intraday auctions. **The proposal shall be consistent with the proposals submitted pursuant to Article 63(1) of Regulation (EU) 2015/1222 on complementary regional intraday auctions and Article 55(1) on intraday capacity pricing.** The proposal shall be subject to consultation in accordance with Article 12.

2. Complementary regional intraday auctions may be implemented within or between bidding zones in addition to the single intraday coupling solution referred to in Article 51. In order to hold regional intraday auctions, continuous trading within and between the relevant bidding zones may be stopped for a limited period of time before the intraday cross-zonal gate closure time, which shall not exceed the minimum time required to hold the auction and in any case 10 minutes.

3. For complementary regional intraday auctions, the methodology for pricing intraday cross-zonal capacity may differ from the methodology established in accordance with Article 55(3) but it shall nevertheless meet the principles provided for in Article 55(1) **of Regulation (EU) 2015/1222**.

4. The competent regulatory authorities may approve the proposal for complementary regional intraday auctions if the following conditions are met:

(a) regional auctions shall not have an adverse impact on the liquidity of the single intraday coupling;

(b) all cross-zonal capacity shall be allocated through the capacity management module;

(c) the regional auction shall not introduce any undue discrimination between market participants from adjacent regions;

(d) the timetables for regional auctions shall be consistent with single intraday coupling to enable market participants to trade as close as possible to real-time;

(e) regulatory authorities shall have consulted the market participants in the **Contracting Parties and** Member States concerned.

5. At least every two years after the decision on complementary regional auctions, the regulatory authorities of the **Contracting Parties and** Member States concerned shall review the compatibility of any regional solutions with single intraday coupling to ensure that the conditions above continue to be fulfilled.

Section 3

Transitional intraday arrangements

Article 64

Provisions relating to explicit allocation

<…>

Article 65

Removal of explicit allocation

<...>

Article 66

Provisions relating to intraday arrangements

<...>

Article 67

Explicit requests for capacity

<...>

CHAPTER 7
Clearing and settlement for single day-ahead and intraday coupling

Article 68

Clearing and settlement

1. The central counter parties shall ensure clearing and settlement of all matched orders in a timely manner. The central counter parties shall act as the counter party to market participants for all their trades with regard to the financial rights and obligations arising from these trades.

2. Each central counter party shall maintain anonymity between market participants.

3. Central counter parties shall act as counter party to each other for the exchange of energy between bidding zones with regard to the financial rights and obligations arising from these energy exchanges.

4. Such exchanges shall take into account:

(a) net positions produced in accordance with Articles 39(2)(b) and 52(1)(b);

(b) scheduled exchanges calculated in accordance with Articles 49 and 61.

5. Each central counter party shall ensure that for each market time unit:

(a) across all bidding zones, taking into account, where appropriate, allocation constraints, there are no deviations between the sum of energy transferred out of all surplus bidding zones and the sum of energy transferred into all deficit bidding zones;

(b) electricity exports and electricity imports between bidding zones equal each other, with any deviations resulting only from considerations of allocation constraints, where appropriate.

6. Notwithstanding paragraph 3, a shipping agent may act as a counter party between different central counter parties for the exchange of energy, if the parties concerned conclude a specific agreement to that effect. If no agreement is reached, the shipping arrangement shall be decided by the regulatory authorities responsible for the bidding zones between which the clearing and settlement of the exchange of energy

is needed.

7. All central counter parties or shipping agents shall collect congestion incomes arising from the single day-ahead coupling specified in Articles 46 to 48 and from the single intraday coupling specified in Articles 58 to 60.

8. All central counter parties or shipping agents shall ensure that collected congestion incomes are transferred to the TSOs no later than two weeks after the date of settlement.

9. If the timing of payments is not harmonised between two bidding zones, the **Contracting Parties and** Member States concerned shall ensure that an entity is appointed to manage the timing mismatch and to bear the relevant costs.

CHAPTER 8
Firmness of allocated cross-zonal capacity

Article 69
<…> Day-ahead firmness deadline

<…> TSOs shall **apply** a **<…>** single day-ahead firmness deadline, which shall not be shorter than half an hour before the day-ahead market gate closure time. **<…>**

Article 70
Firmness of day-ahead capacity and allocation constraints

1. Prior to the day-ahead firmness deadline, each coordinated capacity calculator may adjust cross-zonal capacity and allocation constraints provided to relevant NEMOs.

2. After the day-ahead firmness deadline, all cross-zonal capacity and allocation constraints shall be firm for day-ahead capacity allocation unless the requirements of Article 46(2) are met, in which case cross-zonal capacity and allocation constraints shall be firm as soon as they are submitted to relevant NEMOs.

3. After the day-ahead firmness deadline, cross-zonal capacity which has not been allocated may be adjusted for subsequent allocations.

Article 71
Firmness of intraday capacity

Cross-zonal intraday capacity shall be firm as soon as it is allocated.

Article 72

Firmness in the event of *force majeure* or emergency situations

1. In the event of *force majeure* or an emergency situation **<…>**, where the TSO shall act in an expeditious manner and redispatching or countertrading is not possible, each TSO shall have the right to curtail allocated cross-zonal capacity. In all cases, curtailment shall be undertaken in a coordinated manner following liaison with all directly concerned TSOs.

2. A TSO which invokes *force majeure* or an emergency situation shall publish a notice explaining the nature of the *force majeure* or the emergency situation and its probable duration. This notice shall be made available to the market participants concerned through NEMOs. If capacity is allocated explicitly to market participants, the TSO invoking *force majeure* or an emergency situation shall send notice directly to contractual parties holding cross-zonal capacity for the relevant market time-frame.

3. If allocated capacity is curtailed because of *force majeure* or an emergency situation invoked by a TSO, the TSO shall reimburse or provide compensation for the period of *force majeure* or the emergency situation, in accordance with the following requirements:

(a) if there is implicit allocation, central counter parties or shipping agents shall not be subject to financial damage or financial benefit arising from any imbalance created by such curtailment;

(b) in the event of *force majeure*, if capacity is allocated via explicit allocation, market participants shall be entitled to reimbursement of the price paid for the capacity during the explicit allocation process;

(c) in an emergency situation, if capacity is allocated via explicit allocation, market participants shall be entitled to compensation equal to the price difference of relevant markets between the bidding zones concerned in the relevant time-frame; or

(d) in an emergency situation, if capacity is allocated via explicit allocation but the bidding zone price is not calculated in at least one of the two relevant bidding zones in the relevant timeframe, market participants shall be entitled to reimbursement of the price paid for capacity during the explicit allocation process.

4. The TSO invoking *force majeure* or an emergency situation shall limit the consequences and duration of the *force majeure* situation or emergency situation.

5. Where a **Contracting Party** has so provided, upon request by the TSO concerned the national regulatory authority shall assess whether an event qualifies as *force majeure*.

TITLE III
COSTS

CHAPTER 1
Congestion income distribution methodology for single day-ahead and intraday coupling

Article 73

Congestion income distribution methodology

1. **<…>** TSOs shall **apply the** methodology for sharing congestion income **referred to in Article 9(6)(m)**.

2. The methodology **from** paragraph 1 shall:

(a) facilitate the efficient long-term operation and development of the electricity transmission system and the efficient operation of the electricity market of the **Energy Community**;

(b) comply with the general principles of congestion management provided for in Article 16 of Regulation (EC) No **2019/943**;

(c) allow for reasonable financial planning;

(d) be compatible across time-frames;

(e) establish arrangements to share congestion income deriving from transmission assets owned by parties other than TSOs.

3. TSOs shall distribute congestion incomes in accordance with the methodology in paragraph 1 as soon as reasonably practicable and no later than one week after the congestion incomes have been transferred in accordance with Article 68(8).

CHAPTER 2

Redispatching and countertrading cost sharing methodology for single day-ahead and intraday coupling

Article 74

Redispatching and countertrading cost sharing methodology

1. No later than 16 months after the decision on the capacity calculation regions is taken, all TSOs in each capacity calculation region shall develop a proposal for a common methodology for redispatching and countertrading cost sharing.

2. The redispatching and countertrading cost sharing methodology shall include cost-sharing solutions for actions of cross-border relevance.

3. Redispatching and countertrading costs eligible for cost sharing between relevant TSOs shall be determined in a transparent and auditable manner.

4. The redispatching and countertrading cost sharing methodology shall at least:

(a) determine which costs incurred from using remedial actions, for which costs have been considered in the capacity calculation and where a common framework on the use of such actions has been established, are eligible for sharing between all the TSOs of a capacity calculation region in accordance with the capacity calculation methodology set out in Articles 20 and 21;

(b) define which costs incurred from using redispatching or countertrading to guarantee the firmness of cross-zonal capacity are eligible for sharing between all the TSOs of a capacity calculation region in accor-

dance with the capacity calculation methodology set out in Articles 20 and 21;

(c) set rules for region-wide cost sharing as determined in accordance with points (a) and (b).

5. The methodology developed in accordance with paragraph 1 shall include:

(a) a mechanism to verify the actual need for redispatching or countertrading between the TSOs involved;

(b) an *ex post* mechanism to monitor the use of remedial actions with costs;

(c) a mechanism to assess the impact of the remedial actions, based on operational security and economic criteria;

(d) a process allowing improvement of the remedial actions;

(e) a process allowing monitoring of each capacity calculation region by the competent regulatory authorities.

6. The methodology developed in accordance with paragraph 1 shall also:

(a) provide incentives to manage congestion, including remedial actions and incentives to invest effectively;

(b) be consistent with the responsibilities and liabilities of the TSOs involved;

(c) ensure a fair distribution of costs and benefits between the TSOs involved;

(d) be consistent with other related mechanisms, including at least:

(i) the methodology for sharing congestion income set out in Article 73;

(ii) the inter-TSO compensation mechanism, as set out in Article **49** of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and Commission Regulation (EU) No 838/2010 **as adapted and adopted by Permanent High Level Group Decision 2013/01-PHLG-EnC**;

(e) facilitate the efficient long-term development and operation of the pan-European interconnected system and the efficient operation of the pan-European electricity market;

(f) facilitate adherence to the general principles of congestion management as set out in Article 16 **and 19** of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(g) allow reasonable financial planning;

(h) be compatible across the day-ahead and intraday market time-frames; and (i) comply with the principles of transparency and non-discrimination.

7. **<…>** TSOs of each capacity calculation region shall further harmonise as far as possible between the regions the redispatching and countertrading cost sharing methodologies applied within their respective capacity calculation region.

CHAPTER 3

Capacity allocation and congestion management cost recovery

Article 75

General provisions on cost recovery

1. Costs relating to the obligations imposed on TSOs in accordance with Article 8, including the costs specified in Article 74 and Articles 76 to 79, shall be assessed by the competent regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered in a timely manner through network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

2. **Contracting Parties**' share of the common costs referred to in Article 80(2)(a), regional costs referred to in Article 80(2)(b) and national costs referred to in Article 80(2)(c) assessed as reasonable, efficient and proportionate shall be recovered through NEMO fees, network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

3. If requested by the regulatory authorities, relevant TSOs, NEMOs and delegates in accordance with Article 78 shall, within three months of the request, provide information necessary to facilitate the assessment of the costs incurred.

Article 76

Costs of establishing, amending and operating single day-ahead and intraday coupling

1. **<…>** NEMOs **from Contracting Parties** shall **contribute <…> to** bear**ing** the following costs:

(a) common, regional and national costs of establishing, updating or further developing the price coupling algorithm and single day-ahead coupling;

(b) common, regional and national costs of establishing, updating or further developing the continuous trading matching algorithm and single intraday coupling;

(c) common, regional and national costs of operating single day-ahead and intraday coupling.

2. Subject to agreement with the NEMOs concerned, TSOs may make a contribution to the costs provided for in paragraph 1 subject to approval by the relevant regulatory authorities. In such cases, within two months of receiving a forecast from the NEMOs concerned, each TSO shall be entitled to provide a cost contribution proposal to the relevant regulatory authority for approval.

3. The NEMOs concerned shall be entitled to recover costs in accordance with paragraph 1 which have not been borne by TSOs in accordance with paragraph 2 by means of fees or other appropriate mechanisms only if the costs are reasonable and proportionate, through national agreements with the competent regulatory authority.

Article 77

Clearing and settlement costs

1. All costs incurred by central counter parties and shipping agents shall be recoverable by means of fees or other appropriate mechanisms if they are reasonable and proportionate.

2. The central counter parties and shipping agents shall seek efficient clearing and settlement arrangements

avoiding unnecessary costs and reflecting the risk incurred. The cross-border clearing and settlement arrangements shall be subject to approval by the relevant national regulatory authorities.

Article 78

Costs of establishing and operating the coordinated capacity calculation process

1. Each TSO shall individually bear the costs of providing inputs to the capacity calculation process.

2. All TSOs shall bear jointly the costs of merging the individual grid models.

All TSOs in each capacity calculation region shall bear the costs of establishing and operating the coordinated capacity calculators.

3. Any costs incurred by market participants in meeting the requirements of this Regulation shall be borne by those market participants.

Article 79

Costs of ensuring firmness

The costs of ensuring firmness in accordance with Articles 70(2) and 71 shall be borne by the relevant TSOs, to the extent possible in accordance with Article **19(2)(a)** of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. These costs shall include the costs from compensation mechanisms associated with ensuring the firmness of cross-zonal capacities as well as the costs of redispatching, countertrading and imbalance associated with compensating market participants.

Article 80

Cost sharing between NEMOs and TSOs in different Member States and Contracting Parties

1. All relevant NEMOs and TSOs shall provide a yearly report to the regulatory authorities in which the costs of establishing, amending and operating single day-ahead and intraday coupling are explained in detail. This report shall be published by the Agency **for the Cooperation of Energy Regulators** taking due account of sensitive commercial information. Costs directly related to single day-ahead and intraday coupling shall be clearly and separately identified and auditable. The report shall also provide full details of contributions made to NEMO costs by TSOs in accordance with Article 76(2).

2. The costs referred to in paragraph 1 shall be broken down into:

(a) common costs resulting from coordinated activities of all NEMOs or TSOs from **Contracting Parties and** Member States **(for their interconnection with Contracting Parties)**, participating in the single day-ahead and intraday coupling;

(b) regional costs resulting from activities of NEMOs or TSOs cooperating in a certain region;

(c) national costs resulting from activities of the NEMOs or TSOs in that **Contracting Party**.

3. Common costs referred to in paragraph 2(a) shall be shared among the TSOs and NEMOs in Member States **and Contracting Parties in accordance with Article 80(3) of Regulation (EU) 2015-1222. <…>**

4. NEMOs and TSOs cooperating in a certain region shall jointly agree on a proposal for the sharing of regional costs in accordance with paragraph 2(b). The proposal shall then be individually approved by the competent national authorities of each of the **Contracting Party and** Member States in the region. NEMOs and TSOs cooperating in a certain region may alternatively use the cost sharing arrangements **<…>**.

5. The cost sharing principles shall apply to costs incurred from the entry into force of this Regulation. This is without prejudice to existing solutions used for the development of single day-ahead and intraday coupling and costs incurred prior to the entry into force of this Regulation shall be shared among the NEMOs and TSOs based on the existing agreements governing such solutions.

TITLE IV
DELEGATION OF TASKS AND MONITORING

Article 81
Delegation of tasks

1. A TSO or NEMO may delegate all or part of any task assigned to it under this Regulation to one or more third parties in the case the third party can carry out the respective function at least as effectively as the delegating entity. The delegating entity shall remain responsible for ensuring compliance with the obligations under this Regulation, including ensuring access to information necessary for monitoring by the regulatory authority.

2. Prior to the delegation, the third party concerned shall have clearly demonstrated to the delegating party its ability to meet each of the obligations of this Regulation.

3. In the event that all or part of any task specified in this Regulation is delegated to a third party, the delegating party shall ensure that suitable confidentiality agreements in accordance with the confidentiality obligations of the delegating party have been put in place prior to delegation.

Article 82
Monitoring of the implementation of single day-ahead and intraday coupling

1. The entity or entities performing the MCO functions shall be monitored by the regulatory authorities or relevant authorities of the territory where they are located. Other regulatory authorities or relevant authorities, **the Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC**, shall contribute to the monitoring where adequate. The regulatory authorities or relevant authorities primarily responsible for monitoring a NEMO and the MCO functions shall fully cooperate and shall provide access to information for other regulatory authorities**, the Energy Community Regulatory Board and** the Agency **for the Cooperation of Energy Regulators** and in order

to ensure proper monitoring of single day-ahead and intraday coupling in accordance with **Article 61 of Directive 2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

2. Monitoring of the implementation **of the Contracting Party integration into** single day-ahead and intraday coupling by **the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC,** shall **be performed in coordination with the Energy Community Secretariat. <…>**

3. **<…>**

4. **<…>**

5. All TSOs shall submit to **the Agency for the Cooperation of Energy Regulators and the Energy Community Secretariat** the information required to perform the tasks in accordance with paragraph 2 **<…>**.

6. NEMOs, market participants and other relevant organisations regarding single day-ahead and intraday coupling shall, at the joint request of the **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators and the ENTSO for Electricity, acting in accordance with Articles 2 and 3 of Procedural Act No 2022/01/MC**, submit to the ENTSO for Electricity the information required for monitoring in accordance with paragraph 2 **<…>**, except for information already obtained by the regulatory authorities, the **Energy Community Regulatory Board, the Agency for the Cooperation of Energy Regulators** or the ENTSO for Electricity in the context of their respective implementation monitoring tasks.

TITLE V
TRANSITIONAL AND FINAL PROVISIONS

Article 83

Transitional provisions for Ireland and Northern Ireland

<…>

Article 84

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[3]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with <…>, Regulation (EU) 2015/1222, <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field

3 The text displayed here corresponds to Article 13 of Decision D/2022/03/MC-EnC.

covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

ANNEX I
Capacity Calculation Regions

Article 1
Subject matter and scope

1. The capacity calculation regions (CCRs) cover all existing bidding zone borders between the Contracting Parties and Contracting Parties and Member States as defined in this Annex.

2. Adjustments of the configuration of the CCRs listed in this Annex shall be subject to a proposal of all transmission system operators pursuant to Article 15 paragraphs 2 and 3 of Regulation (EU) 2015/1222 in consultation with the TSOs from Contacting Parties to the Agency for the Cooperation of Energy Regulators.

Article 2
Capacity Calculation Regions

The following are defined as the CCRs of the Energy Community:

- Capacity Calculation Region Shadow South-East Europe (Shadow SEE CCR)
- Capacity Calculation Region Italy-Montenegro (ITME CCR)
- Capacity Calculation Region Eastern Europe (EE CCR)

Article 3
Capacity Calculation Region: Shadow SEE CCR

The Shadow South-East Europe CCR shall include bidding zone borders between Contracting Parties:

- Bosnia and Hercegovina – Serbia (BA-RS), Nezavisni operator sistema u Bosni i Hercegovini (NOS BiH) and Elektromreza Srbije AD (EMS)
- Montenegro – Bosnia and Hercegovina (ME-BA), Crnogorski elektroprenosni sistem AD (CGES) and Nezavisni operator sistema u Bosni i Hercegovini (NOS BiH)
- Montenegro – Albania (ME-AL), Crnogorski elektroprenosni sistem AD (CGES) and Operatori i Sistemit te Transmetimit sh.a. (OST)
- Albania – North Macedonia (AL-MK), Operatori i Sistemit te Transmetimit sh.a. (OST) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)
- Serbia – North Macedonia (RS-MK), Elektromreza Srbije AD (EMS) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)
- Montenegro – Serbia (ME-RS), Crnogorski elektroprenosni sistem AD (CGES) and Elektromreza Srbije AD (EMS)

- Montenegro – Kosovo* (ME-KS), Crnogorski elektroprenosni sistem AD (CGES) and Operator sistemi, transmisioni dhe tregu Sh.A. (KOSTT)

- Albania – Kosovo* (AL-KS), Operatori i Sistemit te Transmetimit sh.a. (OST) and Operator istemi, transmisioni dhe tregu Sh.A. (KOSTT)

- North Macedonia – Kosovo* (MK-KS), Makedonski Elektroprenosen Sistem Operator AD (MEPSO) and Operator sistemi, transmisioni dhe tregu Sh.A. (KOSTT)

- Serbia – Kosovo* (RS-KS), Elektromreza Srbije AD (EMS) and Operator sistemi, transmisioni dhe tregu Sh.A. (KOSTT).

All TSOs of the Shadow SEE CCR shall by 6 months after the entry into force of this Regulation conclude an agreement with the TSOs of the EU SEE CCR as a basis for the cooperation of the TSOs of Member States and Contracting Parties in the SEE Shadow CCR. This agreement shall apply to the following TSOs for the following borders:

- Croatia – Bosnia and Hercegovina (HR - BA), Croatian Transmission System Operator Ltd. (HOPS) and Nezavisni operator sistema u Bosni i Hercegovini (NOS BiH)

- Croatia – Serbia (HR - RS), Croatian Transmission System Operator Ltd. (HOPS) and Elektromreza Srbije AD (EMS)

- Hungary – Serbia (HU - RS), Hungarian Independent Transmission Operator Company Ltd (MAVIR) and Elektromreza Srbije AD (EMS)

- Romania – Serbia (RO - RS), Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A. and Elektromreza Srbije AD (EMS)

- Bulgaria – Serbia (BG - RS), Elektroenergien Sistemen Operator EAD (ESO) and Elektromreza Srbije AD (EMS)

- Bulgaria – North Macedonia (BG - MK), Elektroenergien Sistemen Operator EAD (ESO) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)

- Greece – North Macedonia (BG - MK), Independent Power Transmission Operator S.A. (IPTO) and Makedonski Elektroprenosen Sistem Operator AD (MEPSO)

- Greece – Albania (GR - AL), Independent Power Transmission Operator S.A. (IPTO) and Operatori i Sistemit te Transmetimit sh.a. (OST)

Article 4

Capacity Calculation Region: ITME CCR

The ITME CCR shall include the bidding zone border between Italy and Montenegro (IT-ME),

TERNA Rete Elettrica Nazionale S.p.A (TERNA) and Crnogorski elektroprenosni sistem AD (CGES)

Article 5

Capacity Calculation Region: EE CCR

The Eastern Europe CCR shall include bidding zone border between Ukraine and Moldova

(UA - MD), Ukrenergo NPC SE (Ukrenergo) and I.S. Moldelectrica (MED).

With regards to bidding zone borders between Contracting Parties and Member States, all

TSOs of the EE CCR shall by 6 months after the entry into force of this Regulation conclude an agreement with the TSOs of EU SEE CCR setting the basis for the cooperation of the EU and non-EU TSOs in the EE CCR. This should apply to the following TSOs for the following borders:

- Ukraine - Poland (UA - PL), Ukrenergo NPC SE (Ukrenergo) and PSE S.A. (PSE)

- Ukraine - Slovakia (UA - SL), Ukrenergo NPC SE (Ukrenergo) and Slovenská elektrizaná prenosová süstava, a.s. (SEPS)

- Ukraine - Hungary (UA - HU), Ukrenergo NPC SE (Ukrenergo) and Hungarian Independent Transmission Operator Company Ltd (MAVIR)

- Ukraine - Romania (UA - RO), Ukrenergo NPC SE (Ukrenergo) and Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A (TEL)

- Moldova . Romania (MD - RO), I.S. Moldelectrica (MED) and Compania Nationalã de Transport al Energiei Electrice "Transelectrica" S.A (TEL).

COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in ***bold and blue****.*

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter and scope

1. This Regulation lays down a detailed guideline on electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves.

2. This Regulation shall apply to transmission system operators ('TSOs'), distribution system operators ('DSOs') including closed distribution systems, regulatory authorities, the Agency for the Cooperation of Energy Regulators**, the Energy Community Regulatory Board**, the European Network of Transmission System Operators for Electricity ('ENTSO-E'), third parties to whom responsibilities have been delegated or assigned and other market participants.

3. This Regulation shall apply to all transmission systems and interconnections in the **Energy Community** except the transmission systems **<…>** that are not connected with other transmission systems via interconnections.

4. Where more than one TSO exists in a **Contracting Party**, this Regulation shall apply to all TSOs in a **Contracting Party**. Where a TSO does not have a function relevant to one or more obligations under this Regulation, **Contracting Parties** may provide that the responsibility to comply with those obligations is assigned to one or more specific TSOs.

5. Where a load-frequency control ('LFC') area consists of two or more TSOs, all TSOs of that LFC area may decide, subject to the approval by the relevant regulatory authorities, to exercise one or more obligations under this Regulation in a coordinated manner for all scheduling areas of the LFC area.

6. **<…>**

7. **<…>**

8. This Regulation shall apply to all system states defined in Article 18 of Regulation (EU) 2017/1485**, as adapted and adopted by Ministerial Council Decision 2022/03/MC- EnC**.

Article 2

Definitions

For the purposes of this Regulation, the definitions in Article 2 of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, Article 2 of Regulation (EC) No **2019/943 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) No 543/2013, **as adapted and adopted by Permanent High Level Group Decision 2015/01/MC-EnC**, Article 2 of Commission Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/MC-EnC**, Article 2 of Commission Regulation (EU) 2016/1388 **as adapted and adopted by Permanent High Level Group Decision 2018/05/MC-EnC**, Article 2 of Commission Regulation (EU) 2016/1447, **as adapted and adopted by Permanent High Level Group Decision 2018/04/MC-EnC**, Article 2 of Commission Regulation (EU) 2016/1719, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 3 of Commission Regulation (EU) 2017/1485, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, and Article 3 of Commission Regulation (EU) 2017/2196, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** shall apply.

The following definitions shall also apply:

(1) 'balancing' means all actions and processes, on all timelines, through which TSOs ensure, in a continuous way, the maintenance of system frequency within a predefined stability range as set out in Article 127 of Regulation (EU) 2017/1485 **as adapted and adopted Ministerial Council 2022/03/MC-EnC**, and compliance with the amount of reserves needed with respect to the required quality, as set out in Part IV Title V, Title VI and Title VII of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(2) 'balancing market' means the entirety of institutional, commercial and operational arrangements that establish market-based management of balancing;

(3) 'balancing services' means balancing energy or balancing capacity, or both;

(4) 'balancing energy' means energy used by TSOs to perform balancing and provided by a balancing service provider;

(5) 'balancing capacity' means a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract;

(6) 'balancing service provider' means a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs;

(7) 'balance responsible party' means a market participant or its chosen representative responsible for its imbalances;

(8) 'imbalance' means an energy volume calculated for a balance responsible party and representing the difference between the allocated volume attributed to that balance responsible party and the final position of that balance responsible party, including any imbalance adjustment applied to that balance responsible party, within a given imbalance settlement period;

(9) 'imbalance settlement' means a financial settlement mechanism for charging or paying balance

responsible parties for their imbalances;

(10) 'imbalance settlement period' means the time unit for which balance responsible parties' imbalance is calculated;

(11) 'imbalance area' means the area in which an imbalance is calculated;

(12) 'imbalance price' means the price, be it positive, zero or negative, in each imbalance settlement period for an imbalance in each direction;

(13) 'imbalance price area' means the area for the calculation of an imbalance price;

(14) 'imbalance adjustment' means an energy volume representing the balancing energy from a balancing service provider and applied by the connecting TSO for an imbalance settlement period to the concerned balance responsible parties, used for the calculation of the imbalance of these balance responsible parties;

(15) 'allocated volume' means an energy volume physically injected or withdrawn from the system and attributed to a balance responsible party, for the calculation of the imbalance of that balance responsible party;

(16) 'position' means the declared energy volume of a balance responsible party used for the calculation of its imbalance;

(17) 'self-dispatching model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities;

(18) 'central dispatching model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process;

(19) 'integrated scheduling process' means an iterative process that uses at least integrated scheduling process bids that contain commercial data, complex technical data of individual power generating facilities or demand facilities and explicitly includes the start-up characteristics, the latest control area adequacy analysis and the operational security limits as an input to the process;

(20) 'integrated scheduling process gate closure time' means the point in time when the submission or the update of integrated scheduling process bids is no longer permitted for the given iterations of the integrated scheduling process;

(21) 'TSO-TSO model' means a model for the exchange of balancing services where the balancing service provider provides balancing services to its connecting TSO, which then provides these balancing services to the requesting TSO;

(22) 'connecting TSO' means the TSO that operates the scheduling area in which balancing service providers and balance responsible parties shall be compliant with the terms and conditions related to balancing;

(23) 'exchange of balancing services' means either or both exchange of balancing energy and exchange of balancing capacity;

(24) 'exchange of balancing energy' means the activation of balancing energy bids for the delivery of balancing energy to a TSO in a different scheduling area than the one in which the activated balancing service provider is connected;

(25) 'exchange of balancing capacity' means the provision of balancing capacity to a TSO in a different scheduling area than the one in which the procured balancing service provider is connected;

(26) 'transfer of balancing capacity' means a transfer of balancing capacity from the initially contracted balancing service provider to another balancing service provider;

(27) 'balancing energy gate closure time' means the point in time when submission or update of a balancing energy bid for a standard product on a common merit order list is no longer permitted;

(28) 'standard product' means a harmonised balancing product defined by all TSOs for the exchange of balancing services;

(29) 'preparation period' means the period between the request by the connecting TSO in case of TSO-TSO model or by the contracting TSO in case of TSO-BSP model and the start of the ramping period;

(30) 'full activation time' means the period between the activation request by the connecting TSO in case of TSO-TSO model or by the contracting TSO in case of TSO-BSP model and the corresponding full delivery of the concerned product;

(31) 'deactivation period' means the period for ramping from full delivery to a set point, or from full withdrawal back to a set point;

(32) 'delivery period' means the period of delivery during which the balancing service provider delivers the full requested change of power in-feed to, or the full requested change of withdrawals from the system;

(33) 'validity period' means the period when the balancing energy bid offered by the balancing service provider can be activated, where all the characteristics of the product are respected. The validity period is defined by a start time and an end time;

(34) 'mode of activation' means the mode of activation of balancing energy bids, manual or automatic, depending on whether balancing energy is triggered manually by an operator or automatically in a closed-loop manner;

(35) 'divisibility' means the possibility for a TSO to use only part of the balancing energy bids or balancing capacity bids offered by the balancing service provider, either in terms of power activation or time duration;

(36) 'specific product' means a product different from a standard product;

(37) 'common merit order list' means a list of balancing energy bids sorted in order of their bid prices, used for the activation of those bids;

(38) 'TSO energy bid submission gate closure time' means the latest point in time when a connecting TSO can forward the balancing energy bids received from a balancing service provider to the activation optimisation function;

(39) 'activation optimisation function' means the function of operating the algorithm applied to optimise the activation of balancing energy bids;

(40) 'imbalance netting process function' means the role to operate the algorithm applied for operating the imbalance netting process;

(41) 'TSO-TSO settlement function' means the function of performing the settlement of cooperation processes between the TSOs;

(42) 'capacity procurement optimisation function' means the function of operating the algorithm applied for the optimisation of the procurement of balancing capacity for TSOs exchanging balancing capacity.

(43) 'TSO-BSP model' means a model for the exchange of balancing services where the balancing service provider provides balancing services directly to the contracting TSO, which then provides these balancing services to the requesting TSO;

(44) 'contracting TSO' means the TSO that has contractual arrangements for balancing services with a balancing service provider in another scheduling area;

(45) 'requesting TSO' means the TSO that requests the delivery of balancing energy.

(46) 'Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

Article 3

Objectives and regulatory aspects

1. This Regulation aims at:

(a) fostering effective competition, non-discrimination and transparency in balancing markets;

(b) enhancing efficiency of balancing as well as efficiency of European and national balancing markets;

(c) integrating balancing markets and promoting the possibilities for exchanges of balancing services while contributing to operational security;

(d) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the **Energy Community** while facilitating the efficient and consistent functioning of day-ahead, intraday and balancing markets;

(e) ensuring that the procurement of balancing services is fair, objective, transparent and market- based, avoids undue barriers to entry for new entrants, fosters the liquidity of balancing markets while preventing undue distortions within the internal market in electricity;

(f) facilitating the participation of demand response including aggregation facilities and energy storage while ensuring they compete with other balancing services at a level playing field and, where necessary, act independently when serving a single demand facility;

(g) facilitating the participation of renewable energy sources and support the achievement of the **<…>** targets for the penetration of renewable generation.

2. When applying this Regulation, Member States **and Contracting Parties**, relevant regulatory authorities, and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) ensure that TSOs make use of market-based mechanisms, as far as possible, in order to ensure network security and stability;

(e) ensure that the development of the forward, day-ahead and intraday markets is not compromised;

(f) respect the responsibility assigned to the relevant TSO in order to ensure system security, including

as required by national legislation;

(g) consult with relevant DSOs and take account of potential impacts on their system;

(h) take into consideration agreed European standards and technical specifications.

Article 4

Terms and conditions or methodologies of TSOs

1. **Where this Regulation requires** TSOs **to** develop the terms and conditions or methodologies **they shall** submit them for approval to the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** or to the relevant regulatory authorities in accordance with Article 5(3) **and Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** within the respective deadlines set out in this Regulation **and in the Ministerial Council Decision 2021/13/MC-EnC** , In exceptional circumstances, notably in cases where a deadline cannot be met due to circumstances external to the sphere of TSOs, the deadlines for terms and conditions or methodologies may be prolonged **<…>** jointly by all relevant regulatory authorities in procedures pursuant to Article 5(3), and by the relevant regulatory authority in procedures pursuant to Article 5(4).

2. Where a proposal for terms and conditions or methodologies pursuant to **Articles 5(3) and 5(4) of** this Regulation needs to be developed and agreed by more than one TSO, the participating TSOs shall closely cooperate. TSOs, with the assistance of the ENTSO for Electricity, shall regularly inform the relevant regulatory authorities**, the Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy** about the progress of developing these terms and conditions or methodologies.

3. **<…>**

4. Where TSOs deciding on proposals for terms and conditions or methodologies listed in Article 5(3) are not able to reach an agreement, and where the regions concerned are composed of more than five **Contracting Parties and/or** Member States, they shall decide by qualified majority voting. A qualified majority for proposals in accordance with Article 5(3) shall require the following majority:

(a) TSOs representing at least 72 % of the **Contracting Parties and/or** Member States concerned; and

(b) TSOs representing **Contracting Parties and/or** Member States comprising at least 65 % of the population of the concerned area. A blocking minority for decisions on proposals for terms and conditions or methodologies listed in Article 5(3) shall include at least a minimum number of TSOs representing more than 35 % of the population of the participating **Contracting Parties and/or** Member States, plus TSOs representing at least one additional **Contracting Party and/or** Member State concerned, failing of which the qualified majority shall be deemed attained.

5. TSOs deciding on proposals for terms and conditions or methodologies listed in Article 5(3) in relation to regions composed of five Member States **and/or Contracting Parties** or less shall decide by consensus.

6. For TSO decisions on proposals for terms and conditions or methodologies pursuant to paragraph **<…>** 4, one vote shall be attributed per Member State **or Contracting Party**. If there is more than one

TSO in the territory of a Member State **or a Contracting Party**, the Member State **or the Contracting Party** shall allocate the voting powers among the TSOs.

7. Where TSOs fail to submit an initial or amended proposal for terms and conditions or methodologies to the relevant regulatory authorities**, the Energy Community Regulatory Board and** the Agency **for the Cooperation of Energy Regulators** in accordance with Articles 5 and 6 within the deadlines defined in this Regulation, they shall provide the relevant regulatory authorities, the **Energy Community Regulatory Board and the** Agency **for the Cooperation of Energy Regulators** with the relevant drafts of proposals for the terms and conditions or methodologies and explain why an agreement has not been reached. The **Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**, all relevant regulatory authorities jointly, or the relevant regulatory authority shall take the appropriate steps for the adoption of the required terms and conditions or methodologies in accordance with **paragraphs 3 and 4 of** Article 5, for instance by requesting amendments or revising and completing the drafts pursuant to this paragraph, including where no drafts have been submitted, and approve them.

Article 5

Approval of terms and conditions or methodologies of TSOs

1. Each regulatory authority**, the Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall approve the terms and conditions or methodologies developed by TSOs under paragraphs **<…>** 3 and 4. Before approving the terms and conditions or methodologies, **the Energy Community Regulatory Board or, to the extent Member States are affected**, the Agency **for Cooperation of Energy Regulators** or the relevant regulatory authorities shall revise the proposals where necessary, after consulting the respective TSOs, in order to ensure that they are in line with the purpose of this Regulation **and consistent with Regulation 2017/2195** and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

2. **TSOs shall apply** the following terms and conditions or methodologies and any amendments thereof **<…>** approv**ed** by the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC**:

(a) the frameworks for the establishment of the European platforms pursuant to Articles 20(1), 21(1) and 22(1) **of Regulation (EU) 2017/2195**;

(b) the modifications of the frameworks for the establishment of the European platforms pursuant to Articles 20(5) and 21(5) **of Regulation (EU) 2017/2195**;

(c) the standard products for balancing capacity pursuant to Article 25(2) **of Regulation (EU) 2017/2195**;

(d) the classification methodology for the activation purposes of balancing energy bids pursuant to Article 29(3) **of Regulation (EU) 2017/2195**;

(e) the assessment on the possible increase of the minimum volume of balancing energy bids that shall be forwarded to the European platforms pursuant to Article 29(11) **of Regulation (EU) 2017/2195**;

(f) the methodologies for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy or operating the imbalance netting process pursuant to Article 30(1) and (5) **of Regulation (EU) 2017/2195**;

(g) **the harmonised** methodology for the allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves pursuant to Article 38(3) **of Regulation (EU) 2017/2195**;

(h) the methodology for a co-optimised allocation process of cross-zonal capacity pursuant to Article 40(1) **of Regulation (EU) 2017/2195**;

(i) the TSO-TSO settlement rules for the intended exchange of energy pursuant to Article 50(1) **of Regulation (EU) 2017/2195**;

(j) the harmonisation of the main features of imbalance settlement pursuant to Article 52(2) **of Regulation (EU) 2017/2195**;

(k) **the framework, for the geographical area concerning all TSOs performing the reserve replacement process pursuant to Part IV of Regulation (EU) 2017/1485, for the establishment of the European platform for replacement reserves pursuant to Article 19(1) of Regulation (EU) 2017/2195;**

(l) **for the geographical area comprising all TSOs intentionally exchanging energy within the Continental Europe synchronous area, the TSO-TSO settlement rules for the intended exchange of energy pursuant to Article 50(3);**

(m) **for the Continental Europe synchronous area, the TSO-TSO settlement rules for the unintended exchange of energy pursuant to Article 51(1).**

<…>

3. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by all regulatory authorities of the concerned region:

(a) **<…>**

(b) for the geographical area concerning two or more TSOs exchanging or mutually willing to exchange balancing capacity, the establishment of common and harmonised rules and process for the exchange and procurement of balancing capacity pursuant to Article 33(1);

(c) for the geographical area covering TSOs exchanging balancing capacity, the methodology for calculating the probability of available cross-zonal capacity after intraday cross-zonal gate closure time pursuant to Article 33(6);

(d) the exemption, for the geographical area in which the procurement of balancing capacity has

taken place, for not allowing balancing service providers to transfer their obligations to provide balancing capacity pursuant to Article 34(1);

(e) the application of a TSO-BSP model, in a geographical area comprising two or more TSOs, pursuant to Article 35(1);

(f) the cross-zonal capacity calculation methodology for each capacity calculation region pursuant to Article 37(3);

(g) in a geographical area comprising two or more TSOs, the application of the allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves pursuant to Article 38(1) ;

(h) **<…>**

(i) **<…>**

(j) **<…>**

(k) **<…>**

(l) **<…>**

(m) **<…>**

(n) **<…>**

(o) for the geographical area comprising two or more TSOs exchanging balancing capacity, the principles for balancing algorithms pursuant to Article 58(3).

A Member State **or a Contracting Party** may provide an opinion to the concerned regulatory authority on the proposal for the terms and conditions or methodologies listed in the first subparagraph.

4. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by each regulatory authority of each concerned Member State or **Contracting Party** on a case-by-case basis:

(a) the exemption to publish information on offered prices of balancing energy or balancing capacity bids due to market abuse concerns pursuant to Article 12(4);

(b) where appropriate, the methodology for allocating costs resulting from actions taken by DSOs, pursuant to Article 15(3);

(c) the terms and conditions related to balancing pursuant to Article 18;

(d) the definition and the use of specific products pursuant to Article 26(1);

(e) the limitation on the amount of bids that is forwarded to the European platforms pursuant to Article 29(10);

(f) the exemption to separate procurement of upward and downward balancing capacity pursuant to Article 32(3);

(g) where appropriate, the additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity, administrative costs and other costs related to balancing with balance responsible parties pursuant to Article 44(3);

(h) the derogations to one or more provisions of this Regulation pursuant to Article 62(2);

(i) the costs relating to the obligations imposed on system operators or assigned third entities in accordance with this Regulation pursuant to Article 8(1).

A Member State **or a Contracting Party** may provide an opinion to the concerned regulatory authority on the proposal for the terms and conditions or methodologies listed in the first subparagraph.

5. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. The implementation timescale shall not be longer than 12 months after the approval by the relevant regulatory authorities, except where all relevant regulatory authorities agree to extend the implementation timescale or where different timescales are stipulated in this Regulation. Proposals for terms and conditions or methodologies subject to the approval by several regulatory authorities in accordance with paragraph 3 shall be submitted to the **Energy Community Regulatory Board and, to the extent Member**

States are affected, the Agency **for the Cooperation of Energy Regulators,** within one week of their submission to the regulatory authorities. Proposals for terms and conditions or methodologies subject to the approval by one regulatory authority in accordance with paragraph 4 may be submitted to the **Energy Community Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators** within one month of their submission at the discretion of the regulatory authority while they shall be submitted upon the **request of the Energy Community Regulatory Board or, to the extent Member States are affected, , the request of the** Agency **for Cooperation of Energy Regulators <…> if the Energy Community Regulatory Board or the Agency for Cooperation of Energy Regulators consider** the proposal to have a cross-border impact. Upon request by the relevant regulatory authorities, the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall issue an opinion within three months on the proposals for terms and conditions or methodologies.

6. Where the approval of the terms and conditions or methodologies in accordance with paragraph 3 of this Article or the amendment in accordance with Article 6 requires a decision by more than one regulatory authority, the relevant regulatory authorities shall consult and closely cooperate and coordinate with each other in order to reach an agreement. Where the Agency **for the Cooperation of Energy Regulators or the Energy Community Regulatory Board** issues an opinion, the relevant regulatory authorities shall take that opinion into account. Regulatory authorities or, where competent, the **Energy Community Regulatory Board or, to the extent Member States are involved, the** Agency **for the Cooperation of Energy Regulators acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** shall decide on the terms and conditions or methodologies submitted in accordance with paragraphs **<…>** 3 and 4, within six months following the receipt of the terms and conditions or methodologies by **the Energy Community Regulatory Board or, to the extent Member States are involved,** the Agency **for the Cooperation of Energy Regulators,** or the relevant regulatory authority or, where applicable, by the last relevant regulatory authority concerned. The period shall begin on the day following that on which the proposal was submitted to the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board or <…>** to the last regulatory authority concerned in accordance with paragraph 3 or, where applicable, to the relevant regulatory authority in accordance with paragraph 4.

7. Where the relevant regulatory authorities have not been able to reach agreement within the period referred to in paragraph 6, or upon their joint request, or upon the **<…>** request **of the Energy Community Regulatory Board or, to the extent Member States are involved, the Agency for the Cooperation of Energy Regulators** according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, the **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within six months from the day of referral, in accordance with Article 5(3) and the second subparagraph of Article 6(10) of Regulation (EU) 2019/942.

8. Any party may complain against a relevant system operator or TSO in relation to that system operator's or TSO's obligations or decisions under this Regulation and may refer the complaint to the relevant regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months after receipt of the complaint. That period may be extended by a further two months where

additional information is sought by the relevant regulatory authority. That extended period may be further extended with the agreement of the complainant. The relevant regulatory authority's decision shall be binding unless and until overruled on appeal.

Article 6

Amendments to terms and conditions or methodologies of TSOs

1. Where the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board**, all relevant regulatory authorities jointly or the relevant regulatory authority require an amendment in order to approve the terms and conditions or methodologies submitted in accordance with Article 5(2), (3) and (4) respectively, the relevant TSOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months following the request from the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board** or the relevant regulatory authorities. The **Energy Community Regulatory Board or, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** or the relevant regulatory authorities shall decide on the amended terms and conditions or methodologies within 2 months following their submission.

2. Where the relevant regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies within the 2-month deadline, or upon their joint request, or upon the **request of** the **Energy Community Regulatory Board or, to the extent Member States are affected, the request of the** Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, **the Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the amended terms and conditions or methodologies within 6 months, in accordance with Article 5(3) and the second subparagraph of Article 6(10) of Regulation (EU) 2019/942. If the relevant TSOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in Article 4 shall apply.[1]

3. The Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board,** or the regulatory authorities where they are responsible for the adoption of terms and conditions or methodologies in accordance with Article 5(2), (3) and (4) may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities**, the Energy Community Regulatory Board** and**, to the extent Member States are affected to** the Agency **for the Cooperation of Energy Regulators**. The proposals for amendments to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 10 and approved in accordance with the procedure set out in Articles 4 and 5.

1 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

Article 7

Publication of terms and conditions or methodologies on the internet

TSOs responsible for establishing the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet following approval **according to the provisions of this Regulation** by the Agency **for the Cooperation of Energy Regulators, the Energy Community Regulatory Board,** or the relevant regulatory authorities or, where no such approval is required, following their establishment, except where such information is confidential in accordance with Article 11.

Article 8

Recovery of costs

1. Costs related to the obligations imposed on system operators or assigned third entities in accordance with this Regulation shall be assessed by the relevant regulatory authorities in accordance with Article **59** of Directive (**EU) 2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

2. Costs considered as reasonable, efficient, and proportionate by the relevant regulatory authority shall be recovered through network tariffs or other appropriate mechanisms as determined by the relevant regulatory authorities.

3. If requested by the relevant regulatory authorities, system operators or assigned entities shall, within three months of the request, provide the information necessary to facilitate the assessment of the costs incurred.

4. Any costs incurred by market participants in meeting the requirements of this Regulation shall be borne by those market participants.

Article 9

Stakeholder involvement

The Energy Community Regulatory Board or, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC, in close cooperation with ENTSO-E, shall organise stakeholder involvement regarding the balancing market and other aspects of the implementation of this Regulation. Such involvement shall include regular meetings with stakeholders to identify problems and propose improvements related to the integration of the balancing market.

Article 10

Public consultation

1. TSOs responsible for submitting proposals for terms and conditions or methodologies or their

amendments in accordance with this Regulation shall consult stakeholders, in cluding the relevant authorities of each Member State **and Contracting Party**, on the draft proposals for terms and conditions or methodologies and other implementing measures for a period of not less than one month.

2. **The consultation shall last for a period of not less than one month. <…>**

3. **<…>**

4. At least the proposals pursuant to points **<…>** (b), (c), (d), (e), (f), (g), **<…>**[2] and (o) of Article 5(3) shall be subject to public consultation at the concerned regional level.

5. At least the proposals pursuant to points (a), (b), (c), (d), (e), (f), (g) and (i) of Article 5(4) shall be subject to public consultation in each concerned **Contracting Party**.

6. TSOs responsible for the proposal for terms and conditions or methodologies shall duly consider the views of stakeholders resulting from the consultations undertaken in accordance with paragraphs 2 to 5, prior to its submission for regulatory approval. In all cases, a sound justification for including or not including the views resulting from the consultation shall be provided together with the submission and published in a timely manner before or simultaneously with the publication of the proposal for terms and conditions or methodologies.

Article 11

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any person subject to the provisions of this Regulation.

3. Confidential information received by the persons or regulatory authorities referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **Energy Community or national** legislation.

4. Without prejudice to cases covered by national law or **Energy Community or national legislation**, regulatory authorities, bodies or persons who receive confidential information pursuant to this Regulation may use it only for the purpose of carrying out their duties under this regulation, except where written consent has been provided by the primary owner of the data.

Article 12

Publication of information

1. All entities referred to in Article 1(2) shall provide TSOs with all the relevant information to fulfil their obligations laid down in paragraphs 3 to 5.

2. All entities referred to in Article 1(2) shall ensure that information in paragraphs 3 to 5 is published at a

2 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

time and in a format that does not create an actual or potential competitive advantage or disadvantage to any individual or companies.

3. Each TSO shall publish the following information as soon as it becomes available:

(a) information on the current system balance of its scheduling area or scheduling areas, as soon as possible but no later than 30 minutes after real-time;

(b) information on all balancing energy bids from its scheduling area or scheduling areas, anonymised where necessary, no later than 30 min after the end of the relevant market time unit. The information shall include:

(i) type of product;

(ii) validity period;

(iii) offered volumes;

(iv) offered prices;

(v) information on whether the bid was declared as unavailable;

(c) information on whether the balancing energy bid was converted from a specific product or from an integrated scheduling process no later than 30 min after the end of the relevant market time unit;

(d) information regarding how balancing energy bids from specific products or from integrated scheduling process have been converted into balancing energy bids from standard products no later than 30 min after the end of the relevant market time unit;

(e) aggregated information on balancing energy bids no later than 30 min after the end of the relevant market time unit, which shall include:

(i) total volume of offered balancing energy bids;

(ii) total volume of offered balancing energy bids separately per type of reserves;

(iii) total volume of offered and activated balancing energy bids separately for standard and specific products;

(iv) volume of unavailable bids separately per type of reserves;

(f) information on offered volumes as well as offered prices of procured balancing capacity, anonymised where necessary, no later than one hour after the results of the procurement have been notified to the bidders;

(g) the initial terms and conditions related to balancing referred to in Article 18 at least one month before the application and any amendments to the terms and conditions immediately following approval by the relevant regulatory authority in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**;

(h) information on the allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves pursuant to Article 38 at the latest 24 hours after the allocation and no later than 6 hours before the use of the allocated cross-zonal capacity:

(i) date and time when the decision on allocation was made;

(ii) period of the allocation;

(iii) volumes allocated;

(iv) market values used as a basis for the allocation process in accordance with Article 39 **of Regulation (EU) 2017/2195**;

(i) information on the use of allocated cross-zonal capacity for the exchange of balancing capacity or sharing of reserves pursuant to Article 38 at the latest one week after the use of allocated cross- zonal capacity:

(i) volume of allocated and used cross-zonal capacity per market time unit;

(ii) volume of released cross-zonal capacity for subsequent timeframes per market time unit;

(j) approved methodologies referred to in Articles 40, 41 and 42 of Regulation (EU) 2017/2195 at least one month before the application;

(k) description of the requirements of any algorithm developed and amendments to it referred to in Article 58, points 1 and 2 of Regulation 2017/2195 and in Article 58, points 3 and 4, at least one month before the application;

(l) common annual report referred to in Article 59.

4. Subject to approval pursuant to Article 18, a TSO may withhold the publication of information on offered prices and volumes of balancing capacity or balancing energy bids if justified for reasons of market abuse concerns and if not detrimental to the effective functioning of the electricity markets. A TSO shall report such withholdings at least once a year to the relevant regulatory authority in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

5. No later than two years after entry into force of this Regulation, each TSO shall publish the information pursuant to paragraph 3 in a commonly agreed **or applied** harmonised format at least through the information transparency platform established pursuant to Article 3 of Regulation (EU) No 543/2013 **as adapted and adopted by Ministerial Council Decision 2015/01/MC- EnC**. **<…>**

Article 13

Delegation and assignment of tasks

1. A TSO may delegate all or part of any tasks with which it is entrusted under this Regulation to one or more third parties in case the third party can carry out the respective function at least as effectively as the delegating TSO. The delegating TSO shall remain responsible for ensuring compliance with the obligations under this Regulation, including ensuring access to information necessary for monitoring by the relevant regulatory authorities in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

2. Prior to the delegation, the third party concerned shall demonstrate to the delegating TSO its ability to meet the tasks to be delegated.

3. In the event that all or part of any tasks specified in this Regulation are delegated to a third party, the delegating TSO shall ensure that suitable confidentiality agreements in accordance with the confidentiality obligations of the delegating TSO have been put in place prior to the delegation. After delegating all or part of any tasks to a third party, the delegating TSO must inform the relevant regulatory authority and publish this decision on the internet.

4. Without prejudice to the tasks entrusted to TSOs pursuant to Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, a **Contracting Party**, or where applicable a relevant regulatory authority, may assign tasks or obligations entrusted to TSOs under this Regulation to one or more third parties. The concerned **Contracting Party**, or where applicable the concerned regulatory authority, may only assign TSOs' tasks and obligations which do not require direct cooperation, joint decision-making or entering into contractual relationship with TSOs from other Member States **or Contracting Parties**. Prior to the assignment, the third party concerned shall demonstrate to the **Contracting Party**, or where applicable the relevant regulatory authority, its ability to meet the task to be assigned.

5. In the event that tasks and obligations are assigned to a third party by a **Contracting Party**, or a regulatory authority, references to TSO in this Regulation shall be understood as referring to the assigned entity. The relevant regulatory authority shall ensure regulatory oversight of the assigned entity in respect of the assigned tasks and obligations.

TITLE II
ELECTRICITY BALANCING MARKET

CHAPTER 1
Functions and responsibilities

Article 14
Role of the TSOs

1. Each TSO shall be responsible for procuring balancing services from balancing service providers in order to ensure operational security.

2. Each TSO shall apply a self-dispatching model for determining generation schedules and consumption schedules. TSOs that apply a central dispatching model at the time of the entry into force of this Regulation shall notify to the relevant regulatory authority in accordance with **Article 59 of Directive (EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** in order to continue to apply a central dispatching model for determining generation schedules and consumption schedules. The relevant regulatory authority shall verify whether the tasks and responsibilities of the TSO are consistent with the definition in Article 2(18).

Article 15
Cooperation with DSOs

1. DSOs, TSOs, balancing service providers and balance responsible parties shall cooperate in order to ensure efficient and effective balancing.

2. Each DSO shall provide, in due time, all necessary information in order to perform the imbalance

settlement to the connecting TSO in accordance with the terms and conditions related to balancing pursuant to Article 18.

3. Each TSO may, together with the reserve connecting DSOs within the TSO's control area, jointly elaborate a methodology for allocating costs resulting from actions of DSOs pursuant to paragraphs 4 and 5 of Article 182 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. The methodology shall provide for a fair allocation of costs taking into account the responsibilities of the parties involved.

4. DSOs shall report to the connecting TSO any limits defined pursuant to paragraphs 4 and 5 of Article 182 of Regulation (EU) 2017/1485**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, that could affect the requirements set out in this Regulation.

Article 16

Role of balancing service providers

1. A balancing service provider shall qualify for providing bids for balancing energy or balancing capacity which are activated or procured by the connecting TSO or, in a TSO-BSP model, by the contracting TSO. Successful completion of the prequalification, ensured by the connecting TSO and processed pursuant to Article 159 and Article 162 of Regulation (EU) 2017/1485 **as adapted and adopted by Decision 2022/03/MC-EnC,** shall be considered as a prerequisite for the successful completion of the qualification process to become a balancing service provider pursuant to this Regulation.

2. Each balancing service provider shall submit to the connecting TSO its balancing capacity bids that affect one or more balance responsible parties.

3. Each balancing service provider participating in the procurement process for balancing capacity shall submit and have the right to update its balancing capacity bids before the gate closure time of the procurement process.

4. Each balancing service provider with a contract for balancing capacity shall submit to its connecting TSO the balancing energy bids or integrated scheduling process bids corresponding to the volume, products, and other requirements set out in the balancing capacity contract.

5. Any balancing service provider shall have the right to submit to its connecting TSO the balancing energy bids from standard products or specific products or integrated scheduling process bids for which it has passed the prequalification process pursuant to Article 159 and Article 162 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

6. The price of the balancing energy bids or integrated scheduling process bids from standard and specific products pursuant to paragraph 4 shall not be predetermined in a contract for balancing capacity. A TSO may propose an exemption to this rule in the proposal for the terms and conditions related to balancing set-up pursuant to Article 18. Such an exemption shall only apply to specific products pursuant to Article 26(3)(b) and be accompanied with a justification demonstrating higher economic efficiency.

7. There shall be no discrimination between balancing energy bids or integrated scheduling process bids submitted pursuant to paragraph 4 and balancing energy bids or integrated scheduling process bids submitted pursuant to paragraph 5.

8. For each product for balancing energy or balancing capacity, the reserve providing unit, the reserve providing group, the demand facility or the third party and the associated balance responsible parties pursuant to Article 18(4)(d), shall belong to the same scheduling area.

Article 17

Role of balance responsible parties

1. In real time, each balance responsible party shall strive to be balanced or help the power system to be balanced. The detailed requirements concerning this obligation shall be defined in the proposal for terms and conditions related to balancing set up pursuant to Article 18.

2. Each balance responsible party shall be financially responsible for the imbalances to be settled with the connecting TSO.

3. Prior to the intraday cross-zonal gate closure time, each balance responsible party may change the schedules required to calculate its position pursuant to Article 54. TSOs applying a central dispatching model may establish specific conditions and rules for changing the schedules of a balance responsible party in the terms and conditions related to balancing set up pursuant to Article 18.

4. After the intraday cross-zonal gate closure time, each balance responsible party may change the internal commercial schedules required to calculate its position pursuant to Article 54 in accordance with the rules set out in the terms and conditions related to balancing set up pursuant to Article 18.

Article 18

Terms and conditions related to balancing

1. No later than six months after entry into force of this Regulation and for all scheduling areas of a **Contracting Party**, the TSOs of this **Contracting Party** shall develop a proposal regarding:

(a) the terms and conditions for balancing service providers;

(b) the terms and conditions for balance responsible parties.

Where a LFC area consists of two or more TSOs, all TSOs of that LFC area may develop a common proposal subject to the approval by the relevant regulatory authorities.

2. The terms and conditions pursuant to paragraph 1 shall also include the rules for suspension and restoration of market activities pursuant to Article 36 of Regulation (EU) 2017/2196 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** and rules for settlement in case of market suspension pursuant to Article 39 of Regulation (EU) 2017/2196 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** once approved in accordance with Article 4 of Regulation (EU) 2017/2196 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

3. When developing proposals for terms and conditions for balancing service providers and balance responsible parties, each TSO shall:

(a) coordinate with the TSOs and DSOs that may be affected by those terms and conditions;

(b) respect the frameworks for the establishment of European platforms for the exchange of balancing energy and for the imbalance netting process pursuant to Articles 19, 20, 21 and 22 **of Regulation (EU) 2017/2195**;

(c) involve other DSOs and other stakeholders throughout the development of the proposal and take into account their views without prejudice to public consultation pursuant to Article 10.

4. The terms and conditions for balancing service providers shall:

(a) define reasonable and justified requirements for the provisions of balancing services;

(b) allow the aggregation of demand facilities, energy storage facilities and power generating facilities in a scheduling area to offer balancing services subject to conditions referred to in paragraph 5 (c);

(c) allow demand facility owners, third parties and owners of power generating facilities from conventional and renewable energy sources as well as owners of energy storage units to become balancing service providers;

(d) require that each balancing energy bid from a balancing service provider is assigned to one or more balance responsible parties to enable the calculation of an imbalance adjustment pursuant to Article 49.

5. The terms and conditions for balancing service providers shall contain:

(a) the rules for the qualification process to become a balancing service provider pursuant to Article 16;

(b) the rules, requirements and timescales for the procurement and transfer of balancing capacity pursuant to Articles 32, 33 and 34;

(c) the rules and conditions for the aggregation of demand facilities, energy storage facilities and power generating facilities in a scheduling area to become a balancing service provider;

(d) the requirements on data and information to be delivered to the connecting TSO and, where relevant, to the reserve connecting DSO during the prequalification process and operation of the balancing market;

(e) the rules and conditions for the assignment of each balancing energy bid from a balancing service provider to one or more balance responsible parties pursuant to paragraph 4 (d);

(f) the requirements on data and information to be delivered to the connecting TSO and, where relevant, to the reserve connecting DSO to evaluate the provisions of balancing services pursuant to Article 154(1), Article 154(8), Article 158(1)(e), Article 158(4)(b), Article 161(1)(f) and Article 161(4)(b) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(g) the definition of a location for each standard product and each specific product taking into account paragraph 5 (c);

(h) the rules for the determination of the volume of balancing energy to be settled with the balancing service provider pursuant to Article 45;

(i) the rules for the settlement of balancing service providers defined pursuant to Chapters 2 and 5 of Title V;

(j) a maximum period for the finalisation of the settlement of balancing energy with a balancing service provider in accordance with Article 45, for any given imbalance settlement period;

(k) the consequences in case of non-compliance with the terms and conditions applicable to balancing service providers.

6. The terms and conditions for balance responsible parties shall contain:

(a) the definition of balance responsibility for each connection in a way that avoids any gaps or overlaps in the balance responsibility of different market participants providing services to that connection;

(b) the requirements for becoming a balance responsible party;

(c) the requirement that all balance responsible parties shall be financially responsible for their imbalances, and that the imbalances shall be settled with the connecting TSO;

(d) the requirements on data and information to be delivered to the connecting TSO to calculate the imbalances;

(e) the rules for balance responsible parties to change their schedules prior to and after the intraday energy gate closure time pursuant to paragraphs 3 and 4 of Article 17;

(f) the rules for the settlement of balance responsible parties defined pursuant to Chapter 4 of Title V;

(g) the delineation of an imbalance area pursuant to Article 54(2) and an imbalance price area;

(h) a maximum period for the finalisation of the settlement of imbalances with balance responsible parties for any given imbalance settlement period pursuant to Article 54;

(i) the consequences in case of non-compliance with the terms and conditions applicable to balance responsible parties;

(j) an obligation for balance responsible parties to submit to the connecting TSO any modifications of the position;

(k) the settlement rules pursuant to Articles 52, 53, 54 and 55;

(l) where existing, the provisions for the exclusion of imbalances from the imbalance settlement when they are associated with the introduction of ramping restrictions for the alleviation of deterministic frequency deviations pursuant to Article 137(4) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

7. Each connecting TSO may include the following elements in the proposal for the terms and conditions for balancing service providers or in the terms and conditions for balance responsible parties:

(a) a requirement for balancing service providers to provide information on unused generation capacity and other balancing resources from balancing service providers, after the day-ahead market gate closure time and after the intraday cross-zonal gate closure time;

(b) where justified, a requirement for balancing service providers to offer the unused generation capacity or other balancing resources through balancing energy bids or integrated scheduling process bids in the balancing markets after day ahead market gate closure time, without prejudice to the possibility of balancing service providers to change their balancing energy bids prior to the balancing energy gate closure time or the integrated scheduling process gate closure time due to trading within intraday market;

(c) where justified, a requirement for balancing service providers to offer the unused generation capacity or other balancing resources through balancing energy bids or integrated scheduling process bids in the balancing markets after intraday cross-zonal gate closure time;

(d) specific requirements with regard to the position of balance responsible parties submitted after the day-ahead market timeframe to ensure that the sum of their internal and external commercial trade schedules equals the sum of the physical generation and consumption schedules, taking into account electrical losses compensation, where relevant;

(e) an exemption to publish information on offered prices of balancing energy or balancing capacity bids

due to market abuse concerns pursuant to Article 12(4);

(f) an exemption for specific products defined in Article 26(3)(b) to predetermine the price of the balancing energy bids from a balancing capacity contract pursuant to Article 16(6);

(g) an application for the use of dual pricing for all imbalances based on the conditions established pursuant to Article 52(2)(d)(i) **of Regulation (EU) 2017/2195** and the methodology for applying dual pricing pursuant to Article 52(2)(d)(ii) **of Regulation (EU) 2017/2195**.

8. TSOs applying a central dispatching model shall also include the following elements in the terms and conditions related to balancing:

(a) the integrated scheduling process gate closure time pursuant to Article 24(5);

(b) the rules for updating the integrated scheduling process bids after each integrated scheduling process gate closure time pursuant to Article 24(6);

(c) the rules for using integrated scheduling process bids prior to the balancing energy gate closure time pursuant to Article 24(7);

(d) the rules for converting integrated scheduling process bids pursuant to Article 27.

9. Each TSO shall monitor the fulfilment by all parties of the requirements set out in the terms and conditions for balancing within its scheduling area or scheduling areas.

CHAPTER 2
European platforms for the exchange of balancing energy

Article 19
European platform for the exchange of balancing energy from replacement reserves

1. **<…>**

2. **<…>**

3. **<…>**

4. **<…>**

5. By one year after the **entry into force of this Regulation,** all **Contracting Parties'** TSOs performing the reserve replacement process pursuant to Part IV of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and that have at least one interconnected neighbouring TSO performing the replacement reserves process shall **<…>** use the European platform **established in accordance with Article 19 of Regulation 2017/2195** to:

(a) submit all balancing energy bids from all standard products for replacement reserves;

(b) exchange all balancing energy bids from all standard products for replacement reserves, except for unavailable bids pursuant to Article 29(14);

(c) strive to fulfil all their needs for balancing energy from replacement reserves.

Article 20

European platform for the exchange of balancing energy from frequency restoration reserves with manual activation

1. **<…>**

2. **<…>**

3. **<…>**

4. **<…>**

5. **<…>**

6. **By two years after the entry into force of this Regulation Contracting Parties'** TSOs shall implement and make operational the European platform for the exchange of balancing energy use the European platform **established in accordance with Article 20 of Regulation 2017/2195** to:

(a) submit all balancing energy bids from all standard products for frequency restoration reserves with manual activation;

(b) exchange all balancing energy bids from all standard products for frequency restoration reserves with manual activation, except for unavailable bids pursuant to Article 29(14);

(c) strive to fulfil all their needs for balancing energy from the frequency restoration reserves with manual activation.

Article 21

European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation

1. **<…>**

2. **<…>**

3. **<…>**

4. **<…>**

5. **<…>**

6. **By two years after the entry into force of this Regulation** all **Contracting Parties'** TSOs performing the automatic frequency restoration process pursuant to Part IV of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC <…>** shall use the European platform **established in accordance with Article 21 of Regulation 2017/2195** to:

(a) submit all balancing energy bids from all standard products for frequency restoration reserves with automatic activation;

(b) exchange all balancing energy bids from all standard products for frequency restoration reserves with automatic activation, except for unavailable bids pursuant to Article 29(14);

(c) strive to fulfil all their needs for balancing energy from the frequency restoration reserves with automatic activation.

Article 22

European platform for imbalance netting process

1. **<…>**

2. **<…>**

3. **<…>**

4. By one year after the **entry into force of this Regulation** all **Contracting Parties'** TSOs performing the automatic frequency restoration process pursuant to Part IV of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC <..>** shall use the European platform **established in accordance with Article 22 of Regulation 2017/2195** to perform the imbalance netting process, at least for the Continental Europe synchronous area.

Article 23

Cost sharing between TSOs in different Member States and Contracting Parties

1. All TSOs shall provide a yearly report to the relevant regulatory authorities in accordance with Article **59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** in which the costs of **<…>** operating the European platforms pursuant to Articles 19, 20, 21 and 22 **of Regulation 2017/2195, applicable to the relevant Contracting Party's TSO** are explained in detail.

2. The costs referred to in paragraph 1 shall be broken down into:

(a) common costs resulting from coordinated activities of all TSOs participating in the respective platforms;

(b) regional costs resulting from activities of several but not all TSOs participating in the respective platforms;

(c) national costs resulting from activities of the TSOs in that **Contracting Party** participating in the respective platforms.

3. Common costs referred to in paragraph 2(a) shall be shared among the TSOs in the Member States **and Contracting Parties** participating in the European platforms. **<…> The amount to be paid is calculated in line with Article 23(3) of Regulation (EU) 2017/2195.**

4. To take into account changes in the common costs or changes in the participating TSOs, the calculation of common costs shall be regularly adapted.

5. TSOs cooperating in a certain region shall jointly agree on a proposal for the sharing of regional costs in accordance with paragraph 2(b). The proposal shall then be individually approved by the relevant regulatory authorities of each of the **Contracting Parties** and **<…>** Member States in the region. **<…>**

6. The cost sharing principles shall apply to costs contributing to the establishing, amending and operating the European platforms from the approval of the proposal for the relevant implementation frameworks pursuant to Articles 19(1), 20(1), 21(1) and 22(1) **of Regulation 2017/2195**. In case the implementation frameworks propose that existing projects shall evolve into a European platform, all TSOs participating in the existing projects may propose that a share of the costs incurred before the approval of the proposal

for the implementation frameworks directly related to the development and implementation of this project and assessed as reasonable, efficient and proportionate is considered as part of the common costs pursuant to paragraph 2(a).

Article 24

Balancing energy gate closure time

1. **<…>** All TSOs shall harmonise the balancing energy gate closure time for standard products **with the balancing energy gate closure time** at the Union level, at least for each of the following processes:

(a) replacement reserves;

(b) frequency restoration reserves with manual activation;

(c) frequency restoration reserves with automatic activation.

2. Balancing energy gate closure times shall:

(a) be as close as possible to real time;

(b) not be before the intraday cross-zonal gate closure time;

(c) ensure sufficient time for the necessary balancing processes.

3. After the balancing energy gate closure time, the balancing service providers shall no longer be permitted to submit or update their balancing energy bids.

4. After the balancing energy gate closure time, balancing service providers shall report to the connecting TSO any unavailable volumes of balancing energy bids without undue delay in accordance to 158(4)(b) and 161(4)(b) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. If the balancing service provider has a connection point to a DSO, and if required by the DSO, the balancing service provider shall also report any unavailable volumes of balancing energy bids to the DSO without undue delay.

5. By two years after entry into force of this Regulation, each TSO applying a central dispatching model shall define at least one integrated scheduling process gate closure time which shall:

(a) enable balancing service providers to update their integrated scheduling bids as close as possible to real time;

(b) be no longer than eight hours before real-time;

(c) be set before the TSO energy bid submission gate closure time.

6. After each integrated scheduling process gate closure time, the integrated scheduling process bid may only be changed in accordance with the rules defined by the connecting TSO in the terms and conditions for balancing service providers set up pursuant to Article 18. Those rules shall be implemented before the connecting TSO joins any process for the exchange of balancing energy and shall allow balancing service providers to update their integrated scheduling bids to the extent possible until the intraday cross-zonal gate closure time, while ensuring:

(a) the economic efficiency of the integrated scheduling process;

(b) operational security;

(c) consistency of all iterations of the integrated scheduling process;

(d) fair and equal treatment of all balancing service providers in the scheduling area;

(e) no negative effect on the integrated scheduling process.

7. Each TSO applying a central dispatching model shall establish the rules for using the integrated scheduling process bids prior to the balancing energy gate closure time in accordance with Article 18(8) (c) in order to:

(a) ensure that the TSO meets its reserve capacity requirements in real time;

(b) ensure sufficient resources to solve internal congestions;

(c) ensure the possibility of feasible dispatching of power generating facilities and demand facilities in real time.

Article 25

Requirements for standard products

1. Standard products for balancing energy shall be **applied** as part of **<…>** the implementation **of** the European platforms pursuant to Articles 19, 20 and 21. **N**o later than the time when a **Contracting Party's** TSO uses the respective European platform, the TSO shall use only standard and, where justified, specific balancing energy products in order to maintain the system's balance in accordance with Article 127, Article 157 and Article 160 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. By **one year** after entry into force of this Regulation, all TSOs shall **apply the** list of standard products for balancing capacity for frequency restoration reserves and replacement reserves **adopted pursuant to Article 25 of Regulation 2017/2195**.

3. **<…>**

4. **<…>**

5. **<…>**

6. Standard products for balancing energy and balancing capacity shall:

(a) ensure an efficient standardisation, foster cross-border competition and liquidity, and avoid undue market fragmentation;

(b) facilitate the participation of demand facility owners, third parties and owners of power generating facilities from renewable energy sources as well as owners of energy storage units as balancing service providers.

Article 26

Requirements for specific products

1. **For** the **<…>** implementation **of** the European platforms pursuant to Articles 19, 20 and 21, each TSO may develop a proposal for defining and using specific products for balancing energy and balancing

capacity. This proposal shall include at least:

(a) a definition of specific products and of the time period in which they will be used;

(b) a demonstration that standard products are not sufficient to ensure operational security and to maintain the system balance efficiently or a demonstration that some balancing resources cannot participate in the balancing market through standard products;

(c) a description of measures proposed to minimise the use of specific products subject to economic efficiency;

(d) where applicable, the rules for converting the balancing energy bids from specific products into balancing energy bids from standard products;

(e) where applicable, the information on the process for the conversion of balancing energy bids from specific products into balancing energy bids from standard products and the information on which common merit order list the conversion will take place;

(f) a demonstration that the specific products do not create significant inefficiencies and distortions in the balancing market within and outside the scheduling area.

2. Each TSO using specific products shall review at least once every two years the necessity to use specific products in accordance with the criteria laid down in paragraph 1.

3. The specific products shall be implemented in parallel to the implementation of the standard products. Following the use of the specific products, the connecting TSO may alternatively:

(a) convert the balancing energy bids from specific products into balancing energy bids from standard products;

(b) activate the balancing energy bids from specific products locally without exchanging them.

4. The rules for converting balancing energy bids from specific products into balancing energy bids from standard products pursuant to paragraph 1(d) shall:

(a) be fair, transparent and non-discriminatory;

(b) not create barriers for the exchange of balancing services;

(c) ensure the financial neutrality of TSOs.

Article 27

Conversion of bids in a central dispatching model

1. Each TSO applying a central dispatching model shall use the integrated scheduling process bids for the exchange of balancing services or for the sharing of reserves.

2. Each TSO applying a central dispatching model shall use the integrated scheduling process bids available for the real time management of the system to provide balancing services to other TSOs, while respecting operational security constraints.

3. Each TSO applying a central dispatching model shall convert as far as possible the integrated scheduling process bids pursuant to paragraph 2 into standard products taking into account operational security. The rules for converting the integrated scheduling process bids into standard products shall:

(a) be fair, transparent and non-discriminatory;

(b) not create barriers for the exchange of balancing services;

(c) ensure the financial neutrality of TSOs.

Article 28

Fall-back procedures

1. Each TSO shall ensure that fall-back solutions are in place in case the procedures referred to in paragraphs 2 and 3 fail.

2. Where the procurement of balancing services fails, the concerned TSOs shall repeat the procurement process. TSOs shall inform market participants that fall-back procedures will be used as soon as possible.

3. Where the coordinated activation of balancing energy fails, each TSO may deviate from the common merit order list activation and shall inform market participants as soon as possible.

TITLE III
PROCUREMENT OF BALANCING SERVICES

CHAPTER 1
Balancing energy

Article 29

Activation of balancing energy bids from common merit order list

1. In order to maintain the system's balance in accordance with Article 127, Article 157 and Article 160 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, each TSO shall use cost-effective balancing energy bids available for delivery in its control area based on common merit order lists or another model as **applied pursuant to paragraph 2 of Article 5.**

2. TSOs shall not activate balancing energy bids before the corresponding balancing energy gate closure time, except in the alert state or the emergency state when such activations help alleviate the severity of these system states and except when the bids serve purposes other than balancing pursuant to **Article 5(2)(d)**.

3. By one year after the entry into force of this Regulation, all TSOs shall **apply the** methodology for classifying the activation purposes of balancing energy bids **adopted pursuant to Article 29(3) of Regulation (EU) 2017/2195 in line with Article 5(2)(d). <…>**

4. For each balancing energy bid activated from the common merit order list, the TSO activating the bid shall define the activation purpose based on the methodology pursuant to **Article 5(2)(d)**. The activation purpose shall be notified and visible to all TSOs through the activation optimisation function.

5. In the event that the activation of balancing energy bids deviates from the results of the activation

optimisation function, the TSO shall publish the information about the reasons for the occurrence of such deviation in a timely manner.

6. The request for activation of a balancing energy bid from the activation optimisation function shall oblige the requesting TSO and connecting TSO to accept the firm exchange of balancing energy. Each connecting TSO shall ensure the activation of the balancing energy bid selected by the activation optimisation function. The balancing energy shall be settled pursuant to Article 50 and between the connecting TSO and the balancing service provider pursuant to Chapter 2 of Title V.

7. The activation of balancing energy bids shall be based on a TSO-TSO model with a common merit order list.

8. Each TSO shall submit all necessary data for the operation of the algorithm in paragraphs 1 and 2 of Article 58 **of Regulation 2017/2195** to the activation optimisation function in accordance with the rules established pursuant to Article 31(1).

9. Each connecting TSO shall submit, prior to the TSO energy bid submission gate closure time, all balancing energy bids received from balancing service providers to the activation optimisation function, taking into account the requirements in Articles 26 and 27. The connecting TSOs shall not modify or withhold balancing energy bids, except for:

(a) balancing energy bids related to Articles 26 and 27;

(b) balancing energy bids that are manifestly erroneous and include an unfeasible delivery volume;

(c) balancing energy bids that are not forwarded to the European platforms in accordance with paragraph 10.

10. Each TSO applying a self-dispatching model and operating within a scheduling area with a local intraday gate closure time after the balancing energy gate closure time pursuant to Article 24 may develop a proposal to limit the amount of bids that is forwarded to the European platforms pursuant to Articles 19 to 21. The bids forwarded to the European platforms shall always be the cheapest bids. This proposal shall include:

(a) the definition of the minimum volume that shall be forwarded to the European platforms. The minimum volume of bids submitted by the TSO shall be equal to or higher than the sum of the reserve capacity requirements for its LFC block according to Articles 157 and 160 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and the obligations arising from the exchange of balancing capacity or sharing of reserves;

(b) the rules to release the bids that are not submitted to the European platforms and the definition of the point in time at which the concerned balancing service providers shall be informed of the release of its bids.

11. At least once every two years after the approval of the proposal in paragraph 10 by the respective regulatory authority, all TSOs shall assess the impact of limiting the volume of bids sent to the European platforms and the functioning of the intraday market. This assessment shall include:

(a) an evaluation by the relevant TSOs on the minimum volume of bids that shall be forwarded to the European platforms pursuant to paragraph 10(a);

(b) a recommendation to the relevant TSOs limiting balancing energy bids.

Based on this assessment, all TSOs shall make a proposal to all regulatory authorities to review the minimum volume of balancing energy bids that shall be forwarded to the European platforms pursuant

to paragraph 10(a).

12. Each requesting TSO may request the activation of balancing energy bids from the common merit order lists up to the total volume of balancing energy. The total volume of balancing energy that can be activated by the requesting TSO from balancing energy bids from the common merit order lists is calculated as a sum of volumes of:

(a) balancing energy bids submitted by the requesting TSO not resulting from sharing of reserves or exchange of balancing capacity;

(b) balancing energy bids submitted by other TSOs as a result of balancing capacity procured on behalf of the requesting TSO;

(c) balancing energy bids resulting from the sharing of reserves under the condition that the other TSOs participating in the sharing of reserves have not already requested the activation of those shared volumes.

13. **<…>** When a TSO requests balancing energy bids beyond the limit set out in paragraph 12, all other TSOs shall be informed.

14. Each TSO may declare the balancing energy bids submitted to the activation optimisation function unavailable for the activation by other TSOs because they are restricted due to internal congestion or due to operational security constraints within the connecting TSO scheduling area.

Article 30

Pricing for balancing energy and cross-zonal capacity used for exchange of balancing energy or for operating the imbalance netting process

1. By one year after the entry into force of this Regulation, all TSOs shall **apply the** methodology **adopted in accordance with Article 5(2)(f)** to determine prices for the balancing energy that results from the activation of balancing energy bids for the frequency restoration process pursuant to Articles 143 and 147 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, and the reserve replacement process pursuant to Articles 144 and 148 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. **<…>**

3. **<…>**

4. The harmonised pricing method defined in paragraph 1 shall apply to balancing energy from all standard and specific products pursuant to Article 26(3)(a). For specific products pursuant to Article 26(3)(b), the concerned TSO may propose a different pricing method in the proposal for specific products pursuant to Article 26.

5. Where all TSOs identify inefficiencies in the application of the methodology proposed pursuant to **Article 30(1)(a) of Regulation (EU) 2017/2195**, they may request an amendment and propose a pricing method alternative to the pricing method in **Article 30(1)(a) of Regulation (EU) 2017/2195**. In such case, all TSOs shall perform a detailed analysis demonstrating that the alternative pricing method is more efficient.

Article 31

Activation optimisation function

1. All TSOs shall **apply the** activation optimisation function **established** in accordance with Article 29 and **Article 31 of Regulation (EU) 2017/2195** for the optimisation of the activation of balancing energy bids from different common merit order lists. **<…>**

2. Common merit order lists shall consist of balancing energy bids from standard products. All TSOs shall establish the necessary common merit order lists for the standard products. Upward and downward balancing energy bids shall be separated in different common merit order lists.

3. **<…>**

4. TSOs shall ensure that the balancing energy bids submitted to the common merit order lists are expressed in euros and make reference to the market time unit.

5. Depending on the requirement for standard products for balancing energy, TSOs may create more common merit order lists.

6. Each TSO shall submit its activation requests for balancing energy bids to the activation optimisation function.

7. **The activated balancing service providers shall be responsible for delivering the requested volume until the end of the delivery period.**

8. All TSOs that operate the frequency restoration process and the reserve replacement process to balance their LFC area shall strive to use all balancing energy bids from relevant common merit order lists to balance the system in the most efficient way, taking into account operational security.

9. TSOs that do not use the reserve replacement process to balance their LFC area shall strive to use all balancing energy bids from relevant common merit order lists for frequency restoration reserves to balance the system in the most efficient way, taking into account operational security.

10. Except in the normal state, TSOs may decide to balance the system using only the balancing energy bids from balancing service providers in its own control area if such decision helps alleviate the severity of the current system state. The TSO shall publish a justification for such decision without undue delay.

CHAPTER 2
Balancing capacity

Article 32

Procurement rules

1. All TSOs of the LFC block shall regularly and at least once a year review and define the reserve capacity requirements for the LFC block or scheduling areas of the LFC block pursuant to dimensioning rules as referred in Articles 127, 157 and 160 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Each TSO shall perform an analysis on optimal provision of reserve capacity aiming at minimisation of costs associated with the provision of reserve

capacity. This analysis shall take into account the following options for the provision of reserve capacity:

(a) procurement of balancing capacity within control area and exchange of balancing capacity with neighbouring TSOs, when applicable;

(b) sharing of reserves, when applicable;

(c) the volume of non-contracted balancing energy bids which are expected to be available both within their control area and within the European platforms taking into account the available cross-zonal capacity.

2. Each TSO procuring balancing capacity shall define the rules for the procurement of balancing capacity in the proposal for the terms and conditions related to balancing service providers developed pursuant to Article 18. The rules for the procurement of balancing capacity shall comply with the following principles:

(a) the procurement method shall be market-based for at least the frequency restoration reserves and the replacement reserves;

(b) the procurement process shall be performed on a short-term basis to the extent possible and where economically efficient;

(c) the contracted volume may be divided into several contracting periods.

3. The procurement of upward and downward balancing capacity for at least the frequency restoration reserves and the replacement reserves shall be carried out separately. Each TSO may submit a proposal to the relevant regulatory authority in accordance with **Article 59** of Directive (EU) **20109/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** requesting the exemption to this requirement. The proposal for exemption shall include:

(a) specification of the time period during which the exemption would apply;

(b) specification of the volume of balancing capacity for which the exemption would apply;

(c) analysis of the impact of such an exemption on the participation of balancing resources pursuant to Article 25(6)(b);

(d) justification for the exemption demonstrating that such an exemption would lead to higher economic efficiency.

Article 33

Exchange of balancing capacity

1. Two or more TSOs exchanging or mutually willing to exchange balancing capacity shall develop a proposal for the establishment of common and harmonised rules and processes for the exchange and procurement of balancing capacity while respecting the requirements set out in Article 32.

2. Except in cases where the TSO-BSP model is applied pursuant to Article 35, the exchange of balancing capacity shall always be performed based on a TSO-TSO model whereby two or more TSOs establish a method for the common procurement of balancing capacity taking into account the available cross-zonal capacity and the operational limits defined in Chapters 1 and 2 of Part IV Title VIII of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

3. All TSOs exchanging balancing capacity shall submit all balancing capacity bids from standard products to the capacity procurement optimisation function. TSOs shall not modify or withhold any balancing

capacity bids and shall include them in the procurement process, except under conditions set out in Article 26 and Article 27.

4. All TSOs exchanging balancing capacity shall ensure both the availability of cross-zonal capacity and that the operational security requirements set out in Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** are met, either by:

(a) the methodology for calculating the probability of available cross-zonal capacity after intraday cross-zonal gate closure time pursuant to paragraph 6;

(b) the methodologies for allocating cross-zonal capacity to the balancing timeframe pursuant to Chapter 2 of Title IV.

5. Each TSO using the methodology for calculating the probability of available cross-zonal capacity after intraday cross-zonal gate closure time shall inform other TSOs in their LFC block of the risk of unavailability of reserve capacity in the scheduling area or areas of its control area that may affect the fulfilment of the requirements pursuant to Article 157(2)(b) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

6. TSOs exchanging balancing capacity for frequency restoration reserves and replacement reserves may develop a proposal for a methodology for calculating the probability of available cross- zonal capacity after intraday cross-zonal gate closure time. The methodology shall at least describe:

(a) the procedures to notify to other TSOs in the LFC block;

(b) the description of the process to perform the assessment for the relevant period for the exchange of balancing capacity;

(c) the method to assess the risk of unavailability of cross-zonal capacity due to planned and unplanned outages and due to congestions;

(d) the method to assess the risk of insufficient reserve capacity due to unavailability of cross-zonal capacity;

(e) the requirements for a fall-back solution in case of unavailability of cross-zonal capacity or insufficient reserve capacity;

(f) the requirements for *ex-post* review and monitoring of risks;

(g) the rules in order to ensure the settlement pursuant to Title V.

7. TSOs shall not increase the reliability margin calculated pursuant to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** due to the exchange of balancing capacity for frequency restoration reserves and replacement reserves.

Article 34

Transfer of balancing capacity

1. Within the geographical area in which the procurement of balancing capacity has taken place, the TSOs shall allow balancing service providers to transfer their obligations to provide balancing capacity. The concerned TSO or TSOs may request an exemption where contracting periods for balancing capacity pursuant to Article 32(2)(b) are strictly less than one week.

2. The transfer of balancing capacity shall be allowed at least until one hour before the start of the delivery day.

3. The transfer of balancing capacity shall be allowed if the following conditions are met:

(a) the receiving balancing service provider has passed the qualification process for the balancing capacity for which the transfer is performed;

(b) the transfer of balancing capacity is not expected to endanger operational security;

(c) the transfer of balancing capacity does not exceed the operational limits set out in Chapters 1 and 2 of Part IV Title VIII of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

4. In case the transfer of balancing capacity requires the use of cross-zonal capacity, such transfer shall only be allowed in case:

(a) the cross-zonal capacity required to perform the transfer is already available from previous allocation processes pursuant to Chapter 2 of Title IV;

(b) the cross-zonal capacity is available pursuant to the methodology for calculating the probability of available cross-zonal capacity after intraday cross-zonal gate closure time in accordance with Article 33(6).

5. If a TSO does not allow the transfer of balancing capacity, the concerned TSO shall explain the reason for the rejection to the balancing service providers involved.

CHAPTER 3
TSO-BSP model

Article 35
Exchange of balancing services

1. Two or more TSOs may at their initiative or at the request of their relevant regulatory authorities in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** develop a proposal for the application of the TSO- BSP model.

2. The proposal for application of a TSO-BSP model shall include:

(a) a cost-benefit analysis performed pursuant to Article 61 that identifies the efficiencies of applying the TSO-BSP model for at least the scheduling area or scheduling areas of the TSOs involved;

(b) the requested application period;

(c) a description of the methodology for ensuring sufficient cross-zonal capacity in accordance with Article 33(6).

3. Where the TSO-BSP model applies, the respective TSOs and balancing service providers may be exempted from the application of the requirements in Article 16(2), Article 16(4), Article 16(5) and Article 29(9) for the relevant processes.

4. Where the TSO-BSP model applies, the involved TSOs shall agree on the technical and contractual requirements and on information exchanges for the activation of balancing energy bids. The contracting

TSO and the balancing service provider shall establish contractual arrangements based on the TSO-BSP model.

5. The TSO-BSP model for the exchange of balancing energy from frequency restoration reserves may be applied only where the TSO-BSP model is also applied for the exchange of balancing capacity for frequency restoration reserves.

6. The TSO-BSP model for the exchange of balancing energy from replacement reserves may be applied where the TSO-BSP model is applied for the exchange of balancing capacity for replacement reserves or where one of the two involved TSOs does not operate the reserve replacement process as part of the load-frequency-control structure pursuant to Part IV of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

7. By **one** year after entry into force of this Regulation, all exchanges of balancing capacity shall be based on the TSO-TSO model. This requirement shall not apply to the TSO-BSP model for replacement reserves if one of the two involved TSOs does not operate the reserve replacement process as part of the load-frequency-control structure pursuant to Part IV of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

TITLE IV
CROSS-ZONAL CAPACITY FOR BALANCING SERVICES

CHAPTER 1
Exchange of balancing energy or imbalance netting process

Article 36
Use of cross-zonal capacity

1. All TSOs shall use the available cross-zonal capacity, computed according to paragraphs 2 and 3 of Article 37, for the exchange of balancing energy or for operating the imbalance netting process.

2. Two or more TSOs exchanging balancing capacity may use cross-zonal capacity for the exchange of balancing energy when cross-zonal capacity is:

(a) available pursuant to Article 33(6);

(b) released pursuant to paragraphs 8 and 9 of Article 38;

(c) allocated pursuant to Articles 40, 41 and 42 of **Regulation (EU) 2017/2195**.

Article 37
Cross-zonal capacity calculation

1. After the intraday-cross-zonal gate closure time, TSOs shall continuously update the availability of cross-zonal capacity for the exchange of balancing energy or for operating the imbalance netting process.

Cross-zonal capacity shall be updated every time a portion of cross-zonal capacity has been used or when cross-zonal capacity has been recalculated.

2. Before the implementation of the capacity calculation methodology pursuant to paragraph 3, TSOs shall use the cross-zonal capacity remaining after the intraday cross-zonal gate closure time.

3. By five years after entry into force of this Regulation, all TSOs of a capacity calculation region shall develop a methodology for cross-zonal capacity calculation within the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process. Such methodology shall avoid market distortions and shall be consistent with the cross-zonal capacity calculation methodology applied in the intraday timeframe established under Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

CHAPTER 2
Exchange of balancing capacity or sharing of reserves

Article 38
General requirements

1. Two or more TSOs may at their initiative or at the request of their relevant regulatory authorities in accordance with **Article 59** of Directive (EU) **2019/944** set up a proposal for the application of one of the following processes:

(a) co-optimised allocation process pursuant to Article 40 **of Regulation (EU) 2017/2195;**

(b) market-based allocation process pursuant to Article 41 **of Regulation (EU) 2017/2195;**

(c) allocation process based on economic efficiency analysis pursuant to Article 42 **of Regulation (EU) 2017/2195.**

Cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves before the entry into force of this Regulation may continue to be used for that purpose until the expiry of the contracting period.

2. The proposal for the application of the allocation process shall include:

(a) the bidding zone borders, the market timeframe, the duration of application and the methodology to be applied;

(b) in case of allocation process based on economic efficiency analysis, the volume of allocated cross zonal capacity and the actual economic efficiency analysis justifying the efficiency of such allocation.

3. By **one** year after entry into force of this Regulation, all TSOs shall **apply** the harmonised methodology for the allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves per timeframe pursuant to Article 40 and, where relevant, pursuant to Articles 41 and 42 **of Regulation (EU) 2017/2195**.

4. Cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves shall be used exclusively for frequency restoration reserves with manual activation, for frequency restoration reserves with automatic activation and for replacement reserves. The reliability margin calculated pursuant

to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** shall be used for operating and exchanging frequency containment reserves, except on Direct Current ('DC') interconnectors for which cross-zonal capacity for operating and exchanging frequency containment reserves may also be allocated in accordance with paragraph 1.

5. TSOs may allocate cross-zonal capacity for the exchange of balancing capacity or sharing of reserves only if cross-zonal capacity is calculated in accordance with the capacity calculation methodologies developed pursuant to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council 2022/03/MC-EnC** and (EU) 2016/1719 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

6. TSOs shall include cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves as already allocated cross-zonal capacity in the calculations of cross-zonal capacity.

7. If physical transmission right holders use cross-zonal capacity for the exchange of balancing capacity, the capacity shall be considered as nominated solely for the purpose of excluding it from the application of the use-it-or-sell-it ('UIOSI') principle.

8. All TSOs exchanging balancing capacity or sharing of reserves shall regularly assess whether the cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is still needed for that purpose. Where the allocation process based on economic efficiency analysis is applied, this assessment shall be done at least every year. When cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is no longer needed, it shall be released as soon as possible and returned in the subsequent capacity allocation timeframes. Such cross-zonal capacity shall no longer be included as already allocated cross-zonal capacity in the calculations of cross-zonal capacity.

9. When cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves has not been used for the associated exchange of balancing energy, it shall be released for the exchange of balancing energy with shorter activation times or for operating the imbalance netting process.

Article 39

Calculation of market value of cross-zonal capacity

<…>

Article 40

Co-optimised allocation process

<…>

Article 41

Market-based allocation process

<…>

Article 42

Allocation process based on economic efficiency analysis

<...>

Article 43

Use of cross-zonal capacity by balancing service providers

1. Balancing service providers which have a contract for balancing capacity with a TSO on the basis of a TSO-BSP model pursuant to Article 35 shall have the right to use cross-zonal capacity for the exchange of balancing capacity if they are holders of physical transmission rights.

2. Balancing service providers which use cross-zonal capacity for the exchange of balancing capacity on the basis of a TSO-BSP model pursuant to Article 35 shall nominate their physical transmission rights for the exchange of balancing capacity to the concerned TSOs. Such physical transmission rights shall provide the right to their holders to nominate the exchange of balancing energy to the concerned TSOs and shall therefore be excluded from the application of the UIOSI principle.

3. Cross-zonal capacity allocated for the exchange of balancing capacity in accordance with paragraph 2 shall be included as already allocated cross-zonal capacity in the calculations of cross- zonal capacity.

TITLE V
SETTLEMENT

CHAPTER 1
Settlement principles

Article 44

General principles

1. The settlement processes shall:

(a) establish adequate economic signals which reflect the imbalance situation;

(b) ensure that imbalances are settled at a price that reflects the real time value of energy;

(c) provide incentives to balance responsible parties to be in balance or help the system to restore its balance;

(d) facilitate harmonisation of imbalance settlement mechanisms;

(e) provide incentives to TSOs to fulfil their obligations pursuant to Article 127, Article 153, Article 157 and Article 160 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(f) avoid distorting incentives to balance responsible parties, balancing service providers and TSOs;

(g) support competition among market participants;

(h) provide incentives to balancing service providers to offer and deliver balancing services to the connecting TSO;

(i) ensure the financial neutrality of all TSOs.

2. Each relevant regulatory authority in accordance with **Article 59** of Directive (EU) **2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** shall ensure that all TSOs under its competence do not incur economic gains or losses with regard to the financial outcome of the settlement pursuant to Chapters 2, 3 and 4 of this Title, over the regulatory period as defined by the relevant regulatory authority, and shall ensure that any positive or negative financial outcome as a result of the settlement pursuant to Chapters 2, 3 and 4 of this Title shall be passed on to network users in accordance with the applicable national rules.

3. Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity pursuant to Chapter 5 of this Title, administrative costs and other costs related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority.

4. Each injection or withdrawal into or from a scheduling area of a TSO shall either be settled in accordance with Chapter 3 or Chapter 4 of Title V.

CHAPTER 2
Settlement of balancing energy

Article 45
Balancing energy calculation

1. As regards the settlement of balancing energy for at least the frequency restoration process and the reserve replacement process, each TSO shall establish a procedure for:

(a) the calculation of the activated volume of balancing energy based on requested or metered activation;

(b) claiming the recalculation of the activated volume of balancing energy.

2. Each TSO shall calculate the activated volume of balancing energy according to the procedures pursuant to paragraph 1(a) at least for:

(a) each imbalance settlement period;

(b) its imbalance areas;

(c) each direction, with a negative sign indicating relative withdrawal by the balancing service provider, and a positive sign indicating relative injection by the balancing service provider.

3. Each connecting TSO shall settle all activated volumes of balancing energy calculated pursuant to paragraph 2, with the concerned balancing service providers.

Article 46

Balancing energy for frequency containment process

1. Each connecting TSO may calculate and settle the activated volume of balancing energy for the frequency containment process with balancing service providers pursuant to paragraphs 1 and 2 of Article 45.

2. The price, be it positive, zero or negative, of the activated volume of balancing energy for the frequency containment process shall be defined for each direction as defined in Table 1:

Table 1: Payment for balancing energy

	Balancing energy price positive	**Balancing energy price negative**
Positive balancing energy	Payment from TSO to BSP	Payment from BSP to TSO
Negative balancing energy	Payment from BSP to TSO	Payment from TSO to BSP

Article 47

Balancing energy for frequency restoration process

1. Each connecting TSO shall calculate and settle the activated volume of balancing energy for the frequency restoration process with balancing service providers pursuant to paragraphs 1 and 2 of Article 45

2. The price, be it positive, zero or negative, of the activated volume of balancing energy for the frequency restoration process shall be defined for each direction pursuant to Article 30 as defined in the Table 1.

Article 48

Balancing energy for reserve replacement process

1. Each connecting TSO shall calculate and settle the activated volume of balancing energy for the reserve replacement process with balancing service providers pursuant to paragraphs 1 and 2 of Article 45.

2. The price, be it positive, zero or negative, of the activated volume of balancing energy for reserve replacement process shall be defined for each direction pursuant to Article 30 as defined in the Table 1.

Article 49

Imbalance adjustment to the balance responsible party

1. Each TSO shall calculate an imbalance adjustment to be applied to the concerned balance responsible parties for each activated balancing energy bid.

2. For imbalance areas where several final positions for a single balance responsible party are calculated pursuant to Article 54(3), an imbalance adjustment may be calculated for each position.

3. For each imbalance adjustment, each TSO shall determine the activated volume of balancing energy calculated pursuant to Article 45 and any volume activated for purposes other than balancing.

CHAPTER 3
Settlement of the exchanges of energy between TSOs

Article 50
Intended exchanges of energy

1. By one year after the entry into force of this Regulation, all TSOs shall **apply** common settlement rules applicable to all intended exchanges of energy **<…>** pursuant to Articles 146, 147 and 148 of Regulation (EU) 2017/1485. **<…>**

2. Each TSO-TSO settlement function shall perform the settlement in accordance with the settlement rules pursuant to **Article 5(2)(i)**.

3. By **one year** after the entry into force of this Regulation, all TSOs intentionally exchanging energy within **the Continental Europe** synchronous area shall **apply the** common **TSO-TSO** settlement rules **for the** intended exchanges of energy **in line with Article 5(2)(l).**

4. **<…>**

5. **<…>**

6. **<…>**

7. **<…>**

8. All TSOs shall establish a coordinated mechanism for adjustments to settlements between all TSOs.

Article 51
Unintended exchanges of energy

1. By **one year** after the entry into force of this Regulation, all TSOs of **the Continental Europe** synchronous area shall **apply** a **<…>** common settlement rules applicable to all unintended exchanges of energy **in line with Article 5(2)(m)**. **<…>**

2. **<…>**

3. **<…>**

4. **<…>**

CHAPTER 4
Imbalance settlement

Article 52
Imbalance settlement

1. Each TSO or, where relevant, third party shall settle within its scheduling area or scheduling areas when appropriate with each balance responsible party for each imbalance settlement period pursuant to Article 53 all calculated imbalances pursuant to Article 49 and Article 54 against the appropriate imbalance price calculated pursuant to Article 55.

2. By one year after entry into force of this Regulation, all TSOs shall **apply the harmonised provisions on of the main features of imbalance settlement pursuant to Article 52(2) of Regulation (EU) 2017/2195 in line with art. 5(2)(j) of this regulation.**

3. **<…>**

4. **<…>**

Article 53
Imbalance settlement period

1. By **one** year after the entry into force of this Regulation, all TSOs shall apply the imbalance settlement period of 15 minutes in all scheduling areas while ensuring that all boundaries of market time unit shall coincide with boundaries of the imbalance settlement period.

2. **<…>**

3. **<…>**

Article 54
Imbalance calculation

1. Each **Contracting Party's** TSO shall calculate within its scheduling area or scheduling areas when appropriate the final position, the allocated volume, the imbalance adjustment and the imbalance:

(a) for each balance responsible party;

(b) for each imbalance settlement period;

(c) in each imbalance area.

2. The imbalance area shall be equal to the scheduling area, except in case of a central dispatching model where imbalance area may constitute a part of scheduling area.

3. Until the implementation of **<…> Article 5(2),** each TSO shall calculate the final position of a balance responsible party using one of the following approaches:

(a) balance responsible party has one single final position equal to the sum of its external commercial trade schedules and internal commercial trade schedules;

(b) balance responsible party has two final positions: the first is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from generation, and the second is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from consumption;

(c) in a central dispatching model, a balance responsible party can have several final positions per imbalance area equal to generation schedules of power generating facilities or consumption schedules of demand facilities.

4. Each TSO shall set up the rules for:

(a) the calculation of the final position;

(b) the determination of the allocated volume;

(c) the determination of the imbalance adjustment pursuant to Article 49;

(d) the calculation of the imbalance;

(e) claiming the recalculation of the imbalance by a balance responsible party.

5. Allocated volume shall not be calculated for a balance responsible party which does not cover injections or withdrawals.

6. An imbalance shall indicate the size and the direction of the settlement transaction between the balance responsible party and the TSO; an imbalance can have alternatively:

(a) a negative sign, indicating a balance responsible party's shortage;

(b) a positive sign, indicating a balance responsible party's surplus.

Article 55

Imbalance price

1. Each **Contracting Party's** TSO shall set up rules to calculate the imbalance price, which can be positive, zero or negative, as defined in Table 2:

Table 2: Payment for imbalance

	Imbalance price positive	**Imbalance price negative**
Positive imbalance	Payment from TSO to BRP	Payment from BRP to TSO
Negative imbalance	Payment from BRP to TSO	Payment from TSO to BRP

2. The rules pursuant to paragraph 1 shall include a definition of the value of avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

3. Each TSO shall determine the imbalance price for:

(a) each imbalance settlement period;

(b) its imbalance price areas;

(c) each imbalance direction.

4. The imbalance price for negative imbalance shall not be less than, alternatively:

(a) the weighted average price for positive activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

5. The imbalance price for positive imbalance shall not be greater than, alternatively:

(a) the weighted average price for negative activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

6. In the event that both positive and negative balancing energy from frequency restoration reserves or replacement reserves have been activated during the same imbalance settlement period, the imbalance settlement price shall be determined for positive imbalance and negative imbalance based on at least one of the principles pursuant to paragraphs 4 and 5.

CHAPTER 5
Settlement of balancing capacity

Article 56
Procurement within a scheduling area

1. Each TSO of a scheduling area using balancing capacity bids shall establish rules for the settlement of at least frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

2. Each TSO of a scheduling area using balancing capacity bids shall settle at least all procured frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

Article 57
Procurement outside a scheduling area

1. All TSOs exchanging balancing capacity shall establish rules for the settlement of procured balancing capacity pursuant to Article 33 and Article 35.

2. All TSOs exchanging balancing capacity shall jointly settle procured balancing capacity using the TSO-TSO settlement function pursuant to Article 33. TSOs exchanging balancing capacity based on a TSO-BSP

model shall settle procured balancing capacity pursuant to Article 35.

3. All TSOs exchanging balancing capacity shall establish rules for the settlement of allocation of cross-zonal capacity pursuant to Chapter 2 of Title IV.

4. All TSOs exchanging balancing capacity shall settle the allocated cross-zonal capacity pursuant to Chapter 2 of Title IV.

TITLE VI
ALGORITHM

Article 58
Balancing algorithms

1. **<…>**

2. **<…>**

3. In the proposal pursuant to Article 33, two or more TSOs exchanging balancing capacity shall develop algorithms to be operated by the capacity procurement optimisation functions for the procurement of balancing capacity bids. Those algorithms shall:

(a) minimise the overall procurement costs of all jointly procured balancing capacity;

(b) if applicable, take into account the availability of cross-zonal capacity including possible costs for its provision.

4. All algorithms developed in accordance with this Article shall:

(a) respect operational security constraints;

(b) take into account technical and network constraints;

(c) if applicable, take into account the available cross-zonal capacity.

TITLE VII
REPORTING

Article 59
European report on integration of balancing markets

1. **When monitoring the implementation of Regulation (EU) 2017/2195 in accordance with its Article 59, the ENTSO for Electricity, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC, shall extend this report to include the Contracting Parties, where feasible.**

2. **<…>**

3. **<…>**

4. **<…>**

5. Before the submission of the final report, ENTSO **for Electricity, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC,** shall **deliver the** proposal for a draft report **developed pursuant to paragraph 1 <…>** to the **Energy Community Regulatory Board** which shall be entitled to require amendments within two months after the submission of the proposal.

6. The report pursuant to paragraph **1** shall also contain an executive summary in English of each TSO report on balancing pursuant to Article 60.

7. The reports shall provide disaggregated information and indicators for each scheduling area, each bidding zone border, or each LFC block.

8. ENTSO-E shall publish the reports on internet and submit it to the **Energy Community Regulatory Board** no later than six months after the end of the year it refers to.

9. **<…>**

Article 60

TSO report on balancing

1. At least once every two years, each TSO shall publish a report on balancing covering the previous two calendar years, respecting the confidentiality of information in accordance with Article 11.

2. The report on balancing shall:

(a) include information concerning the volumes of available, procured and used specific products, as well as justification of specific products subject to conditions pursuant to Article 26;

(b) provide the summary analysis of the dimensioning of reserve capacity including the justification and explanation for the calculated reserve capacity requirements;

(c) provide the summary analysis of the optimal provision of reserve capacity including the justification of the volume of balancing capacity;

(d) analyse the costs and benefits, and the possible inefficiencies and distortions of having specific products in terms of competition and market fragmentation, participation of demand response and renewable energy sources, integration of balancing markets and side-effects on other electricity markets;

(e) analyse the opportunities for the exchange of balancing capacity and sharing of reserves;

(f) provide an explanation and a justification for the procurement of balancing capacity without the exchange of balancing capacity or sharing of reserves;

(g) analyse the efficiency of the activation optimisation functions for the balancing energy from frequency restoration reserves and, if applicable, for the balancing energy from replacement reserves.

3. The report on balancing shall either be in English or at least contain an executive summary in English.

4. Based on previously published reports, the relevant regulatory authority in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** shall be entitled to require changes to the structure and content of the next TSO report on balancing.

TITLE VIII
COST-BENEFIT ANALYSIS

Article 61

Cost-benefit analysis

1. When TSOs are required to carry out a cost-benefit analysis pursuant to this Regulation, they shall establish the criteria and methodology for the cost-benefit analysis and submit them to the relevant regulatory authorities in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** by six months before the start of the cost-benefit analysis. The relevant regulatory authorities shall be entitled to jointly require amendments to the criteria and methodology.

2. The cost-benefit analysis shall at least take into account:

(a) the technical feasibility;

(b) the economic efficiency;

(c) the impact on competition and integration of balancing markets;

(d) the costs and benefits of implementation;

(e) the impact on European and national balancing costs;

(f) the potential impact on European electricity market prices;

(g) the ability of TSOs and balancing responsible parties to fulfil their obligations;

(h) the impact on market parties in terms of additional technical or IT requirements assessed in cooperation with the affected stakeholders.

3. All concerned TSOs shall provide the results of the cost-benefit analysis to all relevant regulatory authorities, together with a justified proposal on how to address possible issues identified by the cost-benefit analysis.

TITLE IX
DEROGATIONS AND MONITORING

Article 62

Derogations

1. A regulatory authority in accordance with **Article 59** of Directive (EU) **2019/944 as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC** may, at the request of a TSO or at its own initiative, grant the relevant TSOs a derogation from one or more provisions of this Regulation in accordance with paragraphs 2 to 12.

2. A TSO may request a derogation from the following requirements:

(a) the deadlines by which a TSO shall use the European platforms pursuant to Articles 19(5), 20(6), 21(6) and 22(5);

(b) the definition of the integrated scheduling process gate closure time in a central dispatching model pursuant to Article 24(5) and the possibility to change the integrated scheduling process bids pursuant to Article 24(6);

(c) the maximum volume of cross-zonal capacity allocated on a market-based process pursuant to Article 41(2) or a process based an economic efficiency analysis pursuant to Article 42(2) **of Regulation (EU) 2017/2195**;

(d) the harmonisation of the imbalance settlement period in Article 53(1);

(e) the implementation of the requirements pursuant to Articles 45, 46, 47, 48, 49, 50, 51, 54, 55, 56 and 57.

3. The derogation process shall be transparent, non-discriminatory, non-biased, well documented and based on a reasoned request.

4. TSOs shall file a written request for derogation to the relevant regulatory authority at the latest six months prior to the day of application of the provisions from which the derogation is requested.

5. The request for derogation shall include the following information:

(a) the provisions from which a derogation is requested;

(b) the requested derogation period;

(c) a detailed plan and timeline specifying how to address and ensure the implementation of the concerned provisions of this Regulation after expiration of the derogation period;

(d) an assessment of the consequences of requested derogation on adjacent markets;

(e) an assessment of the possible risks for the integration of balancing markets across Europe caused by the requested derogation.

6. The relevant regulatory authority shall adopt a decision concerning any request for derogation within six months from the day after it receives the request. That time limit may be extended by three months before its expiry where the relevant regulatory authority requires further information from the TSO requesting the derogation. The additional period shall begin when the complete information has been received.

7. The TSO requesting the derogation shall submit any additional information requested by the relevant regulatory authority within two months of such request. If the TSO does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn unless, before its expiry, alternatively:

(a) the relevant regulatory authority decides to provide an extension;

(b) the TSO informs the relevant regulatory authority by means of a reasoned submission that the request for a derogation is complete.

8. When assessing the request for derogation or before granting a derogation at its own initiative, the relevant regulatory authority shall consider the following aspects:

(a) the difficulties related to the implementation of the concerned provision or provisions;

(b) the risks and the implications of the concerned provision or provisions, in terms of operational security;

(c) the actions taken to facilitate the implementation of the concerned provision or provisions;

(d) the impacts of non-implementation of the concerned provision or provisions, in terms of non-discrimination and competition with other European market participants, in particular as regards demand response and renewable energy sources;

(e) the impacts on overall economic efficiency and smart grid infrastructure;

(f) the impacts on other scheduling areas and overall consequences on the European market integration process.

9. The relevant regulatory authority shall issue a reasoned decision concerning a request for a derogation or a derogation granted at its own initiative. Where the relevant regulatory authority grants a derogation, it shall specify its duration. The derogation may be granted only once and for a maximum period of two years, except for the derogations in paragraphs 2(c) and 2(d) which may be granted until 1 January **2030**.

10. The relevant regulatory authority shall notify its decision to the TSO, **the Energy Community Regulatory Board** and the **Energy Community Secretariat**. The decision shall also be published on its website.

11. The relevant regulatory authorities shall maintain a register of all derogations they have granted or refused and shall provide **the Energy Community Regulatory Board** with an updated and consolidated register at least once every six months, a copy of which shall be given to ENTSO- E.

12. The register shall contain, in particular:

(a) the provisions from which the derogation is granted or refused;

(b) the content of the derogation;

(c) the reasons for granting or refusing the derogation;

(d) the consequences resulting from granting the derogation.

Article 63

Monitoring

1. **The Secretariat** shall monitor the implementation of this Regulation **by the Contracting Parties.**

2. **<…>**

3. **<…>**

4. **<…>** TSOs **of the Contracting Parties** shall submit to **the Secretariat** the information required to perform the tasks in accordance with paragraph 1 **<…>**.

5. Market participants and other relevant organisations for the integration of electricity balancing markets **by the Contracting Parties** shall **<…>** submit to **the Secretariat** the information required for monitoring in accordance with paragraphs 1 **<…>**, except for information already obtained by the relevant regulatory authorities in accordance with **Article 59** of Directive (EU) **2019/994, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC, the Energy Community Regulatory Board, the Agency for the Cooperation of Energy Regulators.**

TITLE X
TRANSITIONAL AND FINAL PROVISIONS

Article 64

Transitional provisions for Ireland and Northern Ireland

<…>

Article 65

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[3]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with Regulation (EU) 2019/942 <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

3 The text displayed here corresponds to Article 13 of Decision 2022/03/MC-EnC.

COMMISSION REGULATION (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in ***bold and blue****.*

PART I
GENERAL PROVISIONS

Article 1
Subject matter

For the purpose of safeguarding operational security, frequency quality and the efficient use of the interconnected system and resources, this Regulation lays down detailed guidelines on:

(a) requirements and principles concerning operational security;

(b) rules and responsibilities for the coordination and data exchange between TSOs, between TSOs and DSOs, and between TSOs or DSOs and SGUs, in operational planning and in close to real- time operation;

(c) rules for training and certification of system operator employees;

(d) requirements on outage coordination;

(e) requirements for scheduling between the TSOs' control areas; and

(f) rules aiming at the establishment of Energy Community framework for load- frequency control and reserves.

Article 2
Scope

1. The rules and requirements set out in this Regulation shall apply to the following SGUs:

(a) existing and new power generating modules that are, or would be, classified as type B, C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**;

(b) existing and new transmission-connected demand facilities;

(c) existing and new transmission-connected closed distribution systems;

(d) existing and new demand facilities, closed distribution systems and third parties if they provide demand response directly to the TSO in accordance with the criteria in Article 27 of Commission Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**;

(e) providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Part IV of this Regulation; and

(f) existing and new high voltage direct current ('HVDC') systems in accordance with the criteria in Article 3(1) of Commission Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**.

2. This Regulation shall apply to all transmission systems, distribution systems and interconnections in the **Contracting Parties and with the Member States,** and **to** regional-**coordination centres**, except transmission systems and distribution systems or parts of the transmission systems and distribution systems of **Contracting Parties** of which the systems are not operated synchronously with Continental Europe ('CE') **<…>.**

3. Where more than one TSO exists in a **Contracting Party**, this Regulation shall apply to all TSOs in a **Contracting Party**. Where a TSO does not have a function relevant to one or more obligations under this Regulation, **Contracting Parties** may, under the national regulatory regime, provide that the responsibility of a TSO to comply with one or some or all obligations under this Regulation is assigned to one or more specific TSOs.

4. **<…>**

5. Where the requirements under this Regulation are to be established by a relevant system operator that is not a TSO, **Contracting Parties** may provide that instead the TSO be responsible for establishing the relevant requirements.

Article 3

Definitions

1. For the purposes of this Regulation, the definitions in Article 2 of Regulation (EU) No **2019/943**, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** Article 2 of Commission Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** Article 2 of Commission Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** Article 2 of Commission Regulation (EU) 2016/1719**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets**, as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC,** and Article 2 of Directive (EU) 2019/944 of the European Parliament and of the Council**, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** shall apply.

2. In addition, the following definitions shall apply:

(1) 'operational security' means the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterised by operational security limits;

(2) 'constraint' means a situation in which there is a need to prepare and activate a remedial action in order to respect operational security limits;

(3) 'N-situation' means the situation where no transmission system element is unavailable due to occurrence of a contingency;

(4) 'contingency list' means the list of contingencies to be simulated in order to test the compliance with theoperational security limits;

(5) 'normal state' means a situation in which the system is within operational security limits in the N-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions;

(6) 'frequency containment reserves' or 'FCR' means the active power reserves available to contain system frequency after the occurrence of an imbalance;

(7) 'frequency restoration reserves' or 'FRR' means the active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one LFC area, to restore power balance to the scheduled value;

(8) 'replacement reserves' or 'RR' means the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves;

(9) 'reserve provider' means a legal entity with a legal or contractual obligation to supply FCR, FRR or RR from at least one reserve providing unit or reserve providing group;

(10) 'reserve providing unit' means a single or an aggregation of power generating modules and/or demand units connected to a common connection point fulfilling the requirements to provide FCR, FRR or RR;

(11) 'reserve providing group' means an aggregation of power generating modules, demand units and/or reserve providing units connected to more than one connection point fulfilling the requirements to provide FCR, FRR or RR;

(12) 'load-frequency control area' or 'LFC area' means a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control;

(13) 'time to restore frequency' means the maximum expected time after the occurrence of an instantaneous power imbalance smaller than or equal to the reference incident in which the system frequency returns to the frequency restoration range for synchronous areas with only one LFC area and in the case of synchronous areas with more than one LFC area, the maximum expected time after the occurrence of an instantaneous power imbalance of an LFC area within which the imbalance is compensated;

(14) '(N-1) criterion' means the rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits;

(15) '(N-1) situation' means the situation in the transmission system in which one contingency from the contingency list occurred;

(16) 'active power reserve' means the balancing reserves available for maintaining the frequency;

(17) 'alert state' means the system state in which the system is within operational security limits, but a

contingency from the contingency list has been detected and in case of its occurrence the available remedial actions are not sufficient to keep the normal state;

(18) 'load-frequency control block' or 'LFC block' means a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC blocks, consisting of one or more LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control;

(19) 'area control error' or 'ACE' means the sum of the power control error ('ΔP'), that is the real- time difference between the measured actual real time power interchange value ('P') and the control program ('P0') of a specific LFC area or LFC block and the frequency control error ('K*Δf'), that is the product of the K-factor and the frequency deviation of that specific LFC area or LFC block, where the area control error equals ΔP+K*Δf;

(20) 'control program' means a sequence of set-point values for the netted power interchange of a LFC area or LFC block over alternating current ('AC') interconnectors;

(21) 'voltage control' means the manual or automatic control actions at the generation node, at the end nodes of the AC lines or HVDC systems, on transformers, or other means, designed to maintain the set voltage level or the set value of reactive power;

(22) 'blackout state' means the system state in which the operation of part or all of the transmission system is terminated;

(23) 'internal contingency' means a contingency within the TSO's control area, including interconnectors;

(24) 'external contingency' means a contingency outside the TSO's control area and excluding interconnectors, with an influence factor higher than the contingency influence threshold;

(25) 'influence factor' means the numerical value used to quantify the greatest effect of the outage of a transmission system element located outside of the TSO's control area excluding interconnectors, in terms of a change in power flows or voltage caused by that outage, on any transmission system element. The higher is the value the greater the effect;

(26) 'contingency influence threshold' means a numerical limit value against which the influence factors are checked and the occurrence of a contingency located outside of the TSO's control area with an influence factor higher than the contingency influence threshold is considered to have a significant impact on the TSO's control area including interconnectors;

(27) 'contingency analysis' means a computer based simulation of contingencies from the contingency list;

(28) 'critical fault clearing time' means the maximum fault duration for which the transmission system retains stability of operation;

(29) 'fault' means all types of short-circuits (single-, double- and triple-phase, with and without earth contact), a broken conductor, interrupted circuit, or an intermittent connection, resulting in the permanent non-availability of the affected transmission system element;

(30) 'transmission system element' means any component of the transmission system;

(31) 'disturbance' means an unplanned event that may cause the transmission system to divert from the normal state;

(32) 'dynamic stability' is a common term including the rotor angle stability, frequency stability and voltage stability;

(33) 'dynamic stability assessment' means the operational security assessment in terms of dynamic stability;

(34) 'frequency stability' means the ability of the transmission system to maintain frequency stable in the N-situation and after being subjected to a disturbance;

(35) 'voltage stability' means the ability of a transmission system to maintain acceptable voltages at all nodes in the transmission system in the N-situation and after being subjected to a disturbance;

(36) 'system state' means the operational state of the transmission system in relation to the operational security limits which can be normal state, alert state, emergency state, blackout state and restoration state;

(37) 'emergency state' means the system state in which one or more operational security limits are violated;

(38) 'restoration state' means the system state in which the objective of all activities in the transmission system is to re-establish the system operation and maintain operational security after the blackout state or the emergency state;

(39) 'exceptional contingency' means the simultaneous occurrence of multiple contingencies with a common cause;

(40) 'frequency deviation' means the difference between the actual and the nominal frequency of the synchronous area which can be negative or positive;

(41) 'system frequency' means the electric frequency of the system that can be measured in all parts of the synchronous area under the assumption of a coherent value for the system in the timeframe of seconds, with only minor differences between different measurement locations;

(42) 'frequency restoration process' or 'FRP' means a process that aims at restoring frequency to the nominal frequency and, for synchronous areas consisting of more than one LFC area, a process that aims at restoring the power balance to the scheduled value;

(43) 'frequency restoration control error' or 'FRCE' means the control error for the FRP which is equal to the ACE of a LFC area or equal to the frequency deviation where the LFC area geographically corresponds to the synchronous area;

(44) 'schedule' means a reference set of values representing the generation, consumption or exchange of electricity for a given time period;

(45) 'K-factor of an LFC area or LFC block' means a value expressed in megawatts per hertz ('MW/Hz'), which is as close as practical to, or greater than the sum of the auto-control of generation, self-regulation of load and of the contribution of frequency containment reserve relative to the maximum steady-state frequency deviation;

(46) 'local state' means the qualification of an alert, emergency or blackout state when there is no risk of extension of the consequences outside of the control area including interconnectors connected to this control area;

(47) 'maximum steady-state frequency deviation' means the maximum expected frequency deviation after the occurrence of an imbalance equal to or less than the reference incident at which the system frequency is designed to be stabilised;

(48) 'observability area' means a TSO's own transmission system and the relevant parts of distribution systems and neighbouring TSOs' transmission systems, on which the TSO implements real-time monitoring and modelling to maintain operational security in its control

area including interconnectors;

(49) 'neighbouring TSOs' means the TSOs directly connected via at least one AC or DC interconnector;

(50) 'operational security analysis' means the entire scope of the computer based, manual and automatic activities performed in order to assess the operational security of the transmission system and to evaluate the remedial actions needed to maintain operational security;

(51) 'operational security indicators' means indicators used by TSOs to monitor the operational security in terms of system states as well as faults and disturbances influencing operational security;

(52) 'operational security ranking' means the ranking used by TSOs to monitor the operational security on the basis of the operational security indicators;

(53) 'operational tests' means the tests carried out by a TSO or DSO for maintenance, development of system operation practices and training and to acquire information on transmission system behaviour under abnormal system conditions and the tests carried out by significant grid users for similar purposes on their facilities;

(54) 'ordinary contingency' means the occurrence of a contingency of a single branch or injection;

(55) 'out-of-range contingency' means the simultaneous occurrence of multiple contingencies without a common cause, or a loss of power generating modules with a total loss of generation capacity exceeding the reference incident;

(56) 'ramping rate' means the rate of change of active power by a power generating module, demand facility or HVDC system;

(57) 'reactive power reserve' means the reactive power which is available for maintaining voltage;

(58) 'reference incident' means the maximum positive or negative power deviation occurring instantaneously between generation and demand in a synchronous area, considered in the FCR dimensioning;

(59) 'rotor angle stability' means the ability of synchronous machines to remain in synchronism under N-situation and after being subject to a disturbance;

(60) 'security plan' means the plan containing a risk assessment of critical TSO's assets to major physical- and cyber-threat scenarios with an assessment of the potential impacts;

(61) 'stability limits' means the permitted boundaries for the operation of the transmission system in terms of respecting the limits of voltage stability, rotor angle stability and frequency stability;

(62) 'wide area state' means the qualification of an alert state, emergency state or blackout state when there is a risk of propagation to the interconnected transmission systems;

(63) 'system defence plan' means the technical and organisational measures to be undertaken to prevent the propagation or deterioration of a disturbance in the transmission system, in order to avoid a wide area state disturbance and blackout state;

(64) 'topology' means the data concerning the connectivity of the different transmission system or distribution system elements in a substation and includes the electrical configuration and the position of circuit breakers and isolators;

(65) 'transitory admissible overloads' means the temporary overloads of transmission system

elements which are allowed for a limited period and which do not cause physical damage to the transmission system elements as long as the defined duration and thresholds are respected;

(66) 'virtual tie-line' means an additional input of the controllers of the involved LFC areas that has the

same effect as a measuring value of a physical interconnector and allows exchange of electric energy between the respective areas;

(67) 'flexible alternating current transmission systems' or 'FACTS' means equipment for the alternating current transmission of electric power, aiming at enhanced controllability and increased active power transfer capability;

(68) 'adequacy' means the ability of in-feeds into an area to meet the load in that area;

(69) 'aggregated netted external schedule' means a schedule representing the netted aggregation of all external TSO schedules and external commercial trade schedules between two scheduling areas or between a scheduling area and a group of other scheduling areas;

(70) 'availability plan' means the combination of all planned availability statuses of a relevant asset for a given time period;

(71) 'availability status' means the capability of a power generating module, grid element or demand facility to provide a service for a given time period, regardless of whether or not it is in operation;

(72) 'close to real-time' means the time lapse of not more than 15 minutes between the last intraday gate closure and real-time;

(73) 'consumption schedule' means a schedule representing the consumption of a demand facility or of a group of demand facilities;

(74) 'ENTSO for Electricity operational planning data environment' means the set of application programs and equipment developed in order to allow the storage, exchange and management of the data used for operational planning processes between TSOs;

(75) 'external commercial trade schedule' means a schedule representing the commercial exchange of electricity between market participants in different scheduling areas;

(76) 'external TSO schedule' means a schedule representing the exchange of electricity between TSOs in different scheduling areas;

(77) 'forced outage' means the unplanned removal from service of a relevant asset for any urgent reason that is not under the operational control of the operator of the concerned relevant asset;

(78) 'generation schedule' means a schedule representing the electricity generation of a power generating module or of a group of power generating modules;

(79) 'internal commercial trade schedule' means a schedule representing the commercial exchange of electricity within a scheduling area between different market participants;

(80) 'internal relevant asset' means a relevant asset which is part of a TSO's control area or a relevant asset located in a distribution system, including a closed distribution system, which is connected directly or indirectly to that TSO's control area;

(81) 'netted area AC position' means the netted aggregation of all AC external schedules of an area;

(82) 'outage coordination region' means a combination of control areas for which TSOs define procedures to monitor and where necessary coordinate the availability status of relevant assets in all time-frames;

(83) 'relevant demand facility' means a demand facility which participates in the outage coordination and the availability status of which influences cross-border operational security;

(84) 'relevant asset' means any relevant demand facility, relevant power generating module, or relevant

grid element partaking in the outage coordination;

(85) 'relevant grid element' means any component of a transmission system, including interconnectors, or of a distribution system, including a closed distribution system, such as a single line, a single circuit, a single transformer, a single phase-shifting transformer, or a voltage compensation installation, which participates in the outage coordination and the availability status of which influences cross-border operational security;

(86) 'outage planning incompatibility' means the state in which a combination of the availability status of one or more relevant grid elements, relevant power generating modules, and/or relevant demand facilities and the best estimate of the forecasted electricity grid situation leads to violation of operational security limits taking into account remedial actions without costs which are at the TSO's disposal;

(87) 'outage planning agent' means an entity with the task of planning the availability status of a relevant power generating module, a relevant demand facility or a relevant grid element;

(88) 'relevant power generating module' means a power generating module which participates in the outage coordination and the availability status of which influences cross-border operational security;

(89) 'regional coordination centre' ('RCC') means regional coordination centre established pursuant to Article 35 of the Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC;

(90) 'scheduling agent' means the entity or entities with the task of providing schedules from market participants to TSOs, or where applicable third parties;

(91) 'scheduling area' means an area within which the TSOs' obligations regarding scheduling apply due to operational or organisational needs;

(92) 'week-ahead' means the week prior to the calendar week of operation;

(93) 'year-ahead' means the year prior to the calendar year of operation;

(94) 'affected TSO' means a TSO for which information on the exchange of reserves and/or sharing of reserves and/or imbalance netting process and/or cross-border activation process is needed for the analysis and maintenance of operational security;

(95) 'reserve capacity' means the amount of FCR, FRR or RR that needs to be available to the TSO;

(96) 'exchange of reserves' means the possibility of a TSO to access reserve capacity connected to another LFC area, LFC block, or synchronous area to fulfil its reserve requirements resulting from its own reserve dimensioning process of either FCR, FRR or RR and where that reserve capacity is exclusively for that TSO, and is not taken into account by any other TSO to fulfil its reserve requirements resulting from their respective reserve dimensioning processes;

(97) 'sharing of reserves' means a mechanism in which more than one TSO takes the same reserve capacity, being FCR, FRR or RR, into account to fulfil their respective reserve requirements resulting from their reserve dimensioning processes;

(98) 'alert state trigger time' means the time before alert state becomes active;

(99) 'automatic FRR' means FRR that can be activated by an automatic control device;

(100) 'automatic FRR activation delay' means the period of time between the setting of a new setpoint value by the frequency restoration controller and the start of physical automatic FRR delivery;

(101) 'automatic FRR full activation time' means the time period between the setting of a new setpoint value by the frequency restoration controller and the corresponding activation or deactivation of automatic FRR;

(102) 'average FRCE data' means the set of data consisting of the average value of the recorded instantaneous FRCE of a LFC area or a LFC block within a given measured period time;

(103) 'control capability providing TSO' means the TSO that shall trigger the activation of its reserve capacity for a control capability receiving TSO under the conditions of an agreement for sharing reserves;

(104) 'control capability receiving TSO' means the TSO calculating reserve capacity by taking into account reserve capacity which is accessible through a control capability providing TSO under the conditions of an agreement for sharing reserves;

(105) 'criteria application process' means the process of calculating the target parameters for the synchronous area, the LFC block and the LFC area based on the data obtained in the data collection and delivery process;

(106) 'data collection and delivery process' means the process of collection of the set of data necessary in order to perform the frequency quality evaluation criteria;

(107) 'cross-border FRR activation process' means a process agreed between the TSOs participating in the process that allows for activation of FRR connected in a different LFC area by correcting the input of the involved FRPs accordingly;

(108) 'cross-border RR activation process' means a process agreed between the TSOs participating in the process that allows for activation of RR connected in a different LFC area by correcting the input of the involved RRP accordingly;

(109) 'dimensioning incident' means the highest expected instantaneously occurring active power imbalance within a LFC block in both positive and negative direction;

(110) 'electrical time deviation' means the time discrepancy between synchronous time and coordinated universal time ('UTC');

(111) 'FCR full activation frequency deviation' means the rated value of frequency deviation at which the FCR in a synchronous area is fully activated;

(112) 'FCR full activation time' means the time period between the occurrence of the reference incident and the corresponding full activation of the FCR;

(113) 'FCR obligation' means the part of all of the FCR that falls under the responsibility of a TSO;

(114) 'frequency containment process' or 'FCP' means a process that aims at stabilising the system frequency by compensating imbalances by means of appropriate reserves;

(115) 'frequency coupling process' means a process agreed between all TSOs of two synchronous areas that allows linking the activation of FCR by an adaptation of HVDC flows between the synchronous areas;

(116) 'frequency quality defining parameter' means the main system frequency variables that define the principles of frequency quality;

(117) 'frequency quality target parameter' means the main system frequency target on which the behaviour of FCR, FRR and RR activation processes is evaluated in normal state;

(118) 'frequency quality evaluation criteria' means a set of calculations using system frequency measurements that allows the evaluation of the quality of the system frequency against the frequency quality target parameters;

(119) 'frequency quality evaluation data' means the set of data that allows the calculation of the frequency quality evaluation criteria;

(120) **<...>**

(121) **<...>**

(122) **<...>**

(123) 'FRCE target parameters' means the main target LFC block variables on the basis of which the dimensioning criteria for FRR and RR of the LFC block are determined and evaluated and which are used to reflect the LFC block behaviour in normal operation;

(124) 'frequency restoration power interchange' means the power which is interchanged between LFC areas within the cross-border FRR activation process;

(125) 'frequency setpoint' means the frequency target value used in the FRP, defined as the sum of the nominal system frequency and an offset value needed to reduce an electrical time deviation;

(126) ''FRR availability requirements' means a set of requirements defined by the TSOs of a LFC block regarding the availability of FRR;

(127) ''FRR dimensioning rules' means the specifications of the FRR dimensioning process of a LFC block;

(128) 'imbalance netting process' means a process agreed between TSOs that allows avoiding the simultaneous activation of FRR in opposite directions, taking into account the respective FRCEs as well as the activated FRR and by correcting the input of the involved FRPs accordingly;

(130) 'initial FCR obligation' means the amount of FCR allocated to a TSO on the basis of a sharing key;

(131) 'instantaneous frequency data' means a set of data measurements of the overall system frequency for the synchronous area with a measurement period equal to or shorter than one second used for system frequency quality evaluation purposes;

(132) 'instantaneous frequency deviation' means a set of data measurements of the overall system frequency deviations for the synchronous area with a measurement period equal to or shorter than one second used for system frequency quality evaluation purposes;

(133) 'instantaneous FRCE data' means a set of data of the FRCE of a LFC block with a measurement period equal to or shorter than 10 seconds used for system frequency quality evaluation purposes;

(134) 'level 1 FRCE range' means the first range used for system frequency quality evaluation purposes on LFC block level within which the FRCE should be kept for a specified percentage of the time;

(135) 'level 2 FRCE range' means the second range used for system frequency quality evaluation purposes on LFC block level within which the FRCE should be kept for a specified percentage of the time;

(136) 'LFC block operational agreement' means a multi-party agreement between all TSOs of a LFC block if the LFC block is operated by more than one TSO and means a LFC block operational methodology to be adopted unilaterally by the relevant TSO if the LFC block is operated by only one TSO;

(137) 'replacement power interchange' means the power which is interchanged between LFC areas within the cross-border RR activation process;

(138) 'LFC block imbalances' means the sum of the FRCE, FRR activation and RR activation within the LFC block and the imbalance netting power interchange, the frequency restoration power interchange and the replacement power interchange of this LFC block with other LFC blocks;

(139) 'LFC block monitor' means a TSO responsible for collecting the frequency quality evaluation criteria data and applying the frequency quality evaluation criteria for the LFC block;

(140) 'load-frequency control structure' means the basic structure considering all relevant aspects of load-frequency control in particular concerning respective responsibilities and obligations as well as types and purposes of active power reserves;

(141) 'process responsibility structure' means the structure to determine responsibilities and obligations with respect to active power reserves based on the control structure of the synchronous area;

(142) 'process activation structure' means the structure to categorise the processes concerning the different types of active power reserves in terms of purpose and activation;

(143) 'manual FRR full activation time' means the time period between the setpoint change and the corresponding activation or deactivation of manual FRR;

(144) 'maximum instantaneous frequency deviation' means the maximum expected absolute value of an instantaneous frequency deviation after the occurrence of an imbalance equal to or smaller than the reference incident, beyond which emergency measures are activated;

(145) 'monitoring area' means a part of the synchronous area or the entire synchronous area, physically demarcated by points of measurement at interconnectors to other monitoring areas, operated by one or more TSOs fulfilling the obligations of a monitoring area;

(146) 'prequalification' means the process to verify the compliance of a reserve providing unit or a reserve providing group with the requirements set by the TSO;

(147) 'ramping period' means a period of time defined by a fixed starting point and a length of time during which the input and/or output of active power will be increased or decreased;

(148) 'reserve instructing TSO' means the TSO responsible for the instruction of the reserve providing unit or the reserve providing group to activate FRR and/or RR;

(149) 'reserve connecting DSO' means the DSO responsible for the distribution network to which a reserve providing unit or reserve providing group, providing reserves to a TSO, is connected;

(150) 'reserve connecting TSO' means the TSO responsible for the monitoring area to which a reserve providing unit or reserve providing group is connected;

(151) 'reserve receiving TSO' means the TSO involved in an exchange with a reserve connecting TSO and/or a reserve providing unit or a reserve providing group connected to another monitoring or LFC area;

(152) 'reserve replacement process' or 'RRP' means a process to restore the activated FRR **<…>**;

(153) 'RR availability requirements' means a set of requirements defined by the TSOs of a LFC block regarding the availability of RR;

(154) 'RR dimensioning rules' means the specifications of the RR dimensioning process of a LFC block;

(155) 'standard frequency range' means a defined symmetrical interval around the nominal frequency within which the system frequency of a synchronous area is supposed to be operated;

(156) 'standard frequency deviation' means the absolute value of the frequency deviation that limits the standard frequency range;

(157) 'steady state frequency deviation' means the absolute value of frequency deviation after occurrence of an imbalance, once the system frequency has been stabilised;

(158) 'synchronous area monitor' means a TSO responsible for collecting the frequency quality evaluation criteria data and applying the frequency quality evaluation criteria for the synchronous area;

(159) 'time control process' means a process for time control, where time control is a control action carried out to return the electrical time deviation between synchronous time and UTC time to zero.

(160) 'Member State' means a territory of the European Union referred to in Article 27 of the Treaty.

Article 4

Objectives and regulatory aspects

1. This Regulation aims at:

(a) determining common operational security requirements and principles;

(b) determining common interconnected system operational planning principles;

(c) determining common load-frequency control processes and control structures;

(d) ensuring the conditions for maintaining operational security throughout the **Energy Community**;

(e) ensuring the conditions for maintaining a frequency quality level of all synchronous areas throughout the **Energy Community**;

(f) promoting the coordination of system operation and operational planning;

(g) ensuring and enhancing the transparency and reliability of information on transmission system operation;

(h) contributing to the efficient operation and development of the electricity transmission system and electricity sector in the **Energy Community**.

2. When applying this Regulation, **Contracting Parties**, competent authorities, and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) ensure TSOs make use of market-based mechanisms as far as possible, to ensure network security and stability;

(e) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;

(f) consult with relevant DSOs and take account of potential impacts on their system; and

(g) take into consideration agreed European standards and technical specifications.

Article 5

Terms and conditions or methodologies of TSOs

1. **Where this Regulation requires** TSOs **to** develop the terms and conditions or methodologies **they shall** submit them for approval to the **Energy Community Regulatory Board and, to the extent Member States are affected, the** Agency **for the Cooperation of Energy Regulators,** competent regulatory authorities in accordance with Article 6(3), or to the entity designated by the **Contracting**

Party in accordance with Article 6(4) and (5) within the respective deadlines set out in this Regulation. In exceptional circumstances, notably in cases where a deadline cannot be met due to circumstances external to the sphere of TSOs, the deadlines for terms and conditions or methodologies may be prolonged by the **Energy Community Regulatory Board** in procedures pursuant to Article 6(2), jointly by all competent regulatory authorities in procedures pursuant to Article 6(3), and by the competent regulatory authority in procedures pursuant to Article 6(4) and (5).

2. Where a proposal for terms and conditions or methodologies pursuant to this Regulation needs to be developed and agreed by more than one TSO, the participating TSOs shall closely cooperate. TSOs, with the assistance of ENTSO for Electricity, shall regularly inform the regulatory authorities**, the Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators,** about the progress of developing those terms and conditions or methodologies.

3. **<…>**

4. Where TSOs deciding on proposals for terms and conditions or methodologies in accordance with Article 6(3) are not able to reach an agreement and where the regions concerned are composed of more than five **Contracting Parties and/or** Member States, they shall decide by qualified majority voting. A qualified majority for proposals in accordance with Article 6(3) shall require a majority of:

(a) TSOs representing at least 72 % of the **Contracting Parties and/or** Member States concerned; and

(b) TSOs representing **Contracting Parties and/or** Member States comprising at least 65 % of the population of the concerned region.

5. A blocking minority for decisions on proposals for terms and conditions or methodologies listed in Article 6(3) shall include at least a minimum number of TSOs representing more than 35 % of the population of the participating **Contracting Parties and/or** Member States, plus TSOs representing at least one additional **Contracting Party and/or** Member State concerned, failing of which the qualified majority shall be deemed attained.[1]

6. TSOs deciding on proposals for terms and conditions or methodologies in accordance with Article 6(3) in relation to regions composed of five **Contracting Parties and/or** Member States or less shall decide on the basis of a consensus.

7. For TSO decisions on proposals for terms and conditions or methodologies pursuant to paragraph 5, one vote shall be attributed per **Contracting Party or** per Member State. If there is more than one TSO in the territory of a **Contracting Party or** Member State, the **Contracting Party or** Member State shall allocate the voting powers among the TSOs.

8. Where TSOs fail to submit a **<…>** proposal for terms and conditions or methodologies to the regulatory authorities in accordance with Article **<…>** 6(3) or to the entities designated by the **Contracting Parties** in accordance with Article 6(4) within the deadlines **defined** in this Regulation, they shall provide **<…>** the competent regulatory authorities**, the Energy Community Regulatory Board and** the Agency **for the Cooperation of Energy Regulators**, with the relevant drafts of the terms and conditions or methodologies, and explain why an agreement has not been reached. **The Energy Community Regulatory Board and, to the extent Member States are affected, the Agency for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC shall inform the Energy Community Secretariat and the European Commission, and shall, in**

1 There is a clerical error in the Ministerial Council Decision D2022/03/MC-EnC.

cooperation with the competent regulatory authorities, investigate the reasons for the failure and inform the Energy Community Secretariat and the European Commission thereof. The **Energy Community Secretariat or, to the extent Member States are affected, the European Commission** shall take the appropriate steps **to make possible** the adoption of the required terms and conditions or methodologies **<…> within 4 months from the receipt of the information**.

Article 6

Approval of terms and conditions or methodologies of TSOs

1. Each regulatory authority or where applicable the Agency, as the case might be, shall approve the terms and conditions or methodologies developed by TSOs under paragraph **<…>** 3. The entity designated by the **Contracting Party** shall approve the terms and conditions or methodologies developed by TSOs under paragraph 4. The designated entity shall be the regulatory authority unless otherwise provided by the **Contracting Party**.[2] **Before approving the terms and conditions or methodologies, the regulatory authority, or the designated entity shall revise the proposals where necessary, after consulting the respective TSOs, in order to ensure that they are in line with the purpose of this Regulation and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.**

2. **TSOs shall apply the following terms and conditions or methodologies, as adopted in accordance with Regulation (EU) 2017/1485:**

(a) key organizational requirements, roles and responsibilities in relation to data exchange related to operational security in accordance with Article 40(6);

(b) methodology for building the common grid models in accordance with Article 67(1) and Article 70;

(c) methodology for coordinating operational security analysis in accordance with Article 75.

(d) **methodology for the Continental Europe synchronous area for the definition of minimum inertia in accordance with Article 39(3)(b);**

(e) **methodology, at least per synchronous area, for assessing the relevance of assets for outage coordination in accordance with Article 84;**

(f) **methodologies, conditions and values included in the synchronous area operational agreements in Article 118 concerning:**

(i) the frequency quality defining parameters and the frequency quality target parameter in accordance with Article 127;

(ii) the dimensioning rules for FCR in accordance with Article 153;

(iii) the additional properties of the FCR in accordance with Article 154(2);

(iv) for the CE synchronous area, the minimum activation period to be ensured by FCR providers in accordance with Article 156(10);

(v) for the CE synchronous area, the assumptions and methodology for a cost-benefit analysis in accordance with Article 156(11);

(vi) for synchronous areas other than CE and if applicable, the limits for the exchange of

2 There is a clerical error in the Ministerial Council Decision D2022/03/MC-EnC.

FCR between TSOs in accordance with Article 163(2);

(vii) limits on the amount of exchange of FRR between synchronous areas defined in accordance with Article 176(1) and limits on the amount of sharing of FRR between synchronous areas defined in accordance with Article 177(1);

(viii) limits on the amount of exchange of RR between synchronous areas defined in accordance with Article 178(1) and limits on the amount of sharing of RR between synchronous areas defined in accordance with Article 179(1);

(g) **where the LFC block comprises of LFC areas of Member States and Contracting Parties, methodologies and conditions included in the LFC block operational agreements in Article 119, concerning:**

(i) ramping restrictions for active power output in accordance with Article 137(3) and (4);

(ii) coordination actions aiming to reduce FRCE as defined in Article 152(14);

(iii) measures to reduce FRCE by requiring changes in the active power production or consumption of power generating modules and demand units in accordance with Article 152(16);

(iv) the FRR dimensioning rules in accordance with Article 157(1);

(h) **mitigation measures per synchronous area in accordance with Article 138.**

3. The proposals for the following terms and conditions or methodologies or any amendments thereof shall be subject to approval by all regulatory authorities of the concerned region, on which a **Contracting Party or** Member State may provide an opinion to the concerned regulatory authority:

(a) **<…>**

(b) common provisions for each capacity calculation region for regional operational security coordination in accordance with Article 76;

(c) **<…>**

(d) **<…>**

(e) **where the LFC block comprises of LFC areas of Contracting Parties only,** methodologies and conditions included in the LFC block operational agreements in Article 119, concerning:

(i) ramping restrictions for active power output in accordance with Article 137(3) and (4);

(ii) coordination actions aiming to reduce FRCE as defined in Article 152(14);

(iii) measures to reduce FRCE by requiring changes in the active power production or consumption of power generating modules and demand units in accordance with Article 152(16);

(iv) the FRR dimensioning rules in accordance with Article 157(1);

(f) mitigation measures per **<…>** LFC block in accordance with Article 138;

(g) common proposal **<…>** for the determination of LFC blocks in accordance with Article 141(2).

4. Unless determined otherwise by the **Contracting Party**, the following terms and conditions or methodologies and any amendments thereof shall be subject to individual approval by the entity designated in accordance with paragraph 1 by the **Contracting Party**:

(a) **<…>**

(b) scope of data exchange with DSOs and significant grid users in accordance with Article 40(5);

(c) additional requirements for FCR providing groups in accordance with Article 154(3);

(d) exclusion of FCR providing groups from the provision of FCR in accordance with Article 154(4);

(e) for the CE **<…>** synchronous area, the proposal concerning the interim minimum activation period to be ensured by FCR providers as proposed by the TSO in accordance with Article 156(9);

(f) FRR technical requirements defined by the TSO in accordance with Article 158(3);

(g) rejection of FRR providing groups from the provision of FRR in accordance with Article 159(7);

(h) technical requirements for the connection of RR providing units and RR providing groups defined by the TSO in accordance with Article 161(3); and

(i) rejection of RR providing groups from the provision of RR in accordance with Article 162(6).

5. Where an individual relevant system operator or TSO is required or permitted under this Regulation to specify or agree on requirements that are not subject to paragraph 4, **Contracting Parties** may require prior approval by the competent regulatory authority of these requirements and any amendments thereof.

6. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. Proposals **on** terms and conditions or methodologies subject to the approval by several **or all** regulatory authorities **<…>** shall be submitted to the **Energy Community Regulatory Board and, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, at the same time that they are submitted** to regulatory authorities. **<…>** Upon request by the competent regulatory authorities, the **Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC,** shall issue an opinion within 3 months on the proposals for terms and conditions or methodologies.

7. Where the approval of the terms and conditions or methodologies in accordance with paragraph 3 or the amendment in accordance with Article 7 requires a decision by more than one regulatory authority pursuant to paragraph 3, the competent regulatory authorities shall consult and closely cooperate and coordinate with each other in order to reach an agreement. Where the **Energy Community Regulatory Board or** the Agency **for the Cooperation of Energy Regulators** issues an opinion, the competent regulatory authorities shall take that opinion into account. Regulatory authorities, or where competent the **Energy Community Regulatory Board or** the Agency **for the Cooperation of Energy Regulators** shall take decisions concerning the submitted terms and conditions or methodologies in accordance with paragraph **<…>** (3), within 6 months following the receipt of the terms and conditions or methodologies by the **Energy Community Regulatory Board or** the Agency **for the Cooperation of Energy Regulators** or the regulatory authority or, where applicable, by the last regulatory authority concerned. The period shall begin on the day following that on which the proposal was submitted to the **Energy Community Regulatory Board or** the Agency **for the Cooperation of Energy Regulators** in accordance with paragraph 2 or to the last regulatory authority concerned in accordance with paragraph 3.

8. Where the regulatory authorities have not been able to reach an agreement within the period referred to in paragraph 7 or upon their joint request, or upon Agency's request according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, the **Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators,**

acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within 6 months **<…>.**

9. Where the approval of the terms and conditions or methodologies requires a decision by a single designated entity in accordance with paragraph 4 or competent regulatory authority in accordance with paragraph 5, the designated entity or competent regulatory authority shall reach a decision within 6 months following the receipt of the terms and conditions or methodologies. The period shall begin on the day following that on which the proposal was submitted to the designated entity in accordance with paragraph 4 or competent regulatory authority in accordance with paragraph 5.

10. Any party can complain against a relevant system operator or TSO in relation to that relevant system operator's or TSO's obligations or decisions under this Regulation and may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within 2 months after receipt of the complaint. That period may be extended by a further 2 months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall be binding unless and until overruled on appeal.

Article 7

Amendments to the terms and conditions or methodologies of TSOs

1. Where **<…>** all competent regulatory authorities jointly request an amendment in order to approve the terms and conditions or methodologies submitted in accordance with paragraph **<…>** 3 of Article 6 respectively, the relevant TSOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months following the request from **<…>** the regulatory authorities. The **<…>** the competent regulatory authorities shall decide on the amended terms and conditions or methodologies within 2 months following their submission.

2. Where a designated entity requires an amendment in order to approve the terms and conditions or methodologies submitted in accordance with Article 6(4) or the competent regulatory authority requires an amendment in order to approve the requirements submitted in accordance with Article 6(5), the relevant TSO shall submit a proposal for amended terms and conditions or methodologies or requirements for approval within 2 months following the request from the designated entity or competent regulatory authority. The designated entity or competent regulatory authority shall decide on the amended terms and conditions or methodologies within 2 months following their submission.

3. Where the competent regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies pursuant to paragraph **<…>** 3 of Article 6 within the 2-month deadline, or upon their joint request, or upon the Agency's request according to the third subparagraph of Article 5(3) of Regulation (EU) 2019/942, the **Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** shall adopt a decision concerning the amended terms and conditions or methodologies within 6 months **<…>**. If the relevant TSOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in Article 5(9) shall apply.

4. The **Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators,** the regulatory authorities or designated entities,

where they are responsible for the adoption of terms and conditions or methodologies in accordance with paragraphs **<…>** 3 and 4 of Article 6, may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the **Energy Community Regulatory Board or, to the extent Member States are affected,** the Agency **for the Cooperation of Energy Regulators**. Proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation if applicable in accordance with the procedure set out in Article 11 and approved in accordance with the procedure set out in Articles 5 and 6.

Article 8

Publication on internet

1. TSOs responsible for specifying the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet following approval by the Agency or the competent regulatory authorities or, where no such approval is required, following their specification, except where such information is considered confidential in accordance with Article 12.

2. The publication shall also concern:

(a) enhancements of network operation tools in accordance with Article 55(e);

(b) FRCE target parameters in accordance with Article 128;

(c) ramping restrictions on synchronous area level in accordance with Article 137(1);

(d) ramping restrictions on LFC block level in accordance with Article 137(3);

(e) measures taken in the alert state due to there being insufficient active power reserves in accordance with Article 152(11); and

(f) request of the reserve connecting TSO to an FCR provider to make the information available in real time in accordance with Article 154(11).

Article 9

Recovery of costs

1. The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms.

2. If requested by the relevant regulatory authorities, system operators referred to in paragraph 1 shall, within 3 months of the request, provide the information necessary to facilitate assessment of the costs incurred.

Article 10

Stakeholder involvement

The Energy Community Regulatory Board and, to the extent Member States are affected, the Agency **for the Cooperation of Energy Regulators, acting in accordance with Article 2 of Procedural Act No 2022/01/MC-EnC** in close cooperation with ENTSO for Electricity, shall organise stakeholder involvement regarding secure system operation and other aspects of the implementation of this Regulation. Such involvement shall include regular meetings with stakeholders to identify problems and propose improvements related to the secure system operation.

Article 11

Public consultation

1. TSOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each **Contracting Party and** Member State, on the draft proposals for terms and conditions or methodologies listed in Article 6 **<…>** (3). The consultation shall last for a period of not less than 1 month.

2. **<…>** Proposals submitted by the TSOs at regional level shall be submitted to public consultation at least at regional level. Parties submitting proposals at bilateral or at multilateral level shall carry out a public consultation at least in the **Contracting Parties and** Member States concerned.

3. The TSOs responsible for developing the proposal for terms and conditions or methodologies shall duly take into account the views of stakeholders resulting from the consultations prior to its submission for regulatory approval. In all cases, a sound justification for including or not including the views resulting from the consultation shall be provided together with the submission of the proposal and published in a timely manner before, or simultaneously with the publication of the proposal for terms and conditions or methodologies.

Article 12

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons subject to the provisions of this Regulation.

3. Confidential information received by the persons or regulatory authorities referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **national or Energy Community** legislation.

4. Without prejudice to cases covered by national or **Energy Community** legislation, regulatory authorities,

bodies or persons who receive confidential information pursuant to this Regulation may use it only for the purpose of carrying out their duties under this Regulation.

Article 13

Agreements with TSOs not bound by this Regulation

Where a synchronous area encompasses both **Energy Community** and third country TSOs, within 18 months after entry into force of this Regulation, all **Energy Community** TSOs in that synchronous area shall endeavour to conclude with the third country TSOs not bound by this Regulation an agreement setting the basis for their cooperation concerning secure system operation and setting out arrangements for the compliance of the third country TSOs with the obligations set in this Regulation.

Article 14

Monitoring

1. ENTSO for Electricity **acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC** shall monitor the implementation of this Regulation **in the areas covered by this paragraph**. **To the extent the monitoring covers Contracting Parties located outside the Continental Europe synchronous area or not being member of ENTSO for Electricity, the Energy Community Secretariat shall collect data from the relevant transmission system operators.** Monitoring **by ENTSO for Electricity** shall cover at least the following matters:

(a) operational security indicators in accordance with Article 15;

(b) load-frequency control in accordance with Article 16;

(c) regional coordination assessment in accordance with Article 17;

(d) identification of any divergences in the national implementation of this Regulation for the terms and conditions or methodologies listed in Article 6(3);

(e) identification of any additional improvements of tools and services in accordance with subparagraphs (a) and (b) of Article 55, beyond the improvements identified by the TSOs in accordance with Article 55(e);

(f) identification of any necessary improvements in the annual report on incidents classification scale in accordance with Article 15, which are necessary in order to support sustainable and long-term operational security; and

(g) identification of any difficulties concerning cooperation on secure system operation with third country TSOs.

2. **The Agency for the Cooperation of Energy Regulators may expand a list of the relevant information related to the Contracting Parties to be communicated by the ENTSO for Electricity to the Agency for Cooperation of Energy Regulators in accordance with Article 32 of Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC. The list of relevant information may be subject to updates. The ENTSO for Electricity shall maintain a comprehensive, standardized format, digital data archive of the information**

required by the Agency for the Cooperation of Energy Regulators.

3. Relevant TSOs shall submit to ENTSO for Electricity the information required to perform the tasks referred to in paragraph 1 **<…>**.

4. Based on a request of the regulatory authority, DSOs shall provide TSOs with the information under **this Article** unless that information is already available to the regulatory authorities, TSOs or ENTSO for Electricity in relation to their respective implementation monitoring tasks, with the objective of avoiding duplication of information.

Article 15

Annual report on operational security indicators

1. **<…>** ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC,** shall **extend the** annual report **drafted in accordance with Article 15(1) of Regulation 2017/1485 to include the Energy Community Contracting Parties**. The **Energy Community Regulatory Board** may provide its opinion on the format and contents of that annual report, including the geographical scope of the incidents reported, the electrical interdependencies between the TSOs' control areas and any relevant historical information.

2. The TSOs of each **Contracting Party** shall provide ENTSO for Electricity, by 1 March, with the necessary data and information for the preparation of the annual reports based on the incident classification scale referred to in paragraph 1. The data provided by the TSOs shall cover the preceding year.

3. The annual reports referred to in paragraph 1 shall contain at least the following operational security indicators relevant to operational security:

(a) number of tripped transmission system elements per year per TSO;

(b) number of tripped power generation facilities per year per TSO;

(c) energy not supplied per year due to unscheduled disconnection of demand facilities per TSO;

(d) time duration and number of instances of being in the alert and emergency states per TSO;

(e) time duration and number of events within which there was a lack of reserves identified per TSO;

(f) time duration and number of voltage deviations exceeding the ranges from Tables 1 and 2 of Annex II per TSO;

(g) number of minutes outside the standard frequency range and number of minutes outside the 50

% of maximum steady state frequency deviation per synchronous area;

(h) number of system-split separations or local blackout states; and

(i) number of blackouts involving two or more TSOs.

4. The annual report referred to in paragraph 1 shall contain the following operational security indicators relevant to operational planning:

(a) number of events in which an incident contained in the contingency list led to a degradation of the system operation state;

(b) number of the events referred to in point (a) in which a degradation of system operation conditions

occurred as a result of unexpected discrepancies from load or generation forecasts;

(c) number of events in which there was a degradation in system operation conditions due to an exceptional contingency;

(d) number of the events referred to in point (c) in which a degradation of system operation conditions occurred as a result of unexpected discrepancies from load or generation forecasts; and

(e) number of events leading to a degradation in system operation conditions due to lack of active power reserves.

5. The annual reports shall contain explanations of the reasons for incidents at the operational security ranking scales 2 and 3 as per the incidents classification scale adopted by ENTSO for Electricity. Those explanations shall be based on an investigation of the incidents by TSOs which process shall be set out in the incidents classification scale. TSOs shall inform the respective regulatory authorities about an investigation in due time before it is launched. Regulatory authorities and the **Energy Community Regulatory Board** may be involved in the investigation upon their request.

Article 16

Annual report on load-frequency control

1. ENTSO for Electricity, **acting in accordance with Article 3 of Procedural Act No 2022/01/MC- EnC,** shall **extend** the annual report **drafted in accordance with Article 16(1) of Regulation 2017/1485 to include the Energy Community Contracting Parties.<…>**

2. **After the deadline for transposition of the present Regulation**, the TSOs of each **Contracting Party** shall notify to ENTSO for Electricity, by 1 March every year, the following information for the previous year:

(a) the identification of the LFC blocks, LFC areas and monitoring areas in the **Contracting Party**;

(b) the identification of LFC blocks that are not in the **Contracting Party** and that contain LFC areas and monitoring areas that are in the **Contracting Party**;

(c) the identification of the synchronous areas each **Contracting Party** belongs to;

(d) the data related to the frequency quality evaluation criteria for each synchronous area and each LFC block in subparagraphs (a), (b) and (c) covering each month of at least 2 previous calendar years;

(e) the FCR obligation and the initial FCR obligation of each TSO operating within the **Contracting Party** covering each month of at least 2 previous calendar years; and

(f) a description and date of implementation of any mitigation measures and ramping requirements to alleviate deterministic frequency deviations taken in the previous calendar year in accordance with Articles 137 and 138, in which TSOs of the **Contracting Party** were involved.

3. The data provided by the TSOs shall cover the preceding year. The information concerning synchronous areas, LFC blocks, LFC areas and monitoring areas in subparagraphs (a), (b) and (c) shall be reported once. Where these areas change, this information shall be reported by 1 March of the following year.

4. Where appropriate, all TSOs of a synchronous area or LFC block shall cooperate in collecting the data listed in paragraph 2.

Article 17

Annual report on regional coordination assessment

1. ENTSO for Electricity, **acting in accordance with Article 3 of Procedural Act No 2022/01/MC- EnC,** shall **extend** the annual report **drafted in accordance with Article 17(1) of Regulation 2017/1485 to include the Energy Community Contracting Parties**.

2. By 1 March, each regional **coordination centre** shall prepare an annual report and submit it to ENTSO for Electricity providing the following information for the tasks it performs:

(a) the number of events, average duration and reasons for the failure to fulfil its functions;

(b) the statistics regarding constraints, including their duration, location and number of occurrences together with the associated remedial actions activated and their cost in case they have been incurred;

(c) the number of instances where TSOs refuse to implement the remedial actions recommended by the regional **coordination centre** and the reasons thereof;

(d) the number of outage incompatibilities detected in accordance with Article 80; and

(e) a description of the cases where the lack of regional adequacy has been assessed and a description of mitigation actions set in place.

3. The data provided to ENTSO for Electricity by the regional **coordination centre** shall cover the preceding year.

PART II
OPERATIONAL SECURITY

TITLE 1
OPERATIONAL SECURITY REQUIREMENTS

CHAPTER 1
System states, remedial actions and operational security limits

Article 18

Classification of system states

1. A transmission system shall be in the normal state when all of the following conditions are fulfilled:

(a) voltage and power flows are within the operational security limits defined in accordance with Article 25;

(b) frequency meets the following criteria:

(i) the steady state system frequency deviation is within the standard frequency range; or

(ii) the absolute value of the steady state system frequency deviation is not larger than the maximum steady state frequency deviation and the system frequency limits established for the alert state are

not fulfilled;

(c) active and reactive power reserves are sufficient to withstand contingencies from the contingency list defined in accordance with Article 33 without violating operational security limits;

(d) operation of the concerned TSO's control area is and will remain within operational security limits after the activation of remedial actions following the occurrence of a contingency from the

contingency list defined in accordance with Article 33.

2. A transmission system shall be in the alert state when:

(a) voltage and power flows are within the operational security limits defined in accordance with Article 25; and

(b) the TSO's reserve capacity is reduced by more than 20 % for longer than 30 minutes and there are no means to compensate for that reduction in real-time system operation; or

(c) frequency meets the following criteria:

(i) the absolute value of the steady state system frequency deviation is not larger than the maximum steady state frequency deviation; and

(ii) the absolute value of the steady state system frequency deviation has continuously exceeded 50 % of the maximum steady state frequency deviation for a time period longer than the alert state trigger time or the standard frequency range for a time period longer than time to restore frequency; or

(d) at least one contingency from the contingency list defined in accordance with Article 33 leads to a violation of the TSO's operational security limits, even after the activation of remedial actions.

3. A transmission system shall be in the emergency state when at least one of the following conditions is fulfilled:

(a) there is at least one a violation of a TSO's operational security limits defined in accordance with Article 25;

(b) frequency does not meet the criteria for the normal state and for the alert state defined in accordance with paragraphs 1 and 2;

(c) at least one measure of the TSO's system defence plan is activated;

(d) there is a failure in the functioning of tools, means and facilities defined in accordance with Article 24(1), resulting in the unavailability of those tools, means and facilities for longer than 30 minutes.

4. A transmission system shall be in the blackout state when at least one of the following conditions is fulfilled:

(a) loss of more than 50 % of demand in the concerned TSO's control area;

(b) total absence of voltage for at least three minutes in the concerned TSO's control area, leading to the triggering of restoration plans.

<...>

5. A transmission system shall be in the restoration state when a TSO, being in the emergency or blackout state, has started to activate measures of its restoration plan.

Article 19

Monitoring and determination of system states by TSOs

1. Each TSO shall, in real-time operation, determine the system state of its transmission system.

2. Each TSO shall monitor the following transmission system parameters in real-time in its control area, based on real-time telemetry measurements or on calculated values from its observability area, taking into account the structural and real-time data in accordance with Article 42:

(a) active and reactive power flows;

(b) busbar voltages;

(c) frequency and frequency restoration control error of its LFC area;

(d) active and reactive power reserves; and

(e) generation and load.

3. In order to specify the system state, each TSO shall perform contingency analysis at least once every 15 minutes, monitoring the transmission system's parameters defined in accordance with paragraph 2, against the operational security limits defined in accordance with Article 25 and the criteria for system states defined in accordance with Article 18. Each TSO shall also monitor the level of available reserves against the reserve capacity. When carrying out the contingency analysis, each TSO shall take into account the effect of remedial actions and the measures of the system defence plan.

4. If its transmission system is not in normal state and if that system state is qualified as a wide area state the TSO shall:

(a) inform all TSOs about the system state of its transmission system via an IT tool for the exchange of real-time data at pan-European level; and

(b) provide with additional information on its transmission system elements which are part of the observability area of other TSOs, to those TSOs.

Article 20

Remedial actions in system operation

1. Each TSO shall endeavour to ensure that its transmission system remains in the normal state and shall be responsible for managing operational security violations. To achieve that objective, each TSO shall design, prepare and activate remedial actions taking into account their availability, the time and resources needed for their activation and any conditions external to the transmission system which are relevant for each remedial action.

2. The remedial actions used by TSOs in system operation in accordance with paragraph 1 and with Articles 21 to 23 of this Regulation shall be consistent with the remedial actions taken into account in capacity calculation in accordance with Article 25 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 21

Principles and criteria applicable to remedial actions

1. Each TSO shall apply the following principles when activating and coordinating remedial actions in accordance with Article 23:

(a) for operational security violations which do not need to be managed in a coordinated way, a TSO shall design, prepare and activate remedial actions to restore the system to the normal state and to prevent the propagation of the alert or emergency state outside of the TSO's control area from

the categories defined in Article 22;

(b) for operational security violations which need to be managed in a coordinated way, a TSO shall design, prepare and activate remedial actions in coordination with other concerned TSOs, following the methodology for the preparation of remedial actions in a coordinated way under Article 76(1)(b) and taking into account the recommendation of a regional **coordination centre** in accordance with Article 78(4).

2. When selecting the appropriate remedial actions, each TSO shall apply the following criteria:

(a) activate the most effective and economically efficient remedial actions;

(b) activate remedial actions as close as possible to real-time taking into account the expected time of activation and the urgency of the system operation situation they intend to resolve;

(c) consider the risks of failures in applying the available remedial actions and their impact on operational security such as:

(i) the risks of failure or short-circuit caused by topology changes;

(ii) the risks of outages caused by active or reactive power changes on power generating modules or demand facilities; and

(iii) the risks of malfunction caused by equipment behaviour;

(d) give preference to remedial actions which make available the largest cross-zonal capacity for capacity allocation, while satisfying all operational security limits.

Article 22

Categories of remedial actions

1. Each TSO shall use the following categories of remedial actions:

(a) modify the duration of a planned outage or return to service transmission system elements to achieve the operational availability of those transmission system elements;

(b) actively impact power flows by means of:

(i) tap changes of the power transformers;

(ii) tap changes of the phase-shifting transformers;

(iii) modifying topologies;

(c) control voltage and manage reactive power by means of:

(i) tap changes of the power transformers;

(ii) switching of the capacitors and reactors;

(iii) switching of the power-electronics-based devices used for voltage and reactive power management;

(iv) instructing transmission-connected DSOs and significant grid users to block automatic voltage and reactive power control of transformers or to activate on their facilities the remedial actions set out in points (i) to (iii) if voltage deterioration jeopardises operational security or threatens to lead to a voltage collapse in a transmission system;

(v) requesting the change of reactive power output or voltage setpoint of the transmission- connected synchronous power generating modules;

(vi) requesting the change of reactive power output of the converters of transmission-connected non-synchronous power generating modules;

(d) re-calculate day-ahead and intraday cross-zonal capacities in accordance with Regulation (EU) 2015/1222, **as adapted and adopted by Ministerial Council Decision 2022/03/MC- EnC** once incorporated and adopted in the Energy Community;

(e) redispatch transmission or distribution-connected system users within the TSO's control area, between two or more TSOs;

(f) countertrade between two or more bidding zones;

(g) adjust active power flows through HVDC systems;

(h) activate frequency deviation management procedures;

(i) curtail, pursuant to Article 16(2) of **Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, the already allocated cross-zonal capacity in an emergency situation where using that capacity endangers operational security, all TSOs at a given interconnector agree to such adjustment, and re- dispatching or countertrading is not possible; and

(j) where applicable, include the normal or alert state, manually controlled load-shedding.

2. Where necessary and justified in order to maintain operational security, each TSO may prepare and activate additional remedial actions. The TSO shall report and justify those instances to the relevant regulatory authority and, where applicable, the **Contracting Party**, at least once every year, after the activation of the additional remedial actions. The relevant reports and justifications shall also be published. The **Energy Community Secretariat** or the **Energy Community Regulatory Board** may request the relevant regulatory authority to provide additional information concerning the activation of additional remedial actions in those instances where they affect a neighbouring transmission system.

Article 23

Preparation, activation and coordination of remedial actions

1. Each TSO shall prepare and activate remedial actions in accordance with the criteria set out in Article 21(2) to prevent the system state from deteriorating on the basis of the following elements:

(a) the monitoring and determination of system states in accordance with Article 19;

(b) the contingency analysis in real-time operation in accordance with Article 34; and

(c) the contingency analysis in operational planning in accordance with Article 72.

2. When preparing and activating a remedial action, including redispatching or countertrading pursuant to Articles 25 and 35 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, or a procedure of a TSO's system defence plan which affects other TSOs, the relevant TSO shall assess, in coordination with the TSOs concerned, the impact of such remedial action or measure within and outside of its control area, in accordance with Article 75(1), Article 76(1)(b) and Article 78(1), (2) and (4) and shall provide the TSOs concerned with the information about this impact.

3. When preparing and activating remedial actions which have an impact on the transmission- connected SGUs and DSOs, each TSO shall, if its transmission system is in normal or alert state, assess the impact of such remedial actions in coordination with the affected SGUs and DSOs and select remedial actions that contribute to maintaining normal state and secure operation of all involved parties. Each affected SGU and DSO shall provide to the TSO all necessary information for this coordination.

4. When preparing and activating remedial actions each TSO shall, if its transmission system is not in normal or alert state, coordinate to the extent possible such remedial actions with the affected transmission-connected SGUs and DSOs to maintain the operational security and the integrity of the transmission system.

When a TSO activates a remedial action each impacted transmission-connected significant grid user and DSO shall execute the instructions given by the TSO.

5. Where constraints have only consequences on the local state within the TSO's control area and the operational security violation does not need to be managed in a coordinated way, the TSO responsible for its management may decide not to activate remedial actions with costs to relieve them.

Article 24

Availability of TSO's means, tools and facilities

1. Each TSO shall ensure the availability, reliability and redundancy of the following items:

2. Where the TSO's tools, means and facilities referred to in paragraph 1 affect the transmission- connected DSOs or SGUs involved in supplying balancing services, ancillary services or in system defence or restoration or in delivery of real-time operational data according to Articles 44, 47, 50, 51 and 52, the relevant TSO and those DSOs and SGUs shall cooperate and coordinate to specify and ensure the availability, reliability and redundancy of these tools, means and facilities.

3. Within 18 months from the entry into force of this Regulation each TSO shall adopt a business continuity plan detailing its responses to a loss of critical tools, means and facilities, containing provisions for their maintenance, replacement and development. Each TSO shall review at least annually its business continuity plan and update it as necessary and in any case following any significant change of the critical tools, means and facilities or of the relevant system operation conditions. The TSO shall share parts of the business continuity plan which affect DSOs and SGUs with the DSOs and SGUs concerned.

Article 25

Operational security limits

1. Each TSO shall specify the operational security limits for each element of its transmission system, taking

into account at least the following physical characteristics:

(a) voltage limits in accordance with Article 27;

(b) short-circuit current limits according to Article 30; and

(c) current limits in terms of thermal rating including the transitory admissible overloads.

2. When defining the operational security limits, each TSO shall take into account the capabilities of SGUs to prevent that voltage ranges and frequency limits in normal and alert states lead to their disconnection.

3. In case of changes of one of its transmission system elements, each TSO shall validate and where necessary update the operational security limits.

4. For each interconnector each TSO shall agree with the neighbouring TSO on common operational security limits in accordance with paragraph 1.

Article 26

Security plan for critical infrastructure protection

1. Each TSO shall specify, taking into account **Articles 1(4)(a) and 1(5) of the Procedural Act No 2018/2/MC-EnC and Items 4.2(f) and 5.1 of its Annex**, a confidential security plan containing a risk assessment of assets owned or operated by the TSO, covering major physical or cyber threat scenarios determined by the **Contracting Party**.

2. The security plan shall consider potential impacts to the European interconnected transmission systems, and include organizational and physical measures aiming at mitigating the identified risks.

3. Each TSO shall regularly review the security plan to address changes of threat scenarios and reflect the evolution of the transmission system.

CHAPTER 2

Voltage control and reactive power management

Article 27

Obligations of all TSOs regarding voltage limits

1. In accordance with Article 18, each TSO shall endeavour to ensure that during the normal state the voltage remains in steady-state at the connection points of the transmission system within the ranges specified in the Tables 1 and 2 of Annex II.

2. **<…>**

3. Each TSO shall define the voltage base for the per unit values' notation.

4. Each TSO shall endeavour to ensure that, during the normal state and after the occurrence of a contingency, the voltage remains, within wider voltage ranges for limited times of operation if there is agreement about those wider voltage ranges with transmission-connected DSOs, power generating facility owners in accordance with Article 16(2) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent**

High Level Group Decision 2018/03/PHLG-EnC, or HVDC system owners in accordance with Article 18 of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**.

5. Each TSO shall agree, with the transmission-connected DSOs and the transmission-connected significant grid users, about voltage ranges at the connection points below 110 kV if those voltage ranges are relevant for maintaining operational security limits. Each TSO shall endeavour to ensure that the voltage remains within the agreed range during the normal state and after the occurrence of a contingency.

Article 28

Obligations of SGUs concerning voltage control and reactive power management in system operation

1. By 3 months after **the deadline for transposition** of this Regulation, all SGUs which are transmission-connected power generating modules not subject to Article 16 of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** or which are HVDC systems not subject to Article 18 of Regulation (EU) 2016/1447 **adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** shall inform their TSO about their capabilities compared to the voltage requirements in Article 16 of Regulation (EU) 2016/631**, adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** or in Article 18 of Regulation (EU) 2016/1447, **adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** declaring their voltage capabilities and the time they can withstand without disconnection.

2. SGUs which are demand facilities subject to the requirements of Article 3 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** shall not disconnect due to a disturbance within the voltage ranges referred to in Article 27. By 3 months after **the deadline for transposition** of this Regulation, SGUs which are transmission-connected demand facilities and which are not subject to Article 3 of Regulation (EU) 2016/1388, **as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** shall inform their TSO about their capabilities in relation to the voltage requirements defined in Annex II of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG- EnC,** declaring their voltage capabilities and the time they can withstand without disconnection.

3. Each SGU which is a transmission-connected demand facility shall maintain the reactive power set-points, power factor ranges and voltage setpoints for voltage control in the range agreed with its TSO in accordance with Article 27.

Article 29

Obligations of all TSOs concerning voltage control and reactive power management in system operation

1. If voltage at a connection point to the transmission system is outside the ranges defined in Tables 1 and 2 of Annex II to this Regulation, each TSO shall apply voltage control and reactive power management remedial actions in accordance with Article 22(1)(c) of this Regulation in order to restore voltage at the

connection point within the range specified in Annex II and within time range specified in Article 16 of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and Article 13 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC.**

2. Each TSO shall take into account in its operational security analysis the voltage values at which transmission-connected SGUs not subject to the requirements of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** or Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** may disconnect.

3. Each TSO shall ensure reactive power reserve, with adequate volume and time response, in order to keep the voltages within its control area and on interconnectors within the ranges set out in Annex II.

4. TSOs interconnected by AC interconnectors shall jointly specify the adequate voltage control regime in order to ensure that the common operational security limits established in accordance with Article 25(4) are respected.

5. Each TSO shall agree with each transmission-connected DSO on the reactive power setpoints, power factor ranges and voltage setpoints for voltage control at the connection point between the TSO and the DSO in accordance with Article 15 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC.** To ensure that those parameters are maintained, each transmission-connected DSO shall use its reactive power resources and have the right to give voltage control instructions to distribution-connected SGUs.

6. Each TSO shall be entitled to use all available transmission-connected reactive power capabilities within its control area for effective reactive power management and maintaining the voltage ranges set out in Tables 1 and 2 of Annex II of this Regulation.

7. Each TSO shall, directly or indirectly in coordination with the transmission-connected DSO where applicable, operate reactive power resources within its control area, including the blocking of automatic voltage/reactive power control of transformers, voltage reduction and low voltage demand disconnection, in order to maintain operational security limits and to prevent a voltage collapse of the transmission system.

8. Each TSO shall determine the voltage control actions in coordination with the transmission- connected SGUs and DSOs and with neighbouring TSOs.

9. When relevant for the voltage control and reactive power management of the transmission system, a TSO may require, in coordination with a DSO, a distribution-connected SGU to follow voltage control instructions.

CHAPTER 3

Short-circuit current management

Article 30

Short-circuit current

Each TSO shall determine:

(a) the maximum short-circuit current at which the rated capability of circuit breakers and other equipment is exceeded; and

(b) the minimum short-circuit current for the correct operation of protection equipment.

Article 31

Short-circuit current calculation and related measures

1. Each TSO shall perform short-circuit current calculations in order to evaluate the impact of neighbouring TSOs and transmission-connected SGUs and transmission-connected distribution systems including closed distribution systems on the short-circuit current levels in transmission system. Where a transmission-connected distribution system including closed distribution

2. System has an impact on short-circuit current levels, it shall be included in the transmission system short- circuit current calculations.

3. While performing short-circuit current calculations, each TSO shall:

(a) use the most accurate and high quality available data;

(b) take into account international standards; and

(c) consider as the basis of the maximum short-circuit current calculation such operational conditions, which provide the highest possible level of short-circuit current, including the short- circuit current from other transmission systems and distribution systems including closed distribution systems.

4. Each TSO shall apply operational or other measures to prevent deviation from the maximum and minimum short-circuit current limits referred to in Article 30, at all time-frames and for all protection equipment. If such a deviation occurs, each TSO shall activate remedial actions or apply other measures to ensure that the limits referred to in Article 30 are re-established. A deviation from those limits is allowed only during switching sequences.

CHAPTER 4
Power flow management

Article 32

Power flow limits

1. Each TSO shall maintain power flows within the operational security limits defined when the system is in normal state and after the occurrence of a contingency from the contingency list referred to in Article 33(1).

2. In the (N-1)-situation, in the normal state each TSO shall maintain power flows within the transitory

admissible overloads referred to in Article 25(1)(c), having prepared remedial actions to be applied and executed within the time-frame allowed for transitory admissible overloads.

CHAPTER 5
Contingency analysis and handling

Article 33
Contingency lists

1. Each TSO shall establish a contingency list, including the internal and external contingencies of its observability area, by assessing whether any of those contingencies endangers the operational security of the TSO's control area. The contingency list shall include both ordinary contingencies and exceptional contingencies identified by application of the methodology developed pursuant to Article 75.

2. To establish a contingency list, each TSO shall classify each contingency on the basis of whether it is ordinary, exceptional or out-of-range, taking into account the probability of occurrence and the following principles:

(a) each TSO shall classify contingencies for its own control area;

(b) when operational or weather conditions significantly increase the probability of an exceptional contingency, each TSO shall include that exceptional contingency in its contingency list; and

(c) in order to account for exceptional contingencies with high impact on its own or neighbouring transmission systems, each TSO shall include such exceptional contingencies in its contingency list.

3. Each transmission-connected DSO and SGU which is a power generating facility shall deliver all information relevant for contingency analysis as requested by the TSO, including forecast and real-time data, with possible data aggregation in accordance with Article 50(2).

4. Each TSO shall coordinate its contingency analysis in terms of coherent contingency lists at least with the TSOs from its observability area, in accordance with the Article 75.

5. Each TSO shall inform the TSOs in its observability area about the external contingencies included in its contingency list.

6. Each TSO shall inform, sufficiently in advance, the TSOs concerned in its observability area of any intended topological changes on its transmission system elements which are included as external contingencies in the contingency lists of the TSOs concerned.

7. Each TSO shall ensure that the real-time data is sufficiently accurate to allow the convergence of load-flow calculations which are performed in the contingency analysis.

Article 34
Contingency analysis

1. Each TSO shall perform contingency analysis in its observability area in order to identify the contin-

gencies which endanger or may endanger the operational security of its control area and to identify the remedial actions that may be necessary to address the contingencies, including mitigation of the impact of exceptional contingencies.

2. Each TSO shall ensure that potential violations of the operational security limits in its control area which are identified by the contingency analysis do not endanger the operational security of its transmission system or of interconnected transmission systems.

3. Each TSO shall perform contingency analysis based on the forecast of operational data and on real-time operational data from its observability area. The starting point for the contingency analysis in the N-Situation shall be the relevant topology of the transmission system which shall include planned outages in the operational planning phases.

Article 35

Contingency handling

1. Each TSO shall assess the risks associated with the contingencies after simulating each contingency from its contingency list and after assessing whether it can maintain its transmission system within the operational security limits in the (N-1) situation.

2. When a TSO assesses that the risks associated with a contingency are so significant that it might not be able to prepare and activate remedial actions in a timely manner to prevent non-compliance with the (N-1) criterion or that there is a risk of propagation of a disturbance to the interconnected transmission system, the TSO shall prepare and activate remedial actions to achieve compliance with the (N-1) criterion as soon as possible.

3. In case of an (N-1) situation caused by a disturbance, each TSO shall activate a remedial action in order to ensure that the transmission system is restored to a normal state as soon as possible and that this (N-1) situation becomes the new N-Situation.

4. A TSO shall not be required to comply with the (N-1) criterion in the following situations:

(a) during switching sequences;

(b) during the time period required to prepare and activate remedial actions.

5. Unless a **Contracting Party** determines otherwise, a TSO shall not be required to comply with the (N-1) criterion as long as there are only local consequences within the TSO's control area.

CHAPTER 6
Protection

Article 36

General requirements on protection

1. Each TSO shall operate its transmission system with the protection and backup protection equipment in order to automatically prevent the propagation of disturbances that could endanger the operational

security of its own transmission system and of the interconnected system.

2. At least once every 5 years, each TSO shall review its protection strategy and concepts and update them where necessary to ensure the correct functioning of the protection equipment and the maintenance of operational security.

3. After a protection operation which had an impact outside a TSO's control area including interconnectors, that TSO shall assess whether the protection equipment in its control area worked as planned and shall undertake corrective actions if necessary.

4. Each TSO shall specify setpoints for the protection equipment of its transmission system that ensure reliable, fast and selective fault clearing, including backup protection for fault clearing in case of malfunction of the primary protection system.

5. Before protection and backup protection equipment entry into service or following any modifications, each TSO shall agree with the neighbouring TSOs on the definition of protection setpoints for the interconnectors and shall coordinate with those TSOs before changing the settings.

Article 37

Special protection schemes

Where a TSO uses a special protection scheme, it shall:

(a) ensure that each special protection scheme acts selectively, reliably and effectively;

(b) evaluate, when designing a special protection scheme, the consequences for the transmission system in the event of its incorrect functioning, taking into account the impact on TSOs concerned;

(c) verify that the special protection scheme has a comparable reliability to the protection systems used for the primary protection of transmission system elements;

(d) operate the transmission system with the special protection scheme within the operational security limits determined in accordance with Article 25; and

(e) coordinate special protection scheme functions, activation principles and setpoints with neighbouring TSOs and affected transmission-connected DSOs, including closed distribution systems and affected transmission-connected SGUs.

Article 38

Dynamic stability monitoring and assessment

1. Each TSO shall monitor the dynamic stability of the transmission system by studies conducted offline in accordance with paragraph 6. Each TSO shall exchange the relevant data for monitoring the dynamic stability of the transmission system with the other TSOs of its synchronous area.

2. Each TSO shall perform a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in its transmission system. All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area.

3. When performing coordinated dynamic stability assessments, concerned TSOs shall determine:

(a) the scope of the coordinated dynamic stability assessment, at least in terms of a common grid model;

(b) the set of data to be exchanged between concerned TSOs in order to perform the coordinated dynamic stability assessment;

(c) a list of commonly agreed scenarios concerning the coordinated dynamic stability assessment; and

(d) a list of commonly agreed contingencies or disturbances whose impact shall be assessed through the coordinated dynamic stability assessment.

4. In case of stability problems due to poorly damped inter-area oscillations affecting several TSOs within a synchronous area, each TSO shall participate in a coordinated dynamic stability assessment at the synchronous area level as soon as practicable and provide the data necessary for that assessment. Such assessment shall be initiated and conducted by the concerned TSOs or by ENTSO for Electricity**, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC**.

5. When a TSO identifies a potential influence on voltage, rotor angle or frequency stability in relation with other interconnected transmission systems, the TSOs concerned shall coordinate the methods used in the dynamic stability assessment, providing the necessary data, planning of joint remedial actions aiming at improving the stability, including the cooperation procedures between the TSOs.

6. In deciding the methods used in the dynamic stability assessment, each TSO shall apply the following rules:

(a) if, with respect to the contingency list, steady-state limits are reached before stability limits, the TSO shall base the dynamic stability assessment only on the offline stability studies carried out in the longer term operational planning phase;

(b) if, under planned outage conditions, with respect to the contingency list, steady-state limits and stability limits are close to each other or stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in the day-ahead operational planning phase while those conditions remain. The TSO shall plan remedial actions to be used in real-time

(c) if the transmission system is in the N-situation with respect to the contingency list and stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in all phases of operational planning and re-assess the stability limits as soon as possible after a significant change in the N-situation is detected.

Article 39

Dynamic stability management

1. Where the dynamic stability assessment indicates that there is a violation of stability limits, the TSOs in whose control area the violation has appeared shall design, prepare and activate remedial actions to keep the transmission system stable. Those remedial actions may involve SGUs.

2. Each TSO shall ensure that the fault clearing times for faults that may lead to wide area state transmission system instability are shorter than the critical fault clearing time calculated by the TSO in its dynamic stability assessment carried out in accordance with Article 38.

3. In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:

(a) all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;

(b) where the studies referred to in point (a) demonstrate the need to define minimum required inertia, all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and,

(c) each TSO shall deploy in real-time operation the minimum inertia in its own control area, according to the methodology defined and the results obtained in accordance with paragraph (b).

TITLE 2
DATA EXCHANGE

CHAPTER 1
General requirements on data exchange

Article 40

Organisation, roles, responsibilities and quality of data exchange

1. The exchange and provision of data and information pursuant to this Title shall reflect, to the extent possible, the real and forecasted situation of the transmission system.

2. Each TSO shall be responsible for providing and using high quality data and information.

3. Each TSO shall gather the following information about its observability area and shall exchange this data with all other TSOs to the extent that it is necessary for carrying out the operational security analysis in accordance with Article 72:

(a) generation;

(b) consumption;

(c) schedules;

(d) balance positions;

(e) planned outages and substation topologies; and

(f) forecasts.

4. Each TSO shall represent the information in paragraph (3) as injections and withdrawals at each node of the TSO's individual grid model referred to in Article 64.

5. In coordination with the DSOs and SGUs, each TSO shall determine the applicability and scope of the

data exchange based on the following categories:

(a) structural data in accordance with Article 48;

(b) scheduling and forecast data in accordance with Article 49;

(c) real-time data in accordance with Articles 44, 47 and 50; and

(d) provisions in accordance with Articles 51, 52 and 53.

6. By 6 months after entry into force of this Regulation, **the TSOs shall apply the key organisational requirements, roles and responsibilities in relation to data exchange, as adopted in accordance with Regulation (EU) 2017/1485. <…>**

7. By 18 months after entry into force of this Regulation, each TSO shall agree with the relevant DSOs on effective, efficient and proportional processes for providing and managing data exchanges between them, including, where required for efficient network operation, the provision of data related to distribution systems and SGUs. Without prejudice to the provisions of paragraph 6(g), each TSO shall agree with the relevant DSOs on the format for the data exchange.

8. Transmission-connected SGUs shall have access to the data related to their commissioned network installations at the connection point.

9. Each TSO shall agree with the transmission-connected DSOs on the scope of additional information to be exchanged between them concerning commissioned network installations.

10. DSOs with a connection point to a transmission system shall be entitled to receive the relevant structural, scheduled and real-time information from the relevant TSOs and to gather the relevant structural, scheduled and real-time information from the neighbouring DSOs. Neighbouring DSOs shall determine, in a coordinated manner, the scope of information that may be exchanged.

CHAPTER 2
Data exchange between TSOs

Article 41

Structural and forecast data exchange

1. Neighbouring TSOs shall exchange at least the following structural information related to the observability area:

(a) the regular topology of substations and other relevant data, by voltage level;

(b) technical data on transmission lines;

(c) technical data on transformers connecting the DSOs, SGUs which are demand facilities and generators' block-transformers of SGUs which are power generating facilities;

(d) the maximum and minimum active and reactive power of SGUs which are power generating modules;

(e) technical data on phase-shifting transformers;

(f) technical data on HVDC systems;

(g) technical data on reactors, capacitors and static volt-ampere reactive (VAR) compensators; and

(h) operational security limits defined by each TSO according to Article 25.

2. To coordinate the protection of their transmission systems, neighbouring TSOs shall exchange the protection setpoints of the lines for which the contingencies are included as external contingencies in their contingency lists.

3. To coordinate their operational security analysis and to establish the common grid model in accordance with Articles 67, 68, 69 and 70, each TSO shall exchange, with at least all other TSOs from the same synchronous area, at least the following data:

(a) the topology of the 220 kV and higher voltage transmission systems within its control area;

(b) a model or an equivalent of the transmission system with voltage below 220 kV with significant impact on its own transmission system;

(c) the thermal limits of the transmission system elements; and

(d) a realistic and accurate forecasted aggregate amount of injection and withdrawal, per primary energy source, at each node of the transmission system, for different time-frames.

4. To coordinate the dynamic stability assessments pursuant to Article 38(2) and (4), and to carry them out, each TSO shall exchange with the other TSOs of the same synchronous area or of its relevant part the following data:

(a) data concerning SGUs which are power generating modules relating to, but not limited to:

(i) electrical parameters of the alternator suitable for the dynamic stability assessment, including total inertia;

(ii) protection models;

(iii) alternator and prime mover;

(iv) step-up transformer description;

(v) minimum and maximum reactive power;

(vi) voltage models and speed controller models; and

(vii) prime movers models and excitation system models suitable for large disturbances;

(b) the data on type of regulation and voltage regulation range concerning tap changers, including the description of existing on-load tap changers, and the data on type of regulation and voltage regulation range concerning step-up and network transformers; and

(c) the data concerning HVDC systems and FACTS devices on the dynamic models of the system or the device and its associated regulation suitable for large disturbances.

Article 42

Real-time data exchange

1. In accordance with Articles 18 and 19, each TSO shall exchange with the other TSOs of the same synchronous area the following data on the system state of its transmission system using the IT tool for real-time data exchange at pan-European level as provided by ENTSO for Electricity:

(a) frequency;

(b) frequency restoration control error;

(c) measured active power interchanges between LFC areas;

(d) aggregated generation infeed;

(e) system state in accordance with Article 18;

(f) setpoint of the load-frequency controller; and

(g) power interexchange via virtual tie-lines.

2. Each TSO shall exchange with the other TSOs in its observability area the following data about its transmission system using real-time data exchanges between the TSOs' supervisory control and data acquisition (SCADA) systems and energy management systems:

(a) actual substation topology;

(b) active and reactive power in line bay, including transmission, distribution and lines connecting SGUs;

(c) active and reactive power in transformer bay, including transmission, distribution and SGUs connecting transformers;

(d) active and reactive power in power generating facility bay;

(e) regulating positions of transformers, including phase-shifting transformers;

(f) measured or estimated busbar voltage;

(g) reactive power in reactor and capacitor bay or from a static VAR compensator; and

(h) restrictions on active and reactive power supply capabilities with respect to the observability area.

3. Each TSO shall have the right to request all TSOs from its observability area to provide real- time snapshots of state estimated data from that TSO's control area if that is relevant for the operational security of the transmission system of the requesting TSO.

CHAPTER 3
Data exchange between TSOs and DSOs within the TSO's control area

Article 43
Structural data exchange

1. Each TSO shall determine the observability area of the transmission-connected distribution systems which is needed for the TSO to determine the system state accurately and efficiently, based on the methodology developed in accordance with Article 75.

2. If a TSO considers that a non-transmission-connected distribution system has a significant influence in terms of voltage, power flows or other electrical parameters for the representation of the transmission system's behaviour, such distribution system shall be defined by the TSO as being part of the observability area in accordance with Article 75.

3. The structural information related to the observability area referred to in paragraphs 1 and 2 provided by each DSO to the TSO shall include at least:

(a) substations by voltage;

(b) lines that connect the substations referred to in point (a);

(c) transformers from the substations referred to in point (a);

(d) SGUs; and

(e) reactors and capacitors connected to the substations referred to in point (a).

4. Each transmission-connected DSO shall provide the TSO with an update of the structural information in accordance with paragraph 3 at least every 6 months.

5. At least once a year, each transmission-connected DSO shall provide the TSO, per primary energy sources, the total aggregated generating capacity of the type A power generating modules subject to requirements of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and the best possible estimates of generating capacity of type A power generating modules not subject to or derogated from Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** connected to its distribution system, and the related information concerning their frequency behaviour.

Article 44

Real-time data exchange

Unless otherwise provided by the TSO, each DSO shall provide its TSO, in real-time, the information related to the observability area of the TSO as referred to in Article 43(1) and (2), including:

(a) the actual substation topology;

(b) the active and reactive power in line bay;

(c) the active and reactive power in transformer bay;

(d) the active and reactive power injection in power generating facility bay;

(e) the tap positions of transformers connected to the transmission system;

(f) the busbar voltages;

(g) the reactive power in reactor and capacitor bay;

(h) the best available data for aggregated generation per primary energy source in the DSO area; and

(i) the best available data for aggregated demand in the DSO area.

CHAPTER 4

Data exchange between TSOs, owners of interconnectors or other lines and power generating modules connected to the transmission system

Article 45

Structural data exchange

1. Each SGU which is a power generating facility owner of a type D power generating module connected

to the transmission system shall provide the TSO with at least the following data:

(a) general data of the power generating module, including installed capacity and primary energy source;

(b) turbine and power generating facility data including time for cold and warm start;

(c) data for short-circuit current calculation;

(d) power generating facility transformer data;

(e) FCR data of power generating modules offering or providing that service, in accordance with Article 154;

(f) FRR data of power generating modules offering or providing that service, in accordance with Article 158;

(g) RR data of power generating modules that offer or provide that service in accordance with Article 161;

(h) data necessary for restoration of the transmission system;

(i) data and models necessary for performing dynamic simulation;

(j) protection data;

(k) data necessary for determining the costs of remedial actions in accordance with Article 78(1)(b); where a TSO makes use of market based mechanisms in line with Article 4(2)(d), the provision of prices to be paid by the TSO shall be considered sufficient;

(l) voltage and reactive power control capability.

2. Each SGU which is a power generating facility owner of a type B or a type C power generating module connected to the transmission system shall provide the TSO with at least the following data:

(a) general data of the power generating module, including installed capacity and primary energy source;

(b) data for short-circuit current calculation;

(c) FCR data according to the definition and requirements of the Article 173 for power generating modules offering or providing that service;

(d) FRR data for power generating modules that offer or provide that service;

(e) RR data for power generating modules that offer or provide that service;

(f) protection data;

(g) reactive power control capability;

(h) data necessary for determining the costs of remedial actions in accordance with Article 78(1)(b); where a TSO makes use of market based mechanisms in line with Article 4(2)(d), the provision of prices to be paid by the TSO shall be considered sufficient;

(i) data necessary for performing dynamic stability assessment according to Article 38.

3. A TSO may request the power generating facility owner of a power generating module connected to the transmission system to provide further data where appropriate for operational security analysis in accordance with Title 2 of Part III.

4. Each HVDC system owner or interconnector owner shall provide the TSO with the following data regarding the HVDC system or interconnector:

(a) nameplate data of the installation;

(b) transformers data;

(c) data on filters and filter banks;

(d) reactive power compensation data;

(e) active power control capability;

(f) reactive power and voltage control capability;

(g) active or reactive operational mode prioritization, if existing;

(h) frequency response capability;

(i) dynamic models for dynamic simulation;

(j) protection data; and

(k) fault-ride-through capability.

5. Each AC interconnector owner shall provide the TSO with at least the following data:

(a) nameplate data of the installation;

(b) electrical parameters;

(c) associated protections.

Article 46

Scheduled data exchange

1. Each SGU which is a power generating facility owner of a type B, C or D power generating module connected to the transmission system shall provide the TSO with at least the following data:

(a) active power output and active power reserves amount and availability, on a day-ahead and intra- day basis;

(b) without any delay, any scheduled unavailability or active power restriction;

(c) any forecasted restriction in the reactive power control capability; and

(d) as an exception to points (a) and (b), in regions with a central dispatch system, data requested by the TSO for the preparation of its active power output schedule.

2. Each HVDC system operator shall provide the TSOs with at least the following data:

(a) active power schedule and availability on a day-ahead and intra-day basis;

(b) without delay its scheduled unavailability or active power restriction; and

(c) any forecast restriction in the reactive power or voltage control capability.

3. Each AC interconnector or line operator shall provide its scheduled unavailability or active power restriction data to the TSOs.

Article 47

Real-time data exchange

1. Unless otherwise provided by the TSO, each significant grid user which is a power generating facility owner of type B, C or D power generating module shall provide the TSO, in real-time, at least the following data:

(a) position of the circuit breakers at the connection point or another point of interaction agreed with the TSO;

(b) active and reactive power at the connection point or another point of interaction agreed with the TSO; and

(c) in the case of power generating facility with consumption other than auxiliary consumption net active and reactive power.

2. Unless otherwise provided by the TSO, each HVDC system or AC interconnector owner shall provide, in real-time, at least the following data regarding the connection point of the HVDC system or AC interconnector to the TSOs:

(a) position of the circuit breakers;

(b) operational status; and

(c) active and reactive power.

CHAPTER 5

Data exchange between TSOs, DSOs and distribution-connected power generating modules

Article 48

Structural data exchange

1. Unless otherwise provided by the TSO, each power generating facility owner of a power generating module which is a SGU pursuant to Article 2(1)(a) and by aggregation of the SGUs pursuant to Article 2(1)(e) connected to the distribution system shall provide at least the following data to the TSO and to the DSO to which it has a connection point:

(a) general data of the power generating module, including installed capacity and primary energy source or fuel type;

(b) FCR data according to the definition and requirements of Article 173 for power generating facilities offering or providing the FCR service;

(c) FRR data for power generating facilities offering or providing the FRR service;

(d) RR data for power generating modules offering or providing the RR service;

(e) protection data;

(f) reactive power control capability;

(g) capability of remote access to the circuit breaker;

(h) data necessary for performing dynamic simulation according to the provisions in Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**; and

(i) voltage level and location of each power generating module.

2. Each power generating facility owner of a power generating module which is a SGU in accordance with

Article 2(1)(a) and (e) shall inform the TSO and the DSO to which it has a connection point, within the agreed time and not later than the first commissioning or any changes to the existing installation, about any change in the scope and the contents of the data listed in paragraph 1.

Article 49

Scheduled data exchange

Unless otherwise provided by the TSO, each power generating facility owner of a power generating module which is a SGU in accordance with Article 2(1)(a) and 2(1)(e) connected to the distribution system shall provide the TSO and the DSO to which it has the connection point, with at least the following data:

(a) its scheduled unavailability, scheduled active power restriction and its forecasted scheduled active power output at the connection point;

(b) any forecasted restriction in the reactive power control capability; and

(c) as an exception to paragraphs (a) and (b), in regions with a central dispatch system, data requested by the TSO for the preparation of its active power output schedule.

Article 50

Real-time data exchange

1. Unless otherwise provided by the TSO, each power generating facility owner of a power generating module which is a SGU in accordance with Article 2(1)(a) and (e) connected to the distribution system shall provide the TSO and the DSO to which it has the connection point, in real- time, at least the following data:

(a) status of the switching devices and circuit breakers at the connection point; and

(b) active and reactive power flows, current, and voltage at the connection point.

2. Each TSO shall define in coordination with the responsible DSOs which SGUs may be exempted from providing the real-time data listed in paragraph 1 directly to the TSO. In such cases, the responsible TSOs and DSOs shall agree on the aggregated real-time data of the SGUs concerned to be delivered to the TSO.

Article 51

Data exchange between TSOs and DSOs concerning significant power generating modules

1. Unless otherwise provided by the TSO, each DSO shall provide to its TSO the information specified in Articles 48, 49 and 50 with the frequency and level of detail requested by the TSO.

2. Each TSO shall make available to the DSO, to whose distribution system SGUs are connected, the information specified in Articles 48, 49 and 50 as requested by the DSO.

3. A TSO may request further data from a power generating facility owner of a power generating module which is a SGU in accordance with Article 2(1)(a) and (e) connected to the distribution system, if it is necessary for the operational security analysis and for the validation of models.

CHAPTER 6

Data exchange between TSOs and demand facilities

Article 52

Data exchange between TSOs and transmission-connected demand facilities

1. Unless otherwise provided by the TSO, each transmission-connected demand facility owner shall provide the following structural data to the TSO:

(a) electrical data of the transformers connected to the transmission system;

(b) characteristics of the load of the demand facility; and

(c) characteristics of the reactive power control.

2. Unless otherwise provided by the TSO, each transmission-connected demand facility owner shall provide the following data to the TSO:

(a) scheduled active and forecasted reactive power consumption on a day-ahead and intraday basis, including any changes of those schedules or forecast;

(b) any forecasted restriction in the reactive power control capability;

(c) in case of participation in demand response, a schedule of its structural minimum and maximum power range to be curtailed; and

(d) by exception to point (a), in regions with a central dispatch system, the data requested by the TSO for the preparation of its active power output schedule.

3. Unless otherwise provided by the TSO, each transmission-connected demand facility owner shall provide the following data to the TSO in real-time:

(a) active and reactive power at the connection point; and

(b) the minimum and maximum power range to be curtailed.

4. Each transmission-connected demand facility owner shall describe to its TSO its behaviour at the voltage ranges referred to in Article 27.

Article 53

Data exchange between TSOs and distribution-connected demand facilities or third parties participating in demand response

1. Unless otherwise provided by the TSO, each SGU which is a distribution-connected demand facility and which participates in demand response other than through a third party shall provide the following scheduled and real-time data to the TSO and to the DSO:

(a) structural minimum and maximum active power available for demand response and the maximum and minimum duration of any potential usage of this power for demand response;

(b) a forecast of unrestricted active power available for demand response and any planned demand response;

(c) real-time active and reactive power at the connection point; and

(d) a confirmation that the estimations of the actual values of demand response are applied.

2. Unless otherwise provided by the TSO, each SGU which is a third party participating in demand response as defined in Article 27 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** shall provide the TSO and the DSO at the day-ahead and close to real-time and on behalf of all of its distribution-connected demand facilities, with the following data:

(a) structural minimum and maximum active power available for demand response and the maximum and minimum duration of any potential activation of demand response in a specific geographical area defined by the TSO and DSO;

(b) a forecast of unrestricted active power available for the demand response and any planned level of demand response in a specific geographical area defined by the TSO and DSO;

(c) real-time active and reactive power; and

(d) a confirmation that the estimations of the actual values of demand response are applied.

TITLE 3
COMPLIANCE

CHAPTER 1
Roles and responsibilities

Article 54
Responsibility of the SGUs

1. Each SGU shall notify the TSO or DSO to which it has a connection point about any planned modification of its technical capabilities which could have an impact on its compliance with the requirements of this Regulation, prior to its execution.

2. Each SGU shall notify the TSO or DSO to which it has a connection point about any operational disturbance in its facility which could have an impact on its compliance with the requirements of this Regulation as soon as possible after its occurrence.

3. Each SGU shall notify the TSO or DSO to which it has a connection point of the planned test schedules and procedures to be followed for verifying the compliance of its facility with the requirements of this Regulation, in due time and prior to their launch. The TSO or DSO shall approve in advance and in a timely manner the planned test schedules and procedures and the approval shall not be unreasonably withheld. Where the SGU has a connection point to the DSO and interacts, pursuant to paragraph 2, only with the DSO, the TSO shall be entitled to request from the concerned DSO any compliance testing results, which are relevant for the operational security of its transmission system.

4. Upon request from the TSO or DSO, pursuant to Article 41(2) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and Article 35(2) of

Regulation (EU) 2016/1388, **as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** the SGU shall carry out compliance tests and simulations in accordance with those Regulations at any time throughout the lifetime of its facility and in particular after any fault, modification or replacement of any equipment, which could have an impact on the facility's compliance with the requirements of this Regulation regarding the capability of the facility to achieve the values declared, the time requirements applicable to those values and the availability or contracted provision of ancillary services. Third parties providing demand response directly to the TSO, providers of redispatching of power generating modules or demand facilities by means of aggregation, and other providers of active power reserves shall ensure that the facilities in their portfolio comply with the requirements of this Regulation.

Article 55

Tasks of TSOs regarding system operation

Each TSO shall be responsible for the operational security of its control area and, in particular, it shall:

(a) develop and implement network operation tools that are relevant for its control area and related to real-time operation and operational planning;

(b) develop and deploy tools and solutions for the prevention and remedy of disturbances;

(c) use services provided by third parties, through procurement when applicable, such as redispatching or countertrading, congestion management services, generation reserves and other ancillary services;

(d) comply with the incidents classification scale adopted by ENTSO for **<…>** and submit to ENTSO for Electricity the information required to perform the tasks for producing the incidents classification scale; and

(e) monitor on an annual basis the appropriateness of the network operation tools established pursuant to points (a) and (b) required to maintain operational security. Each TSO shall identify any appropriate improvements to those network operation tools, taking into account the annual reports prepared by ENTSO for Electricity based on the incidents classification scale in accordance with Article 15. Any identified enhancement shall be implemented subsequently by the TSO.

CHAPTER 2
Operational testing

Article 56

Purpose and responsibilities

1. Each TSO and each transmission-connected DSO or SGU may perform operational testing respectively of its transmission system elements and of their facilities under simulated operational conditions and for a limited period of time. When doing so, they shall provide notification in due time and prior to the test launch and shall minimise the effect on real-time system operation. The operational testing shall aim at providing:

(a) proof of compliance with all relevant technical and organisational operational provisions of this Regulation for a new transmission system element at its first entry into operation;

(b) proof of compliance with all relevant technical and organisational operational provisions of this Regulation for a new facility of the SGU or of DSO at its first entry into operation;

(c) proof of compliance with all relevant technical and organisational operational provisions of this Regulation upon any change of a transmission system element or a facility of the SGU or of the DSO, which is relevant for system operation;

(d) assessment of possible negative effects of a failure, short-circuit or other unplanned and

unexpected incident in system operation, on the transmission system element, or on the facility of the SGU or of the DSO.

2. The results of the operational testing referred to in paragraph 1 shall be used by a TSO, DSO or a SGU, in order for:

(a) the TSO to ensure correct functioning of transmission system elements;

(b) the DSO and SGUs to ensure correct functioning of distribution systems and of the SGUs' facilities;

(c) the TSO, DSO or SGU to maintain existing and develop new operational practices;

(d) the TSO to ensure fulfilment of ancillary services;

(e) the TSO, DSO or SGU to acquire information about performance of transmission system elements and facilities of the SGUs and DSOs under any conditions and in compliance with all relevant operational provisions of this Regulation, in terms of:

(i) controlled application of frequency or voltage variations aimed at gathering information on transmission system and elements' behaviour; and

(ii) tests of operational practices in emergency state and restoration state.

3. Each TSO shall ensure that operational testing does not endanger the operational security of its transmission system. Any operational testing may be postponed or interrupted due to unplanned system conditions, or due to safety of personnel, of the general public, of the plant or apparatus being tested, or of transmission system elements or of the facilities of the DSO or SGU.

4. In the event of degradation of the state of the transmission system in which the operational testing is performed, the TSO of that transmission system shall be entitled to interrupt the operational testing. If conducting a test affects another TSO and its system state is also degraded, the TSO or SGU or DSO conducting the test shall, upon being informed by the TSO concerned, immediately cease the operational test.

5. Each TSO shall ensure that the results of relevant operational tests carried out together with all related analyses are:

(a) incorporated into the training and certification process of the employees in charge of real-time operation;

(b) used as inputs to the research and development process of ENTSO for Electricity; and

(c) used to improve operational practices including also those in emergency and restoration state.

Article 57

Performing operational tests and analysis

1. Each TSO or DSO to which the SGU has a connection point retains the right to test a SGU's compliance

with the requirements of this Regulation, the SGU's expected input or output and the SGU's contracted provision of ancillary services at any time throughout the lifetime of the facility. The procedure for those operational tests shall be notified to the SGU by the TSO or DSO in due time prior to the launch of the operational test.

2. The TSO or DSO to which the SGU has a connection point shall publish the list of information and documents to be provided as well as the requirements to be fulfilled by the SGU for operational testing of compliance. Such list shall cover at least the following information:

(a) all documentation and equipment certificates to be provided by the SGU;

(b) details of the technical data of the SGU facility with relevance for the system operation;

(c) requirements for models for dynamic stability assessment; and

(d) studies by the SGU demonstrating expected outcome of the dynamic stability assessment, where applicable.

3. Where applicable, each TSO or DSO shall publish the allocation of responsibilities of the SGU and of the TSO or DSO for operational testing of compliance.

TITLE 4
TRAINING

Article 58
Training program

1. By 18 months after entry into force of this Regulation each TSO shall develop and adopt:

2. The TSO's training programs shall include the knowledge of the transmission system elements, the operation of the transmission system, use of the on-the-job systems and processes, inter-TSO operations, market arrangements, recognising of and responding to exceptional situations in system operation, operational planning activities and tools.

3. TSO employees in charge of real-time operation of transmission system shall, as a part of its initial training, undergo training on interoperability issues between transmission systems based upon operational experiences and feedback from the joint training carried out with neighbouring TSOs in accordance with Article 63. That training on interoperability issues shall include preparation and activation of coordinated remedial actions required in all system states.

4. Each TSO shall include in its training program for the employees in charge of real-time operation of the transmission system the frequency of the trainings and the following components:

(a) a description of the transmission system elements;

(b) operation of the transmission system in all system states including restoration;

(c) use of the on-the-job systems and processes;

(d) coordination of inter-TSO operations and market arrangements;

(e) recognition of and response to exceptional operational situations;

(f) relevant areas of electrical power engineering;

(g) relevant aspects of the **Energy Community** internal electricity market;

(h) relevant aspects of the network codes or guidelines adopted according to Articles **59** and **61** of Regulation **(EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(i) safety and security of persons, nuclear and other equipment in transmission system operation;

(j) inter-TSO cooperation and coordination in real-time operation and in operational planning at the level of main control rooms which shall be given in English unless otherwise specified;

(k) joint training with transmission-connected DSOs and SGUs, where appropriate;

(l) behavioural skills with particular focus on stress management, human acting in critical situation, responsibility and motivation skills; and

(m) operational planning practices and tools, including those used with the relevant regional **coordination centre** in the operational planning.

5. The training program for employees in charge of operational planning shall include at least the aspects in points (c), (f), (g), (h), (j) and (m) of paragraph 4.

6. The training program for employees in charge of balancing shall include at least the aspects in points (c), (g) and (h) of paragraph 4.

7. Each TSO shall maintain records of employees' training programs for their period of employment. Upon request of the relevant regulatory authority, each TSO shall provide the scope and details of its training programs.

8. Each TSO shall review its training programs at least annually or following significant system changes. Each TSO shall update its training programs to reflect changing operational circumstances, market rules, network configuration and system characteristics, with particular focus on new technologies, changing generation and demand patterns and market evolution.

Article 59

Training conditions

1. Each TSO's training programs for employees in charge of real-time operation shall include on- the-job and offline training. On-the-job training shall be carried out under the supervision of an experienced employee in charge of real-time operation. Offline training shall be carried out in an environment which simulates the control room and with network modelling details at a level appropriate to the tasks being trained for.

2. Each TSO shall implement training for employees in charge of real-time operation based on a comprehensive database model of their network with respective data from other networks of, at least, the observability area, at a level of detail which is sufficient to replicate inter-TSO operational issues. Training scenarios shall be based on real and simulated system conditions. Where relevant, the role of other TSOs, transmission-connected DSOs and significant grid users shall also be simulated unless they can be directly represented in joint trainings.

3. Each TSO shall coordinate the offline training of the employees in charge of real-time operation with the transmission-connected DSOs and SGUs regarding the impact of their facilities on real- time operation of

the transmission system, in a comprehensive and proportionate manner, reflecting the up-to-date network topology and characteristics of secondary equipment. When relevant, TSOs, transmission-connected DSOs and SGUs shall run joint offline training simulations or training workshops.

Article 60

Training coordinators and trainers

1. The training coordinator's responsibilities shall include the designing, monitoring and updating of the training programs, as well as the determination of:

(a) the qualifications and selection process for TSO employees to be trained;

(b) the training required for certification of the system operator employees in charge of real-time operation;

(c) the processes, including relevant documentation, for the initial and the rolling training programs;

(d) the process for certification of system operator employees in charge of real-time operation; and

(e) the process for extension of a training period and certification period for the system operator employees in charge of real-time operation.

2. Each TSO shall determine the skills and the level of competence of on-the-job trainers. On-the- job trainers shall have an appropriate level of operational experience following their certification.

3. Each TSO shall have a register of the system operator employees in charge of real-time operation who carry out the functions of on-the-job trainers and review their capability to provide practical training when deciding upon the extension of their certification.

Article 61

Certification of system operator employees in charge of real-time operation

1. An individual may become a system operator employee in charge of real-time operation provided he or she is trained and subsequently certified by a nominated representative from his or her TSO for the concerned tasks within the timescale defined in the training programme. A system operator employee in charge of real-time operation shall not work unsupervised in the control room unless he or she is certified.

2. By 18 months after entry into force of this Regulation, each TSO shall define and implement a process, including the level of competence, for the certification of the system operator employees in charge of real-time operation.

3. TSO employees in charge of real-time operation shall be certified following a successful formal assessment which shall comprise an oral and/or a written exam, and/or a practical assessment with pre-defined success criteria.

4. The TSO shall keep a copy of the issued certificate and of the formal assessment results. Upon request by the regulatory authority, the TSO shall provide a copy of the certification examination records.

5. Each TSO shall record the period of validity of the certification issued to any employee in charge of real-time operation.

6. Each TSO shall determine the maximum period of the certification, which shall not exceed 5 years but which may be extended on the basis of criteria determined by each TSO, and may take into account the participation of employees in charge of real-time operation in a continuous training programme with sufficient practical experience.

Article 62

Common language for communication between the system operator employees in charge of real time operation

1. Unless otherwise agreed, the common contact language between the employees of a TSO and those of the neighbouring TSO shall be English.

2. Each TSO shall train its relevant system operator employees to achieve sufficient skills in the common contact languages agreed with the neighbouring TSOs.

Article 63

Cooperation between TSOs on training

1. Each TSO shall organise regular training sessions with its neighbouring TSOs to improve the knowledge of the characteristics of neighbouring transmission systems as well as thecommunication and coordination between employees of neighbouring TSOs in charge of real-time operation. The inter-TSO training shall include detailed knowledge of coordinated actions required under each system state.

2. Each TSO shall determine, in cooperation with at least the neighbouring TSO, the need and frequency for joint training sessions, including the minimum content and scope of those sessions, taking into account the level of mutual influence and operational cooperation needed. This inter- TSO training may include, but should not be limited to, joint training workshops and joint training simulator sessions.

3. Each TSO shall participate with other TSOs, at least once a year, in training sessions on the management of inter-TSO issues in real-time operation. The frequency shall be defined taking into account the level of mutual influence of transmission systems and the type of interconnection — DC/AC links.

4. Each TSO shall exchange experiences from real-time operation, including visits and the exchange of experiences between system operator employees in charge of real-time operation, with their neighbouring TSOs, with any TSO with which there is or has been inter-TSO operational interaction and with the relevant regional **coordination centre**.

PART III
OPERATIONAL PLANNING

TITLE 1
DATA FOR OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING

Article 64

General provisions regarding individual and common grid models

1. To perform operational security analysis pursuant to Title 2 of this Part, each TSO shall prepare individual grid models in accordance with the methodologies established in application of Article 17 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** and Article 18 of Regulation (EU) 2016/1719, **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** for each of the following time-frames, applying the data format established pursuant to Article 114(**1**) **of Regulation 2017/1485**:

(a) year-ahead, in accordance with Articles 66, 67 and 68;

(b) where applicable, week-ahead, in accordance with Article 69;

(c) day-ahead, in accordance with Article 70; and

(d) intraday, in accordance with Article 70.

2. The individual grid models shall include the structural information and data set out in Article 41.

3. Each TSO shall build the individual grid models and each regional **coordination centre** shall contribute to building the common grid models applying the data format established pursuant to Article 114(**1**) **of Regulation 2017/1485**.

Article 65

Year-ahead scenarios

1. All TSOs shall jointly develop a common list of year-ahead scenarios against which they assess the operation of the interconnected transmission system for the following year. Those scenarios shall allow the identification and the assessment of the influence of the interconnected transmission system on operational security. The scenarios shall include the following variables:

(a) electricity demand;

(b) the conditions related to the contribution of renewable energy sources;

(c) determined import/export positions, including agreed reference values allowing the merging task;

(d) the generation pattern, with a fully available production park;

(e) the year-ahead grid development.

2. When developing the common list of scenarios, TSOs shall take into account the following elements:

(a) the typical cross-border exchange patterns for different levels of consumption and of renewable energy sources and conventional generation;

(b) the probability of occurrence of the scenarios;

(c) the potential deviations from operational security limits for each scenario;

(d) the amount of power generated and consumed by the power generating facilities and demand facilities connected to distribution systems.

3. Where TSOs do not succeed in establishing the common list of scenarios referred to in paragraph 1, they shall use the following default scenarios:

(a) Winter Peak, 3rd Wednesday of January current year, 10:30 CET;

(b) Winter Valley, 2nd Sunday of January current year, 03:30 CET;

(c) Spring Peak, 3rd Wednesday of April current year, 10:30 CET;

(d) Spring Valley, 2nd Sunday of April current year, 03:30 CET;

(e) Summer Peak, 3rd Wednesday of July previous year, 10:30 CET;

(f) Summer Valley, 2nd Sunday of July previous year, 03:30 CET;

(g) Autumn Peak, 3rd Wednesday of October previous year, 10:30 CET;

(h) Autumn Valley, 2nd Sunday of October previous year, 03:30 CET.

4. **The TSOs of the Contracting Parties shall apply the common list of scenarios established for the following year and adopted in accordance with Regulation (EU) 2017/1485.**

Article 66

Year-ahead individual grid models

1. Each TSO shall determine a year-ahead individual grid model for each of the scenarios developed pursuant to Article 65, using its best estimates of the variables defined in Article 65(1). Each TSO shall publish its year-ahead individual grid models on the ENTSO for Electricity operational planning data environment **<…>**.

2. When defining its year-ahead individual grid model, each TSO shall:

(a) agree with the neighbouring TSOs upon the estimated power flow on HVDC systems linking their control areas;

(b) balance for each scenario the sum of:

(i) net exchanges on AC lines;

(ii) estimated power flows on HVDC systems;

(iii) load, including an estimation of losses; and

(iv) generation.

3. Each TSO shall include in its year-ahead individual grid models the aggregated power outputs for power generating facilities connected to distribution systems. Those aggregated power outputs shall:

(a) be consistent with the structural data provided in accordance with the requirements of Articles 41, 43, 45 and 48;

(b) be consistent with the scenarios developed in accordance with Article 65; and

(c) distinguish the type of primary energy source.

Article 67

Year-ahead common grid models

1. By 6 months after entry into force of this Regulation, **<…>** TSOs shall **apply** the methodology for building the year-ahead common grid models from the individual grid models established in accordance with Article 66(1) and for saving them. **<…>**

2. Each TSO shall have the right to request from another TSO any information on modifications to the network topology or on operational arrangements, such as protection setpoints or system protection schemes, single line diagrams and configuration of substations or additional grid models

relevant for the provision of an accurate representation of the transmission system to undertake operational security analysis.

Article 68

Updates of year-ahead individual and common grid models

1. When a TSO modifies or notices a modification of its best estimates for the variables used for determining its year-ahead individual grid model established in accordance with Article 66(1), which is significant for operational security, it shall update its year-ahead individual grid model and publish it on the ENTSO for Electricity operational planning data environment.

2. Whenever an individual grid model is updated, the year-ahead common grid model shall be updated accordingly applying the methodology determined in accordance with Article 67(1).

Article 69

Week-ahead individual and common grid models

1. Where two or more TSOs consider it necessary, they shall determine the most representative scenarios for coordinating the operational security analysis of their transmission system for the week-ahead time-frame and shall develop a methodology for merging the individual grid models analogous to the methodology for building the year-ahead common grid model from year-ahead individual grid models in accordance with Article 67(1).

2. Each TSO referred to in paragraph 1 shall establish or update its week-ahead individual grid models pursuant to the scenarios determined in accordance with paragraph 1.

3. The TSOs referred to in paragraph 1 or the third parties to which the task referred to in paragraph 1 has been delegated, shall build the week-ahead common grid models following the methodology developed in accordance with paragraph 1 and using the individual grid models established in accordance with paragraph 2.

Article 70

Methodology for building day-ahead and intraday common grid models

1. By 6 months after entry into force of this Regulation, **<…>** TSOs shall **apply** the methodology for building the day-ahead and intraday common grid models from the individual grid models and for saving them. **<…>**

2. Each TSO shall create day-ahead and intraday individual grid models in accordance with paragraph 1 and publish them on the ENTSO for Electricity operational planning data environment.

3. When creating the day-ahead or intraday individual grid models referred to in paragraph 2, each TSO shall include:

(a) up-to-date load and generation forecasts;

(b) the available results of the day-ahead and intraday market processes;

(c) the available results of the scheduling tasks described in Title 6 of Part III;

(d) for power generating facilities connected to distribution systems, aggregated active power output differentiated on the basis of the type of primary energy source, in line with data provided in accordance with Articles 40, 43, 44, 48, 49 and 50;

(e) up-to-date topology of the transmission system.

4. All remedial actions already decided shall be included in the day-ahead and intraday individual grid models and shall be clearly distinguishable from the injections and withdrawals established in accordance with Article 40(4) and the network topology without remedial actions applied.

5. Each TSO shall assess the accuracy of the variables in paragraph 3 by comparing the variables with their actual values, taking into account the principles determined pursuant to Article 75(1)(c).

6. If, following the assessment referred to in paragraph 5, a TSO considers that the accuracy of the variables is insufficient to evaluate operational security, it shall determine the causes of the inaccuracy. If the causes depend on the TSO's processes for establishing the individual grid models, that TSO shall review those processes to obtain more accurate results. If the causes depend on variables provided by other parties, that TSO together with those other parties shall endeavour to ensure that the variables concerned are accurate.

Article 71

Quality control for grid models

When defining the quality controls in accordance with Articles 67(1)(b) and 70(1)(c), all TSOs shall jointly determine controls aimed at least to check:

(a) the coherence of the connection status of interconnectors;

(b) that voltage values are within the usual operational values for those transmission system elements having influence on other control areas;

(c) the coherence of transitory admissible overloads of interconnectors; and

(d) that active power and reactive power injections or withdrawals are compatible with usual operational values.

TITLE 2
OPERATIONAL SECURITY ANALYSIS

Article 72

Operational security analysis in operational planning

1. Each TSO shall perform coordinated operational security analyses for at least the following time-frames:

(a) year-ahead;

(b) week-ahead, when applicable in accordance with Article 69;

(c) day-ahead; and

(d) intraday.

2. When performing a coordinated operational security analysis, the TSO shall apply the methodology adopted pursuant to Article 75.

3. To perform operational security analyses, each TSO shall, in the N-Situation, simulate each contingency from its contingency list established in accordance with Article 33 and verify that, in the (N-1)-situation, the operational security limits defined in accordance with Article 25 are not exceeded in its control area.

4. Each TSO shall perform its operational security analyses using at least the common grid models established in accordance with Articles 67, 68, 70 and, where applicable, 69 and shall take into account the planned outages when carrying out those analyses.

5. Each TSO shall share the results of its operational security analysis with at least the TSOs whose elements are included in the TSO's observability area and are affected according to that operational security analysis, in order to allow those TSOs to verify that operational security limits are respected within their control areas.

Article 73

Year-ahead up to and including week-ahead operational security analysis

1. Each TSO shall perform year-ahead and, where applicable, week-ahead operational security analyses in order to detect at least the following constraints:

(a) power flows and voltages exceeding operational security limits;

(b) violations of stability limits of the transmission system identified in accordance with Article 38(2) and (6); and

(c) violations of short-circuit thresholds of the transmission system.

2. When a TSO detects a possible constraint, it shall design remedial actions in accordance with Articles 20 to 23. If remedial actions without costs are not available and the constraint is linked to the planned unavailability of some relevant assets, the constraint shall constitute an outage planning incompatibility and the TSO shall initiate outage coordination in accordance with Article 95 or 100 depending of the time of the year when this action is initiated.

Article 74

Day-ahead, intraday and close to real-time operational security analysis

1. Each TSO shall perform day-ahead, intraday and close to real-time operational security analyses to detect possible constraints and prepare and activate the remedial actions with any other concerned TSOs and, if applicable, affected DSOs or SGUs.

2. Each TSO shall monitor load and generation forecasts. When those forecasts indicate a significant deviation in load or generation, the TSO shall update its operational security analysis.

3. When performing close to real-time operational security analysis in its observability area, each TSO shall use state estimation.

Article 75

Methodology for coordinating operational security analysis

1. By 12 months after entry into force of this Regulation, **<…>** TSOs shall **apply** the methodology for coordinating operational security analysis. **<…>**

2. **<…>**

3. **<…>**

4. **<…>**

5. **<…>**

6. **<…>**

Article 76

Proposal for regional operational security coordination

1. By 3 months after **applying** the methodology for coordinating operational security analysis in Article 75(1), all TSOs of each capacity calculation region, **as established in accordance with Article 15(1) of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** shall jointly develop a proposal for common provisions for regional operational security coordination, to be applied by the regional-**coordination centre** and the TSOs of the capacity calculation region. The proposal shall respect the methodologies for coordinating operational security analysis developed in accordance with Article 75(1) and complement where necessary the methodologies developed in accordance with Articles 35 and 74 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.** The proposal shall determine:

(a) conditions and frequency of intraday coordination of operational security analysis and updates to the common grid model by the regional **coordination centre**;

(b) the methodology for the preparation of remedial actions managed in a coordinated way, considering their cross-border relevance as determined in accordance with Article 35 of Regulation (EU) 2015/1222,

as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC, taking into account the requirements in Articles 20 to 23 and determining at least:

2. In determining whether congestion have cross-border relevance, the TSOs shall take into account the congestion that would appear in the absence of energy exchanges between control areas.

Article 77

Organisation for regional operational security coordination

<...>

Article 78

Regional operational security coordination

1. Each TSO shall provide the regional **coordination centre** with all the information and data required to perform the coordinated regional operational security assessment, including at least:

(a) the updated contingency list, established according to the criteria defined in the methodology for coordinating operational security analysis **applied** in accordance with Article 75(1);

(b) the updated list of possible remedial actions, among the categories listed in Article 22, and their anticipated costs provided in accordance with Article 35 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** if a remedial action includes redispatching or countertrading, aimed at contributing to relieve any constraint identified in the region; and

(c) the operational security limits established in accordance with Article 25.

2. Each regional **coordination centre** shall:

(a) perform the coordinated regional operational security assessment in accordance with Article 76 on the basis of the common grid models established in accordance with Article 79, the contingency list and the operational security limits provided by each TSOs in paragraph 1. It shall deliver the results of the coordinated regional operational security assessment at least to all TSOs of the capacity calculation region. Where it detects a constraint, it shall recommend to the relevant TSOs the most effective and economically efficient remedial actions and may also recommend remedial actions other than those provided by the TSOs. This recommendation for remedial actions shall be accompanied by explanations as to its rationale;

(b) coordinate the preparation of remedial actions with and among TSOs in accordance with Article 76(1)(b), to enable TSOs achieve a coordinated activation of remedial actions in real-time.

3. When performing the coordinated regional operational security assessment and identifying the appropriate remedial actions, each regional **coordination centre** shall coordinate with other regional **coordination centres**.

4. When a TSO receives from the relevant regional **coordination centre** the results of the coordinated regional operational security assessment with a proposal for a remedial action, it shall evaluate the recommended remedial action for the elements involved in that remedial action and located in its control area. In so doing, it shall apply the provisions of Article 20. The TSO shall decide whether to implement the recommended remedial action. Where it decides not to implement the recommended remedial action, it

shall provide an explanation for this decision to the RCSC. Where the TSO decides to implement the recommended remedial action, it shall apply this action for the elements located in its control area provided that it is compatible with real-time conditions.

Article 79

Common grid model building

1. Each regional **coordination centre** shall check the quality of the individual grid models in order to contribute to building the common grid model for each mentioned time-frame in accordance with the methodologies referred to in Articles 67(1) and 70(1).

2. Each TSO shall make available to its regional **coordination centre** the individual grid model necessary to build the common grid model for each time-frame through the ENTSO for Electricity operational planning data environment.

3. Where necessary, each regional **coordination centre** shall request the TSOs concerned to correct their individual grid models in order to achieve their conformity with the quality controls and for their improvement.

4. Each TSO shall correct its individual grid models, after verifying the need for correction if applicable, on the basis of the requests of the regional **coordination centre** or another TSO.

5. In accordance with the methodologies referred to in Articles 67(1) and 70(1), and in accordance with Article 28 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** a regional **coordination centre** shall be appointed by all TSOs to build the common grid model for each time-frame and store it on the ENTSO for Electricity operational planning data environment.

Article 80

Regional outage coordination

1. The outage coordination regions within which the TSOs shall proceed to outage coordination shall be at least equal to the capacity calculation regions **as established in accordance with Article 15(1) of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. The TSOs of two or more outage coordination regions can agree to merge them into one unique outage coordination region. In that case they shall identify the regional **coordination centre** performing the tasks referred to in Article 77(3) **of Regulation 2017/1485**.

3. Each TSO shall provide the regional **coordination centre** with the information necessary to detect and solve regional outage planning incompatibilities, including at least:

(a) the availability plans of its internal relevant assets, stored on the ENTSO for Electricity operational planning data environment;

(b) the most recent availability plans for all non-relevant assets of its control area which are:

(i) capable of influencing the results of the outage planning incompatibility analysis;

(ii) modelled in the individual grid models which are used for the outage incompatibility assessment;

(c) scenarios on which the outage planning incompatibilities have to be investigated and used to build the corresponding common grid models derived from the common grid models for different time-frames established in accordance with Articles 67 and 79.

4. Each regional **coordination centre** shall perform regional operational security analyses on the basis of the information provided by the relevant TSOs in order to detect any outage planning incompatibility. It shall provide all TSOs of the outage coordination region with a list of detected outage planning incompatibilities and the solutions it proposes to solve those outage planning incompatibilities.

5. In performing their obligations under paragraph 4, each regional **coordination centre** shall coordinate its analyses with other regional **coordination centres**.

6. In performing their obligations in accordance with Article 98(3) and Article 100(4)(b), all TSOs shall take into account the results of the assessment provided by the regional **coordination centre** in accordance with paragraph 3 and paragraph 4.

Article 81

Regional adequacy assessment

1. Each regional **coordination centre** shall perform regional adequacy assessments for at least the week-ahead time-frame.

2. Each TSO shall provide the regional **coordination centre** with the information necessary to perform the regional adequacy assessments referred to in paragraph 1, including:

(a) the expected total load and available resources of demand response;

(b) the availability of power generation modules; and

(c) the operational security limits.

3. Each regional **coordination centre** shall perform adequacy assessments on the basis of the information provided by the relevant TSOs with the aim of detecting situations where a lack of adequacy is expected in any of the control areas or at regional level, taking into account possible cross-border exchanges and operational security limits. It shall deliver the results together with the actions it proposes to reduce risks to the TSOs of the capacity calculation region**, as established in accordance with Article 15(1) of Regulation (EU) 2015/1222, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Those actions shall include proposals for remedial actions that allow the increase of cross-border exchanges.

4. When performing a regional adequacy assessment, each regional **coordination centre** shall coordinate with other regional **coordination centres**.

TITLE 3
OUTAGE COORDINATION

CHAPTER 1
Outage coordination regions, relevant assets

Article 82

Outage coordination objective

Each TSO shall, with the support of the regional **coordination centre** for the instances specified in this Regulation, perform outage coordination in accordance with the principles of this Title in order to monitor the availability status of the relevant assets and coordinate the availability plans to ensure the operational security of the transmission system.

Article 83

Regional coordination

1. All TSOs of an outage coordination region shall jointly develop a regional coordination operational procedure, aimed at establishing operational aspects for the implementation of the outage coordination in each region, which includes:

(a) frequency, scope and type of coordination for, at least, the year-ahead and week-ahead time- frames;

(b) provisions concerning the use of the assessments carried out by the regional **coordination centre** in accordance with Article 80;

(c) practical arrangements for the validation of the year-ahead relevant grid element availability plans, as required by Article 98.

2. Each TSO shall participate in the outage coordination of its outage coordination regions and apply the regional coordination operational procedures established in accordance with paragraph 1.

3. If outage planning incompatibilities arise between different outage coordination regions, all TSOs and regional **coordination centre** of those regions shall coordinate to resolve those outage planning incompatibilities.

4. Each TSO shall provide to the other TSOs from the same outage coordination region all relevant information at its disposal on the infrastructure projects related to the transmission system, distribution systems, closed distribution systems, power generating modules, or demand facilities that may have an impact on the operation of the control area of another TSO within the outage coordination region.

5. Each TSO shall provide the transmission-connected DSOs located in its control area with all relevant information at its disposal on the infrastructure projects related to the transmission system that may have an impact on the operation of the distribution system of these DSOs.

6. Each TSO shall provide the transmission-connected closed-DSOs ('CDSOs') located in its control area with all relevant information at its disposal on the infrastructure projects related to the transmission system that may have an impact on the operation of the closed distribution system of those CDSOs.

Article 84

Methodology for assessing the relevance of assets for outage coordination

1. By 12 months after entry into force of this Regulation, **<…>** TSOs shall **apply** methodology at least per synchronous area, for assessing the relevance for the outage coordination of power generating modules, demand facilities, and grid elements located in a transmission system or in a distribution system, including closed distribution systems.

2. **<…>**[3]

3. **<…>**

Article 85

Lists of relevant power generating modules and relevant demand facilities

1. By 3 months **after the deadline for transposition of this Regulation**, all TSOs of each outage coordination region shall jointly assess the relevance of power generating modules and demand facilities for outage coordination on the basis of the methodology **referred to in Article 84(1),** and establish a single list, for each outage coordination region, of relevant power generating modules and relevant demand facilities.

2. All TSOs of an outage coordination region shall jointly make the list of relevant power generating modules and relevant demand facilities of that outage coordination region available on the ENTSO for Electricity operational planning data environment.

3. Each TSO shall notify to its regulatory authority the list of relevant power generating modules and relevant demand facilities for each outage coordination region in which it participates.

4. For each internal relevant asset which is a power generating module or demand facility, the TSO shall:

(a) inform the owner of the relevant power generating module or relevant demand facility about its inclusion in the list;

(b) inform DSOs about the relevant power generating modules and the relevant demand facilities which are connected to their distribution system; and

(c) inform CDSOs about the relevant power generating modules and the relevant demand facilities which are connected to their closed distribution system.

Article 86

Update of the lists of relevant power generating modules and relevant demand facilities

1. Before 1 July of each calendar year, all TSOs of each outage coordination region shall jointly re-assess the relevance of power generating modules and demand facilities for outage coordination on the basis of the methodology **referred to in** Article 84(1).

2. Where necessary, all TSOs of each outage coordination region shall jointly decide to update the list of

3 There is a clerical error in the Ministerial Council Decision 2022/03/MC-EnC.

relevant power generating modules and relevant demand facilities of that outage coordination region before 1 August of each calendar year.

3. All TSOs of an outage coordination region shall make the updated list of that outage coordination region available on the ENTSO for Electricity operational planning data environment.

4. Each TSO of an outage coordination region shall inform the parties referred to in Article 85(4) about the content of the updated list.

Article 87

Lists of relevant grid elements

1. By 3 months after **entry into force of this Regulation**, all TSOs of each outage coordination region shall jointly assess, on the basis of this methodology, the relevance for the outage coordination of grid elements located in a transmission system or in a distribution system including a closed distribution system and shall establish a single list, per outage coordination region, of relevant grid elements.

2. The list of relevant grid elements of an outage coordination region shall contain all grid elements of a transmission system or a distribution system, including a closed distribution system located in that outage coordination region, which are identified as relevant by application of the methodology **referred to in** Article 84(1).

3. All TSOs of an outage coordination region shall jointly make the list of relevant grid elements available on the ENTSO for Electricity operational planning data environment.

4. Each TSO shall notify to its regulatory authority the list of relevant grid elements for each outage coordination region in which it participates.

5. For each internal relevant asset which is a grid element, the TSO shall:

(a) inform the owner of the relevant grid element about its inclusion in the list;

(b) inform DSOs about the relevant grid elements which are connected to their distribution system; and

(c) inform CDSOs about the relevant grid elements which are connected to their closed distribution system.

Article 88

Update of the list of relevant grid elements

1. Before 1 July of each calendar year, all TSOs of each outage coordination region shall jointly re-assess, on the basis of the methodology **referred to in** Article 84(1), the relevance for the outage coordination of grid elements located in a transmission system or a distribution system including a closed distribution system.

2. Where necessary, all TSOs of an outage coordination region shall jointly decide to update the list of relevant grid elements of that outage coordination region before 1 August of each calendar year.

3. All TSOs of an outage coordination region shall make the updated list available on the ENTSO for Electricity operational planning data environment.

4. Each TSO of an outage coordination region shall inform the parties referred to in Article 85(4) about the content of the updated list.

Article 89

Appointment of outage planning agents

1. Each TSO shall act as the outage planning agent for each relevant grid element it operates.

2. For all other relevant assets, the owner shall appoint, or act as, the outage planning agent for the concerned relevant asset and shall inform its TSO about that appointment.

Article 90

Treatment of relevant assets located in a distribution system or in a closed distribution system

1. Each TSO shall coordinate with the DSO the outage planning of internal relevant assets connected to its distribution system.

2. Each TSO shall coordinate with the CDSO the outage planning of internal relevant assets connected to its closed distribution system.

CHAPTER 2
Development and update of availability plans of relevant assets

Article 91

Variations to deadlines for the year-ahead outage coordination

All TSOs within a synchronous area may jointly agree to adopt and implement a time-frame for the year-ahead outage coordination that deviates from the time-frame defined in Articles 94, 97 and 99, provided that the outage coordination of other synchronous areas is not impacted.

Article 92

General provisions on availability plans

1. The availability status of a relevant asset shall be one of the following:

(a) 'available' where the relevant asset is capable of and ready for providing service regardless of whether it is or it is not in operation;

(b) 'unavailable' where the relevant asset is not capable of or ready for providing service;

(c) 'testing' where the capability of the relevant asset for providing service is being tested.

2. The 'testing' status shall only apply in case of a potential impact on the transmission system and for the following time periods:

(a) between first connection and final commissioning of the relevant asset; and

(b) directly following maintenance of the relevant asset.

3. The availability plans shall contain at least the following information:

(a) the reason for the 'unavailable' status of a relevant asset;

(b) where such conditions are identified, the conditions to be fulfilled before applying the 'unavailable' status of a relevant asset in real-time;

(c) the time required to restore a relevant asset back to service where necessary in order to maintain operational security.

4. The availability status for each relevant asset in the year-ahead time-frame shall be provided with daily resolution.

5. When generation schedules and consumption schedules are submitted to the TSO pursuant to Article 111, the time resolution of the availability statuses shall be consistent with those schedules.

Article 93

Long-term indicative availability plans

1. By 2 years before the start of any year-ahead outage coordination, each TSO shall assess the corresponding indicative availability plans for internal relevant assets, provided by the outage planning agents in accordance with Articles 4, 7 and 15 of Regulation (EU) No 543/2013**, as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC,** and shall provide its preliminary comments including any detected outage planning incompatibilities, to all affected outage planning agents.

2. Each TSO shall carry out the assessment concerning the indicative availability plans for internal relevant assets referred to in paragraph 1 every year until the start of the year-ahead outage coordination.

Article 94

Provision of year-ahead availability plan proposals

1. Before 1 August of each calendar year, an outage planning agent other than a TSO taking part in an outage coordination region, a DSO or a CDSO, shall submit to the TSO(s) taking part in an outage coordination region, and where relevant to the DSO(s) or CDSO(s), an availability plan covering the following calendar year for each of its relevant assets.

2. The TSO(s) referred to in paragraph 1 shall endeavour to examine the requests for amendment of an availability plan when received. Where this is not possible, it shall examine the requests for amendment of an availability plan after the year-ahead outage coordination has been finalised.

3. The TSO(s) referred to in paragraph 1 shall examine the requests for amendment of an availability plan after the year-ahead outage coordination has been finalised:

(a) following the order in which the requests were received; and

(b) applying the procedure established in accordance with Article 100.

Article 95

Year-ahead coordination of the availability status of relevant assets for which the outage planning agent is not a TSO taking part in an outage coordination region, nor a DSO or a CDSO

1. Each TSO shall assess on a year-ahead time-frame whether outage planning incompatibilities arise from the availability plans received pursuant to Article 94.

2. When a TSO detects outage planning incompatibilities, it shall implement the following process:

(a) inform each affected outage planning agent of the conditions it shall fulfil to mitigate the detected outage planning incompatibilities;

(b) the TSO may request that one or more outage planning agents submit an alternative availability plan fulfilling the conditions referred to in point (a); and

(c) the TSO shall repeat the assessment pursuant to paragraph 1 to determine whether any outage planning incompatibilities remain.

3. Following a TSO's request in accordance with point (b) of paragraph 2, if the outage planning agent fails to submit an alternative availability plan aimed at mitigating all outage planning incompatibilities, the TSO shall develop an alternative availability plan which shall:

(a) take into account the impact reported by the affected outage planning agents as well as the DSO or CDSO where relevant;

(b) limit the changes in the alternative availability plan to what is strictly necessary to mitigate the outage planning incompatibilities; and

(c) notify its regulatory authority, the affected DSOs and CDSOs if any, and the affected outage planning agents about the alternative availability plan, including the reasons for developing it, as well as the impact reported by the affected outage planning agents and, where relevant, the DSOs or CDSOs.

Article 96

Year-ahead coordination of the availability status of relevant assets for which the outage planning agent is a TSO taking part in an outage coordination region, a DSO or a CDSO

1. Each TSO shall plan the availability status of relevant grid elements interconnecting different control areas for which it acts as an outage planning agent in coordination with the TSOs of the same outage coordination region.

2. Each TSO, DSO and CDSO shall plan the availability status of the relevant grid elements for which they perform duties of outage planning agents and that are not interconnecting different control areas, using as a basis the availability plans developed in accordance with paragraph 1.

3. When establishing the availability status of relevant grid elements in accordance with paragraphs 1 and 2, the TSO, DSO and CDSO shall:

(a) minimize the impact on the market while preserving operational security; and

(b) use as a basis the availability plans submitted and developed in accordance with Article 94.

4. Where a TSO detects an outage planning incompatibility, the TSO shall be entitled to propose a change to the availability plans of the internal relevant assets for which the outage planning agent is neither a TSO taking part in an outage coordination region, nor a DSO or a CDSO and shall identify a solution in coordination with the outage planning agents, DSOs and CDSOs concerned, using the means at its disposal.

5. Where the 'unavailable' status of a relevant grid element has not been planned after taking the measures in paragraph 4 and the absence of such planning would threaten operational security, the TSO shall:

(a) take the necessary actions to plan the 'unavailable' status while ensuring operational security, taking into account the impact reported to the TSO by affected outage planning agents;

(b) notify the actions referred to in point (a) to all affected parties; and

(c) notify the relevant regulatory authorities, the affected DSOs or CDSOs if any and the affected outage planning agents of the actions taken, including the rationale for such actions, the impact reported by affected outage planning agents and the DSOs or CDSOs where relevant.

6. Each TSO shall make available on the ENTSO for Electricity operational planning data environment all information at its disposal about grid-related conditions to be fulfilled and remedial actions to be prepared and activated before executing the 'unavailable' or 'testing' availability status of a relevant grid element.

Article 97

Provision of preliminary year-ahead availability plans

1. Before 1 November of each calendar year, each TSO shall provide to all other TSOs, via the ENTSO for Electricity operational planning data environment, the preliminary year-ahead availability plans for the following calendar year for all the internal relevant assets.

2. Before 1 November of each calendar year, for each internal relevant asset located in a distribution system, the TSO shall provide the DSO with the preliminary year-ahead availability plan.

3. Before 1 November of each calendar year, for every internal relevant asset located in a closed distribution system, the TSO shall provide the CDSO with the preliminary year-ahead availability plan.

Article 98

Validation of year-ahead availability plans within outage coordination regions

1. Each TSO shall analyse whether any outage planning incompatibility arises when taking into account all the preliminary year-ahead availability plans.

2. In the absence of outage planning incompatibilities, all TSOs of an outage coordination region shall jointly validate the year-ahead availability plans for all relevant assets of that outage coordination region.

3. If a TSO detects an outage planning incompatibility, the involved TSOs of the outage coordination region(s) concerned shall jointly identify a solution in coordination with the concerned outage planning agents, DSOs and CDSOs, using the means at their disposal, while respecting to the extent possible the availability plans submitted by outage planning agents, which are neither a TSO taking part in an outage coordination region, nor a DSO or a CDSO, and developed in accordance with Articles 95 and 96. Where

a solution is identified, all TSOs of the concerned outage coordination region(s) shall update and validate the year-ahead availability plans for all relevant assets.

4. Where no solution is found for an outage planning incompatibility each concerned TSO, subject to approval by the competent regulatory authority where the **Contracting Party** so provides, shall:

(a) force to 'available' status all the 'unavailable' or 'testing' statuses for the relevant assets involved in an outage planning incompatibility during the period concerned; and

(b) notify to the relevant regulatory authorities, the affected DSOs or CDSOs, if any, and the affected outage planning agents of the actions taken including the rationale for such actions, the impact reported by affected outage planning agents and the DSOs or CDSOs where relevant.

5. All TSOs of the concerned outage coordination regions shall consequently update and validate the year-ahead availability plans for all relevant assets.

Article 99

Final year-ahead availability plans

1. Before 1 December of each calendar year, each TSO shall:

(a) finalise the year-ahead outage coordination of internal relevant assets; and

(b) finalise the year-ahead availability plans for internal relevant assets and store them on the ENTSO for Electricity operational planning data environment.

2. Before 1 December of each calendar year, the TSO shall provide to its outage planning agent the final year-ahead availability plan of each internal relevant asset.

3. Before 1 December of each calendar year, the TSO shall provide to the relevant DSO the final year-ahead availability plan for each internal relevant asset located in a distribution system.

4. Before 1 December of each calendar year, the TSO shall provide to the relevant CDSO the final year-ahead availability plan for each internal relevant asset located in a closed distribution system.

Article 100

Updates to the final year-ahead availability plans

1. An outage planning agent shall be able to launch a procedure for the amendment of the final year-ahead availability plan in the time between the finalisation of the year-ahead outage coordination and its real-time execution.

2. The outage planning agent which is not a TSO taking part in an outage coordination region shall be able to submit to the relevant TSO(s) a request for amendment of the final year-ahead availability plan of the relevant assets under its responsibility.

3. In case of a request for amendment pursuant to paragraph 2, the following procedure shall be applied:

(a) the recipient TSO shall acknowledge the request and assess as soon as reasonably practicable whether the amendment leads to outage planning incompatibilities;

(b) where outage planning incompatibilities are detected, the involved TSOs of the outage coordination region shall jointly identify a solution in coordination with the outage planning agents concerned and, if relevant, the DSOs and CDSOs, using the means at their disposal;

(c) where no outage planning incompatibility has been detected or if no outage planning incompatibility remains, the recipient TSO shall validate the requested amendment, and the TSOs concerned shall consequently notify all affected parties and update the final year-ahead availability plan on the ENTSO for Electricity operational planning data environment; and

(d) where no solution is found for outage planning incompatibilities the recipient TSO shall reject the requested amendment.

4. When a TSO taking part in an outage coordination region intends to amend the final year-ahead availability plan of a relevant asset for which it acts as the outage planning agent, it shall initiate the following procedure:

(a) the requesting TSO shall prepare a proposal for amendment to the year-ahead availability plan, including an assessment of whether it could lead to outage planning incompatibilities and shall submit its proposal to all other TSOs of its outage coordination region(s);

(b) where outage planning incompatibilities are detected, the involved TSOs of the outage coordination region shall jointly identify a solution in coordination with the concerned outage planning agents and, if relevant, the DSOs and the CDSOs, using the means at their disposal;

(c) where no outage planning incompatibility has been detected or if a solution to an outage planning incompatibility is found, the concerned TSOs shall validate the requested amendment and consequently they shall notify all affected parties and update the final year-ahead availability plan on the ENTSO for Electricity operational planning data environment;

(d) where no solution to outage planning incompatibilities are found, the requesting TSO shall retract the procedure for amendment.

CHAPTER 3
Execution of availability plans

Article 101
Management of the 'testing' status of relevant assets

1. The outage planning agent of a relevant asset the availability status of which has been declared as 'testing' shall provide the TSO, and, if connected to a distribution system, including closed distribution systems, the DSO or the CDSO within 1 month before the start of the 'testing' status, with:

(a) a detailed test plan;

(b) an indicative generation or consumption schedule if the concerned relevant asset is a relevant power generating module or a relevant demand facility; and

(c) changes to the topology of the transmission system or distribution system if the concerned relevant asset is a relevant grid element.

2. The outage planning agent shall update the information referred to in paragraph 1 as soon as it is subject to any change.

3. The TSO of a relevant asset the availability status of which has been declared as 'testing' shall provide the information received in accordance with paragraph 1 to all other TSOs of its outage coordination region(s), upon their request.

4. Where the relevant asset referred to in paragraph 1 is a relevant grid element interconnecting two or more control areas, the TSOs of the concerned control areas shall agree on the information to be provided pursuant to paragraph 1.

Article 102

Procedure for handling forced outages

1. Each TSO shall develop a procedure to address the case where a forced outage would endanger its operational security. The procedure shall allow the TSO to ensure that the 'available' or 'unavailable' status of other relevant assets in its control area can be changed to 'unavailable' or 'available' respectively.

2. The TSO shall follow the procedure referred to in paragraph 1 only where no agreement is reached with outage planning agents regarding solutions to forced outages. The TSO shall notify the regulatory authority accordingly.

3. When undertaking the procedure, the TSO shall respect, to the extent possible, the technical limits of the relevant assets.

4. An outage planning agent shall notify the forced outage of one or more of its relevant assets to the TSO and, if connected to a distribution system or to a closed distribution system, the DSO or the CDSO respectively, as soon as possible following the start of the forced outage.

5. When notifying the forced outage, the outage planning agent shall provide the following information:

(a) the reason for the forced outage;

(b) the expected duration of the forced outage; and

(c) where applicable, the impact of the forced outage on the availability status of other relevant assets for which it is the outage planning agent.

6. When the TSO detects that one or several forced outages referred to in paragraph 1 could lead the transmission system out of the normal state, it shall inform the affected outage planning agent(s) about the deadline at which operational security can no longer be maintained unless their relevant asset(s) in forced outage returns to 'available' status. The outage planning agents shall inform the TSO whether they are capable of respecting that deadline and shall provide reasoned justifications where they are unable to respect that deadline.

7. Following any amendments to the availability plan due to forced outages and in accordance with the time-frame established in Articles 7, 10 and 15 of Regulation (EU) No 543/2013, **as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC,** the concerned TSO shall update the ENTSO for Electricity operational planning data environment with the most recent information.

Article 103

Real-time execution of the availability plans

1. Each power generating facility owner shall ensure that all relevant power generating modules it owns and which are declared 'available' are ready to produce electricity pursuant to their declared technical capabilities when necessary to maintain operational security, except in case of forced outages.

2. Each power generating facility owner shall ensure that all relevant power generating modules it owns and which are declared 'unavailable' do not produce electricity.

3. Each demand facility owner shall ensure that all relevant demand facilities it owns and which are declared 'unavailable' do not consume electricity.

4. Each relevant grid element owner shall ensure that all relevant grid elements it owns and which are declared 'available' are ready to transport electricity pursuant to their declared technical capabilities when necessary to maintain operational security, except in case of forced outages.

5. Each relevant grid element owner shall ensure that all relevant grid elements it owns and which are declared 'unavailable' do not transport electricity.

6. Where specific grid-related conditions apply for the execution of the 'unavailable' or 'testing' status of a relevant grid element in accordance with Article 96(6), the TSO, DSO or CDSO concerned shall assess the fulfilment of those conditions before the execution of that status. If those conditions are not fulfilled, it shall instruct the relevant grid element owner to not execute the 'unavailable' or 'testing' status or a part thereof.

7. Where a TSO identifies that executing an 'unavailable' or 'testing' status of a relevant asset leads or could lead the transmission system out of normal state, it shall instruct the owner of the relevant asset when it is connected to the transmission system, or the DSO or CDSO if connected to a distribution system or to a closed distribution system, to delay the execution of that 'unavailable' or 'testing' status of that relevant asset according to its instructions and to the extent possible, while respecting the technical and safety limits.

TITLE 4
ADEQUACY

Article 104

Forecast for control area adequacy analysis

Each TSO shall make any forecast used for control area adequacy analyses pursuant to Articles 105 and 107 available to all other TSOs through the ENTSO for Electricity operational planning data environment.

Article 105

Control area adequacy analysis

1. Each TSO shall perform control area adequacy analysis by assessing the possibility for the sum of gen-

eration within its control area and cross-border import capabilities to meet the total load within its control area under various operational scenarios, taking into account the required level of active power reserves set out in Articles 118 and 119.

2. When performing a control area adequacy analysis pursuant to paragraph 1, each TSO shall:

(a) use the latest availability plans and the latest available data for:

(i) the capabilities of power generating modules provided pursuant to Article 43(5) and Articles 45 and 51;

(ii) cross-zonal capacity;

(iii) possible demand response provided pursuant to Articles 52 and 53;

(b) take into account the contributions of generation from renewable energy sources and load; (c)assess the probability and expected duration of an absence of adequacy and the expected energy not supplied as a result of such absence.

3. As soon as possible, following the assessment of an absence of adequacy within its control area, each TSO shall notify the absence to its regulatory authority or when explicitly foreseen in national law, another competent authority, and where applicable, any affected party.

4. As soon as possible, following the assessment of an absence of adequacy within its control area, each TSO shall inform all TSOs through the ENTSO for Electricity operational planning data environment.

Article 106

Control area adequacy up to and including week-ahead

1. Each TSO shall contribute to the pan-European annual summer and winter generation adequacy outlooks applying the methodology adopted by ENTSO for Electricity **<...>**.

2. Twice a year, each TSO shall perform a control area adequacy analysis for the following summer and winter respectively, taking into account pan-European scenarios consistent with the pan- European annual summer and winter generation adequacy outlooks.

3. Each TSO shall update its control area adequacy analyses if it detects any probable changes to the availability status of power generating modules, load estimations, renewable energy sources estimations or cross zonal capacities that could significantly affect the expected adequacy.

Article 107

Control area adequacy in day-ahead and intraday

1. Each TSO shall perform a control area adequacy analysis in a day-ahead and intraday time- frame on the basis of:

(a) schedules referred to in Article 111;

(b) forecasted load;

(c) forecasted generation from renewable energy sources;

(d) active power reserves in accordance with the data provided pursuant to Article 46(1)(a);

(e) control area import and export capacities consistent with cross-zonal capacities calculated where applicable in accordance with Article 14 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(f) capabilities of power generating modules in accordance with the data provided pursuant to Article 43(4) and Articles 45 and 51 and their availability statuses; and

(g) capabilities of demand facilities with demand response in accordance with the data provided pursuant to Articles 52 and 53 and their availability statuses.

2. Each TSO shall evaluate:

(a) the minimum level of import and the maximum level of export compatible with its control area adequacy;

(b) the expected duration of a potential absence of adequacy; and

(c) the amount of energy not supplied in the absence of adequacy.

3. Where, following the analysis in paragraph 1, adequacy is not fulfilled, each TSO shall notify the absence of adequacy to its regulatory authority or other competent authority. The TSO shall provide its regulatory authority or other competent authority with an analysis of the causes of the absence of adequacy and propose mitigating actions.

TITLE 5
ANCILLARY SERVICES

Article 108
Ancillary services

1. Each TSO shall monitor the availability of ancillary services.

2. With regard to active power and reactive power services, and in coordination with other TSOs where appropriate, each TSO shall:

(a) design, set up and manage the procurement of ancillary services;

(b) monitor, on the basis of data provided pursuant to Title 2 of Part II, whether the level and location of available ancillary services allows ensuring operational security; and

(c) use all available economically efficient and feasible means to procure the necessary level of ancillary services.

3. Each TSO shall publish the levels of reserve capacity necessary to maintain operational security.

4. Each TSO shall communicate the available level of active power reserves to other TSOs upon request.

Article 109

Reactive power ancillary services

1. For each operational planning time-frame, each TSO shall assess, against their forecasts, whether its available reactive power ancillary services are sufficient to maintain the operational security of the transmission system.

2. In order to increase the efficiency of operation of its transmission system elements, each TSO shall monitor:

(a) the available reactive power capacities of power generating facilities;

(b) the available reactive power capacities of transmission-connected demand facilities;

(c) the available reactive power capacities of DSOs;

(d) the available transmission-connected equipment dedicated to providing reactive power; and

(e) the ratios of active power and reactive power at the interface between the transmission system and transmission-connected distribution systems.

3. Where the level of reactive power ancillary services is not sufficient for maintaining operational security, each TSO shall:

(a) inform neighbouring TSOs; and

(b) prepare and activate remedial actions pursuant to Article 23.

TITLE 6
SCHEDULING

Article 110

Establishment of scheduling processes

1. When establishing a scheduling process TSOs shall take into account and complement where necessary the operational conditions of the generation and load data methodology developed in accordance with Article 16 of Regulation (EU) 2015/1222.

2. Where a bidding zone covers only one control area, the geographical scope of the scheduling area is equal to the bidding zone. Where a control area covers several bidding zones, the geographical scope of the scheduling area is equal to the bidding zone. Where a bidding zone covers several control areas, TSOs within that bidding zone may jointly decide to operate a common scheduling process, otherwise, each control area within that bidding zone is considered a separate scheduling area.

3. For each power generating facility and demand facility subject to requirements for scheduling set out in the national terms and conditions, the concerned owner shall appoint or act as a scheduling agent.

4. Each market participant and shipping agent, subject to requirements for scheduling set out in the national terms and conditions, shall appoint or act as a scheduling agent.

5. Each TSO operating a scheduling area shall establish arrangements necessary to process the schedules

provided by scheduling agents.

6. Where a scheduling area covers more than one control area, the TSOs responsible for the control areas shall agree about which TSO shall operate the scheduling area.

Article 111

Notification of schedules within scheduling areas

1. Each scheduling agent, except scheduling agents of shipping agents, shall submit to the TSO operating the scheduling area, if requested by the TSO, and, where applicable, to third party, the following schedules:

(a) generation schedules;

(b) consumption schedules;

(c) internal commercial trade schedules; and

(d) external commercial trade schedules.

2. Each scheduling agent of a shipping agent or, where applicable, a central counterparty shall submit to the TSO operating a scheduling area covered by market coupling, if requested by the concerned TSO, and where applicable to third party, the following schedules:

(a) external commercial trade schedules as:

(i) multilateral exchanges between the scheduling area and a group of other scheduling areas;

(ii) bilateral exchanges between the scheduling area and another scheduling area;

(b) internal commercial trade schedules between the shipping agent and central counter parties;

(c) internal commercial trade schedules between the shipping agent and other shipping agents.

Article 112

Coherence of schedules

1. Each TSO operating a scheduling area shall check whether the generation, consumption, external commercial trade schedules and external TSO schedules in its scheduling area are in sum balanced.

2. For external TSO schedules, each TSO shall agree on the values of the schedule with the respective TSO. In the absence of an agreement, the lower value shall apply.

3. For bilateral exchanges between two scheduling areas, each TSO shall agree on the external commercial trade schedules with the respective TSO. In the absence of an agreement about the values of the commercial trade schedules, the lower value shall apply.

4. All TSOs operating scheduling areas shall verify that all aggregated netted external schedules between all scheduling areas within the synchronous area are balanced. If a mismatch occurs and the TSOs do not agree on the values of the aggregated netted external schedules, the lower values shall apply.

5. Each scheduling agent of a shipping agent or, where applicable, a central counterparty shall provide TSOs, upon their request, with the values of external commercial trade schedules of each scheduling area involved in market coupling in the form of aggregated netted external schedules.

6. Each scheduled exchange calculator shall provide to TSOs, upon their request, with the values of scheduled exchanges related to the scheduling areas involved in the market coupling in the form of aggregated netted external schedules, including bilateral exchanges between two scheduling areas.

Article 113

Provision of information to other TSOs

1. At the request of another TSO, the requested TSO shall calculate and provide:

(a) aggregated netted external schedules; and

(b) netted area AC position, where the scheduling area is interconnected to other scheduling areas via AC transmission links.

2. When required for the creation of common grid models, in accordance with Article 70(1), each TSO operating a scheduling area shall provide any requesting TSO with:

(a) generation schedules; and

(b) consumption schedules.

TITLE 7
ENTSO FOR ELECTRICITY OPERATIONAL PLANNING DATA ENVIRONMENT

Article 114

General provisions for ENTSO for Electricity operational planning data environment

1. **<...>**

2. **<...>**

3. All TSOs and regional **coordination centre** shall have access to all information contained on the ENTSO for Electricity operational planning data environment.

4. **<...>**

5. **<...>**

Article 115

Individual grid models, common grid models and operational security analysis

1. The ENTSO for Electricity operational planning data environment shall store all individual grid models and related relevant information for all the relevant time-frames set out in this Regulation, in Article 14(1) of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and in Article 9 of Regulation (EU) 2016/1719**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. The information on individual grid models contained on the ENTSO for Electricity operational planning data environment shall allow for their merging into common grid models.

3. The common grid model established for each of the time-frames shall be made available on the ENTSO for Electricity operational planning data environment.

4. For the year-ahead time-frame, the following information shall be available on the ENTSO for Electricity operational planning data environment:

(a) year-ahead individual grid model per TSO and per scenario determined in accordance with Article 66; and

(b) year-ahead common grid model per scenario defined in accordance with Article 67.

5. For the day-ahead and intraday time-frames, the following information shall be available on the ENTSO for Electricity operational planning data environment:

(a) day-ahead and intraday individual grid models per TSO and according to the time resolution defined pursuant to Article 70(1);

(b) scheduled exchanges at the relevant time instances per scheduling area or per scheduling area border, whichever is deemed relevant by the TSOs, and per HVDC system linking scheduling areas;

(c) day-ahead and intraday common grid models according to the time resolution defined pursuant to Article 70(1); and

(d) a list of prepared and agreed remedial actions identified to cope with constraints having cross- border relevance.

Article 116

Outage coordination

1. The ENTSO for Electricity operational planning data environment shall contain a module for the storage and exchange of all relevant information for outage coordination.

2. The information referred to in paragraph 1 shall include at least availability status of relevant assets and the information about availability plans referred to in Article 92.

Article 117

System adequacy

1. The ENTSO for Electricity operational planning data environment shall contain a module for the storage and exchange of all relevant information for performing a coordinated adequacy analysis.

2. The information referred to in paragraph 1 shall include at least:

(a) the season-ahead system adequacy data provided by each TSO;

(b) the season-ahead pan-European system adequacy analysis report;

(c) forecasts used for adequacy in line with Article 104; and

(d) information about a lack of adequacy in line with Article 105(4).

PART IV
LOAD-FREQUENCY CONTROL AND RESERVES

TITLE 1
OPERATIONAL AGREEMENTS

Article 118

Synchronous area operational agreements

1. By 12 months after entry into force of this Regulation, all TSOs of each synchronous area shall jointly develop common proposals**, unless already adopted on a contractual basis,** for:

(a) the dimensioning rules for FCR in accordance with Article 153;

(b) additional properties of FCR in accordance with Article 154(2);

(c) the frequency quality defining parameters and the frequency quality target parameters in accordance with Article 127;

(d) for the Continental Europe ('CE') **<…>** synchronous area, the frequency restoration control error target parameters for each LFC block in accordance with Article 128;

(e) the methodology to assess the risk and the evolution of the risk of exhaustion of FCR of the synchronous area in accordance with Article 131(2);

(f) the synchronous area monitor in accordance with Article 133;

(g) the calculation of the control program from the netted area AC position with a common ramping period for ACE calculation for a synchronous area with more than one LFC area in accordance with Article 136;

(h) if applicable, restrictions for the active power output of HVDC interconnectors between synchronous areas in accordance with Article 137;

(i) the LFC structure in accordance with Article 139;

(j) if applicable, the methodology to reduce the electrical time deviation in accordance with Article 181;

(k) whenever the synchronous area is operated by more than one TSO, the specific allocation of responsibilities between TSOs in accordance with Article 141;

(l) operational procedures in case of exhausted FCR in accordance with Article 152(7) **of Regulation 2017/1485**;

(m) **<…>**

(n) operational procedures to reduce the system frequency deviation to restore the system state to normal state and to limit the risk of entering into the emergency state in accordance with Article 152(10);

(o) the roles and responsibilities of the TSOs implementing an imbalance netting process, a cross- border FRR activation process or a cross-border RR activation process in accordance with Article 149(2);

(p) requirements concerning the availability, reliability and redundancy of the technical infrastructure in accordance with Article 151(2);

(q) common rules for the operation in normal state and alert state in accordance with Article 152(6) and the actions referred to in Article 152(15);

(r) for the CE **<…>** synchronous area, the minimum activation period to be ensured by FCR providers in accordance with Article 156(10);

(s) for the CE **<…>**synchronous area, the assumptions and methodology for a cost-benefit analysis in accordance with Article 156(11) **of Regulation 2017/1485**;

(t) if applicable, for synchronous areas other than CE, limits for the exchange of FCR between the TSOs in accordance with Article 163(2);

(u) the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO as regards the exchange of FRR and RR defined in accordance with Article 165(1);

(v) the roles and responsibilities of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of FRR and RR defined in accordance with Article 166(1);

(w) the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO for the exchange of reserves between synchronous areas, and of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of reserves between synchronous areas defined in accordance with Article 171(2);

(x) the methodology to determine limits on the amount of sharing of FCR between synchronous areas defined in accordance with Article 174(2);

(y) **<…>**

(z) the methodology to determine limits on the amount of exchange of FRR between synchronous areas defined in accordance with Article 176(1) and the methodology to determine limits on the amount of sharing of FRR between synchronous areas defined in accordance with Article 177(1); and

(aa) the methodology to determine limits on the amount of exchange of RR between synchronous areas defined in accordance with Article 178(1) and the methodology to determine limits on the amount of sharing of RR between synchronous areas defined in accordance with Article 179(1).

2. All TSOs of each synchronous area shall submit the methodologies and conditions listed in Article 6(3)(d) for approval by all the regulatory authorities of the concerned synchronous area. Within 1 month after the approval of these methodologies and conditions, all TSOs of each synchronous area shall conclude a synchronous area operational agreement which shall enter into force within 3 months after the approval of the methodologies and conditions.

Article 119

LFC block operational agreements

1. By 12 months after entry into force of this Regulation, all TSOs of each LFC block shall jointly develop common proposals for:

(a) where the LFC block consists of more than one LFC area, FRCE target parameters for each LFC area defined in accordance with Article 128(4);

(b) LFC block monitor in accordance with Article 134(1);

(c) ramping restrictions for active power output in accordance with Article 137(3) and (4);

(d) where the LFC block is operated by more than one TSO, the specific allocation of responsibilities between TSOs within the LFC block in accordance with Article 141(9);

(e) if applicable, appointment of the TSO responsible for the tasks in Article 145(6);

(f) additional requirements for the availability, reliability and redundancy of technical infrastructure defined in accordance with Article 151(3);

(g) operational procedures in case of exhausted FRR or RR in accordance with Article 152(8);

(h) the FRR dimensioning rules defined in accordance with Article 157(1);

(i) the RR dimensioning rules defined in accordance with Article 160(2);

(j) where the LFC block is operated by more than one TSO, the specific allocation of responsibilities defined in accordance with Article 157(3), and, if applicable, the specific allocation of responsibilities defined in accordance Article 160(6);

(k) the escalation procedure defined in accordance with Article 157(4) and, if applicable, the escalation procedure defined in accordance with Article 160(7);

(l) the FRR availability requirements, the requirements on the control quality defined in accordance with Article 158(2), and if applicable, the RR availability requirements and the requirements on the control quality defined in accordance with Article 161(2);

(m) if applicable, any limits on the exchange of FCR between the LFC areas of the different LFC blocks within the CE synchronous area and the exchange of FRR or RR between the LFC areas of an LFC block of a synchronous area consisting of more than one LFC block defined in accordance with Article 163(2), Article 167 and Article 169(2);

(n) the roles and the responsibilities of the reserve connecting TSO, the reserve receiving TSO and of the affected TSO for the exchange of FRR and/or RR with TSOs of other LFC blocks defined in accordance with Article 165(6);

(o) the roles and the responsibilities of the control capability providing TSO, the control capability receiving TSO and of the affected TSO for the sharing of FRR and RR defined in accordance with Article 166(7);

(p) roles and the responsibilities of the control capability providing TSO, the control capability receiving TSO and of the affected TSO for the sharing of FRR and RR between synchronous areas in accordance with Article 175(2);

(q) coordination actions aiming to reduce the FRCE as defined in Article 152(14); and

(r) measures to reduce the FRCE by requiring changes in the active power production or consumption of power generating modules and demand units in accordance with Article 152(16).

2. All TSOs of each LFC block shall submit the methodologies and conditions listed in Article 6(3)(e) for approval by all the regulatory authorities of the concerned LFC block. Within 1 month after the approval of these methodologies and conditions, all TSOs of each LFC block shall conclude an LFC block operational agreement which shall enter into force within 3 months after the approval of the methodologies and conditions.

Article 120

LFC area operational agreement

By 12 months after entry into force of this Regulation, all TSOs of each LFC area shall establish an LFC area operational agreement that shall include at least:

(a) the specific allocation of responsibilities between TSOs within the LFC area in accordance with Article 141(8);

(b) the appointment of the TSO responsible for the implementation and operation of the frequency restoration process in accordance with Article 143(4).

Article 121

Monitoring area operational agreement

By 12 months after entry into force of this Regulation, all TSOs of each monitoring area shall establish a monitoring area operational agreement that shall include at least the allocation of responsibilities between TSOs within the same monitoring area in accordance with Article 141(7).

Article 122

Imbalance netting agreement

All TSOs participating in the same imbalance netting process shall establish an imbalance netting agreement that shall at least include the roles and responsibilities of the TSOs in accordance with Article 149(3).

Article 123

Cross-border FRR activation agreement

All TSOs participating in the same cross-border FRR activation process shall establish a cross- border FRR activation agreement that shall include at least the roles and responsibilities of the TSOs in accordance with Article 149(3).

Article 124

Cross-border RR activation agreement

All TSOs participating in the same cross-border RR activation process shall establish a cross-border RR activation agreement that shall include at least the roles and responsibilities of the TSOs in accordance with Article 149(3).

Article 125

Sharing agreement

All TSOs participating in the same sharing process of FCR, FRR or RR shall establish a sharing agreement that shall include at least:

(a) in case of sharing FRR or RR within a synchronous area, the roles and responsibilities of the control capability receiving TSO and of the control capability providing TSO and the affected TSOs in accordance with Article 165(3); or

(b) in case of sharing reserves between synchronous areas, the roles and responsibilities of the control capability receiving TSO and of the control capability providing TSO in accordance with Article 171(4) and the procedures in case the sharing of reserves between synchronous areas is not executed in real-time in accordance with Article 171(9).

Article 126

Exchange agreement

All TSOs participating in the same exchange of FCR, FRR or RR shall establish an exchange agreement that shall include at least:

(a) in case of exchange of FRR or RR within a synchronous area, the roles and responsibilities of the reserve connecting and reserve receiving TSOs in accordance with to Article 165(3); or

(b) in case of exchange of reserves between synchronous areas, the roles and responsibilities of the reserve connecting and reserve receiving TSOs in accordance with Article 171(4) and the procedures in case the exchange of reserves between synchronous areas is not executed in real-time in accordance with Article 171(9).

TITLE 2
FREQUENCY QUALITY

Article 127

Frequency quality defining and target parameters

1. The frequency quality defining parameters shall be:

(a) the nominal frequency for all synchronous areas;

(b) the standard frequency range for all synchronous areas;

(c) the maximum instantaneous frequency deviation for all synchronous areas;

(d) the maximum steady-state frequency deviation for all synchronous areas;

(e) the time to restore frequency for all synchronous areas;

(f) **<...>**

(g) **<…>**

(h) **<…>**

(i) the alert state trigger time for all synchronous areas.

2. The nominal frequency shall be 50 Hz for all synchronous areas.

3. The default values of the frequency quality defining parameters listed in paragraph 1 are set out in Table 1 of Annex III**, related to the Continental Europe synchronous area. Contracting Parties' TSOs operating in other synchronous areas are excluded from the obligation to reach these values and operate according to the rules of these synchronous areas.**

4. The frequency quality target parameter shall be the maximum number of minutes outside the standard frequency range per year per synchronous area and its default value per synchronous area are set out in Table 2 of Annex III.

5. The values of the frequency quality defining parameters in Table 1 of Annex III and of the frequency quality target parameter in Table 2 of Annex III shall apply unless all TSOs of a synchronous area propose different values pursuant to paragraphs 6, 7 and 8.

6. All TSOs of CE **<…>** synchronous area shall have the right to propose in the synchronous area operational agreement values different from those set out in Tables 1 and 2 of Annex III regarding:

(a) the alert state trigger time;

(b) the maximum number of minutes outside the standard frequency range.

7. **<…>**

8. The proposal for modification of the values pursuant to paragraph 6 **<…>** shall be based on an assessment of the recorded values of the system frequency for a period of at least 1 year and the synchronous area development and it shall meet the following conditions:

(a) the proposed modification of the frequency quality defining parameters in Table 1 of Annex III or the frequency quality target parameter in Table 2 of Annex III takes into account:

(i) the system's size, based on the consumption and generation of the synchronous area and the inertia of the synchronous area;

(ii) the reference incident;

(iii) grid structure and/or network topology;

(iv) load and generation behaviour;

(v) the number and response of power generating modules with limited frequency sensitive mode — over frequency and limited frequency sensitive mode — under frequency as defined in Article 13(2) and Article 15(2)(c) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**;

(vi) the number and response of demand units operating with activated demand response system frequency control or demand response very fast active power control as defined in Articles 29 and 30 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**; and

(vii) the technical capabilities of power generating modules and demand units;

(b) all TSOs of the synchronous area shall conduct a public consultation concerning the impact on stake-

holders of the proposed modification of the frequency quality defining parameters in Table 1 of Annex III or the frequency quality target parameter in Table 2 of Annex III.

9. All TSOs shall endeavour to comply with the values for the frequency quality defining parameters or for the frequency quality target parameter. All TSOs shall verify the fulfilment of the frequency quality target parameter at least annually.

Article 128

FRCE target parameters

1. All TSOs of the CE **<…>** synchronous area shall specify in the synchronous area operational agreement the values of the level 1 FRCE range and the level 2 FRCE range for each LFC block of the CE **<…>** synchronous area at least annually.

2. All TSOs of the CE **<…>** synchronous area, if consisting of more than one LFC block, shall ensure that the Level 1 FRCE ranges and the Level 2 FRCE ranges of the LFC blocks of those synchronous areas are proportional to the square root of the sum of the initial FCR obligations of the TSOs constituting the LFC blocks in accordance with Article 153.

3. All TSOs of the CE **<…>** synchronous area shall endeavour to comply with the following FRCE target parameters for each LFC block of the synchronous area:

(a) the number of time intervals per year outside the Level 1 FRCE range within a time interval equal to the time to restore frequency shall be less than 30 % of the time intervals of the year; and

(b) the number of time intervals per year outside the Level 2 FRCE range within a time interval equal to the time to restore frequency shall be less than 5 % of the time intervals of the year.

4. Where an LFC block consists of more than one LFC area, all TSOs of the LFC block shall specify in the LFC block operational agreement the values of the FRCE target parameters for each LFC area.

<…>

5. All TSOs shall verify, at least annually, that the FRCE target parameters are fulfilled.

Article 129

Criteria application process

The criteria application process shall comprise:

(a) the collection of frequency quality evaluation data; and

(b) the calculation of frequency quality evaluation criteria.

Article 130

Frequency quality evaluation data

1. The frequency quality evaluation data shall be:

(a) for the synchronous area:

(i) the instantaneous frequency data; and

(ii) the instantaneous frequency deviation data;

(b) for each LFC block of the synchronous area, the instantaneous FRCE data.

2. The measurement accuracy of the instantaneous frequency data and of the instantaneous FRCE data, where measured in Hz, shall be 1 mHz or better.

Article 131

Frequency quality evaluation criteria

1. The frequency quality evaluation criteria shall comprise:

(a) for the synchronous area during operation in normal state or alert state as determined by Article 18(1) and (2), on a monthly basis, for the instantaneous frequency data:

(i) the mean value;

(ii) the standard deviation;

(iii) the 1-,5-,10-, 90-,95- and 99-percentile;

(iv) the total time in which the absolute value of the instantaneous frequency deviation was larger than the standard frequency deviation, distinguishing between negative and positive instantaneous frequency deviations;

(v) the total time in which the absolute value of the instantaneous frequency deviation was larger an the maximum instantaneous frequency deviation, distinguishing between negative and sitive instantaneous frequency deviations;

(vi) the number of events in which the absolute value of the instantaneous frequency deviation of the synchronous area exceeded 200 % of the standard frequency deviation and the instantaneous frequency deviation was not returned to 50 % of the standard frequency deviation for the CE synchronous area **<…>**, within the time to restore frequency. The data shall distinguish between negative and positive frequency deviations;

(vii) **<…>**

(b) for each LFC block of the CE **<…>** synchronous area during operation in normal state or alert state in accordance with Article 18(1) and (2), on a monthly basis:

(i) for a data-set containing the average values of the FRCE of the LFC block over time intervals equal to the time to restore frequency:

— the mean value,

— the standard deviation,

— the 1-,5-,10-, 90-,95- and 99-percentile,

— the number of time intervals in which the average value of the FRCE was outside the Level 1 FRCE range, distinguishing between negative and positive FRCE, and

— the number of time intervals in which the average value of the FRCE was outside the Level 2 FRCE range, distinguishing between negative and positive FRCE;

(ii) for a data-set containing the average values of the FRCE of the LFC block over time intervals with a length of one minute: the number of events on a monthly basis for which the FRCE exceeded 60 % of the reserve capacity on FRR and was not returned to 15 % of the reserve capacity on FRR within the time to restore frequency, distinguishing between negative and positive FRCE;

(c) **<...>**

2. All TSOs of each synchronous area shall specify in the synchronous area operational agreement a common methodology to assess the risk and the evolution of the risk of exhaustion of FCR in the synchronous area. That methodology shall be performed at least annually and shall be based at least on historical instantaneous system frequency data for not less than 1 year. All TSOs of each synchronous area shall provide the required input data for this assessment.

Article 132

Data collection and delivery process

1. The data collection and delivery process shall comprise the following:

(a) measurements of the system frequency;

(b) calculation of the frequency quality evaluation data; and

(c) delivery of the frequency quality evaluation data for the criteria application process.

2. The data collection and delivery process shall be implemented by the synchronous area monitor appointed in accordance with Article 133.

Article 133

Synchronous area monitor

1. All TSOs of a synchronous area shall appoint one TSO of that synchronous area in the synchronous area operational agreement as synchronous area monitor.

2. The synchronous area monitor shall implement the data collection and delivery process of the synchronous area referred to in Article 132.

3. The synchronous area monitor shall implement the criteria application process referred to in Article 129.

4. The synchronous area monitor shall collect the frequency quality evaluation data of its synchronous area and perform the criteria application process, including the calculation of the frequency quality evaluation criteria, once every 3 months and within 3 months after the end of the analysed period.

Article 134

LFC block monitor

1. All TSOs of a LFC block shall appoint one TSO of that LFC block in the LFC block operational agreement as LFC block monitor.

2. The LFC block monitor shall collect the frequency quality evaluation data for the LFC block in accordance with the criteria application process referred to in Article 129.

3. Each TSO of a LFC area shall provide the LFC block monitor with the LFC area measurements necessary for collecting frequency quality evaluation data for the LFC block.

4. The LFC block monitor shall deliver the frequency quality evaluation data of the LFC block and its LFC areas once every 3 months and within 2 months after the end of the analysed period.

Article 135

Information on load and generation behaviour

In accordance with Article 40, each connecting TSO shall have the right to request the information necessary from SGUs to monitor the load and generation behaviour related to imbalances. That information may include:

(a) the time-stamped active power setpoint for real-time and future operation; and

(b) the time-stamped total active power output.

Article 136

Ramping period within the synchronous area

All TSOs of each synchronous area with more than one LFC area shall specify in the synchronous area operational agreement a common ramping period of aggregated netted schedules between the LFC areas in the synchronous area. The calculation of the control program from the netted area AC position for ACE calculation shall be performed with the common ramping period.

Article 137

Ramping restrictions for active power output

1. All TSOs of two synchronous areas shall have the right to specify in the synchronous area operational agreement restrictions for the active power output of HVDC interconnectors between synchronous areas to limit their influence on the fulfilment of the frequency quality target parameters of the synchronous area by determining a combined maximum ramping rate for all HVDC interconnectors connecting one synchronous area to another synchronous area.

2. The restrictions in paragraph 1 shall not apply for imbalance netting, frequency coupling as well as

cross-border activation of FRR and RR over HVDC interconnectors.

3. All connecting TSOs of an HVDC interconnector shall have the right to determine in the LFC block operational agreement common restrictions for the active power output of that HVDC interconnector to limit its influence on the fulfilment of the FRCE target parameter of the connected LFC blocks by agreeing on ramping periods and/or maximum ramping rates for this HVDC interconnector. Those common restrictions shall not apply for imbalance netting, frequency coupling as well as cross-border activation of FRR and RR over HVDC interconnectors. All TSOs of a synchronous area shall coordinate these measures within the synchronous area.

4. All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:

(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units;

(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block; and

(c) coordination of the ramping between power generating modules, demand units and active power consumption within the LFC block.

Article 138

Mitigation

Where the values calculated for the period of one calendar year concerning the frequency quality target parameters or the FRCE target parameters are outside the targets set for the synchronous area or for the LFC block, all TSOs of the relevant synchronous area or of the relevant LFC block shall:

(a) analyse whether the frequency quality target parameters or the FRCE target parameters will remain outside the targets set for the synchronous area or for the LFC block and in case of a justified risk that this may happen, analyse the causes and develop recommendations; and

(b) develop mitigation measures to ensure that the targets for the synchronous area or for the LFC block can be met in the future.

TITLE 3
LOAD-FREQUENCY CONTROL STRUCTURE

Article 139

Basic structure

1. All TSOs of each synchronous area shall specify the load-frequency-control structure for the synchronous area in the synchronous area operational agreement. Each TSO shall be responsible for implementing the

load-frequency-control structure of its synchronous area and operating in accordance with it.

2. The load-frequency control structure of each synchronous area shall include:

(a) a process activation structure in accordance with Article 140; and

(b) a process responsibility structure in accordance with Article 141.

3. **The provisions related to the load-frequency control structure apply only to the transmission system operators operating in the Continental Europe synchronous area. Contracting Parties' TSOs operating in other synchronous areas are excluded from the obligation to reach the objectives set out in these from provisions within Title 3 and to operate according to the rules of these synchronous areas.**

Article 140

Process activation structure

1. The process activation structure shall include:

(a) a FCP pursuant to Article 142;

(b) a FRP pursuant to Article 143; and

(c) for the CE synchronous area, a time control process pursuant to Article 181.

2. The process activation structure may include:

Article 141

Process responsibility structure

1. When specifying the process responsibility structure, all TSOs of each synchronous area shall take into account at least the following criteria:

(a) the size and the total inertia, including synthetic inertia, of the synchronous area;

(b) the grid structure and/or network topology; and

(c) the load, generation and HVDC behaviour.

2. By 4 months after entry into force of this Regulation, all TSOs of a synchronous area shall jointly develop a common proposal regarding the determination of the LFC blocks, which shall comply with the following requirements:

(a) a monitoring area corresponds to or is part of only one LFC area;

(b) a LFC area corresponds to or is part of only one LFC block;

(c) a LFC block corresponds to or is part of only one synchronous area; and

(d) each network element is part of only one monitoring area, only one LFC area and only one LFC block.

3. All TSOs of each monitoring area shall continuously calculate and monitor the real-time active power interchange of the monitoring area.

4. All TSOs of each LFC area shall:

(a) continuously monitor the FRCE of the LFC area;

(b) implement and operate a FRP for the LFC area;

(c) endeavour to fulfil the FRCE target parameters of the LFC area as defined in Article 128; and

(d) have the right to implement one or several of the processes referred to in Article 140(2).

5. All TSOs of each LFC block shall:

(a) endeavour to fulfil the FRCE target parameters of the LFC block as defined in Article 128; and

(b) comply with the FRR dimensioning rules in accordance with Article 157 and the RR dimensioning rules in accordance with Article 160.

6. All TSOs of each synchronous area shall:

(a) implement and operate a FCP for the synchronous area;

(b) comply with FCR dimensioning rules in accordance with Article 153; and

(c) endeavour to fulfil the frequency quality target parameters in accordance with Article 127.

7. All TSOs of each monitoring area shall specify in the monitoring area operational agreement the allocation of responsibilities between TSOs in the monitoring area for the implementation of the obligation set out in paragraph 3.

8. All TSOs of each LFC area shall specify in the LFC area operational agreement the allocation of responsibilities between TSOs in the LFC area for the implementation of the obligations set out in paragraph 4.

9. All TSOs of each LFC block shall specify in the LFC block operational agreement the allocation of responsibilities between TSOs in the LFC block for the implementation of the obligations set out paragraph 5.

10. All TSOs of each synchronous area shall specify in the synchronous area operational agreement the allocation of responsibilities between TSOs in the synchronous area for the implementation of the obligations set out in paragraph 6.

11. All TSOs of two or more LFC areas connected by interconnections shall have the right to form an LFC block if the requirements for the LFC block set out in paragraph 5 are fulfilled.

Article 142

Frequency containment process

1. The control target of FCP shall be the stabilization of the system frequency by activation of FCR.

2. The overall characteristic for FCR activation in a synchronous area shall reflect a monotonic decrease of the FCR activation as a function of the frequency deviation.

Article 143

Frequency restoration process

1. The control target of the FRP shall be to:

2. The FRCE is:

(a) the ACE of an LFC area, where there is more than one LFC area in a synchronous area; or

(b) the frequency deviation, where one LFC area corresponds to the LFC block and the synchronous area.

3. The ACE of a LFC area shall be calculated as the sum of the product of the K-Factor of the LFC area with the frequency deviation plus de subtraction of:

(a) the total interconnector and virtual tie-line active power flow; and

(b) the control program in accordance with Article 136.

4. Where a LFC area consists of more than one monitoring area, all TSOs of the LFC area shall appoint one TSO in the LFC area operational agreement responsible for the implementation and operation of the frequency restoration process.

5. Where a LFC area consists of more than one monitoring area, the frequency restoration process of this LFC area shall enable the control of the active power interchange of each monitoring area to a value determined as secure based on a real-time operational security analysis.

Article 144

Reserve replacement process

1. The control target of the RRP shall be to fulfil at least one of the following goals by activation of RR:

(a) progressively restore the activated FRR;

(b) support FRR activation;

(c) **<…>**

2. The RRP shall be operated through instructions for manual RR activation in order to fulfil the control target in accordance with paragraph 1.

Article 145

Automatic and manual frequency restoration process

1. Each TSO of each LFC area shall implement an automatic frequency restoration process ('aFRP') and a manual frequency restoration process ('mFRP').

2. **<…>**

3. If an LFC area consists of more than one monitoring area, all TSOs of the LFC area shall set out a process for the implementation of an aFRP and an mFRP in the LFC area operational agreement. Where an LFC block consists of more than one LFC area, all TSOs of the LFC areas shall set out a process for the implementation of an mFRP in the LFC block operational agreement.

4. The aFRP shall be operated in a closed-loop manner where the FRCE is an input and the setpoint for automatic FRR activation is an output. The setpoint for automatic FRR activation shall be calculated by a single frequency restoration controller operated by a TSO within its LFC area. For the CE **<…>** synchronous area, the frequency restoration controller shall:

(a) be an automatic control device designed to reduce the FRCE to zero;

(b) have proportional-integral behaviour;

(c) have a control algorithm which prevents the integral term of a proportional-integral controller from accumulating the control error and overshooting; and

(d) have functionalities for extraordinary operational modes for the alert and emergency states.

5. The mFRP shall be operated through instructions for manual FRR activation in order to fulfil the control target in accordance with Article 143(1).

6. In addition to the aFRP implementation in the LFC areas, all TSOs of an LFC block which consists of more than one LFC area shall have the right to appoint one TSO of the LFC block in the LFC block operational agreement to:

(a) calculate and monitor the FRCE of the whole LFC block; and

(b) take the FRCE of the whole LFC block into account for the calculation of the setpoint value for aFRR activation in accordance with Article 143(3) in addition to the FRCE of its LFC area.

Article 146

Imbalance netting process

1. The control target of the imbalance netting process shall aim at reducing the amount of simultaneous counteracting FRR activations of the different participating LFC areas by imbalance netting power interchange.

2. Each TSO shall have the right to implement the imbalance netting process for the LFC areas in the same LFC block, between different LFC blocks or between different synchronous areas, by concluding an imbalance netting agreement.

3. TSOs shall implement the imbalance netting process in a way which does not affect:

(a) the stability of the FCP of the synchronous area or synchronous areas involved in the imbalance netting process;

(b) the stability of the FRP and the RRP of each LFC area operated by participating or affected TSOs; and

(c) operational security.

4. TSOs shall implement the imbalance netting power interchange between LFC areas of a synchronous area in at least one of the following ways:

(a) by defining an active power flow over a virtual tie-line which shall be part of the FRCE calculation;

(b) by adjusting the active power flows over HVDC interconnectors.

5. TSOs shall implement the imbalance netting power interchange between LFC areas of different synchronous areas by adjusting the active power flows over HVDC interconnectors.

6. TSOs shall implement the imbalance netting power interchange of a LFC area in a way which does not exceed the actual amount of FRR activation necessary to regulate the FRCE of that LFC area to zero without imbalance netting power interchange.

7. All TSOs participating in the same imbalance netting process shall ensure that the sum of all imbalance netting power interchanges is equal to zero.

8. The imbalance netting process shall include a fallback mechanism which shall ensure that the imbalance netting power interchange of each LFC area is zero or limited to a value for which operational security can be guaranteed.

9. Where a LFC block consists of more than one LFC area and the reserve capacity on FRR as well as the reserve capacity on RR is calculated based on the LFC block imbalances, all TSOs of the same LFC block shall implement an imbalance netting process and interchange the maximum amount of imbalance netting power defined in paragraph 6 with other LFC areas of the same LFC block.

10. Where an imbalance netting process is implemented for LFC areas of different synchronous areas, all TSOs shall interchange the maximum amount of imbalance netting power defined in paragraph 6 with other TSOs of the same synchronous area participating in that imbalance netting process.

11. Where an imbalance netting process is implemented for LFC areas which are not part of the same LFC block, all TSOs of the LFC blocks involved shall comply with the obligations in Article 141(5) regardless of imbalance netting power interchange.

Article 147

Cross-border FRR activation process

1. The control target of the cross-border FRR activation process shall aim at enabling a TSO to perform the FRP by frequency restoration power interchange between LFC areas.

2. Each TSO shall have the right to implement the cross-border FRR activation process for LFC areas within the same LFC block, between different LFC blocks or between different synchronous areas by concluding a cross-border FRR activation agreement.

3. TSOs shall implement the cross-border FRR activation process in a way which does not affect:

(a) the stability of the FCP of the synchronous area or synchronous areas involved in the cross-border FRR activation process;

(b) the stability of the FRP and the RRP of each LFC area operated by participating or affected TSOs; and

(c) operational security.

4. TSOs shall implement the frequency restoration power interchange between LFC areas of the same synchronous area through one of the following actions:

(a) defining an active power flow over a virtual tie-line which shall be part of the FRCE calculation where FRR activation is automated;

(b) adjusting a control program or defining an active power flow over a virtual tie-line between LFC areas where FRR activation is manual; or

(c) adjusting the active power flows over HVDC interconnectors.

5. TSOs shall implement the frequency restoration power interchange between LFC areas of different synchronous areas by adjusting the active power flows over HVDC interconnectors.

6. All TSOs participating in the same cross-border FRR activation process shall ensure that the sum of all frequency restoration power interchanges is equal to zero.

7. The cross-border FRR activation process shall include a fallback mechanism which shall ensure that the

frequency restoration power interchange of each LFC area is zero or limited to a value for which operational security can be guaranteed.

Article 148

Cross-border RR activation process

1. The control target of the cross-border RR activation process shall aim at enabling a TSO to perform the RRP through control program between LFC areas.

2. Each TSO shall have the right to implement the cross-border RR activation process for LFC areas within the same LFC block, between different LFC blocks or between different synchronous areas by concluding a cross-border RR activation agreement.

3. TSOs shall implement the cross-border RR activation process in a way which does not affect:

(a) the stability of the FCP of the synchronous area or synchronous areas involved in the cross-border RR activation process;

(b) the stability of the FRP and the RRP of each LFC area operated by participating or affected TSOs; and

(c) the operational security.

4. TSOs shall implement the control program between LFC areas of the same synchronous area by carrying out at least one of the following actions:

(a) determining an active power flow over a virtual tie-line which shall be part of the FRCE calculation;

(b) adjusting a control program; or

(c) adjusting active power flows over HVDC interconnectors.

5. TSOs shall implement the control program between LFC areas of different synchronous areas by adjusting active power flows over HVDC interconnectors.

6. All TSOs participating in the same cross-border RR activation process shall ensure that the sum of all control programs is equal to zero.

7. The cross-border RR activation process shall include a fall-back mechanism which shall ensure that the control program of each LFC area is zero or limited to a value for which operational security can be guaranteed.

Article 149

General requirements for cross-border control processes

1. All TSOs participating in an exchange or sharing of FRR or RR shall implement a cross-border FRR or RR activation process, as appropriate.

2. All TSOs of a synchronous area shall specify in the synchronous area operational agreement the roles and responsibilities of the TSOs implementing an imbalance netting process, a cross-border FRR activation process or a cross-border RR activation process between LFC areas of different LFC blocks or of different synchronous areas.

3. All TSOs participating in the same imbalance netting process, in the same cross-border FRR activation process or in the same cross-border RR activation process shall specify in the respective agreements, the roles and responsibilities of all TSOs including:

(a) the provision of all input data necessary for:

(i) the calculation of the power interchange with respect to the operational security limits; and

(ii) the performance of real-time operational security analysis by participating and affected TSOs;

(b) the responsibility of calculating the power interchange; and

(c) the implementation of operational procedures to ensure the operational security.

4. Without prejudice to Article 146(9), (10) and (11) and as part of the agreements referred to in Articles 122, 123 and 124, all TSOs participating in the same imbalance netting process, cross- border FRR activation process or cross-border RR activation process shall have the right to specify a sequential approach for calculation of the power interchange. The sequential calculation of the power interchange shall allow any group of TSOs operating LFC areas or LFC blocks connected by interconnections to interchange imbalance netting, frequency restoration or reserve replacement power among themselves ahead of an interchange with other TSOs.

Article 150

TSO notification

1. TSOs who intend to exercise the right to implement an imbalance netting process, a cross-border FRR activation process, a cross-border RR activation process, an exchange of reserves or a sharing of reserves shall, 3 months before exercising such right, notify all other TSOs of the same synchronous area about:

(a) the TSOs involved;

(b) the expected amount of power interchange due to the imbalance netting process, cross-border FRR activation process or cross-border RR activation process;

(c) the reserve type and maximum amount of exchange or sharing of reserves; and

(d) the timeframe of exchange or sharing of reserves.

2. Where an imbalance netting process, a cross-border FRR activation process or a cross-border RR activation process is implemented for LFC areas that are not part of the same LFC block, each TSO of the concerned synchronous areas shall have the right to declare itself as an affected TSO to all TSOs of the synchronous area based on an operational security analysis and within 1 month after receipt of the notification pursuant to paragraph 1.

3. The affected TSO shall have the right to:

(a) require the provision of real-time values of imbalance netting power interchange, frequency restoration power interchange and control program necessary for real-time operational security analysis; and

(b) require the implementation of an operational procedure enabling the affected TSO to set limits for the imbalance netting power interchange, frequency restoration power interchange and control program between the respective LFC areas based on operational security analysis in real- time.

Article 151

Infrastructure

1. All TSOs shall assess what technical infrastructure is necessary to implement and operate the processes referred to in Article 140 and considered critical pursuant to the security plan referred to in Article 26.

2. All TSOs of a synchronous area shall specify, in the synchronous area operational agreement, minimum requirements for the availability, reliability and redundancy of the technical infrastructure referred to in paragraph 1 including:

(a) the accuracy, resolution, availability and redundancy of active power flow and virtual tie-line measurements;

(b) the availability and redundancy of digital control systems;

(c) the availability and redundancy of communication infrastructure; and

(d) communication protocols.

3. All TSOs of a LFC block shall set out additional requirements for the availability, reliability and redundancy of the technical infrastructure in the LFC block operational agreement.

4. Each TSO of a LFC area shall:

(a) ensure a sufficient quality and availability of the FRCE calculation;

(b) perform real-time quality monitoring of the FRCE calculation;

(c) take action in case of FRCE miscalculation; and

(d) where the FRCE is determined by the ACE, perform an *ex-post* quality monitoring of the FRCE calculation by comparing FRCE to reference values at least on an annual basis.

TITLE 4
OPERATION OF LOAD-FREQUENCY CONTROL

Article 152

System states related to system frequency

1. Each TSO shall operate its control area with sufficient upward and downward active power reserve, which may include shared or exchanged reserves, to face imbalances between demand and supply within its control area. Each TSO shall control the FRCE as defined in the Article 143 in order to reach the required frequency quality within the synchronous area in cooperation with all TSOs in the same synchronous area.

2. Each TSO shall monitor close to real-time generation and exchange schedules, power flows, node injections and withdrawals and other parameters within its control area relevant for anticipating a risk of a frequency deviation and shall take, in coordination with other TSOs of its synchronous area, measures to limit their negative effects on the balance between generation and demand.

3. All TSOs of each synchronous area shall specify a real-time data exchange in accordance with Article 42 which shall include:

(a) the system state of the transmission system in accordance with Article 18; and

(b) the real-time measurement data of the FRCE of the LFC blocks and LFC areas of the synchronous area.

4. The synchronous area monitor shall determine the system state with regard to the system frequency in accordance with Article 18(1) and (2).

5. The synchronous area monitor shall ensure that all TSOs of all synchronous areas are informed in case the system frequency deviation fulfils one of the criteria for the alert state referred to in Article 18.

6. All TSOs of a synchronous area shall define in the synchronous area operational agreement common rules for the operation of load-frequency control in the normal state and alert state.

7. **<...>**

8. All TSOs of a LFC block shall specify operational procedures for cases of exhausted FRR or RR in the LFC block operational agreement. In those operational procedures the TSOs of a LFC block shall have the right to require changes in the active power production or consumption of power generating modules and demand units.

9. The TSOs of a LFC block shall endeavour to avoid FRCEs which last longer than the time to restore frequency.

10. All TSOs of a synchronous area shall specify in the synchronous area operational agreement the operational procedures for the alert state due to a violation of system frequency limits. The operational procedures shall aim at reducing the system frequency deviation in order to restore the system state to the normal state and to limit the risk of entering the emergency state. The operational procedures shall include the right of TSOs to deviate from the obligation set in Article 143(1).

11. If the system state is in the alert state due to insufficient active power reserves in accordance with Article 18, the TSOs of the concerned LFC blocks shall, in close cooperation with the other TSOs of the synchronous area and the TSOs of other synchronous areas, act to restore and replace the necessary levels of active power reserves. For that purpose, the TSOs of a LFC block shall have the right to require changes in the active power production or consumption of power generating modules or demand units within its control area to reduce or to remove the violation of the requirements concerning active power reserve.

12. If the 1-minute average of the FRCE of a LFC block is above the Level 2 FRCE range at least during the time necessary to restore frequency and where the TSOs of a LFC block do not expect that FRCE will be sufficiently reduced by undertaking the actions in paragraph 15, TSOs shall have the right to require changes in the active power production or consumption of power generating modules and demand units within their respective areas to reduce the FRCE as specified in paragraph 16.

13. For the CE **<...>** synchronous area, where the FRCE of a LFC block exceeds 25 % of the reference incident of the synchronous area for more than 30 consecutive minutes and if the TSOs of that LFC block do not expect to reduce sufficiently the FRCE with the actions taken pursuant to paragraph 15, the TSOs shall require changes in the active power production or consumption of power generating modules and demand units within their respective areas to reduce the FRCE as specified in paragraph 16.

14. The LFC block monitor shall be responsible for identifying any violation of the limits in paragraphs 12 and 13 and:

(a) shall inform the other TSOs of the LFC block; and

(b) together with the TSOs of the LFC block shall implement coordinated actions to reduce the FRCE which

shall be specified in the LFC block operational agreement.

15. For the cases referred to in paragraphs 11 to 13 all the TSOs of each synchronous area shall specify in the synchronous area operational agreement actions to enable the TSOs of a LFC block to actively reduce the frequency deviation with the cross-border activation of reserves. In cases referred to in paragraphs 11 to 13 the TSOs of the synchronous area shall endeavour to enable the TSOs of the concerned LFC block to reduce their FRCE.

16. The TSOs of a LFC block shall specify, in the LFC block operational agreement, measures to reduce the FRCE by means of changes in the active power production or consumption of power generating modules and demand units within their area.

TITLE 5
FREQUENCY CONTAINMENT RESERVES

Article 153
FCR dimensioning

1. All TSOs of each synchronous area shall determine, at least annually, the reserve capacity for FCR required for the synchronous area and the initial FCR obligation of each TSO in accordance with paragraph 2.

2. All TSOs of each synchronous area shall specify dimensioning rules in the synchronous area operational agreement in accordance with the following criteria:

(a) the reserve capacity for FCR required for the synchronous area shall cover at least the reference incident and, for the CE **<…>** synchronous area, the results of the probabilistic dimensioning approach for FCR carried out pursuant to point (c);

(b) the size of the reference incident shall be determined in accordance with the following conditions:

(i) for the CE synchronous area, the reference incident shall be 3 000 MW in positive direction and 3 000 MW in negative direction;

(ii) **<…>**

(c) for the CE **<…>** synchronous area, all TSOs of the synchronous area shall have the right to define a probabilistic dimensioning approach for FCR taking into account the pattern of load, generation and inertia, including synthetic inertia as well as the available means to deploy minimum inertia in real-time in accordance with the methodology referred to in Article 39, with the aim of reducing the probability of insufficient FCR to below or equal to once in 20 years; and

(d) the shares of the reserve capacity on FCR required for each TSO as initial FCR obligation shall be based on the sum of the net generation and consumption of its control area divided by the sum of net generation and consumption of the synchronous area over a period of 1 year.

Article 154

FCR technical minimum requirements

1. Each reserve connecting TSO shall ensure that the FCR fulfils the properties listed for its synchronous area in the Table of Annex V.

2. All TSOs of a synchronous area shall have the right to specify, in the synchronous area operational agreement, common additional properties of the FCR required to ensure operational security in the synchronous area, by means of a set of technical parameters and within the ranges in Article 15(2)(d) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and Articles 27 and 28 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC.** Those common additional properties of FCR shall take into account the installed capacity, structure and pattern of consumption and generation of the synchronous area. The TSOs shall apply a transitional period for the introduction of additional properties, defined in consultation with the affected FCR providers.

3. The reserve connecting TSO shall have the right to set out additional requirements for FCR providing groups within the ranges in Article 15(2)(d) of Regulation (EU) 2016/631 **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and Articles 27 and 28 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** in order to ensure operational security. Those additional requirements shall be based on technical reasons such as the geographical distribution of the power generating modules or demand units belonging to an FCR providing group. The FCR provider shall ensure that the monitoring of the FCR activation of the FCR providing units within a reserve providing group is possible.

4. The reserve connecting TSO shall have the right to exclude FCR providing groups from the provision of FCR in order to ensure operational security. This exclusion shall be based on technical reasons such as the geographical distribution of the power generating modules or demand units belonging to an FCR providing group.

5. Each FCR providing unit and each FCR providing group shall have only one reserve connecting TSO.

6. Each FCR providing unit and each FCR providing group shall comply with the properties required for FCR in the Table of Annex V and with any additional properties or requirements specified in accordance with paragraphs 2 and 3 and activate the agreed FCR by means of a proportional governor reacting to frequency deviations or alternatively based on a monotonic piecewise linear power-frequency characteristic in case of relay activated FCR. They shall be capable of activating FCR within the frequency ranges specified in Article 13(1) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**.

7. Each TSO of the CE synchronous area shall ensure that the combined reaction of FCR of a LFC area comply with the following requirements:

(a) the activation of FCR shall not be artificially delayed and begin as soon as possible after a frequency deviation;

(b) in case of a frequency deviation equal to or larger than 200 mHz, at least 50 % of the full FCR capacity shall be delivered at the latest after 15 seconds;

(c) in case of a frequency deviation equal to or larger than 200 mHz, 100 % of the full FCR capacity shall

be delivered at the latest after 30 seconds;

(d) in case of a frequency deviation equal to or larger than 200 mHz, the activation of the full FCR capacity shall rise at least linearly from 15 to 30 seconds; and

(e) in case of a frequency deviation smaller than 200 mHz the related activated FCR capacity shall be at least proportional with the same time behaviour referred to in points (a) to (d).

8. Each reserve connecting TSO shall monitor its contribution to the FCP and its FCR activation with respect to its FCR obligation, including FCR providing units and FCR providing groups. Each FCR provider shall make available to the reserve connecting TSO, for each of its FCR providing units and FCR providing groups, at least the following information:

(a) time-stamped status indicating if FCR is on or off;

(b) time-stamped active power data needed to verify FCR activation, including time-stamped instantaneous active power;

(c) droop of the governor for type C and type D power generating modules as defined in Article 5 of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** acting as FCR providing units, or its equivalent parameter for FCR providing groups consisting of type A and/or type B power generating modules as defined in Article 5 of Regulation (EU) 2016/631 **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** and/or demand units with demand response active power control as defined in Article 28 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**.

9. Each FCR provider shall have the right to aggregate the respective data for more than one FCR providing unit if the maximum power of the aggregated units is below 1,5 MW and a clear verification of activation of FCR is possible.

10. At the request of the reserve connecting TSO, the FCR provider shall make the information listed in paragraph 9 available in real-time, with a time resolution of at least 10 seconds.

11. At the request of the reserve connecting TSO and where necessary for the verification of the activation of FCR, a FCR provider shall make available the data listed in paragraph 9 concerning technical installations that are part of the same FCR providing unit.

Article 155

FCR prequalification process

1. By 12 months after entry into force of this regulation, each TSO shall develop an FCR prequalification process and shall make publicly available the details of the FCR prequalification process.

2. A potential FCR provider shall demonstrate to the reserve connecting TSO that it complies with the technical and the additional requirements set out in Article 154 by completing successfully the prequalification process of potential FCR providing units or FCR providing groups, described in paragraphs 3 to 6 of this Article.

3. A potential FCR provider shall submit a formal application to the reserve connecting TSO together with the required information of potential FCR providing units or FCR providing groups. Within 8 weeks from

receipt of the application, the reserve connecting TSO shall confirm whether the application is complete. Where the reserve connecting TSO considers that the application is incomplete, the potential FCR provider shall submit the additional required information within 4 weeks from receipt of the request for additional information. Where the potential FCR provider does not supply the requested information within that deadline, the application shall be deemed withdrawn.

4. Within 3 months from confirmation that the application is complete, the reserve connecting TSO shall evaluate the information provided and decide whether the potential FCR providing units or FCR providing groups meet the criteria for an FCR prequalification. The reserve connecting TSO shall notify its decision to the potential FCR provider.

5. Where the compliance with certain requirements of this Regulation has already been verified by the reserve connecting TSO, it will be recognised in the prequalification.

6. The qualification of FCR providing units or FCR providing groups shall be re-assessed:

(a) at least once every 5 years;

(b) in case the technical or availability requirements or the equipment have changed; and

(c) in case of modernisation of the equipment related to FCR activation.

Article 156

FCR provision

1. Each TSO shall ensure the availability of at least its FCR obligations agreed between all TSOs of the same synchronous area in accordance with Articles 153, 163, 173 and 174.

2. All TSOs of a synchronous area shall determine, at least on an annual basis, the size of the K- factor of the synchronous area, taking into account at least the following factors:

(a) the reserve capacity on FCR divided by the maximum steady-state frequency deviation;

(b) the auto-control of generation;

(c) the self-regulation of load, taking into account the contribution in accordance with Articles 27 and 28 of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**;

(d) the frequency response of HVDC interconnectors referred to in Article 172; and

(e) the LFSM and FSM activation in accordance with Articles 13 and 15 of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG- EnC**.

3. All TSOs of a synchronous area consisting of more than one LFC area shall, in the synchronous area operational agreement, determine the shares of the K-factor for each LFC area, which shall be based on at least:

(a) the initial FCR obligations;

(b) auto-control of generation;

(c) the self-regulation of load;

(d) frequency coupling via HVDC between synchronous areas;

(e) exchange of FCR.

4. An FCR provider shall guarantee the continuous availability of FCR, with the exception of a forced outage of a FCR providing unit, during the period of time in which it is obliged to provide FCR.

5. Each FCR provider shall inform its reserve connecting TSO, as soon as possible, about any changes in the actual availability of its FCR providing unit and/or its FCR providing group, in whole or in part, relevant for the results of prequalification.

6. Each TSO shall ensure, or shall require its FCR providers to ensure that the loss of a FCR providing unit does not endanger the operational security by:

(a) limiting the share of the FCR provided per FCR providing unit to 5 % of the reserve capacity of FCR required for each of the whole CE **<…>** synchronous area;

(b) **<…>**

(c) replacing the FCR which is made unavailable due to a forced outage or the unavailability of an FCR providing unit or FCR providing group as soon as technically possible and in accordance

with the conditions that shall be defined by the reserve connecting TSO.

7. An FCR providing unit or FCR providing group with an energy reservoir that does not limit its capability to provide FCR shall activate its FCR for as long as the frequency deviation persists. **<…>**

8. A FCR providing unit or FCR providing group with an energy reservoir that limits its capability to provide FCR shall activate its FCR for as long as the frequency deviation persists, unless its energy reservoir is exhausted in either the positive or negative direction. **<…>**For the CE **<…>** synchronous area, each FCR provider shall ensure that the FCR from its FCR providing units or groups with limited energy reservoirs are continuously available during normal state. For the CE **<…>** synchronous area, as of triggering the alert state and during the alert state, each FCR provider shall ensure that its FCR providing units or groups with limited energy reservoirs are able to fully activate FCR continuously for a time period to be defined pursuant to paragraphs 10 and 11. Where no period has been determined pursuant to paragraphs 10 and 11, each FCR provider shall ensure that its FCR providing units or groups with limited energy reservoirs are able to fully activate FCR continuously for at least 15 minutes or, in case of frequency deviations that are smaller than a frequency deviation requiring full FCR activation, for an equivalent length of time, or for a period defined by each TSO, which shall not be greater than 30 or smaller than 15 minutes.

9. For the CE **<…>** synchronous area, all TSOs shall **apply the methodology** concerning the minimum activation period to be ensured by FCR providers **adapted pursuant to Regulation (EU) 2017/1485**. **<…>**

10. **<…>**

11. The FCR provider shall specify the limitations of the energy reservoir of its FCR providing units or FCR providing groups in the prequalification process in accordance with Article 155.

12. A FCR provider using FCR providing units or FCR providing group with an energy reservoir that limits their capability to provide FCR shall ensure the recovery of the energy reservoirs in the positive or negative directions in accordance with the following criteria:

(a) **<…>**

(b) for the CE **<…>** synchronous area, the FCR provider shall ensure the recovery of the energy reservoirs as soon as possible, within 2 hours after the end of the alert state.

TITLE 6
FREQUENCY RESTORATION RESERVES

Article 157
FRR dimensioning

1. All TSOs of a LFC Block shall set out FRR dimensioning rules in the LFC Block operational agreement.

2. The FRR dimensioning rules shall include at least the following:

(a) all TSOs of a LFC block in the CE **<…>** synchronous area shall determine the required reserve capacity of FRR of the LFC block based on consecutive historical records comprising at least the historical LFC block imbalance values. The sampling of those historical records shall cover at least the time to restore frequency. The time period considered for those records shall be representative and include at least one full year period ending not earlier than 6 months before the calculation date;

(b) all TSOs of a LFC block in the CE **<…>** synchronous area shall determine the reserve capacity on FRR of the LFC block sufficient to respect the current FRCE target parameters in Article 128 for the time period referred to in point (a) based at least on a probabilistic methodology. In using that probabilistic methodology, the TSOs shall take into account the restrictions defined in the agreements for the sharing or exchange of reserves due to possible violations of operational security and the FRR availability requirements. All TSOs of a LFC block shall take into account any expected significant changes to the distribution of LFC block imbalances or take into account other relevant influencing factors relative to the time period considered;

(c) all TSOs of a LFC block shall determine the ratio of automatic FRR, manual FRR, the automatic FRR full activation time and manual FRR full activation time in order to comply with the requirement of paragraph (b). For that purpose, the automatic FRR full activation time of a LFC block and the manual FRR full activation time of the LFC block shall not be more than the time to restore frequency;

(d) the TSOs of a LFC block shall determine the size of the reference incident which shall be the largest imbalance that may result from an instantaneous change of active power of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line within the LFC block;

(e) all TSOs of a LFC block shall determine the positive reserve capacity on FRR, which shall not be less than the positive dimensioning incident of the LFC block;

(f) all TSOs of a LFC block shall determine the negative reserve capacity on FRR, which shall not be less than the negative dimensioning incident of the LFC block;

(g) all TSOs of a LFC block shall determine the reserve capacity on FRR of a LFC block, any possible geographical limitations for its distribution within the LFC block and any possible geographical limitations for any exchange of reserves or sharing of reserves with other LFC blocks to comply with the operational security limits;

(h) all TSOs of a LFC block shall ensure that the positive reserve capacity on FRR or a combination of reserve capacity on FRR and RR is sufficient to cover the positive LFC block imbalances for at least 99 % of the time, based on the historical records referred to in point (a);

(i) all TSOs of a LFC block shall ensure that the negative reserve capacity on FRR or a combination of reserve

capacity on FRR and RR is sufficient to cover the negative LFC block imbalances for at least 99 % of the time, based on the historical record referred to in point (a);

(j) all TSOs of a LFC block may reduce the positive reserve capacity on FRR of the LFC block resulting from the FRR dimensioning process by concluding a FRR sharing agreement with other LFC blocks in accordance with provisions in Title 8. The following requirements shall apply to that sharing agreement:

(k) all TSOs of a LFC block may reduce the negative reserve capacity on FRR of the LFC block, resulting from the FRR dimensioning process by concluding a FRR sharing agreement with other LFC blocks in accordance with the provisions of Title 8. The following requirements shall apply to that sharing agreement:

3. All TSOs of a LFC block where the LFC block comprises more than one TSO shall set out, in the LFC block operational agreement, the specific allocation of responsibilities between the TSOs of the LFC areas for the implementation of the obligations established in paragraph 2.

4. All TSOs of a LFC block shall have sufficient reserve capacity on FRR at any time in accordance with the FRR dimensioning rules. The TSOs of a LFC block shall specify in the LFC block operational agreement an escalation procedure for cases of severe risk of insufficient reserve capacity on FRR in the LFC block.

Article 158

FRR minimum technical requirements

1. The FRR minimum technical requirements shall be the following:

(a) each FRR providing unit and each FRR providing group shall be connected to only one reserve connecting TSO;

(b) a FRR providing unit or FRR providing group shall activate FRR in accordance with the setpoint received from the reserve instructing TSO;

(c) the reserve instructing TSO shall be the reserve connecting TSO or a TSO designated by the reserve connecting TSO in an FRR exchange agreement pursuant to Article 165(3) or 171(4);

(d) a FRR providing unit or FRR providing group for automatic FRR shall have an automatic FRR activation delay not exceeding 30 seconds;

(e) a FRR provider shall ensure that the FRR activation of the FRR providing units within a reserve providing group can be monitored. For that purpose, the FRR provider shall be capable of supplying to the reserve connecting TSO and the reserve instructing TSO real-time measurements of the connection point or another point of interaction agreed with the reserve connecting TSO concerning:

(i) time-stamped scheduled active power output;

(ii) time-stamped instantaneous active power for:

— each FRR providing unit,

— each FRR providing group, and

— each power generating module or demand unit of a FRR providing group with a maximum active power output larger than or equal to 1,5 MW;

(f) a FRR providing unit or FRR providing group for automatic FRR shall be capable of activating its complete automatic reserve capacity on FRR within the automatic FRR full activation time;

(g) a FRR providing unit or FRR providing group for manual FRR shall be capable of activating its complete manual reserve capacity on FRR within the manual FRR full activation time;

(h) a FRR provider shall fulfil the FRR availability requirements; and

(i) a FRR providing unit or FRR providing group shall fulfil the ramping rate requirements of the LFC block.

2. All TSOs of a LFC block shall specify FRR availability requirements and requirements on the control quality of FRR providing units and FRR providing groups for their LFC block in the LFC block operational agreement pursuant to Article 119.

3. The reserve connecting TSO shall adopt the technical requirements for the connection of FRR providing units and FRR providing groups to ensure the safe and secure delivery of FRR.

4. Each FRR provider shall:

(a) ensure that its FRR providing units and FRR providing groups fulfil the FRR technical minimum requirements, the FRR availability requirements and the ramping rate requirements in paragraphs 1 to 3; and

(b) inform its reserve instructing TSO about a reduction of the actual availability of its FRR providing unit or its FRR providing group or a part of its FRR providing group as soon as possible.

5. Each reserve instructing TSO shall ensure the monitoring of the compliance with the FRR minimum technical requirements in paragraph 1, the FRR availability requirements in paragraph 2, the ramping rate requirements in paragraph 1 and the connection requirements in paragraph 3 by its FRR providing units and FRR providing groups.

Article 159

FRR prequalification process

1. By 12 months after entry into force of this Regulation each TSO shall develop a FRR prequalification process and shall clarify and make publicly available its details.

2. A potential FRR provider shall demonstrate to the reserve connecting TSO or the TSO designated by the reserve connecting TSO in the FRR exchange agreement that it complies with the FRR minimum technical requirements in Article 158(1), the FRR availability requirements in Article 158(2), the ramping rate requirements in Article 158(1) and the connection requirements in Article 158(3) by completing successfully the prequalification process of potential FRR providing units or FRR providing groups, described in paragraphs 3 to 6 of this Article.

3. A potential FRR provider shall submit a formal application to the relevant reserve connecting TSO or the designated TSO together with the required information of potential FRR providing units or FRR providing groups. Within 8 weeks from receipt of the application, the reserve connecting TSO or the designated TSO shall confirm whether the application is complete. Where the reserve connecting TSO or the designated TSO considers that the application is incomplete they shall request additional information and the potential FRR provider shall submit the additional required information within 4 weeks from the receipt of the request. Where the potential FRR provider does not supply the requested information within that deadline, the application shall be deemed to be withdrawn.

4. Within 3 months after the reserve connecting TSO or the designated TSO confirms that the application is complete, the reserve connecting TSO or the designated TSO shall evaluate the information provided

and decide whether the potential FRR providing units or FRR providing groups meet the criteria for a FRR prequalification. The reserve connecting TSO or the designated TSO shall notify their decision to the potential FRR provider.

5. The qualification of FRR providing units or FRR providing groups by the reserve connecting TSO or the designated TSO shall be valid for the entire LFC Block.

6. The qualification of FRR providing units or FRR providing groups shall be re-assessed:

(a) at least once every 5 years; and

(b) where the technical or availability requirements or the equipment have changed.

7. To ensure operational security, the reserve connecting TSO shall have the right to exclude FRR providing groups from the provision of FRR based on technical arguments such as the geographical distribution of the power generating modules or demand units belonging to a FRR providing group.

TITLE 7
REPLACEMENT RESERVES

Article 160
RR dimensioning

1. All TSOs of an LFC block shall have the right to implement a reserve replacement process.

2. To comply with the FRCE target parameters referred to in Article 128, all TSOs of a LFC block with a RRP, performing a combined dimensioning process of FRR and RR to fulfil the requirements of Article 157(2), shall define RR dimensioning rules in the LFC block operational agreement.

3. The RR dimensioning rules shall comprise at least the following requirements:

(a) for the CE **<…>** synchronous area there shall be sufficient positive reserve capacity on RR to restore the required amount of positive FRR. **<…>**

(b) for the CE **<…>** synchronous area, there shall be sufficient negative reserve capacity on RR to restore the required amount of negative FRR. **<…>**

(c) there shall be sufficient reserve capacity on RR, where this is taken into account to dimension the reserve capacity on FRR in order to respect the FRCE quality target for the period of time concerned; and

(d) compliance with the operational security within a LFC block to determine the reserve capacity on RR.

4. All TSOs of an LFC block may reduce the positive reserve capacity on RR of the LFC block, resulting from the RR dimensioning process, by developing a RR sharing agreement for that positive reserve capacity on RR with other LFC blocks in accordance with the provisions of Title 8 of Part IV. The control capability receiving TSO shall limit the reduction of its positive reserve capacity on RR in order to:

(a) guarantee that it can still meet its FRCE target parameters set out in Article 128;

(b) ensure that operational security is not endangered; and

(c) ensure that the reduction of the positive reserve capacity on RR does not exceed the remaining positive reserve capacity on RR of the LFC block.

5. All TSOs of a LFC block may reduce the negative reserve capacity on RR of the LFC block, resulting from the RR dimensioning process, by developing a RR sharing agreement for that negative reserve capacity on RR with other LFC blocks in accordance with the provisions of Title 8 of Part IV. The control capability receiving TSO shall limit the reduction of its negative reserve capacity on RR in order to:

(a) guarantee that it can still meet its FRCE target parameters set out in Article 128;

(b) ensure that operational security is not endangered; and

(c) ensure that the reduction of the negative reserve capacity on RR does not exceed the remaining negative reserve capacity on RR of the LFC block.

6. Where a LFC block is operated by more than one TSO and if the process is necessary for the LFC block, all TSOs of that LFC block shall specify in the LFC block operational agreement the allocation of responsibilities between the TSOs of different LFC areas for the implementation of the dimensioning rules set out in paragraph 3.

7. A TSO shall have sufficient reserve capacity on RR in accordance with the RR dimensioning rules at any time. The TSOs of a LFC block shall specify in the LFC block operational agreement an escalation procedure for cases of severe risk of insufficient reserve capacity on RR in the LFC block.

Article 161

RR minimum technical requirements

1. RR providing units and RR providing groups shall comply with the following minimum technical requirements:

(a) connection to only one reserve connecting TSO;

(b) RR activation according to the setpoint received from the reserve instructing TSO;

(c) the reserve instructing TSO shall be the reserve connecting TSO or a TSO that shall be designated by the reserve connecting TSO in the RR exchange agreement pursuant to Article 165(3) or 171(4);

(d) activation of complete reserve capacity on RR within the activation time defined by the instructing TSO;

(e) de-activation of RR according to the setpoint received from the reserve instructing TSO;

(f) a RR provider shall ensure that the RR activation of the RR providing units within a reserve providing group can be monitored. For that purpose, the RR provider shall be capable of supplying to the reserve connecting TSO and the reserve instructing TSO real-time measurements of the connection point or another point of interaction agreed with the reserve connecting TSO concerning:

(i) the time-stamped scheduled active power output, for each RR providing unit and group and for each power generating module or demand unit of a RR providing group with a maximum active power output larger than or equal to 1,5 MW;

(ii) the time-stamped instantaneous active power, for each RR providing unit and group, and for each power generating module or demand unit of a RR providing group with a maximum active power output larger than or equal to 1,5 MW;

(g) fulfilment of the RR availability requirements.

2. All TSOs of a LFC block shall specify RR availability requirements and requirements on the control quality

of RR providing units and RR providing groups in the LFC block operational agreement.

3. The reserve connecting TSO shall adopt the technical requirements for the connection of RR providing units and RR providing groups to ensure the safe and secure delivery of RR in the prequalification process description.

4. Each RR provider shall:

(a) ensure that its RR providing units and RR providing groups fulfil the RR technical minimum requirements and the RR availability requirements referred to in paragraphs 1 to 3; and

(b) inform its reserve instructing TSO about a reduction of the actual availability or a forced outage of its RR providing unit or its RR providing group or a part of its RR providing group as soon as possible.

5. Each reserve instructing TSO shall ensure compliance with the RR technical requirements, the RR availability requirements and the connection requirements referred to in this Article with regard to its RR providing units and RR providing groups.

Article 162

RR prequalification process

1. Each TSO of a LFC block which has implemented a RRP shall develop a RR prequalification process within 12 months after entry into force of this Regulation and shall clarify and make publicly available the details thereof.

2. A potential RR provider shall demonstrate to the reserve connecting TSO or the TSO designated by the reserve connecting TSO in the RR exchange agreement that it complies with the RR technical minimum requirements, the RR availability requirements and the connection requirements referred to in Article 161 by completing successfully the prequalification process of potential RR providing units or RR providing groups, described in paragraphs 3 to 6.

3. A potential RR provider shall submit a formal application to the relevant reserve connecting TSO or the designated TSO together with the required information of potential RR providing units or RR providing groups. Within 8 weeks from receipt of the application, the reserve connecting TSO or the designated TSO shall confirm whether the application is complete. Where the reserve connecting TSO or the designated TSO considers that the application is incomplete, the potential RR provider shall submit the additional required information within 4 weeks from the receipt of the request for additional information. Where the potential RR provider does not supply the requested information within that deadline, the application shall be deemed withdrawn.

4. Within 3 months from confirmation of the completeness of the application, the reserve connecting TSO or the designated TSO shall evaluate the information provided and decide whether the potential RR providing units or RR providing groups meet the criteria for a RR prequalification. The reserve connecting TSO or the designated TSO shall notify its decision to the potential RR provider.

5. The qualification of RR providing units or RR providing groups shall be reassessed:

(a) at least once every 5 years; and

(b) where the technical or availability requirements or the equipment have changed.

6. To ensure operational security, the reserve connecting TSO shall have the right to reject the provision

of RR by RR providing groups, based on technical arguments such as the geographical distribution of the power generating modules or demand units establishing a RR providing group.

TITLE 8
EXCHANGE AND SHARING OF RESERVES

CHAPTER 1
Exchange and sharing of reserves within a synchronous area

Article 163
Exchange of FCR within a synchronous area

1. All TSOs involved in the exchange of FCR within a synchronous area shall comply with the requirements set out in paragraphs 2 to 9. The exchange of FCR implies a transfer of a FCR obligation from the reserve receiving TSO to the reserve connecting TSO for the corresponding reserve capacity on FCR.

2. All TSOs involved in the exchange of FCR within a synchronous area shall respect the limits and requirements for the exchange of FCR within the synchronous area specified in the Table of Annex VI.

3. In case of exchange of FCR, the reserve connecting TSO and reserve receiving TSO shall notify it in accordance with Article 150.

4. Any reserve connecting TSO, reserve receiving TSO or affected TSO involved in the exchange of FCR may refuse the exchange of FCR where it would result in power flows that violate the operational security limits when activating the reserve capacity on FCR subject to the exchange of FCR.

5. Each affected TSO shall verify that its reliability margin, established in accordance with Article 22 of Regulation (EU) 2015/1222**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** is sufficient to accommodate the power flows resulting from the activation of the reserve capacity on FCR subject to the exchange of FCR.

6. All TSOs of a LFC area shall adjust the parameters of their FRCE calculation to account for the exchange of FCR.

7. The reserve connecting TSO shall be responsible for the requirements referred to in Articles 154 and 156 as regards the reserve capacity on FCR subject to the exchange of FCR.

8. The FCR providing unit or group shall be responsible towards its reserve connecting TSO for FCR activation.

9. The concerned TSOs shall ensure that exchange of FCR does not prevent any TSO from fulfilling the reserve requirements in Article 156.

Article 164

Sharing of FCR within a synchronous area

A TSO shall not share FCR with other TSOs of its synchronous area to fulfil its FCR obligation and to reduce the total amount of FCR of the synchronous area in accordance with Article 153.

Article 165

General requirements for the exchange of FRR and RR within a synchronous area

1. All TSOs of a synchronous area shall define in the synchronous area operational agreement the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO for the exchange of FRR and/or RR.

2. Where an exchange of FRR/RR takes place, the reserve connecting TSO and reserve receiving TSO shall notify that exchange pursuant to the notification requirements in Article 150.

3. The reserve connecting and reserve receiving TSOs participating in the exchange of FRR/RR shall specify in a FRR or RR exchange agreement their roles and responsibilities, including:

(a) the responsibility of the reserve instructing TSO for the reserve capacity on FRR and RR subject to the exchange of FRR/RR;

(b) the amount of the reserve capacity on FRR and RR subject to the exchange of FRR/RR;

(c) the implementation of the cross-border FRR/RR activation process in accordance with Articles 147 and 148;

(d) FRR/RR technical minimum requirements related to the cross-border FRR/RR activation process where the reserve connecting TSO is not the reserve instructing TSO;

(e) the implementation of the FRR/RR prequalification for the reserve capacity on FRR and RR subject to exchange in accordance with Articles 159 and 162;

(f) the responsibility to monitor the fulfilment of the FRR/RR technical requirements and FRR/RR availability requirements for the reserve capacity on FRR and RR subject to exchange in accordance with Articles 158(5) and 161(5); and

(g) procedures to ensure that the exchange of FRR/RR does not lead to power flows which violate the operational security limits.

4. Any reserve connecting TSO, reserve receiving TSO or affected TSO involved in the exchange of FRR or RR may refuse the exchange referred to in paragraph 2 where it would result in power flows that violate the operational security limits when activating the reserve capacity on FRR and RR subject to the exchange of FRR or RR.

5. The concerned TSOs shall ensure that exchange of FRR/RR does not prevent any TSO from complying with the reserve requirements established in the FRR or RR dimensioning rules in Articles 157 and 160.

6. All TSOs of a LFC block shall specify in the LFC block operational agreement the roles and responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO for the exchange of FRR and/or RR with TSOs of other LFC blocks.

Article 166

General requirements for sharing FRR and RR within a synchronous area

1. All TSOs of a synchronous area shall specify in the synchronous area operational agreement the roles and responsibilities of the control capability providing TSO, the control capability receiving TSO and the affected TSO for sharing FRR/RR.

2. Where FRR/RR sharing takes place, the control capability providing TSO and control capability receiving TSO shall notify that sharing pursuant to the notification requirements in Article 150.

3. The control capability receiving TSO and the control capability providing TSO participating in the sharing of FRR/RR shall specify in a FRR or RR sharing agreement their roles and responsibilities, including:

(a) the amount of reserve capacity on FRR and RR subject to the sharing of FRR/RR;

(b) the implementation of the cross-border FRR/RR activation process in accordance with Articles 147 and 148;

(c) procedures to ensure that the activation of the reserve capacity on FRR and RR subject to the sharing of FRR/RR does not lead to power flows that violate the operational security limits.

4. Any control capability providing TSO, control capability receiving TSO or affected TSO involved in the sharing of FRR/RR may refuse sharing of FRR/RR where it would result in power flows that violate the operational security limits when activating the reserve capacity on FRR and RR subject to the sharing of FRR/RR.

5. In case of sharing of FRR/RR, the control capability providing TSO shall make available to the control capability receiving TSO a share of its own reserve capacity on FRR and RR required to comply with its reserve requirements for FRR and/or RR resulting from the FRR/RR dimensioning rules in Articles 157 and 160. The control capability providing TSO can be either:

(a) the reserve instructing TSO for the reserve capacity on FRR and RR subject to the sharing of

FRR/RR; or

(b) the TSO having access to its reserve capacity on FRR and RR subject to the sharing of FRR/RR through an implemented cross-border FRR/RR activation process as part of an FRR/RR exchange agreement.

6. Each control capability receiving TSO shall be responsible for coping with incidents and imbalances in case the reserve capacity on FRR and RR subject to the sharing of FRR/RR are unavailable due to:

(a) restrictions to provide frequency restoration or adjust the control program related to operational security; and

(b) partial or full usage of the reserve capacity on FRR and RR by the control capability providing TSO.

7. All TSOs of a LFC block shall specify in the LFC block operational agreement their roles and responsibilities of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of FRR and RR with TSOs of other LFC blocks.

Article 167

Exchange of FRR within a synchronous area

All TSOs in a synchronous area consisting of more than one LFC block involved in the exchange of FRR within the synchronous area shall comply with the requirements and limits for the exchange of FRR set out in the Table of Annex VII.

Article 168

Sharing of FRR within a synchronous area

Each TSO of a LFC block shall have the right to share FRR with other LFC blocks of its synchronous area within the limits set by the FRR dimensioning rules in Article 157(1) and in accordance with Article 166.

Article 169

Exchange of RR within a synchronous area

All TSOs in a synchronous area consisting of more than one LFC block involved in the exchange of RR within the synchronous area shall comply with the requirements and limits for the exchange of RR set out in the Table of Annex VIII.

Article 170

Sharing of RR within a synchronous area

Each TSO of a LFC block shall have the right to share RR with other LFC blocks of the same synchronous area within the limits set by the RR dimensioning rules in Article 160(4) and (5) and in accordance with Article 166.

CHAPTER 2
Exchange and sharing of reserves between synchronous areas

Article 171

General requirements

1. Each operator and/or owner of an HVDC interconnector which interconnects synchronous areas shall provide to the connecting TSOs the capability to perform the exchange and sharing of FCR, FRR and RR if this technology is installed.

2. All TSOs of the synchronous area shall specify in the synchronous area operational agreement the roles

and the responsibilities of the reserve connecting TSO, the reserve receiving TSO and the affected TSO for the exchange of reserves as well as for the control capability providing TSO, control capability receiving TSO and affected TSO for the sharing of reserves between synchronous areas.

3. The reserve connecting TSO and reserve receiving TSO or the control capability providing TSO and the control capability receiving TSO shall notify the exchange or sharing of FCR, FRR or RR in accordance with Article 150.

4. The reserve connecting TSO and reserve receiving TSO involved in the exchange of reserves shall specify, in an exchange agreement, their roles and responsibilities, including:

(a) the responsibility of the reserve instructing TSO for the reserve capacity of the reserve exchange;

(b) the amount of the reserve capacity subject to the exchange of reserves;

(c) the implementation of the cross-border FRR/RR activation process in accordance with Articles 147 and 148;

(d) the implementation of the prequalification for the reserve capacity subject to the exchange of reserves in accordance with Articles 155, 159 and 162;

(e) the responsibility to monitor compliance with the technical requirements and availability requirements of the reserve capacity subject to the exchange of reserves pursuant to Articles 158(5) and 161(5); and

(f) procedures to ensure that the exchange of reserves does not lead to power flows that violate the operational security limits.

5. The control capability providing and control capability receiving TSO involved in the sharing of reserves shall specify their roles and responsibilities in a sharing agreement, including:

(a) the amount of reserve capacity subject to the sharing of reserves;

(b) the implementation of the cross-border FRR/RR activation process in accordance with Articles 147 and 148; and

(c) the procedures to ensure that the sharing of reserves does not lead to power flows that violate the operational security limits.

6. The reserve connecting TSO and reserve receiving TSO involved in the exchange of reserves, or the control capability providing and control capability receiving TSO involved in the sharing of reserves shall develop and adopt an HVDC operating and coordination agreement with the HVDC interconnector owners and/or HVDC interconnector operators or with legal entities comprising HVDC interconnector owners and/or HVDC interconnector operators, including:

(a) the interactions across all timescales, including planning and activation;

(b) the MW/Hz sensitivity factor, linearity/dynamic or static/step response function of each HVDC interconnector connecting synchronous areas; and

(c) the share/interaction of these functions across multiple HVDC paths between the synchronous areas.

7. Any reserve connecting TSO, reserve receiving TSO, control capability providing TSO, control capability receiving TSO or affected TSO involved in the exchange or sharing of reserves may refuse the exchange or sharing of reserve where it would result in power flows that violate the operational security limits when activating the reserve capacity subject to the exchange or sharing of reserve.

8. The involved TSOs shall ensure that exchange of reserves between synchronous areas does not prevent

any TSO from complying with the reserve requirements in Articles 153, 157 and 160.

9. The reserve connecting TSO and reserve receiving TSO and the control capability providing and control capability receiving TSO shall specify procedures in an exchange agreement or sharing agreement for cases when the exchange or the sharing of reserves between synchronous areas cannot be executed in real-time.

Article 172

Frequency coupling between synchronous areas

1. All TSOs of the synchronous areas connected via an HVDC interconnector shall have the right to implement a frequency coupling process to provide linked frequency response. The frequency coupling process may be used by TSOs to enable FCR exchange and/or sharing between synchronous areas.

2. All TSOs of each synchronous area shall specify the technical design of the frequency coupling process in the synchronous area operational agreement. The frequency coupling process shall take into account:

(a) the operational impact between the synchronous areas;

(b) the stability of the FCP of the synchronous area;

(c) the ability of the TSOs of the synchronous area to comply with the frequency quality target parameters defined in accordance with Article 127; and

(d) the operational security.

3. Each HVDC interconnector operator shall control the active power flow over the HVDC interconnector in accordance with the implemented frequency coupling process.

Article 173

Exchange of FCR between synchronous areas

1. All TSOs of a synchronous area involved in a frequency coupling process shall have the right to use the FCR exchange process to exchange FCR between synchronous areas.

2. All TSOs of synchronous areas involved in the exchange of FCR between synchronous areas shall organise that exchange so that the TSOs of one synchronous area receive from another synchronous area a share of the total reserve capacity on FCR required for their synchronous area pursuant to Article 153.

3. The share of the total reserve capacity on FCR required for synchronous area where it is exchanged shall be provided in the second synchronous area in addition to the total reserve capacity on FCR required for that second synchronous area in accordance with Article 153.

4. All TSOs of the synchronous area shall specify in the synchronous area operational agreement the limits for FCR exchange.

5. All TSOs of the involved synchronous areas shall develop an FCR exchange agreement whereby they specify conditions for the exchange of FCR.

Article 174

Sharing of FCR between synchronous areas

1. All TSOs of a synchronous area involved in a frequency coupling process shall have the right to use that process to share FCR between the synchronous areas.

2. All TSOs of the synchronous area shall specify the limits for FCR sharing in the synchronous area operational agreement, in accordance with the following criteria:

3. All TSOs of the involved synchronous areas shall specify the conditions for sharing FCR between the involved synchronous areas in their respective synchronous area operational agreements.

Article 175

General requirements for sharing of FRR and RR between synchronous areas

1. In case of sharing of FRR or RR, the control capability providing TSO shall make available to the control capability receiving TSO a share of its own reserve capacity on FRR and RR required to comply with the reserve requirements for FRR and/or RR resulting from the FRR/RR dimensioning rules referred to in Articles 157 and 160. The control capability providing TSO can be either:

(a) the reserve instructing TSO for the reserve capacity on FRR and RR subject to the sharing of FRR or RR; or

(b) the TSO having access to its reserve capacity on FRR and RR subject to the sharing of FRR/RR through an implemented cross-border FRR/RR activation process as part of a FRR/RR exchange agreement.

2. All TSOs of an LFC block shall specify in the LFC block operational agreement their roles and responsibilities of the control capability providing TSO, the control capability receiving TSO and the affected TSO for the sharing of FRR and RR with TSOs of other LFC blocks in other synchronous areas.

Article 176

Exchange of FRR between synchronous areas

1. All TSOs of each synchronous area shall specify in the synchronous area operational agreement a method to determine the limits for the exchange of FRR with other synchronous areas. That method shall take into account:

(a) the operational impact between the synchronous areas;

(b) the stability of the FRP of the synchronous area;

(c) the ability of TSOs of the synchronous area to comply with the frequency quality target parameters defined in accordance with Article 127 and the FRCE target parameters defined in accordance with Article 128; and

(d) the operational security.

2. All TSOs of the LFC blocks involved in the exchange of FRR between synchronous areas shall organise that exchange so that the TSOs of a LFC block in the first synchronous area may receive a share of the total

reserve capacity on FRR required for their LFC block as determined in accordance with the Article 157(1) from a LFC block in the second synchronous area.

3. The share of the total reserve capacity on FRR required for the LFC block in the synchronous area where it is exchanged shall be provided from the LFC block in the second synchronous area in addition to the total reserve capacity on FRR required for that second LFC block in accordance with Article 157(1).

4. Each operator of a HVDC interconnector shall control the active power flow over the HVDC interconnector following the instructions provided by either the reserve connecting TSO or reserve receiving TSO in accordance with the FRR technical minimum requirements referred to in Article 158.

5. All TSOs of the LFC blocks to which the reserve connecting TSO and the reserve receiving TSO belong shall specify the conditions for exchange of FRR in an FRR exchange agreement.

Article 177

Sharing of FRR between synchronous areas

1. All TSOs of each synchronous area shall specify in the synchronous area operational agreement a methodology to determine limits for the sharing of FRR with other synchronous areas. That methodology shall take into account:

(a) the operational impact between the synchronous areas;

(b) the stability of the FRP of the synchronous area;

(c) the maximum reduction of FRR that can be taken into account in the FRR dimensioning in accordance with Article 157 as a result of the FRR sharing;

(d) the ability of the synchronous area to comply with the frequency quality target parameters defined in accordance with Article 127 and the FRCE target parameters defined in accordance with Article 128; and

(e) the operational security.

2. All TSOs of the LFC blocks involved in the sharing of FRR between synchronous areas shall organise that sharing so that the TSOs of a LFC block in the first synchronous area may receive a share of the total reserve capacity on FRR required for their LFC block as defined in accordance with the Article 157(1) from a LFC block in the second synchronous area.

3. Each operator of a HVDC interconnector shall control the active power flow over the HVDC interconnector following the instructions provided by either the control capability providing TSO or control capability receiving TSO in accordance with the FRR technical minimum requirements in Article 158(1).

4. All TSOs of the LFC blocks to which the control capability providing TSO and the control capability receiving TSOs belong shall specify the conditions for sharing FRR in an FRR sharing agreement.

Article 178

Exchange of RR between synchronous areas

1. All TSOs of each synchronous area shall define in the synchronous area operational agreement a method to determine limits for the exchange of RR with other synchronous areas. That method shall take into

account:

(a) the operational impact between the synchronous areas;

(b) the stability of the RRP of the synchronous area;

(c) the ability of the synchronous area to comply with the frequency quality target parameters defined in accordance with Article 127 and the FRCE target parameters defined in accordance with Article 128; and

(d) the operational security.

2. All TSOs of the LFC blocks involved in the exchange of RR between synchronous areas shall organise that exchange so that the TSOs of a LFC block in the first synchronous area may receive a share of the total reserve capacity on RR required for their LFC block as defined in Article 160(2) from a LFC block in the second synchronous area.

3. The share of the total reserve capacity on RR required for the LFC block in the synchronous area where it is exchanged shall be provided from the LFC block in the second synchronous area in addition to the total reserve capacity on RR required for that second LFC block in accordance with Article 160(2).

4. Each operator of a HVDC interconnector shall control the active power flow over the HVDC interconnector following the instructions provided by either the reserve connecting TSO or the reserve receiving TSO in accordance with the RR technical minimum requirements in Article 161.

5. All TSOs of the LFC blocks to which the reserve connecting TSO and the reserve receiving TSO belong shall specify the conditions for the exchange of RR in an RR exchange agreement.

Article 179

Sharing of RR between synchronous areas

1. All TSOs of each synchronous area shall define in the synchronous area operational agreement a method for determining the limits for sharing of RR with other synchronous areas. That method shall take into account:

(a) the operational impact between the synchronous areas;

(b) the stability of the RRP of the synchronous area;

(c) the maximum reduction of RR that can be taken into account in the RR dimensioning rules in accordance with Article 160 as a result of the RR sharing;

(d) the ability of the TSOs of the synchronous area to comply with the frequency quality target parameters defined in accordance with Article 127 and the ability of the LFC blocks to comply with the FRCE error target parameters defined in accordance with Article 128; and

(e) the operational security.

2. All TSOs of the LFC blocks involved in the sharing of RR between synchronous areas shall organise that sharing so that the TSOs of an LFC block in the first synchronous area may receive a share of the total reserve capacity on RR required for their LFC block as defined in accordance with Article 160(2) from a LFC block in the second synchronous area.

3. Each operator of an HVDC interconnector shall control the active power flow over the HVDC interconnector following the instructions provided by either the control capability providing TSO or the control

capability receiving TSO in accordance with the RR technical minimum requirements in Article 161.

4. All TSOs of each LFC block to which the reserve control capability providing TSO and reserve control capability receiving TSO belong to, shall specify the conditions for the sharing of RR in an RR sharing agreement.

CHAPTER 3
Cross-border activation process for FRR/RR

Article 180
Cross-border activation process for FRR/RR

All TSOs involved in the cross-border activation of FRR and RR in the same or different synchronous areas shall comply with the requirements set out in Articles 147 and 148.

TITLE 9
TIME CONTROL PROCESS

Article 181
Time control process

1. The control target of the electrical time control process shall be to control the average value of the system frequency to the nominal frequency.

2. Where applicable, all TSOs of a synchronous area shall define in the synchronous area operational agreement the methodology to correct the electrical time deviation, which shall include:

(a) the time ranges within which TSOs shall endeavour to maintain the electrical time deviation;

(b) the frequency setpoint adjustments to return electrical time deviation to zero; and

(c) the actions to increase or decrease the average system frequency by means of active power reserves.

3. The synchronous area monitor shall:

(a) monitor the electrical time deviation;

(b) calculate the frequency setpoint adjustments; and

(c) coordinate the actions of the time control process.

TITLE 10
COOPERATION WITH DSOS

Article 182

Reserve providing groups or units connected to the DSO grid

1. TSOs and DSOs shall cooperate in order to facilitate and enable the delivery of active power reserves by reserve providing groups or reserve providing units located in the distribution systems.

2. For the purposes of the prequalification processes for FCR in Article 155, FRR in Article 159 and RR in Article 162, each TSO shall develop and specify, in an agreement with its reserve connecting DSOs and intermediate DSOs, the terms of the exchange of information required for these prequalification processes for reserve providing units or groups located in the distribution systems and for the delivery of active power reserves. The prequalification processes for FCR in Article 155, FRR in Article 159 and RR in Article 162 shall specify the information to be provided by the potential reserve providing units or groups, which shall include:

(a) voltage levels and connection points of the reserve providing units or groups;

(b) the type of active power reserves;

(c) the maximum reserve capacity provided by the reserve providing units or groups at each connection point; and

(d) the maximum rate of change of active power for the reserve providing units or groups.

3. The prequalification process shall rely on the agreed timeline and rules concerning information exchanges and the delivery of active power reserves between the TSO, the reserve connecting DSO and the intermediate DSOs. The prequalification process shall have a maximum duration of 3 months from the submission of a complete formal application by the reserve providing unit or group.

4. During the prequalification of a reserve providing unit or group connected to its distribution system, each reserve connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in its distribution system, based on technical reasons such as the geographical location of the reserve providing units and reserve providing groups.

5. Each reserve connecting DSO and each intermediate DSO shall have the right, in cooperation with the TSO, to set, before the activation of reserves, temporary limits to the delivery of active power reserves located in its distribution system. The respective TSOs shall agree with their reserve connecting DSOs and intermediate DSOs on the applicable procedures.

TITLE 11
TRANSPARENCY OF INFORMATION

Article 183

General transparency requirements

1. All TSOs shall ensure that the information listed in this Title is published at a time and in a format that does not create an actual or potential competitive advantage or disadvantage to any individual party or category of party and taking due account of sensitive commercial information.

2. Each TSO shall use available knowledge and tools to overcome technical limits and to ensure the availability and the accuracy of the information made available to ENTSO for Electricity in accordance with Article 16 and Article 185(3).

3. Each TSO shall ensure the availability and the accuracy of the information made available to ENTSO for Electricity in accordance with Articles 184 to 190.

4. All material for publication mentioned in Articles 184 to 190 shall be made available to ENTSO for Electricity at least in English. ENTSO for Electricity shall publish this material on the

information transparency platform established in accordance with Article 3 of Regulation (EU) No 543/2013**, as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC**.

Article 184

Information on operational agreements

1. Each TSO shall share the contents of its synchronous area operational agreement with its regulatory authority or, where applicable, with another competent authority no later than 1 month before its entry into force.

2. All TSOs of each synchronous area shall notify the contents of their synchronous area operational agreement to ENTSO for Electricity for publication no later than 1 week after its entry into force.

3. Each TSO of each LFC block shall share the contents of its LFC block operational agreement with its regulatory authority or, where applicable, with another competent authority.

Article 185

Information on frequency quality

1. Where the TSOs of a synchronous area propose to modify the values for the frequency quality defining parameters or the frequency quality target parameter in accordance with Article 127, they shall notify the modified values to ENTSO for Electricity for publication at least 1 month before the entry into force of the synchronous area operational agreement.

2. Where applicable, all TSOs of each synchronous area shall notify the values of the FRCE target parameters for each LFC block and each LFC area to ENTSO for Electricity for publication at least 1 month before their applicability.

3. All TSOs of each synchronous area shall notify the methodology used to determine the risk of exhaustion of FCR to ENTSO for Electricity for publication at least 3 months before the application of the synchronous area operational agreement.

4. The synchronous area monitor of each synchronous area shall notify the results of the criteria application process for their synchronous area to ENTSO for Electricity for publication within 3 months after the last time-stamp of the measurement period and at least four times a year. Those results shall include at least:

(a) the values of the frequency quality evaluation criteria calculated for the synchronous area and for each LFC block within the synchronous area in accordance with Article 133(3); and

(b) the measurement resolution, measurement accuracy and calculation method specified in accordance with Article 132;

5. All TSOs of each synchronous area shall notify the ramping period specified in accordance with Article 136 to ENTSO for Electricity for publication at least 3 months before their applicability.

Article 186

Information on the load-frequency control structure

1. All TSOs of each synchronous area shall notify the following information to ENTSO for Electricity for publication at least 3 months before the application of the synchronous area operational agreement:

(a) information on the process activation structure of the synchronous area, including at least information on the monitoring areas, LFC areas and LFC blocks defined and their respective TSOs; and

(b) information on the process responsibility structure of the synchronous area, including at least information on the processes developed in accordance with Article 140(1) and (2).

2. All TSOs implementing an imbalance netting process shall publish information regarding that process which shall include at least the list of participating TSOs and the starting date of the imbalance netting process.

Article 187

Information on FCR

1. All TSOs of each synchronous area shall notify the dimensioning approach for FCR for their synchronous area in accordance with Article 153(2) to ENTSO for Electricity for publication at least 1 month before its applicability.

2. Where applicable, all TSOs of each synchronous area shall notify the total amount of reserve capacity on FCR and the shares of reserve capacity on FCR required for each TSO specified in accordance with Article 153(1) as the initial FCR obligation to ENTSO for Electricity for publication at least 1 month before their applicability.

3. All TSOs of each synchronous area shall notify the FCR properties established for their synchronous area in accordance with Article 154(2) and the additional requirements for FCR providing groups in accordance with Article 154(3) to ENTSO for Electricity for publication at least 3 months before their applicability.

Article 188

Information on FRR

1. All TSOs of each LFC block shall notify the FRR availability requirements and requirements for the control quality specified in accordance with Article 158(2) and the technical requirements for the connection specified in accordance with Article 158(3) for their LFC block to ENTSO for Electricity for publication at least 3 months before their applicability.

2. All TSOs of each LFC block shall notify the FRR dimensioning rules specified for their LFC block in accordance with Article 157(1) to ENTSO for Electricity for publication at least 3 months before the applicability of the LFC block operational agreement.

3. All TSOs of each synchronous area shall notify, by 30 November of each year, an outlook of the reserve capacities on FRR of each LFC block for the next year to ENTSO for Electricity for publication.

4. All TSOs of each synchronous area shall notify, within 30 days after the end of the quarter, the actual reserve capacities on FRR of each LFC block of the past quarter to ENTSO for Electricity for publication.

Article 189

Information on RR

1. All TSOs of each LFC block that operates a reserve replacement process shall notify the RR availability requirements specified in accordance with Article 161(2) and the technical requirements for the connection specified in accordance with Article 161(3) for their LFC block available to ENTSO for Electricity for publication within 3 months before their applicability.

2. All TSOs of each synchronous area shall notify, by 30 November of each year, an outlook of the reserve capacities RR of each LFC block for the following year to ENTSO for Electricity for publication.

3. All TSOs of each synchronous area shall notify, within 30 days after the end of the quarter, the actual reserve capacities RR of each LFC block of the past quarter to ENTSO for Electricity for publication.

Article 190

Information on sharing and exchange

1. All TSOs of each synchronous area shall notify the annual compilations of the agreements for the sharing of FRR and for the sharing of RR for each LFC block within the synchronous area to ENTSO for Electricity for publication in accordance with Articles 188(3) and 189(2). Those compilations shall include the following information:

(a) the identity of the LFC blocks where there is an agreement for the sharing of FRR or RR; and

(b) the share of FRR and RR reduced due to each agreement for the sharing of FRR or RR.

2. All TSOs of each synchronous area shall notify the information on the sharing of FCR between synchronous areas to ENTSO for Electricity for publication in accordance with Article 187(1). That information shall include the following:

(a) the amount of shared reserve capacity on FCR between TSOs that entered into agreements for the sharing of FCR; and

(b) the effects of the sharing of FCR on the reserve capacity on FCR of the involved TSOs.

3. Where applicable, all TSOs shall publish the information on the exchange of FCR, FRR and RR.

PART V
FINAL PROVISIONS

Article 191

Amendments to contracts and general terms and conditions

All relevant clauses in contracts and general terms and conditions of TSOs, DSOs and significant grid users relating to system operation shall comply with the requirements of this Regulation. To that effect, those contracts and general terms and conditions shall be modified accordingly.

Article 192

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[4]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with Regulation (EU) 2017/2485 <…> by 31 December 2023.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

4 The text displayed here corresponds to Article 13 of Decision 2022/03/MC-EnC.

ANNEX I

<...>

ANNEX II

Voltage ranges referred to in Article 27:

Table 1

Voltage ranges at the connection point between 110 kV and 300 kV

Synchronous area	Voltage range
Continental Europe	0,90 pu-1,118 pu

Table 2

Voltage ranges at the connection point between 300 kV and 330 kV

Synchronous area	Voltage range
Continental Europe (Moldova and Ukraine)	0,90 pu-1,1 pu
Continental Europe (others)	0,90 pu-1,05 pu

Table 3

Voltage ranges at the connection point between 330 kV and 400 kV (750 kV for Ukraine)

Synchronous area	Voltage range
Continental Europe	0,90 pu-1,05 pu

ANNEX III

Frequency quality defining parameters referred to in Article 127:

Table 1: Frequency quality defining parameters of the synchronous areas

	CE
standard frequency range	± 50 mHz
maximum instantaneous frequency deviation	800 mHz
maximum steady-state frequency deviation	200 mHz
time to recover frequency	not used
frequency recovery range	not used
time to restore frequency	15 minutes
frequency restoration range	not used
alert state trigger time	5 minutes

Frequency quality target parameters referred to in Article 127:

Table 2: Frequency quality target parameters of the synchronous areas

	CE
maximum number of minutes outside the standard frequency range	15 000

ANNEX IV

<...>

ANNEX V

FCR technical minimum requirements referred to in Article 154:

Table: FCR properties in the different synchronous areas

Minimum accuracy of frequency measurement	**CE**	**10 mHz or the industrial standard if better**
Maximum combined effect of inherent frequency response insensitivity and possible intentional frequency response dead band of the governor of the FCR providing units or FCR providing groups.	CE	10 mHz
FCR full activation time	CE	30 s
FCR full activation frequency deviation.	CE	± 200 mHz

ANNEX VI

Limits and requirements for the exchange of FCR referred to in Article 163:

Table: Limits and requirements for the exchange of FCR

Synchronous area	Exchange of FCR allowed between:	Limits for the exchange of FCR
CE synchronous area	TSOs of adjacent LFC blocks	- the TSOs of an LFC block shall ensure that at least 30 % of their total combined initial FCR obligations, is physically provided inside their LFC block; and the amount of reserve capacity on FCR, physically located in an LFC block as a result of the exchange of FCR with other LFC blocks, shall be limited to the maximum of: - 30 % of the total combined initial FCR obligations of the TSOs of the LFC block to which the reserve capacity on FCR is physically connected; and - 100 MW of reserve capacity on FCR
	TSOs of the LFC areas of the same LFC block	the TSOs of the LFC areas constituting a LFC block shall have the right to specify in the LFC block operational agreement internal limits for the exchange of FCR between the LFC areas of the same LFC block in order to: - avoid internal congestions in case of the activation of FCR; - ensure an even distribution of reserve capacity on FCR for the case of network splitting; and - avoid that the stability of the FCP or the operational security is affected.
Other synchronous areas	TSOs of the synchronous area	The TSOs of the synchronous area shall have the right to specify in the synchronous area operational agreement limits for the exchange of FCR in order to: - avoid internal congestions in case of the activation of FCR; - ensure an even distribution of FCR in case of network splitting; and - avoid that the stability of the FCP or the operational security is affected.

ANNEX VII

Requirements and limits for the exchange of FRR within the synchronous area referred to in Article 167:

Table: Requirements and limits for the exchange of FRR within a synchronous area

Synchronous area	**Exchange of FRR allowed between**	**Limits for the exchange of FRR**
All synchronous areas consisting of more than one LFC block	TSOs of different LFC blocks	The TSOs of a LFC block shall ensure that at least 50 % of their total combined reserve capacity on FRR resulting from the FRR dimensioning rules in Article 157(1) and before any reduction due to the sharing of FRR in accordance with Article 157(2) remains located within their LFC block.
	TSOs of the LFC areas of the same LFC block	The TSOs of the LFC areas constituting a LFC block shall have the right, if needed, to specify internal limits, for the exchange of FRR between the LFC areas of the LFC block in the LFC block operational agreement to: - avoid internal congestions due to the activation of the reserve capacity on FRR subject to the exchange of FRR; - ensure an even distribution of FRR throughout the synchronous area and LFC blocks in case of network splitting; - avoid that the stability of the FRP or the operational security is affected.

ANNEX VIII

Requirements and limits for the exchange of RR within the synchronous area referred to in Article 169:

Table: Requirements and limits for the exchange of RR within the synchronous area

Synchronous area	**Exchange of RR allowed between**	**Limits for the exchange of RR**
All synchronous areas consisting of more than one LFC block	TSOs of different LFC blocks	The TSOs of the LFC areas constituting a LFC block shall ensure that at least 50 % of their total combined reserve capacity on RR resulting from the RR dimensioning rules according to Article 160(3) and before any reduction of reserve capacity on RR as a result of the sharing of RR according to Article 160(4) and Article 160(5) remains located within their LFC block.
	TSOs of the LFC areas of the same LFC block	The TSOs of the LFC areas constituting a LFC block shall have the right, if required, to define internal limits for the exchange of RR between LFC areas of the LFC block in the LFC block operational agreement as to: - avoid internal congestions due to the activation of reserve capacity on RR subject to the exchange of RR; - ensure an even distribution of RR throughout the synchronous area in case of network splitting; and - avoid that the stability of the RRP or the operational security is affected.

COMMISSION REGULATION (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration

Incorporated and adapted by the Ministerial Council Decision 2022/03/MC-EnC of 15 December 2022 on the incorporation of Regulation (EU) 2019/942, Regulation (EU) 2019/943, Regulation (EU) 2015/1222, Regulation (EU) 2016/1719, Regulation (EU) 2017/2195, Regulation (EU) 2017/2196, Regulation (EU) 2017/1485 in the Energy Community acquis, amending Annex I of the Energy Community Treaty, and on the amendments of the Ministerial Council Decisions 2021/13/MC-EnC and 2011/02/MC-EnC.

The adaptations made by Ministerial Council Decision 2022/03/MC-EnC are highlighted in ***bold and blue.***

CHAPTER I
GENERAL PROVISIONS

Article 1
Subject matter

For the purposes of safeguarding operational security, preventing the propagation or deterioration of an incident to avoid a widespread disturbance and the blackout state as well to allow for the efficient and rapid restoration of the electricity system from the emergency or blackout states, this Regulation establishes a network code which lays down the requirements on:

(a) the management by TSOs of the emergency, blackout and restoration states;

(b) the coordination of system operation across the **Energy Community** in the emergency, blackout and restoration states;

(c) the simulations and tests to guarantee a reliable, efficient and fast restoration of the interconnected transmission systems to the normal state from the emergency or blackout states;

(d) the tools and facilities needed to guarantee a reliable, efficient and fast restoration of the interconnected transmission systems to the normal state from the emergency or blackout states.

Article 2
Scope

1. This Regulation shall apply to TSOs, DSOs, SGUs, defence service providers, restoration service providers, balance responsible parties, balancing service providers, nominated electricity market operators ('NEMO'), and other entities designated to execute market functions pursuant to Commission Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** and to Commission Regulation (EU) 2016/1719**, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. In particular, this Regulation shall apply to the following SGUs:

(a) existing and new power generating modules classified as type C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**;

(b) existing and new power generating modules classified as type B in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** where they are identified as SGUs in accordance with Article 11(4) and Article 23(4);

(c) existing and new transmission-connected demand facilities;

(d) existing and new transmission connected closed distribution systems;

(e) providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**; and

(f) existing and new high voltage direct current ('HVDC') systems and direct current-connected power park modules in accordance with the criteria set out in Article 4(1) of Commission Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**.

3. This Regulation shall apply to existing and new type A power generating modules, in accordance with the criteria set out in Article 5 of Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** to existing and new type B power generating modules other than those referred to in paragraph 2(b), as well as to existing and new demand facilities, closed distribution systems and third parties providing demand response where they qualify as defence service providers or restoration service providers pursuant to Article 4(4).

4. Type A and type B power generating modules referred to in paragraph 3, demand facilities and closed distribution systems providing demand response may fulfil the requirements of this Regulation either directly or indirectly through a third party, under the terms and conditions set in accordance with Article 4(4).

5. This Regulation shall apply to energy storage units of a SGU, a defence service provider or a restoration service provider, which can be used to balance the system, provided that they are identified as such in the system defence plans, restoration plans or in the relevant service contract.

6. This Regulation shall apply to all transmission systems, distribution systems and interconnections in the **Contracting Parties and with the Member States , and to regional coordination centres,** except transmission systems and distribution systems or parts of the transmission systems and distribution systems of **Contracting Parties** of which the systems are not operated synchronously with Continental Europe **('CE')** synchronous area.

7. In **Contracting Parties** where more than one transmission system operator exists, this Regulation shall apply to all transmission system operators within that **Contracting Party**. Where a transmission system operator does not have a function relevant to one or more obligations under this Regulation, **Contracting Parties** may provide that the responsibility for complying with those obligations is assigned to one or more different, specific transmission system operators.

8. **< ... >**

Article 3

Definitions

For the purposes of this Regulation, the definitions provided for in Article 2 of Directive**(EU) 2019/944** of the European Parliament and of the Council**, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, Article 2 of Regulation (EU) No **2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Commission Regulation (EU) No 543/2013, **as adapted and adopted by Permanent High Level Group Decision 2015/01/PHLG-EnC,** Article 2 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, Article 2 of Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** Article 2 of Commission Regulation (EU) 2016/1388, **as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** Article 2 of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** Article 2 of Regulation (EU) 2016/1719 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, and Article 2 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** shall apply.

In addition, the following definitions shall apply:

(1) 'defence service provider' means a legal entity with a legal or contractual obligation to provide a service contributing to one or several measures of the system defence plan;

(2) 'restoration service provider' means a legal entity with a legal or contractual obligation to provide a service contributing to one or several measures of the restoration plan;

(3) 'high priority significant grid user' means the significant grid user for which special conditions apply for disconnection and re-energisation;

(4) 'netted demand' means the netted value of active power seen from a given point of the system, computed as (load — generation), generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time;

(5) 'restoration plan' means all technical and organisational measures necessary for the restoration of the system back to normal state;

(6) 're-energisation' means reconnecting generation and load to energise the parts of the system that have been disconnected;

(7) 'top-down re-energisation strategy' means a strategy that requires the assistance of other TSOs to re-energise parts of the system of a TSO;

(8) 'bottom-up re-energisation strategy' means a strategy where part of the system of a TSO can be re-energised without the assistance from other TSOs;

(9) 'resynchronisation' means synchronising and connecting again two synchronised regions at the resynchronisation point;

(10) 'frequency leader' means the TSO appointed and responsible for managing the system frequency within a synchronised region or a synchronous area in order to restore system frequency back to the nominal frequency;

(11) 'synchronised region' means the fraction of a synchronous area covered by interconnected TSOs

with a common system frequency and which is not synchronised with the rest of the synchronous area;

(12) 'resynchronisation leader' means the TSO appointed and responsible for the resynchronisation of two synchronised regions;

(13) 'resynchronisation point' means the device used to connect two synchronised.

Article 4

Regulatory aspects

1. When applying this Regulation, **Contracting Parties**, regulatory authorities, competent entities and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) ensure that TSOs make use of market-based mechanisms as far as is possible to ensure network security and stability;

(e) respect technical, legal, personal safety and security constraints;

(f) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;

(g) consult with relevant DSOs and take account of potential impacts on their system; and

(h) take into consideration agreed European standards and technical specifications.

2. Each TSO shall submit the following proposals to the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** for approval:

(a) the terms and conditions to act as defence service providers on a contractual basis in accordance with paragraph 4;

(b) the terms and conditions to act as restoration service providers on a contractual basis in accordance with paragraph 4;

(c) the list of SGUs responsible for implementing on their installations the measures that result from mandatory requirements set out in Regulations (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** and (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** and/or from national legislation and the list of the measures to be implemented by these SGUs, identified by the TSOs under Articles 11(4)(c) and 23(4)(c);

(d) the list of high priority significant grid users referred to in Articles 11(4)(d) and 23(4)(d) or the principles applied to define those and the terms and conditions for disconnecting and re-energising the high priority grid users, unless defined by the national legislation of **Contracting Parties**.

(e) the rules for suspension and restoration of market activities in accordance with Article 36(1);

(f) specific rules for imbalance settlement and settlement of balancing energy in case of suspension of market activities, in accordance with Article 39(1);

(g) the test plan in accordance with Article 43(2).

3. Where a **Contracting Party** has so provided, the proposals referred to in points (a) to (d) and (g) of paragraph 2 may be submitted for approval to an entity other than the regulatory authority. Regulatory authorities and entities designated by the **Contracting Parties** pursuant to this paragraph shall decide on the proposals referred to in paragraph 2 within six months from the date of submission by the TSO.

4. The terms and conditions to act as defence service provider and as restoration service provider shall be established either in the national legal framework or on a contractual basis. If established on a contractual basis, each TSO shall develop by **31 December 2023** a proposal for the relevant terms and conditions, which shall define at least:

(a) the characteristics of the service to be provided;

(b) the possibility of and conditions for aggregation; and

(c) for restoration service providers, the target geographical distribution of power sources with black start and island operation capabilities.

5. By **31 December 2023**, each TSO shall notify the regulatory authority or the entity designated by the **Contracting Party** the system defence plan designed pursuant to Article 11 and the restoration plan designed pursuant to Article 23, or at least the following elements of those plans:

(a) the objectives of the system defence plan and the restoration plan, including the phenomena to be managed or the situations to be solved;

(b) the conditions triggering the activation of the measures of the system defence plan and the restoration plan;

(c) the rationale of each measure, explaining how it contributes to the objectives of the system defence plan and the restoration plan, and the party responsible for implementing those measures; and

(d) the deadlines set out pursuant to Articles 11 and 23 for the implementation of the measures.

6. Where a TSO is required or permitted under this Regulation to specify, establish or agree on requirements, terms and conditions or methodologies that are not subject to approval in accordance with paragraph 2, **Contracting Parties** may require prior approval by the regulatory authority, the entity designated by the **Contracting Party** or other competent authorities of the **Contracting Parties** of these requirements, terms and conditions or methodologies.

7. If a TSO deems an amendment to the documents, approved in accordance with paragraph 3, to be necessary, the requirements provided for in paragraphs 2 to 5 shall apply to the proposed amendment. TSOs proposing an amendment shall take into account the legitimate expectations, where necessary, of power generating facility owners, demand facility owners and other stakeholders based on the initially specified or agreed requirements or methodologies.

8. Any party can complain against a relevant system operator or TSO in relation to that relevant system operator's or TSO's obligations or decisions under this Regulation and may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months after receipt of the complaint. That period may be extended by a further two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of

the complainant. The regulatory authority's decision shall be binding unless and until overruled on appeal.

Article 5

Consultation and coordination

1. Where this Regulation provides that a TSO shall consult concerned parties for actions it defines before real-time or in real-time, the following procedure shall apply:

(a) the TSO shall liaise with at least the parties identified in the Articles of this Regulation requiring consultation;

(b) the TSO shall explain the rationale and objective of the consultation and of the decision that it has to take;

(c) the TSO shall collect from the parties referred to in point (a) any relevant information and their assessment;

(d) the TSO shall duly take into account the views, situations and constraints of the parties consulted;

(e) before taking a decision, the TSO shall provide an explanation to the parties consulted of the reasons for following or not their views.

2. Where this Regulation provides that a TSO shall coordinate the execution of a set of actions in real-time with several parties, the following procedure shall apply:

(a) the TSO shall liaise at least with the parties identified in the Articles of this Regulation requiring real time coordination;

(b) the TSO shall explain the rationale and objective of the coordination and of the actions to be taken;

(c) the TSO shall make an initial proposal on actions to be taken by each party;

(d) the TSO shall collect from the parties referred to in point (a) any relevant information and their assessment;

(e) the TSO shall make a final proposal on actions to be taken by each party, duly taking into account the views, situations and constraints of the concerned parties and setting a deadline for parties to express their opposition to the actions proposed by the TSO;

(f) where the concerned parties do not oppose executing the actions proposed by the TSO, each party, including the TSO, shall execute the actions in line with the proposal;

(g) where one or more of the parties refuse the action proposed by the TSO within the set deadline, the TSO shall refer the action proposed to the relevant authority for decision, together with a justification of the rationale and objectives of the action proposed by the TSO and of the assessment and position of the parties;

(h) if real-time referral to the relevant authority is not possible, the TSO shall initiate an equivalent action that has the least or no impact on the parties that refused to execute the action proposed.

3. A party may refuse to execute real time actions proposed by the TSO under the coordination procedure described in paragraph 2 if it justifies that the proposed action would lead to the violation of one or more technical, legal, personal safety or security constraint(s).

Article 6

Regional coordination

1. When designing its system defence plan pursuant to Article 11 and its restoration plan pursuant to Article 23 or when reviewing its system defence plan pursuant to Article 50 and its restoration plan pursuant to Article 51, each TSO shall ensure the consistency with the corresponding measures in the plans of TSOs within its synchronous area and in the plans of neighbouring TSOs belonging to another synchronous area of at least the following measures:

(a) inter-TSO assistance and coordination in emergency state, pursuant to Article 14;

(b) frequency management procedures, pursuant to Article 18 and Article 28, excluding the establishment of target frequency in case of bottom-up re-energisation strategy before any resynchronisation to the interconnected transmission system;

(c) assistance for active power procedure, pursuant to Article 21;

(d) top-down re-energisation strategy, pursuant to Article 27.

2. The consistency assessment of the system defence plan and the restoration plan in accordance with paragraph 1 shall include the following tasks:

(a) exchange of information and data related to the measures referred to in paragraph 1 among the TSOs concerned;

(b) identification of incompatibilities of measures referred to in paragraph 1, in the plans of the involved TSOs;

(c) identification of potential threats to operational security in the capacity calculation region. These threats include, inter alia, regional common mode failures with significant impact on the transmission systems of the involved TSOs;

(d) assessment of the effectiveness of measures referred to in paragraph 1 specified in the system defence plans and the restoration plans of the involved TSOs, to manage the potential threats referred to in point (c);

(e) consultation with Regional Coordination Centres (RCCs) to assess the consistency of measures referred to in paragraph 1 within the entire concerned synchronous area;

(f) identification of mitigation actions in case of incompatibilities in the system defence plans and the restoration plans of the involved TSOs or in case that measures are missing in the system defence plans and the restoration plans of the involved TSOs.

3. By **31 December 2023**, each TSO shall transmit the measures referred to in paragraph 1 to the relevant **RCC**(s) **established pursuant to Article 35 of the Regulation (EU) 2019/943, as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Within 3 months from the submission of the measures, the **RCC**(s) shall produce a technical report on the consistency of the measures based on the criteria set out in paragraph 2. Each TSO shall ensure the availability of its own skilled experts to assist the **RCC**(s) in preparing this report.

4. The **RCC**(s) shall transmit without delay the technical report referred to in paragraph 3 to all the TSOs involved, which shall in turn transmit it to the relevant regulatory authorities, as well as to **the Energy Community Regulatory Board and** ENTSO for Electricity, for the purposes of Article 52.

5. All TSOs of each capacity calculation region shall agree on a threshold above which the impact of actions

of one or more TSOs in the emergency, blackout or restoration states is considered significant for other TSOs within the capacity calculation region.

Article 7

Public consultation

1. The relevant TSOs shall consult stakeholders, including the competent authorities of each **Contracting Party**, on proposals subject to approval in accordance with points (a), (b), (e), (f) and (g) of Article 4(2). The consultation shall last for a period of not less than one month.

2. The relevant TSOs shall duly take into account the views of the stakeholders resulting from the consultations prior to the submission of the draft proposal. In all cases, a sound justification for including or not including the views of the stakeholders shall be provided and published in a timely manner before, or simultaneously with, the publication of the proposal.

Article 8

Recovery of costs

1. The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms.

2. If requested by the relevant regulatory authorities, system operators referred to in paragraph 1 shall, within three months of the request, provide the information necessary to facilitate assessment of the costs incurred.

Article 9

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons subject to the provisions of this Regulation.

3. Confidential information received by the persons referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national legislation, the other provisions of this Regulation or other relevant **Energy Community and national** legislation.

4. Without prejudice to cases covered by **Energy Community and** national legislation, regulatory authorities, bodies or persons who receive confidential information pursuant to this Regulation may use it

only for the purpose of carrying out their duties under this Regulation.

Article 10

Agreement with TSOs not bound by this Regulation

Where a synchronous area encompasses both **Energy Community** and third country TSOs, by **30 June 2024**, all TSOs **of Contracting Parties** in that synchronous area shall endeavour to conclude with the third country TSOs not bound by this Regulation an agreement setting the basis for their cooperation concerning secure system operation and setting out arrangements for the compliance of the third country TSOs with the obligations set in this Regulation.

CHAPTER II
SYSTEM DEFENCE PLAN

SECTION 1
General provisions

Article 11

Design of the system defence plan

1. By **31 December 2023**, each TSO shall design a system defence plan in consultation with relevant DSOs, SGUs, national regulatory authorities, or entities referred to in Article 4(3), neighbouring TSOs and the other TSOs in its synchronous area.

2. When designing its system defence plan, each TSO shall take into account at least the following elements:

(a) the operational security limits set out in accordance with Article 25 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(b) the behaviour and capabilities of load and generation within the synchronous area;

(c) the specific needs of the high priority significant grid users listed pursuant to point (d) of paragraph 4; and

(d) the characteristics of its transmission system and of the underlying DSOs systems.

3. The system defence plan shall contain at least the following provisions:

(a) the conditions under which the system defence plan is activated, in accordance with Article 13;

(b) the system defence plan instructions to be issued by the TSO; and

(c) the measures subject to real-time consultation or coordination with the identified parties.

4. In particular, the system defence plan shall include the following elements:

(a) a list of the measures to be implemented by the TSO on its installations;

(b) a list of the measures to be implemented by DSOs and of the DSOs responsible for implementing those measures on their installations;

(c) a list of the SGUs responsible for implementing on their installations the measures that result from the mandatory requirements set out in Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision No 2018/05/PHLG-EnC,** and (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** or from national legislation and a list of the measures to be implemented by those SGUs;x

(d) a list of high priority significant grid users and the terms and conditions for their disconnection, and

(e) the implementation deadlines for each measure listed in the system defence plan.

5. The system defence plan shall include at least the following technical and organisational measures specified in Section 2 of Chapter II:

(a) system protection schemes including at least:

(i) automatic under-frequency control scheme in accordance with Article 15;

(ii) automatic over-frequency control scheme in accordance with Article 16; and

(iii) automatic scheme against voltage collapse in accordance with Article 17.

(b) system defence plan procedures, including at least:

(i) frequency deviation management procedure in accordance with Article 18;

(ii) voltage deviation management procedure in accordance with Article 19;

(iii) power flow management procedure in accordance with Article 20;

(iv) assistance for active power procedure in accordance with Article 21; and

(v) manual demand disconnection procedure in accordance with Article 22.

6. The measures contained in the system defence plan shall comply with the following principles:

(a) their impact on the system users shall be minimal;

(b) they shall be economically efficient;

(c) only those measures that are necessary shall be activated; and

(d) they shall not lead the TSO's transmission system or the interconnected transmission systems into emergency state or blackout state.

Article 12

Implementation of the system defence plan

1. By **30 June 2024,** each TSO shall implement those measures of its system defence plan that are to be implemented on the transmission system. It shall maintain the implemented measures henceforth.

2. By **31 December 2023,** each TSO shall notify the transmission connected DSOs of the measures, including the deadlines for implementation, which are to be implemented on:

(a) the DSO's installations pursuant to Article 11(4); or

(b) the installations of SGUs identified pursuant to Article 11(4) connected to their distribution systems; or

(c) the installations of defence service providers connected to their distribution systems; or

(d) the installations of DSOs connected to their distribution systems.

3. By **31 December 2023,** each TSO shall notify the SGUs identified pursuant to point (c) of Article 11(4) or the defence service providers directly connected to its transmission system of the measures which are to be implemented on their installations, including the deadlines for the implementation.

4. When provided for in national legislation, the TSO shall notify directly SGUs identified pursuant to point (c) of Article 11(4), defence service providers or DSOs connected to distribution systems of the measures which are to be implemented on their installations, including the deadlines for their implementation. It shall inform the concerned DSO of this notification.

5. Where a TSO notifies a DSO in accordance with paragraph 2, the DSO shall notify in turn, without delay, the SGUs, the defence service providers and the DSOs connected to its distribution system of the measures of the system defence plan that they have to implement on their respective installations, including the deadlines for their implementation.

6. Each notified DSO, SGU and defence service provider shall:

(a) implement the measures notified pursuant to this Article no later than 12 months from the date of notification;

(b) confirm the implementation of the measures to the notifying system operator, who shall, when different from the TSO, notify the confirmation to the TSO; and

(c) maintain the measures implemented on its installations.

Article 13

Activation of the system defence plan

1. Each TSO shall activate the procedures of its system defence plan pursuant to point (b) of Article 11(5) in coordination with DSOs and SGUs identified pursuant to Article 11(4) and with defence service providers.

2. In addition to the automatically activated schemes of the system defence plan, pursuant to point (a) of Article 11(5), each TSO shall activate a procedure of the system defence plan when:

(a) the system is in emergency state in accordance with the criteria set out in Article 18(3) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and there are no remedial actions available to restore the system to the normal state; or

(b) based on the operational security analysis, the operational security of the transmission system requires the activation of a measure of the system defence plan pursuant to Article 11(5) in addition to the available remedial actions.

3. Each DSO and SGU identified pursuant to Article 11(4), as well as each defence service provider shall execute without undue delay the system defence plan instructions issued by the TSO pursuant to point (c) of Article 11(3), in accordance with the system defence plan procedures provided for in point (b) of Article 11(5).

4. Each TSO shall activate procedures of its system defence plan referred to in point (b) of Article 11(5) having a significant cross-border impact in coordination with the impacted TSOs.

Article 14

Inter-TSO assistance and coordination in emergency state

1. Upon request from a TSO in emergency state, each TSO shall provide through interconnectors any possible assistance to the requesting TSO, provided this does not cause its transmission system or the interconnected transmission systems to enter into emergency or blackout state.

2. When the assistance needs to be provided through direct current interconnectors, it may consist in carrying out the following actions, taking into account the technical characteristics and capability of HVDC system:

(a) manual regulation actions of the transmitted active power to help the TSO in emergency state to bring power flows within operational security limits or frequency of neighbouring synchronous area within system frequency limits for alert state defined pursuant to Article 18(2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(b) automatic control functions of the transmitted active power based on the signals and criteria set out in Article 13 of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**;

(c) automatic frequency control pursuant to Articles 15 to 18 of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** in case of islanded operation;

(d) voltage and reactive power control pursuant to Article 24 of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**, and

(e) other appropriate action.

3. Each TSO may proceed to a manual disconnection of any transmission system element having a significant cross-border impact, including an interconnector, subject to the following requirements:

(a) the TSO shall coordinate with neighbouring TSOs; and

(b) this action shall not lead the remaining interconnected transmission system into emergency state or blackout state.

4. Notwithstanding paragraph 3, a TSO may manually disconnect any transmission system element having a significant cross-border impact, including an interconnector, without coordination, in exceptional circumstances implying a violation of the operational security limits, to prevent endangering personnel safety or damaging equipment. Within 30 days of the incident, the TSO shall prepare a report at least in English containing a detailed explanation of the rationale, implementation and impact of this action and submit it to the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** and neighbouring TSOs, and make it available to the significantly affected system users.

SECTION 2
Measures of the System Defence Plan

Article 15
Automatic under-frequency control scheme

1. The scheme for the automatic control of under-frequency of the system defence plan shall include a scheme for the automatic low frequency demand disconnection and the settings of the limited frequency sensitive mode-underfrequency in the TSO load frequency control (LFC) area.

2. In the design of its system defence plan, each TSO shall provide for the activation of the limited frequency sensitive mode-underfrequency prior to the activation of the scheme for the automatic low frequency demand disconnection, where the rate of change of frequency allows it.

3. Prior to the activation of the automatic low frequency demand disconnection scheme, each TSO and DSO identified pursuant to Article 11(4) shall foresee that energy storage units acting as load connected to its system:

(a) automatically switch to generation mode within the time limit and at an active power set-point established by the TSO in the system defence plan; or

(b) when the energy storage unit is not capable of switching within the time limit established by the TSO in the system defence plan, automatically disconnect the energy storage unit acting as load.

4. Each TSO shall establish in its system defence plan the frequency thresholds at which the automatic switching or disconnection of energy storage units shall occur. These frequency thresholds shall be lower or equal to the system frequency limit defined for the emergency state in Article 18(3) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and higher than the frequency limit for demand disconnection starting mandatory level laid down in the Annex.

5. Each TSO shall design the scheme for the automatic low frequency demand disconnection in accordance with the parameters for shedding load in real-time laid down in the Annex. The scheme shall include the disconnection of demand at different frequencies, from a 'starting mandatory level' to a 'final mandatory level', within an implementation range whilst respecting a minimum number and maximum size of steps. The implementation range shall define the maximum admissible deviation of netted demand to be disconnected from the target netted demand to be disconnected at a given frequency, calculated through a linear interpolation between starting and final mandatory levels. The implementation range shall not allow the disconnection of less netted demand than the amount of netted demand to be disconnected at the starting mandatory level. A step cannot be considered as such if no netted demand is disconnected when this step is reached.

6. Each TSO or DSO shall install the relays necessary for low frequency demand disconnection taking into account at least load behaviour and dispersed generation.

7. When implementing the scheme for the automatic low frequency demand disconnection pursuant to the notification under Article 12(2), each TSO or DSO shall:

(a) avoid setting an intentional time delay in addition to the operating time of the relays and circuit breakers;

(b) minimise the disconnection of power generating modules, especially those providing inertia; and

(c) limit the risk that the scheme leads to power flow deviations and voltage deviations outside operational security limits.

If a DSO cannot fulfil the requirements under points (b) and (c), it shall notify the TSO and propose which requirement shall apply. The TSO, in consultation with the DSO shall establish the applicable requirements based on a joint cost-benefit analysis.

8. The scheme for the automatic low frequency demand disconnection of the system defence plan may provide for netted demand disconnection based on frequency gradient provided that:

(a) it is activated only:

(i) when the frequency deviation is higher than the maximum steady state frequency deviation and the frequency gradient is higher than the one produced by the reference incident;

(ii) when the frequency deviation is higher than the maximum steady state frequency deviation and the frequency gradient is higher than the one produced by the reference incident;

(b) it complies with the Annex; and

(c) it is necessary and justified in order to maintain efficiently the operational security.

9. In case the scheme for the automatic low frequency demand disconnection of the system defence plan includes netted demand disconnection based on frequency gradient, as described in paragraph 8, the TSO shall submit, within 30 days of the implementation, a report containing a detailed explanation of the rationale, implementation and impact of this measure to the national regulatory authority.

10. A TSO may include in the scheme for automatic low frequency demand disconnection of its system defence plan additional steps for netted demand disconnection below the final mandatory level of demand disconnection set out in the Annex.

11. Each TSO shall be entitled to implement additional system protection schemes that are triggered by a frequency smaller or equal to the frequency of the final mandatory level of demand disconnection and which aim at a faster restoration process. The TSO shall ensure that such additional schemes do not further deteriorate frequency.

Article 16

Automatic over-frequency control scheme

1. The scheme for automatic over-frequency control of the system defence plan shall lead to an automatic decrease of the total active power injected in each LFC area.

2. In consultation with the other TSOs of its synchronous area, each TSO shall set out the following parameters of its scheme for automatic over-frequency control:

(a) the frequency thresholds for its activation; and

(b) the reduction ratio of injection of active power.

3. Each TSO shall design its automatic over-frequency control scheme taking into account the capabilities of the power generating modules concerning the limited frequency sensitive mode — overfrequency and of the energy storage units, in its LFC area. If the limited frequency sensitive mode — overfrequency does not exist or is not sufficient to fulfil the requirements set out in points (a) and (b) of paragraph 2, each

TSO shall set up in addition a step-wise linear disconnection of generation in its LFC area. The TSO shall establish the maximum size of the steps for disconnection of power generating modules and/or of HVDC systems in consultation with the other TSOs of its synchronous area.

Article 17

Automatic scheme against voltage collapse

1. The automatic scheme against voltage collapse of the system defence plan may include one or more of the following schemes, depending on the results of a TSO's assessment of system security:

(a) a scheme for low voltage demand disconnection according to Article 19(2) of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**;

(b) a blocking scheme for on load tap changer according to Article 19(3) of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**; and

(c) system protection schemes for voltage management.

2. Unless the assessment pursuant to paragraph 1 demonstrates that implementing a blocking scheme for on load tap changer is not necessary to prevent a voltage collapse in the TSO control area, the TSO shall establish the conditions under which the on load tap changer shall block according to Article 19(3) of Regulation (EU) 2016/1388, **as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** including at least:

(a) the blocking method (local or remote from control room);

(b) the voltage level threshold at the connection point;

(c) the flow direction of reactive power; and

(d) the maximum lapse of time between the detection of the threshold and the blocking.

Article 18

Frequency deviation management procedure

1. The procedure for the management of frequency deviations of the system defence plan shall contain a set of measures to manage a frequency deviation outside the frequency limits defined for the alert state in Article 18(2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. The frequency deviation management procedure shall be in line with the procedures set out for remedial actions which need to be managed in a coordinated way in accordance with Article 78(4) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and shall fulfil at least the following requirements:

(a) a decrease of generation shall be smaller than the decrease of load during under-frequency events; and

(b) a decrease of generation shall be greater than the decrease of load during over-frequency events.

2. Each TSO shall adapt the operating mode of its LFC in order to prevent interference with manual activation or deactivation of active power as laid down in paragraphs 3 and 5.

3. Each TSO shall be entitled to establish an active power set-point that each SGU identified pursuant to point (c) of Article 11(4) shall maintain, provided that the set-point fulfils the technical constraints of the SGU. Each TSO shall be entitled to establish an active power set-point that each defence service provider shall maintain provided this measure applies to them pursuant to the terms and conditions referred to in Article 4(4) and the set-point respects the technical constraints of the defence service provider. The SGUs and defence service providers shall execute without undue delay the instructions given by the TSO directly or indirectly through DSOs and shall remain in that state until further instructions are issued. Where the instructions are given directly, the TSO shall inform the relevant DSOs without undue delay.

4. Each TSO shall be entitled to disconnect SGUs and defence service providers, directly or indirectly through DSOs. SGUs and defence service providers shall remain disconnected until further instructions are issued. Where SGUs are directly disconnected, the TSO shall inform the relevant DSOs without undue delay. Within 30 days of the incident, the TSO shall prepare a report containing a detailed explanation of the rationale, implementation and impact of this action and submit it to the relevant regulatory authority in accordance with Article 59 of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC,** as well as make it available to the significantly affected system users.

5. Prior to the activation of the automatic low frequency demand disconnection scheme set out in Article 15 and provided that the rate of change of frequency allows it, each TSO shall, directly or indirectly through DSOs, activate demand response from the relevant defence service providers and:

(a) switch energy storage units acting as load to generation mode at an active power set-point established by the TSO in the system defence plan; or

(b) when the energy storage unit is not capable of switching fast enough to stabilise frequency, manually disconnect the energy storage unit.

Article 19

Voltage deviation management procedure

1. The procedure for the management of voltage deviations of the system defence plan shall contain a set of measures to manage voltage deviations outside the operational security limits set out in Article 25 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. Each TSO shall be entitled to establish a reactive power range or voltage range and instruct the DSOs and SGUs identified for this measure pursuant to Article 11(4) to maintain it, in accordance with Articles 28 and 29 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

3. Upon request of neighbouring TSO in emergency state, each TSO shall make available all reactive power capabilities that do not lead its transmission system into emergency state or blackout state.

Article 20

Power flow management procedure

1. The procedure for power flow management of the system defence plan shall include a set of measures to manage power flow outside the operational security limits set out in Article 25 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

2. Each TSO shall be entitled to establish an active power set-point that each SGU identified pursuant to point (c) Article 11(4) shall maintain provided that the set-point respects the technical constraints of the SGU. Each TSO shall be entitled to establish an active power set-point that each defence service provider shall maintain provided this measure applies to them pursuant to the terms and conditions referred to in Article 4(4) and the set-point respects the technical constraints of the defence service providers. The SGUs and defence service providers shall execute without undue delay the instructions given by the TSO directly or indirectly through DSOs and shall remain in that state until further instructions are issued. Where the instructions are given directly, the TSO shall inform the relevant DSOs without undue delay.

3. Each TSO shall be entitled to disconnect SGUs and defence service providers, directly or indirectly through DSOs. SGUs and defence service providers shall remain disconnected until further instructions are issued. Where SGU are directly disconnected, the TSO shall inform the relevant DSOs without undue delay. Within 30 days of the incident, the TSO shall prepare a report containing a detailed explanation of the rationale, implementation and impact of this action and submit it to the relevant regulatory authority in accordance with Article 59 of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

Article 21

Assistance for active power procedure

1. In case of absence of control area adequacy in the day-ahead or intraday timeframe, identified pursuant to paragraphs 1 and 2 of Article 107 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC,** and prior to any potential suspension of market activities pursuant to Article 35, a TSO shall be entitled to request assistance for active power from:

(a) any balancing service provider, which, upon the TSO request, shall change its availability status to make available all its active power, provided it was not already activated through the balancing market, and conforming to its technical constraints;

(b) any SGU connected in its LFC area, which does not already provide a balancing service to the TSO, and which, upon the TSO request, shall make available all its active power, conforming to its technical constraints; and

(c) other TSOs that are in the normal or alert state.

2. A TSO may activate the assistance for active power from a balancing service provider or a SGU, under points (a) and (b) of paragraph 1, only if it has activated all balancing energy bids available, taking into account the available cross zonal capacity at the moment of absence of adequacy of the control area.

3. Each TSO who has been subject to a request for assistance for active power pursuant to paragraph

1(c) shall:

(a) make available its unshared bids;

(b) be entitled to activate the available balancing energy, in order to provide the corresponding power to the requesting TSO; and

(c) be entitled to request the assistance for active power from its balancing service providers and from any SGU connected in its LFC area which does not already provide a balancing service to the TSO, in order to provide the corresponding assistance for active power to the requesting TSO.

4. When activating the active power requested pursuant to paragraph 1(c), the requesting and the requested TSOs shall be entitled to use:

(a) available cross-zonal capacity in case the activation is made before the intraday cross-zonal gate closure time and if the provision of concerned cross-zonal capacities has not been suspended pursuant to Article 35;

(b) additional capacity that may be available due to real-time status of the system in which case the requesting and the requested TSOs shall coordinate with other significantly affected TSOs in accordance with Article 6(5).

5. Once the requested and requesting TSOs have agreed on the conditions for the provision of assistance for active power, the agreed amount of active power and timeslot for the provision shall be firm, unless the transmission system of the TSO providing the assistance enters into the emergency or blackout state.

Article 22

Manual demand disconnection procedure

1. In addition to the measures set out in Articles 18 to 21, each TSO may establish an amount of netted demand to be manually disconnected, directly by the TSO or indirectly through DSOs, when necessary to prevent the propagation or worsening of an emergency state. Where demand is to be directly disconnected, the TSO shall inform the relevant DSOs without delay.

2. The TSO shall activate the manual disconnection of the netted demand referred to in paragraph 1 to:

(a) resolve overloads or under voltage situations; or

(b) resolve situations in which assistance for active power pursuant to Article 21 has been requested but is not sufficient to maintain adequacy in day-ahead and intraday timeframes in its control area, pursuant to Article 107 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, leading to a risk of frequency deterioration in the synchronous area.

3. The TSO shall notify DSOs of the amount of netted demand established pursuant to paragraph 1 to be disconnected on their distribution systems. Each DSO shall disconnect the notified amount of netted demand, without undue delay.

4. Within 30 days of the incident, the TSO shall prepare a report containing a detailed explanation of the rationale, implementation and impact of this action and submit it to the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

CHAPTER III
RESTORATION PLAN

SECTION 1
General provisions

Article 23
Design of the restoration plan

1. By **31 December 2023**, each TSO shall design a restoration plan in consultation with relevant DSOs, SGUs, national regulatory authorities or entities referred to in Article 4(3), neighbouring TSOs and the other TSOs in that synchronous area.

2. When designing its restoration plan, each TSO shall take into account, at least, the following elements:

(a) the behaviour and capabilities of load and generation;

(b) the specific needs of the high priority significant grid users listed pursuant to paragraph (4); and

(c) the characteristics of its network and of the underlying DSOs networks.

3. The restoration plan shall contain at least the following provisions:

(a) the conditions under which the restoration plan is activated, as provided for in Article 25;

(b) restoration plan instructions to be issued by the TSO; and

(c) measures subject to real-time consultation or coordination with identified parties.

4. In particular, the restoration plan shall include the following elements:

(a) a list of the measures to be implemented by the TSO on its installations;

(b) a list of the measures to be implemented by DSOs and of the DSOs responsible for implementing those measures on their installations;

(c) a list of the SGUs responsible for implementing on their installations the measures that result from mandatory requirements set out in Regulations (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** and (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** or from national legislation and a list of the measures to be implemented by those SGUs;

(d) the list of high priority significant grid users and the terms and conditions for their disconnection and re-energisation;

(e) a list of substations which are essential for its restoration plan procedures;

(f) the number of power sources in the TSO's control area necessary to re-energise its system with bottom-up re-energisation strategy having black start capability, quick re-synchronisation capability (through houseload operation) and island operation capability; and

(g) the implementation deadlines for each listed measure.

5. The restoration plan shall include at least the following technical and organisational measures specified in Chapter III:

(a) re-energisation procedure, in accordance with Section 2;

(b) frequency management procedure, in accordance with Section 3; and

(c) resynchronisation procedure, in accordance with Section 4.

6. The measures contained in the restoration plan shall comply with the following principles:

(a) their impact on system users shall be minimal;

(b) they shall be economically efficient;

(c) only those measures that are necessary shall be activated; and

(d) they shall not lead the interconnected transmission systems into emergency state or blackout state.

Article 24

Implementation of the restoration plan

1. By **30 June 2024,** each TSO shall implement those measures of its restoration plan that are to be implemented on the transmission system. It shall maintain the implemented measures henceforth.

2. By **31 December 2023,** each TSO shall notify the transmission connected DSOs of the measures, including the deadlines for implementation, which are to be implemented on:

(a) the DSO's installations pursuant to Article 23(4); and

(b) the installations of SGUs identified pursuant to Article 23(4) and connected to their distribution systems; and

(c) the installations of restoration service providers connected to their distribution systems; and

(d) the installations of DSOs connected to their distribution systems.

3. By **31 December 2023,** each TSO shall notify the SGUs identified pursuant to Article 23(4) and restoration service providers directly connected to its transmission system of the measures that are to be implemented on their installations, including the deadlines for implementation pursuant to point (g) of Article 23(4).

4. When provided for in national legislation, the TSO shall notify directly the SGUs identified pursuant to Article 23(4) and restoration service providers and DSOs connected to distribution systems and shall inform the concerned DSO of this notification.

5. Where a TSO notifies a DSO in accordance with paragraph 2, the DSO shall notify in turn, without delay, the SGUs, restoration service providers and DSOs connected to its distribution system of the measures of the restoration plan which they have to implement on their respective installations, including the deadlines for implementation, pursuant to point (g) of Article 23(4).

6. Each notified DSO, SGUs and restoration service provider shall:

(a) implement the measures notified no later than 12 months from the date of notification;

(b) confirm the implementation of the measures to the notifying system operator, who shall, when different from the TSO, notify the TSO; and

(c) maintain the measures implemented on its installations.

Article 25

Activation of the restoration plan

1. Each TSO shall activate the procedures of its restoration plan in coordination with the DSOs and SGUs identified pursuant to Article 23(4) and with restoration service providers in the following cases:

(a) when the system is in the emergency state in accordance with the criteria in Article 18(3) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, once the system is stabilised following activation of the measures of the system defence plan; or

(b) when the system is in the blackout state in accordance with the criteria in Article 18(4) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

2. During system restoration, each TSO shall identify and monitor:

(a) the extent and borders of the synchronised region or synchronised regions to which its control area belongs;

(b) the TSOs with which it shares a synchronised region or synchronised regions; and

(c) the available active power reserves in its control area.

3. Each DSO and SGU identified pursuant to Article 23(4), as well as each restoration service provider shall execute without undue delay the restoration plan instructions issued by the TSO, pursuant to point (b) of Article 23(3) in accordance with the restoration plan procedures.

4. Each TSO shall activate those procedures of its restoration plan that have a significant cross-border impact in coordination with the impacted TSOs.

SECTION 2

Re-energisation

Article 26

Re-energisation procedure

1. The re-energisation procedure of the restoration plan shall contain a set of measures allowing the TSO to apply:

(a) a top-down re-energisation strategy; and

(b) a bottom-up re-energisation strategy.

2. Regarding the bottom-up re-energisation strategy, the re-energisation procedure shall contain at least measures for:

(a) managing voltage and frequency deviations due to re-energisation;

(b) monitoring and managing island operation; and

(c) resynchronising island operation areas.

Article 27

Activation of the re-energisation procedure

1. When activating the re-energisation procedure, each TSO shall set up the strategy to be applied, taking into account:

(a) the availability of power sources capable of re-energisation in its control area;

(b) the expected duration and risks of possible re-energisation strategies;

(c) the conditions of the power systems;

(d) the conditions of the directly connected systems, including at least the status of interconnectors;

(e) the high priority significant grid users listed pursuant to Article 23(4); and

(f) the possibility to combine top-down and bottom-up re-energisation strategies.

2. When applying a top-down re-energisation strategy, each TSO shall manage the connection of load and generation with the aim to regulate the frequency towards the nominal frequency with a maximum tolerance of the maximum steady-state frequency deviation. Each TSO shall apply the conditions for connection of load and generation defined by the frequency leader, where appointed in accordance with Article 29.

3. When applying a bottom-up re-energisation strategy, each TSO shall manage the connection of load and generation with the aim to regulate the frequency towards the target frequency established in accordance with point (c) of Article 28(3).

4. During re-energisation, the TSO shall, after consultation with DSOs, establish and notify the amount of netted demand to be reconnected on distribution networks. Each DSO shall reconnect the notified amount of netted demand, while respecting the block loading and taking into account the automatic re-connection of load and generation in its network.

5. Each TSO shall inform its neighbouring TSOs on its capability to support a top-down re-energisation strategy.

6. For the activation of a top-down re-energisation strategy, the TSO shall request neighbouring TSOs to support the re-energisation. This support may consist in assistance for active power, in accordance with paragraphs 3 to 5 of Article 21. The requested TSOs shall provide assistance for the re-energisation, unless it would lead their systems to the emergency or blackout states. In this case, the requesting TSO shall use the bottom-up re-energisation strategy.

SECTION 3
Frequency management

Article 28
Frequency management procedure

1. The frequency management procedure of the restoration plan shall contain a set of measures aiming at restoring system frequency back to the nominal frequency.

2. Each TSO shall activate its frequency management procedure:

(a) in preparation of the resynchronisation procedure, when a synchronous area is split in several synchronised regions;

(b) in case of frequency deviation in the synchronous area; or

(c) in case of re-energisation.

3. The frequency management procedure shall include at least:

(a) a list of actions regarding the setting of the load-frequency controller before the appointment of frequency leaders;

(b) the appointment of frequency leaders;

(c) the establishment of target frequency in case of bottom-up re-energisation strategy;

(d) frequency management after frequency deviation; and

(e) frequency management after synchronous area split.

(f) the determination of the amount of load and generation to be reconnected, taking into account the available active power reserves within the synchronised region in order to avoid major frequency deviations.

Article 29
Appointment of a frequency leader

1. During system restoration, when a synchronous area is split in several synchronised regions, the TSOs of each synchronised region shall appoint a frequency leader, in accordance with paragraph 3.

2. During system restoration, when a synchronous area is not split but the system frequency exceeds the frequency limits for the alert state as defined in Article 18(2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, all TSOs of the synchronous area shall appoint a frequency leader, in accordance with paragraph 3.

3. The TSO with the highest real-time estimated K-factor shall be appointed as the frequency leader, unless the TSOs of the synchronised region, or of the synchronous area, agree to appoint another TSO as the frequency leader. In that case, the TSOs of the synchronised region, or of the synchronous area, shall consider the following criteria:

(a) the amount of available active power reserves and especially frequency restoration reserves;

(b) the capacities available on interconnectors;

(c) the availability of frequency measurements of TSOs of the synchronised region or of the synchronous area; and

(d) the availability of measurements on critical elements within the synchronised region or the synchronous area.

4. Notwithstanding paragraph 3, where the size of the synchronous area concerned and the real time situation allow it, the TSOs of the synchronous area may appoint a predetermined frequency leader.

5. The TSO appointed as frequency leader pursuant to paragraphs 1 and 2 shall inform the other TSOs of the synchronous area of its appointment without delay.

6. The appointed frequency leader shall act as such until:

(a) another frequency leader is appointed for its synchronised region;

(b) a new frequency leader is appointed as the result of resynchronisation of its synchronised region with another synchronised region; or

(c) the synchronous area has been completely resynchronised, the system frequency is within the standard frequency range and the LFC operated by each TSO of the synchronous area is back to its normal operating mode in accordance with Article 18(1) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

Article 30

Frequency management after frequency deviation

1. During system restoration, when a frequency leader has been appointed pursuant to Article 29(3), the TSOs of the synchronous area, other than the frequency leader, shall as a first measure suspend the manual activation of frequency restoration reserves and replacement reserves.

2. The frequency leader shall establish, after consultation with the other TSOs of the synchronous area, the operating mode to be applied on the LFC operated by each TSO of the synchronous area.

3. The frequency leader shall manage the manual activation of frequency restoration reserves and replacement reserves within the synchronous area, aiming at regulating the frequency of the synchronous area towards the nominal frequency and taking into account the operational security limits defined pursuant to Article 25 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Upon request, each TSO of the synchronous area shall support the frequency leader.

Article 31

Frequency management after synchronous area split

1. During system restoration, when a frequency leader has been appointed pursuant to Article 29(3), the TSOs of each synchronised region, with the exception of the frequency leader, shall as a first measure suspend the manual activation of frequency restoration reserves and replacement reserves.

2. The frequency leader shall establish, after consultation with the other TSOs of the synchronised region,

the operating mode to be applied on the LFC operated by each TSO of the synchronised region.

3. The frequency leader shall manage the manual activation of frequency restoration reserves and replacement reserves within the synchronised region, aiming at regulating the frequency of the synchronised region towards the target frequency established by the resynchronisation leader, if any, pursuant to point (a) of Article 34(1) and taking into account the operational security limits set out pursuant to Article 25 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. When no resynchronisation leader is appointed for the synchronised region, the frequency leader shall aim at regulating the frequency towards the nominal frequency. Upon request, each TSO of the synchronised region shall support the frequency leader.

SECTION 4
Resynchronisation

Article 32
Resynchronisation procedure

The resynchronisation procedure of the restoration plan shall include, at least:

(a) the appointment of a resynchronisation leader;

(b) the measures allowing the TSO to apply a resynchronisation strategy; and

(c) the maximum limits for phase angle, frequency and voltage differences for connecting lines.

Article 33
Appointment of a resynchronisation leader

1. During system restoration, when two synchronised regions can be resynchronised without endangering the operational security of the transmission systems, the frequency leaders of these synchronised regions shall appoint a resynchronisation leader in consultation with at least the TSO(s) identified as the potential resynchronisation leader and in accordance with paragraph 2. Each frequency leader shall inform without delay the TSOs from its synchronised region of the appointed resynchronisation leader.

2. For each pair of synchronised regions to be resynchronised, the resynchronisation leader shall be the TSO that:

(a) has in operation at least one substation equipped with a parallel switching device on the border between the two synchronised regions to be resynchronised;

(b) has access to the frequency measurements from both synchronised regions;

(c) has access to the voltage measurements on the substations between which potential resynchronisation points are located; and

(d) is able to control the voltage of potential resynchronisation points.

3. Where more than one TSO fulfils the criteria under paragraph 2, the TSO with the highest number

of potential resynchronisation points between the two synchronised regions shall be appointed as the resynchronisation leader, unless the frequency leaders of the two synchronised regions agree to appoint another TSO as resynchronisation leader.

4. The appointed resynchronisation leader shall act as such until:

(a) another resynchronisation leader is appointed for the two synchronised regions; or

(b) the two synchronised regions have been resynchronised, and all the steps in Article 34 have been completed.

Article 34

Resynchronisation strategy

1. Prior to the resynchronisation, the resynchronisation leader shall:

(a) establish, in accordance with the maximum limits referred to in Article 32:

(i) the target value of the frequency for resynchronisation;

(ii) the maximum frequency difference between the two synchronised regions;

(iii) the maximum active and reactive power exchange; and

(iv) the operating mode to be applied on the LFC;

(b) select the resynchronisation point, taking into account the operational security limits in the synchronised regions;

(c) establish and prepare all necessary actions for the resynchronisation of the two synchronised regions at the resynchronisation point;

(d) establish and prepare a subsequent set of actions to create additional connections between the synchronised regions; and

(e) assess the readiness of the synchronised regions for resynchronisation, taking into account the conditions set out in point (a).

2. When carrying out the tasks enumerated in paragraph 1, the resynchronisation leader shall consult the frequency leaders of the involved synchronised regions and, for the tasks listed in points (b) to (e), it shall also consult the TSOs operating the substations used for resynchronisation.

3. Each frequency leader shall inform the TSOs within its synchronised region of the planned resynchronisation without undue delay.

4. When all conditions established in accordance with point (a) of paragraph 1 are fulfilled, the resynchronisation leader shall execute the resynchronisation by activating the actions established in accordance with point (c) and (d) of paragraph 1.

CHAPTER IV
MARKET INTERACTIONS

Article 35

Procedure for suspension of market activities

1. A TSO may temporarily suspend one or more market activities laid down in paragraph 2 where:

(a) the transmission system of the TSO is in blackout state; or

(b) the TSO has exhausted all options provided by the market and the continuation of market activities under the emergency state would deteriorate one or more of the conditions referred to in Article 18(3) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**; or

(c) the continuation of market activities would decrease significantly the effectiveness of the restoration process to the normal or alert state; or

(d) tools and communication means necessary for the TSOs to facilitate market activities are not available.

2. The following market activities may be suspended pursuant to paragraph 1:

(a) the provision of cross zonal capacity for capacity allocation on the corresponding bidding zone borders for each market time unit where it is expected that the transmission system shall not be restored to the normal or alert state;

(b) the submission by a balancing service provider of balancing capacity and balancing energy bids;

(c) the provision by a balance responsible party of a balanced position at the end of the day-ahead time-frame if required by the terms and conditions related to balancing;

(d) the provision of modifications of the position of balance responsible parties;

(e) the provision of schedules referred to in Article 111(1) and (2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, and

(f) other relevant market activities the suspension of which is deemed necessary to preserve and/or restore the system.

3. In case of suspension of market activities pursuant to paragraph 1, upon request of the TSO, each SGU shall operate, where technically possible, at an active power set-point established by the TSO.

4. When suspending market activities pursuant to paragraph 1, the TSO may fully or partially suspend the operation of its processes impacted by such suspension.

5. When suspending market activities pursuant to paragraph 1, the TSO shall coordinate at least with the following parties:

(a) the TSOs of the capacity calculation regions of which the TSO is a member of;

(b) the TSOs with which the TSO has arrangements for the coordination of balancing;

(c) the 'NEMO' and other entities assigned or delegated to execute market functions in accordance with Regulation (EU) 2015/1222 **and Regulation (EU) 2015/1222 as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** within its control area;

(d) the TSOs of a load-frequency control block of which the TSO is a member of; and

(e) the coordinated capacity calculator of the capacity calculation regions of which the TSO is a member of.

6. In case of suspension of market activities, each TSO shall launch the communication procedure set out in Article 38.

Article 36

Rules for suspension and restoration of market activities

1. By **31 December 2023**, each TSO shall develop a proposal for rules concerning the suspension and restoration of market activities.

2. The TSO shall publish these rules on its website following their approval by the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

3. The rules for suspension and restoration of market activities shall be compatible to the extent possible with:

(a) the rules on provision of cross zonal capacity within the concerned capacity calculation regions;

(b) the rules for submission by balancing service providers of balancing capacity and balancing energy bids resulting from arrangements with other TSOs for the coordination of balancing;

(c) the rules for provision by balance responsible party of a balanced position at the end of day-ahead timeframe if required by the terms and conditions related to balancing;

(d) rules for provision of modifications of the position of balance responsible parties; and

(e) the rules for provision of schedules referred to in Article 111(1) and (2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC.**

4. When developing the rules for suspension and restoration of market activities, each TSO shall convert the situations referred to in Article 35(1) into objectively defined parameters taking into account the following factors:

(a) the percentage of load disconnection in the LFC area of the TSO corresponding to:

(i) the inability of a significant share of balancing responsible parties to maintain their balance; or

(ii) the necessity for the TSO not to follow the usual balancing processes to perform an efficient re-energisation;

(b) the percentage of generation disconnection in the LFC area of the TSO corresponding to the inability of a significant share of balancing responsible parties to maintain their balance;

(c) the share and geographic distribution of unavailable transmission system elements corresponding to:

(i) the desynchronisation of a significant part of the LFC area rendering the usual balancing processes counterproductive; or

(ii) the reduction to zero of cross zonal capacity on a bidding zone border(s);

(d) the inability of the following affected entities to execute their market activities for reason(s) outside their control:

(i) balance responsible parties;

(ii) balancing service providers;

(iii) NEMOs and other entities assigned or delegated to execute market functions pursuant to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**;

(iv) transmission connected DSOs;

(e) the absence of properly functioning tools and communication means necessary to perform:

(i) the single day-ahead or intraday coupling or any explicit capacity allocation mechanism; or

(ii) the frequency restoration process; or

(iii) the reserve replacement process; or

(iv) the provision by balance responsible party of a balanced position in day ahead and the provision of change of its position; or

(v) the provision of schedules referred to in Article 111(1) and (2) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**.

5. The rules for suspension and restoration of market activities shall define a time delay to be respected for each parameter defined pursuant to paragraph 4, prior to starting the procedure for suspension of market activities.

6. The concerned TSO shall assess in real-time the parameters defined pursuant to paragraph 4, on the basis of the information at its disposal.

7. **When reporting** on the level of harmonisation of the rules for suspension and restoration of market activities established by the TSOs and identifying, as appropriate, areas that require harmonisation**, in accordance with Article 36(7) of Regulation (EU) 2017/2196, the ENTSO for Electricity, acting in accordance with Article 3 of Procedural Act No 2022/01/MC-EnC, shall extend this report to include the Contracting Parties**.

8. By **30 June 2024**, each TSO shall submit to ENTSO for Electricity the data required to prepare and submit the report in accordance with paragraph 7.

Article 37

Procedure for restoration of market activities

1. The concerned TSO, in coordination with the NEMO(s) active in its control area and with the neighbouring TSOs, shall launch the procedure for the restoration of market activities suspended pursuant to Article 35(1) when:

(a) the situation triggering the suspension has ended and no other situation referred to in Article 35(1) applies; and

(b) the entities referred to in Article 38(2) have been duly informed in advance in accordance with Article 38.

2. The concerned TSO, in coordination with neighbouring TSOs, shall launch the restoration of TSO processes impacted by the suspension of market activities when the conditions of paragraph 1 are fulfilled or before, if necessary to restore market activities.

3. The concerned NEMO(s), in coordination with TSOs and entities referred to in Article 35(5), shall launch the restoration of the relevant single day ahead and/or single intraday coupling processes as soon as the TSO(s) notifies that the TSOs' processes have been restored.

4. When the provision of cross zonal capacity has been suspended and subsequently restored, each concerned TSO shall update the cross zonal capacities for capacity allocation by using, from the following, the most feasible and efficient option for each market time unit:

(a) by using the latest available cross zonal capacities calculated by the coordinated capacity calculator;

(b) by launching the regional capacity calculation processes applicable in accordance with Articles 29 and 30 of Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**; or,

(c) by determining, in coordination with TSOs of the capacity calculation region, cross zonal capacities based on the actual physical network conditions.

5. When part of the total coupled area where market activities have been suspended is back to the normal state or alert state, the NEMO(s) of this area shall be entitled to execute a market coupling in a part of the total coupled area, in consultation with the TSOs and entities referred to in Article 35(5), provided that the TSO has restored the capacity calculation process.

6. No later than 30 days after the market activities have been restored, the TSO(s) that suspended and restored market activities shall prepare a report at least in English containing a detailed explanation of the rationale, implementation and impact of the market suspension and a reference to the compliance with the rules for suspension and restoration of market activities and shall submit it to the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, and make it available to the entities referred to in Article 38(2).

7. The regulatory authorities of the **Contracting Parties** or the **Energy Community Regulatory Board** may issue a recommendation to the concerned TSO(s) to promote good practices and prevent similar incidents in the future.

Article 38

Communication procedure

1. The rules for suspension and restoration of market activities developed pursuant to Article 36 shall also contain a communication procedure detailing the tasks and actions expected from each party in its different roles during the suspension and restoration of market activities.

2. The communication procedure shall provide that information is sent, simultaneously, to the following entities:

(a) the parties referred to in Article 35(5);

(b) the balance responsible parties;

(c) the balancing service providers;

(d) the transmission connected DSOs; and

(e) the relevant regulatory authority of the concerned **Contracting Parties** in accordance with Article **59**

of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

3. The communication procedure shall include at least the following steps:

(a) the notification by the TSO that market activities have been suspended in accordance with Article 35;

(b) the notification by the TSO of best estimate for the time and date for transmission system restoration;

(c) the notification by the NEMO and other entities designated to execute market functions according to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and to Regulation (EU) 2016/1719 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** of the suspension of their activities, if any;

(d) the updates by the TSOs on the process for restoration of the transmission system;

(e) the notification by the entities referred to in points (a) to (d) of paragraph 2, that their market tools and communication systems are operational;

(f) the notification by the TSO(s) that the transmission system has been restored back to normal state or alert state;

(g) the notification by the NEMO and other entities assigned or delegated to execute market functions according to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** of the best estimate for time and date when market activities will be restored; and

(h) the confirmation by the NEMO and other entities assigned or delegated to execute market functions according to Regulation (EU) 2015/1222 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** that market activities have been restored.

4. All notifications and updates by the TSO(s), the NEMO(s) and other entities assigned or delegated to execute market functions referred to in paragraph 3, shall be published on the websites of those entities. When notification or update on the website is not possible, the entity subject to the obligation to notify, shall inform via email, or via any other available means, at least those parties directly participating in the suspended market activities.

5. Notification pursuant to point (e) of paragraph 3 shall be done via email or via any other available means to the concerned TSO.

Article 39

Rules for settlement in case of suspension of market activities

1. By **31 December 2023**, each TSO shall develop a proposal for rules for imbalance settlement and settlement of balancing capacity and balancing energy which shall be applicable for imbalance settlement periods during which the market activities were suspended. The TSO may propose the same rules it applies for normal operations.

The TSO shall publish these rules on its website following their approval by the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**.

A TSO may delegate the TSO's tasks referred to in this Article to one or more third parties, provided that

the third party can carry out the respective function at least as effectively as the TSO(s). A **Contracting Party** or, where applicable, a regulatory authority, may assign the tasks referred to in this Article to one or more third parties, provided that the third party can carry out the respective function at least as effectively as the TSO(s).

2. The rules referred to in paragraph 1 shall address the settlements of TSO's and third parties, where relevant, with balance responsible parties, and balancing services providers.

3. The rules developed in accordance with paragraph 1 shall:

(a) ensure the financial neutrality of each TSO and relevant third party referred to in paragraph 1;

(b) avoid distortions of incentives or counterproductive incentives to balance responsible parties, balance service providers and TSOs;

(c) incentivise balance responsible parties to strive to be balanced or help the system to restore its balance;

(d) avoid any financial penalties imposed on balance responsible parties and balancing service providers due to the execution of the actions requested by the TSO;

(e) discourage TSOs from suspending market activities, unless strictly necessary, and incentivise TSOs to restore the market activities as soon as possible; and

(f) incentivise balance service providers to offer services to the connecting TSO that helps restore the system to normal state.

CHAPTER V
INFORMATION EXCHANGE AND COMMUNICATION, TOOLS AND FACILITIES

Article 40
Information exchange

1. In addition to the provisions of Articles 40 to 53 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, each TSO, when in the emergency, blackout or restoration states, shall be entitled to gather the following information:

(a) from DSOs identified in accordance with Article 23(4), the necessary information about at least:

(i) the part of their network that is in island operation;

(ii) the ability to synchronise parts of their network that is in island operation; and

(iii) the capability to start island operation.

(b) from SGUs identified in accordance with Article 23(4) and restoration service providers, information about at least the following conditions:

(i) the current status of the installation;

(ii) the operational limits;

(iii) the full activation time and the time to increase generation; and

(iv) the time critical processes.

2. During the emergency, blackout or restoration states, each TSO shall provide in due time and for the

purposes of system defence plan procedures and restoration plan procedures, the following information, where available to the TSO:

(a) to neighbouring TSOs, information about at least:

(i) the extent and borders of the synchronised region or synchronised regions to which its control area belongs;

(ii) the restrictions to operate the synchronised region;

(iii) the maximum duration and amount of active and reactive power that can be supplied via interconnectors; and

(iv) any other technical or organisational restrictions;

(b) to the frequency leader of its synchronised region, information about at least:

(i) the restrictions to maintain island operation;

(ii) the available additional load and generation; and

(iii) the availability of operational reserves;

(c) to transmission connected DSOs identified in accordance with Article 11(4) and 23(4), information about at least:

(i) the system state of its transmission system;

(ii) the limits of active and reactive power, block loading, tap and circuit breaker position at the connection points;

(iii) the information on the current and planned status of power generating modules connected to the DSO, if not available to the DSO directly; and

(iv) all necessary information leading to further coordination with distribution connected parties;

(d) to defence service providers, information about at least:

(i) the system state of its transmission system; and

(ii) the scheduled measures that require participation of the defence service providers;

(e) to DSOs and SGUs identified pursuant to Article 23(4) and to restoration service providers, information about at least:

(i) the system state of its transmission system;

(ii) the ability and plans to re-energise couplings; and

(iii) the scheduled measures that require their participation.

3. TSOs in emergency, blackout or restoration state shall exchange among themselves information concerning, at least:

(a) the circumstances that led to the current system state of its transmission system, to the extent that they are known; and

(b) the potential problems making assistance for active power necessary.

4. A TSO in emergency, blackout or restoration state shall provide, in due time, information about the system state of its transmission system and, where available, additional information explaining the situation on the transmission system:

(a) to the NEMO(s), who shall make this information available to their market participants, as provided

for in Article 38;

(b) to its relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, or when explicitly provided for in national law, to the entities referred to in Article 4(3); and

(c) to any other relevant party, as appropriate.

5. TSOs shall inform each affected party about the test plan developed pursuant to Article 43(2) and (3).

Article 41

Communication systems

1. Each DSO and SGU identified in accordance with points (b) and (c) of Article 23(4), each restoration service provider and each TSO shall have a voice communication system in place with sufficient equipment redundancy and backup power supply sources to allow the exchange of the information needed for the restoration plan for at least 24 hours, in case of total absence of external electrical energy supply or in case of failure of any individual voice communication system equipment. **Contracting Parties** may require a minimum backup power capacity higher than 24 hours.

2. Each TSO shall establish, in consultation with the DSOs and SGUs identified in accordance with Article 23(4) and with restoration service providers, the technical requirements to be fulfilled by their voice communication systems as well as by the TSO's own voice communication system in order to allow their interoperability and to guarantee that the TSO's incoming call can be identified by the other party and answered immediately.

3. Each TSO shall establish, in consultation with its neighbouring TSOs and the other TSOs of its synchronous area, the technical requirements to be fulfilled by their voice communication systems as well as by the TSO's own voice communication system in order to allow their interoperability and to guarantee that the TSO's incoming call can be identified by the other party and answered immediately.

4. Notwithstanding paragraph 1, those SGUs identified in accordance with Article 23(4) that are type B power generating modules and those restoration service providers that are type A or B power generating modules, shall have the possibility to have only a data communication system, instead of a voice communication system, if agreed upon with the TSO. This data communication system shall fulfil the requirements laid down in paragraphs 1 and 2.

5. **Contracting Parties** may require that, in addition to the voice communication system, a complementary communication system be used to support the restoration plan; in that case, the complementary communication system shall fulfil the requirements laid down in paragraph 1.

Article 42

Tools and facilities

1. Each TSO shall make available critical tools and facilities referred to in Article 24 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** for at least 24 hours in case of loss of primary power supply.

2. Each DSO and SGU identified pursuant to Article 23(4) as well as restoration service provider shall make available critical tools and facilities referred to in Article 24 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC** and used in the restoration plan for at least 24 hours in case of loss of primary power supply, as defined by the TSO.

3. Each TSO shall have at least one geographically separate backup control room. The backup control room shall include at least the critical tools and facilities referred to in Article 24 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**. Each TSO shall arrange a backup power supply for its backup control room for at least 24 hours in case of loss of primary power supply.

4. Each TSO shall prepare a transfer procedure for moving functions from the main control room to the backup control room as quickly as possible, and in any case in a maximum time of three hours. The procedure shall include the operation of the system during the transfer.

5. Substations identified as essential for the restoration plan procedures pursuant to Article 23(4) shall be operational in case of loss of primary power supply for at least 24 hours. **<…>**

CHAPTER VI
COMPLIANCE AND REVIEW

SECTION 1
Compliance testing of TSO, DSO and SGU capabilities

Article 43
General principles

1. Each TSO shall periodically assess the proper functioning of all equipment and capabilities considered in the system defence plan and the restoration plan. To this end, each TSO shall periodically verify the compliance of such equipment and capabilities, in accordance with paragraph 2 and with Article 41(2) of Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** Article 35(2) of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision No 2018/05/PHLG-EnC,** and Article 69(1) and (2) of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**.

2. By **30 June 2024,** each TSO shall define a test plan in consultation with the DSOs, the SGUs identified pursuant to Articles 11(4) and 23(4), the defence service providers and the restoration service providers. The test plan shall identify the equipment and capabilities relevant for the system defence plan and the restoration plan that have to be tested.

3. The test plan shall include the periodicity and conditions of the tests, following the minimum requirements outlined in Articles 44 to 47. The test plan shall follow the methodology laid down in Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group**

Decision 2018/05/PHLG-EnC, and Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC,** for the corresponding tested capability. For SGUs that are not subject to Regulation (EU) 2016/631, **as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC,** Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision No 2018/05/PHLG-EnC,** and Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**, the test plan shall follow the provisions of national law.

4. Each TSO, DSO, SGU, defence service provider and restoration service provider shall not endanger the operational security of the transmission system and of the interconnected transmission system during the test. The test shall be conducted in a way that minimises the impact on system users.

5. The test is deemed to be successful when it fulfils the conditions established by the relevant system operator pursuant to paragraph 3. As long as a test fails to fulfil these criteria, the TSO, DSO, SGU, defence service provider and restoration service provider shall repeat the test.

Article 44

Compliance testing of power generating module capabilities

1. Each restoration service provider which is a power generating module delivering black start service shall execute a black start capability test, at least every three years, following the methodology laid down in Article 45(5) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**.

2. Each restoration service provider which is a power generating module delivering a quick re-synchronisation service shall execute tripping to houseload test after any changes of equipment having an impact on its houseload operation capability, or after two unsuccessful consecutive tripping in real operation, following the methodology laid down in Article 45(6) of Regulation (EU) 2016/631**, as adapted and adopted by Permanent High Level Group Decision 2018/03/PHLG-EnC**.

Article 45

Compliance testing of demand facilities providing demand side response

1. Each defence service provider delivering demand response shall execute a demand modification test, after two consecutive unsuccessful responses in real operation or at least every year, following the methodology laid down in Article 41(1) of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**.

2. Each defence service provider delivering demand response low frequency demand disconnection shall execute a low frequency demand disconnection test within a period to be defined at national level and following the methodology laid down in Article 37(4) of Regulation (EU) 2016/1388**, as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC,** for transmission connected demand facilities or according to a similar methodology defined by the relevant system operator for other demand facilities.

Article 46

Compliance testing of HVDC capabilities

Each restoration service provider which is an HVDC system delivering a black start service shall execute a black start capability test, at least every three years, following the methodology laid down in Article 70(11) of Regulation (EU) 2016/1447**, as adapted and adopted by Permanent High Level Group Decision 2018/04/PHLG-EnC**.

Article 47

Compliance testing of low frequency demand disconnection relays

Each DSO and TSO shall execute testing on the low frequency demand disconnection relays implemented on its installations, within a period to be defined at national level and following the methodology laid down in Article 37(6) and Article 39(5) of Regulation (EU) 2016/1388, **as adapted and adopted by Permanent High Level Group Decision 2018/05/PHLG-EnC**.

Article 48

Testing of communication systems

1. Each DSO and SGU identified pursuant to Article 23(4), each TSO and each restoration service provider shall test the communication systems defined in Article 41, at least every year.

2. Each DSO and SGU identified pursuant to Article 23(4), each TSO and each restoration service provider shall test the backup power supply of their communication systems at least every five years.

3. By **30 June 2024,** each TSO, in consultation with other TSOs, shall define a test plan for testing the inter-TSO communication.

Article 49

Testing of tools and facilities

1. Each TSO shall test the capability of main and backup power sources to supply its main and backup control rooms, provided for in Article 42, at least every year.

2. Each TSO shall test the functionality of critical tools and facilities referred to in Article 24 of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**, at least every three years, covering both main and backup tools and facilities. Where these tools and facilities involve DSOs or SGUs, these parties shall participate in this test.

3. Each TSO shall test the capability of backup power sources to supply essential services of the substations identified as essential for the restoration plan procedures pursuant to Article 23(4), at least every five years. When these substations are in distribution systems, DSOs shall execute this test.

4. Each TSO shall test the transfer procedure for moving from the main control room to the backup control room, provided for in Article 42(4), at least every year.

SECTION 2

Compliance testing and review of system defence plans and restoration plans

Article 50

Compliance testing and periodic review of the system defence plan

1. Each DSO concerned by the implementation of the low frequency demand disconnection on its installations shall update once a year the communication to the notifying system operator provided for in point (b) of Article 12(6). This communication shall include the frequency settings at which netted demand disconnection is initiated and the percentage of netted demand disconnected at every such setting.

2. Each TSO shall monitor the proper implementation of the low frequency demand disconnection on the basis of the yearly written communication referred to in paragraph 1 and on the basis of implementation details of TSOs' installations where applicable.

3. Each TSO shall review, at least every five years, its complete system defence plan to assess its effectiveness. The TSO shall in this review take into account at least:

(a) the development and evolution of its network since the last review or first design;

(b) the capabilities of new equipment installed on the transmission and distribution systems since the last review or first design;

(c) the SGUs commissioned since the last review or first design, their capabilities and relevant services offered;

(d) the tests carried out and the analysis of system incidents pursuant to Article 56(5) of Regulation (EU) 2017/1485 **as adapted and adopted by Ministerial Council Decision 2022/03/MC-EnC**; and

(e) the operational data collected during normal operation and after disturbance.

4. Each TSO shall review the relevant measures of its system defence plan in accordance with paragraph 3 before any substantial change in the configuration of the grid.

5. When the TSO identifies the need to adapt the system defence plan, it shall amend its system defence plan and implement these amendments in accordance with points (c) and (d) of Article 4(2) and Articles 11 and 12.

Article 51

Compliance testing and periodic review of the restoration plan

1. Each TSO shall review the measures of its restoration plan using computer simulation tests, using data from the DSOs identified pursuant to Article 23(4) and the restoration service providers, at least every five years. The TSO shall define these simulation tests in a dedicated testing procedure covering at least:

(a) the energising restoration path from restoration service providers with black start or island operation capabilities;

(b) the supply of power generating modules main auxiliaries;

(c) the demand reconnection process; and

(d) the process for resynchronisation of networks in island operation.

2. In addition, where deemed necessary by the TSO for the effectiveness of the restoration plan, each TSO shall execute operational testing of parts of the restoration plan, in coordination with the DSOs identified pursuant to Article 23(4) and the restoration service providers. The TSO shall set out, in consultation with the DSOs and restoration service providers, those operational tests in a dedicated testing procedure.

3. Each TSO shall review its restoration plan to assess its effectiveness, at least every five years.

4. Each TSO shall review the relevant measures of its restoration plan in accordance with paragraph 1 and review their effectiveness before any substantial change in the configuration of the grid.

5. When the TSO identifies the need to adapt the restoration plan, it shall amend its restoration plan and implement these amendments in accordance with points (c) and (d) of Article 4(2) and Articles 23 and 24.

CHAPTER VII
IMPLEMENTATION

Article 52
Monitoring

1. **ENTSOE-E acting in accordance with Article 3 of Procedural Act No 2022/01/MC- EnC,** shall monitor the implementation of this Regulation **in the areas covered by this paragraph. To the extent the monitoring covers Contracting Parties located outside the Continental Europe synchronous area or not being member of ENTSO for Electricity, the Energy Community Secretariat shall collect data from the relevant transmission system operators.** Monitoring **by ENTSO for Electricity** shall cover in particular the following matters:

(a) identification of any divergences in the national implementation of this Regulation for the items listed in Article 4(2);

(b) consistency assessment of system defence plans and restoration plans carried out by TSOs in accordance with Article 6;

(c) thresholds above which the impact of actions of one or more TSOs in the emergency, blackout or restoration states is considered significant for other TSOs within the capacity calculation region in accordance with Article 6;

(d) the level of harmonisation of the rules for suspension and restoration of market activities established by the TSOs in accordance with Article 36(1) and for the purposes of the report provided for in Article 36(7);

(e) the level of harmonisation of the rules for imbalance settlement and settlement of balancing energy in case of market suspension, referred to in Article 39.

2. **<...>**

3. Relevant TSOs shall submit to ENTSO for Electricity the information required to perform the tasks referred to in paragraph 1 **<…>**.

4. Following a request of the relevant regulatory authority in accordance with Article **59** of Directive **(EU) 2019/944, as adapted and adopted by Ministerial Council Decision 2021/13/MC-EnC**, DSOs and the entities pursuant to Article 39(1) shall provide TSOs with the information under **Article 52** paragraph 2 **of Regulation 2017/2196** unless that information is already available to the regulatory authorities, TSOs, the **Energy Community Regulatory Board** or ENTSO for Electricity in relation to their respective implementation monitoring tasks, with the objective of avoiding duplication of information.

Article 53

Stakeholder involvement

The **Energy Community Regulatory Board**, in close cooperation with ENTSO for Electricity, shall organise stakeholder involvement regarding the implementation of this Regulation. Such involvement shall include regular meetings with stakeholders to identify problems and propose improvements related to the requirements of this Regulation.

CHAPTER VIII
FINAL PROVISIONS

Article 54

Amendments to contracts and general terms and conditions

All relevant clauses in contracts and general terms and conditions of TSOs, DSOs and SGUs relating to system operation shall comply with the requirements of this Regulation. To that effect, those contracts and general terms and conditions shall be modified accordingly.

Article 55

Entry into force

This Decision D/2022/03/MC-EnC enters into force upon its adoption and is addressed to the Parties and institutions of the Energy Community.[1]

Article 2 of Decision D/2022/03/MC-EnC

Each Contracting Party shall bring into force the laws, regulations and administrative provisions necessary to comply with <…>, Regulation (EU) 2017/2196, <…> by 31 December 2023.

1 The text displayed here corresponds to Article 13 of Decision 2022/03/MC-EnC.

Each Contracting Party shall notify the Energy Community Secretariat of completed transposition by sending the text of the provisions of national law which they adopt in the field covered by this Decision and of any subsequent changes within two weeks following the adoption of such measures.

ANNEX

Automatic low frequency demand disconnection scheme characteristics:

Parameter	Values SA Continental Europe	<…>	<…>	<…>	Measuring Unit
Demand disconnection starting mandatory level: Frequency	49	<…>	<…>	<…>	Hz
Demand disconnection starting mandatory level: Demand to be disconnected	5	<…>	<…>	<…>	% of the Total Load at national level
Demand disconnection final mandatory level: Frequency	48	<…>	<…>	<…>	Hz
Demand disconnection final mandatory level: Cumulative Demand to be disconnected	45	<…>	<…>	<…>	% of the Total Load at national level
Implementation range	± 7	<…>	<…>	<…>	% of the Total Load at national level, for a given Frequency
Minimum number of steps to reach the final mandatory level	6	<…>	<…>	<…>	Number of steps
Maximum Demand disconnection for each step	10	<…>	<…>	<…>	% of the Total Load at national level, for a given step

REGULATION (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators

Incorporated and adapted by Permanent High Level Group Decision 2018/03/PHLG-EnC of 12 January 2018

The adaptations made by Permanent High Level Group Decision 2018/03/PHLG-EnC are highlighted in **bold and blue**.

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter

This Regulation establishes a network code which lays down the requirements for grid connection of power-generating facilities, namely synchronous power-generating modules, power park modules and offshore power park modules, to the interconnected system. It, therefore, helps to ensure fair conditions of competition in the internal electricity market, to ensure system security and the integration of renewable electricity sources, and to facilitate **Energy Community wide** trade in electricity.

This regulation also lays down the obligations for ensuring that system operators make appropriate use of the power-generating facilities' capabilities in a transparent and non-discriminatory manner to provide a level playing field throughout the **Energy Community**.

Article 2
Definitions

For the purposes of this Regulation, the definitions in Article 2 of Directive 2012/27/EU of the European Parliament and of the Council, Article 2 of Regulation (EC) No 714/2009, <...>, Article 2 of Commission Regulation (EU) No 543/2013 and Article 2 of Directive 2009/72/EC shall apply.

In addition, the following definitions shall apply:

(1) 'entity' means a regulatory authority, other national authority, system operator or other public or private body appointed under national law;

(2) 'synchronous area' means an area covered by synchronously interconnected TSOs, such as the synchronous areas of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as 'Baltic' which are part of a wider synchronous area **and the power systems of Georgia, Moldova and Ukraine**;

(3) 'voltage' means the difference in electrical potential between two points measured as the root-mean-square value of the positive sequence phase-to-phase voltages at fundamental frequency;

(4) 'apparent power' means the product of voltage and current at fundamental frequency, and the square

root of three in the case of three-phase systems, usually expressed in kilovolt-amperes ('kVA') or mega-volt-amperes ('MVA');

(5) 'power-generating module' means either a synchronous power-generating module or a power park module;

(6) 'power-generating facility' means a facility that converts primary energy into electrical energy and which consists of one or more power-generating modules connected to a network at one or more connection points;

(7) 'power-generating facility owner' means a natural or legal entity owning a power-generating facility;

(8) 'main generating plant' means one or more of the principal items of equipment required to convert the primary source of energy into electricity;

(9) 'synchronous power-generating module' means an indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism;

(10) 'power-generating module document' or 'PGMD' means a document provided by the power-generating facility owner to the relevant system operator for a type B or C power-generating module which confirms that the power-generating module's compliance with the technical criteria set out in this Regulation has been demonstrated and provides the necessary data and statements, including a statement of compliance;

(11) 'relevant TSO' means the TSO in whose control area a power-generating module, a demand facility, a distribution system or a HVDC system is or will be connected to the network at any voltage level;

(12) 'network' means a plant and apparatus connected together in order to transmit or distribute electricity;

(13) 'relevant system operator' means the transmission system operator or distribution system operator to whose system a power-generating module, demand facility, distribution system or HVDC system is or will be connected;

(14) 'connection agreement' means a contract between the relevant system operator and either the power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner, which includes the relevant site and specific technical requirements for the power-generating facility, demand facility, distribution system, distribution system connection or HVDC system;

(15) 'connection point' means the interface at which the power-generating module, demand facility, distribution system or HVDC system is connected to a transmission system, offshore network, distribution system, including closed distribution systems, or HVDC system, as identified in the connection agreement;

(16) 'maximum capacity' or 'P_{max}' means the maximum continuous active power which a power-generating module can produce, less any demand associated solely with facilitating the operation of that power-generating module and not fed into the network as specified in the connection agreement or as agreed between the relevant system operator and the power-generating facility owner;

(17) 'power park module' or 'PPM' means a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system;

(18) 'offshore power park module' means a power park module located offshore with an offshore connection point;

(19) 'synchronous compensation operation' means the operation of an alternator without prime mover to regulate voltage dynamically by production or absorption of reactive power;

(20) 'active power' means the real component of the apparent power at fundamental frequency, expressed in watts or multiples thereof such as kilowatts ('kW') or megawatts ('MW');

(21) 'pump-storage' means a hydro unit in which water can be raised by means of pumps and stored to be used for the generation of electrical energy;

(22) 'frequency' means the electric frequency of the system expressed in hertz that can be measured in all parts of the synchronous area under the assumption of a consistent value for the system in the time frame of seconds, with only minor differences between different measurement locations. Its nominal value is 50Hz;

(23) 'droop' means the ratio of a steady-state change of frequency to the resulting steady-state change in active power output, expressed in percentage terms. The change in frequency is expressed as a ratio to nominal frequency and the change in active power expressed as a ratio to maximum capacity or actual active power at the moment the relevant threshold is reached;

(24) 'minimum regulating level' means the minimum active power, as specified in the connection agreement or as agreed between the relevant system operator and the power-generating facility owner, down to which the power-generating module can control active power;

(25) 'setpoint' means the target value for any parameter typically used in control schemes;

(26) 'instruction' means any command, within its authority, given by a system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner in order to perform an action;

(27) 'secured fault' means a fault which is successfully cleared according to the system operator's planning criteria;

(28) 'reactive power' means the imaginary component of the apparent power at fundamental frequency, usually expressed in kilovar ('kVAr') or megavar ('MVAr');

(29) 'fault-ride-through' means the capability of electrical devices to be able to remain connected to the network and operate through periods of low voltage at the connection point caused by secured faults;

(30) 'alternator' means a device that converts mechanical energy into electrical energy by means of a rotating magnetic field;

(31) 'current' means the rate at which electric charge flows which is measured by the root-mean-square value of the positive sequence of the phase current at fundamental frequency;

(32) 'stator' means the portion of a rotating machine which includes the stationary magnetic parts with their associated windings;

(33) 'inertia' means the property of a rotating rigid body, such as the rotor of an alternator, such that it maintains its state of uniform rotational motion and angular momentum unless an external torque is applied;

(34) 'synthetic inertia' means the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power-generating module to a prescribed level of performance;

(35) 'frequency control' means the capability of a power-generating module or HVDC system to adjust its active power output in response to a measured deviation of system frequency from a setpoint, in order to maintain stable system frequency;

(36) 'frequency sensitive mode' or 'FSM' means the operating mode of a power-generating module or

HVDC system in which the active power output changes in response to a change in system frequency, in such a way that it assists with the recovery to target frequency;

(37) 'limited frequency sensitive mode - overfrequency' or 'LFSM-O' means a power-generating module or HVDC system operating mode which will result in active power output reduction in response to a change in system frequency above a certain value;

(38) 'limited frequency sensitive mode - underfrequency''LFSM-U' means a power-generating module or HVDC system operating mode which will result in active power output increase in response to a change in system frequency below a certain value;

(39) 'frequency response deadband' means an interval used intentionally to make the frequency control unresponsive;

(40) 'frequency response insensitivity' means the inherent feature of the control system specified as the minimum magnitude of change in the frequency or input signal that results in a change of output power or output signal;

(41) 'P-Q-capability diagram' means a diagram describing the reactive power capability of a power-generating module in the context of varying active power at the connection point;

(42) 'steady-state stability' means the ability of a network or a synchronous power-generating module to revert and maintain stable operation following a minor disturbance;

(43) 'island operation' means the independent operation of a whole network or part of a network that is isolated after being disconnected from the interconnected system, having at least one power-generating module or HVDC system supplying power to this network and controlling the frequency and voltage;

(44) 'houseload operation' means the operation which ensures that power-generating facilities are able to continue to supply their in-house loads in the event of network failures resulting in power-generating modules being disconnected from the network and tripped onto their auxiliary supplies;

(45) 'black start capability' means the capability of recovery of a power-generating module from a total shutdown through a dedicated auxiliary power source without any electrical energy supply external to the power-generating facility;

(46) 'authorised certifier' means an entity that issues equipment certificates and power-generating module documents and whose accreditation is given by the national affiliate of the European cooperation for Accreditation ('EA') **or another competent national authority**;

(47) 'equipment certificate' means a document issued by an authorised certifier for equipment used by a power-generating module, demand unit, distribution system, demand facility or HVDC system. The equipment certificate defines the scope of its validity at a national or other level at which a specific value is selected from the range allowed at a European level. For the purpose of replacing specific parts of the compliance process, the equipment certificate may include models that have been verified against actual test results;

(48) 'excitation control system' means a feedback control system that includes the synchronous machine and its excitation system;

(49) 'U-Q/P_{max}-profile' means a profile representing the reactive power capability of a power-generating module or HVDC converter station in the context of varying voltage at the connection point;

(50) 'minimum stable operating level' means the minimum active power, as specified in the connection agreement or as agreed between the relevant system operator and the power-generating facility owner,

at which the power-generating module can be operated stably for an unlimited time;

(51) 'overexcitation limiter' means a control device within the AVR which prevents the rotor of an alternator from overloading by limiting the excitation current;

(52) 'underexcitation limiter' means a control device within the AVR, the purpose of which is to prevent the alternator from losing synchronism due to lack of excitation;

(53) 'automatic voltage regulator' or 'AVR' means the continuously acting automatic equipment controlling the terminal voltage of a synchronous power-generating module by comparing the actual terminal voltage with a reference value and controlling the output of an excitation control system;

(54) 'power system stabiliser' or 'PSS' means an additional functionality of the AVR of a synchronous power-generating module whose purpose is to damp power oscillations;

(55) 'fast fault current' means a current injected by a power park module or HVDC system during and after a voltage deviation caused by an electrical fault with the aim of identifying a fault by network protection systems at the initial stage of the fault, supporting system voltage retention at a later stage of the fault and system voltage restoration after fault clearance;

(56) 'power factor' means the ratio of the absolute value of active power to apparent power;

(57) 'slope' means the ratio of the change in voltage, based on reference 1 pu voltage, to a change in reactive power in-feed from zero to maximum reactive power, based on maximum reactive power;

(58) 'offshore grid connection system' means the complete interconnection between an offshore connection point and the onshore system at the onshore grid interconnection point;

(59) 'onshore grid interconnection point' means the point at which the offshore grid connection system is connected to the onshore network of the relevant system operator;

(60) 'installation document' means a simple structured document containing information about a type A power-generating module or a demand unit, with demand response connected below 1 000 V, and confirming its compliance with the relevant requirements;

(61) 'statement of compliance' means a document provided by the power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner to the system operator stating the current status of compliance with the relevant specifications and requirements;

(62) 'final operational notification' or 'FON' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner who complies with the relevant specifications and requirements, allowing them to operate respectively a power-generating module, demand facility, distribution system or HVDC system by using the grid connection;

(63) 'energisation operational notification' or 'EON' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner prior to energisation of its internal network;

(64) 'interim operational notification' or 'ION' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner which allows them to operate respectively a power-generating module, demand facility, distribution system or HVDC system by using the grid connection for a limited period of time and to initiate compliance tests to ensure compliance with the relevant specifications and requirements;

(65) 'limited operational notification' or 'LON' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner who had previously attained FON status but is temporarily subject to either a significant modification or loss of capability resulting in non-compliance with the relevant specifications and requirements.

Article 3

Scope of application

1. The connection requirements set out in this Regulation shall apply to new power-generating modules which are considered significant in accordance with Article 5, unless otherwise provided.

The relevant system operator shall refuse to allow the connection of a power-generating module which does not comply with the requirements set out in this Regulation and which is not covered by a derogation granted by the regulatory authority, or other authority where applicable in a **Contracting Party** pursuant to Article 60. The relevant system operator shall communicate such refusal, by means of a reasoned statement in writing, to the power-generating facility owner and, unless specified otherwise by the regulatory authority, to the regulatory authority.

2. This Regulation shall not apply to:

(a) power-generating modules connected to the transmission system and distribution systems, or to parts of the transmission system or distribution systems, of islands of Member States of which the systems are not operated synchronously with either the Continental Europe, Great Britain, Nordic, Ireland and Northern Ireland or Baltic synchronous area;

(b) power-generating modules that were installed to provide back-up power and operate in parallel with the system for less than five minutes per calendar month while the system is in normal system state. Parallel operation during maintenance or commissioning tests of that power-generating module shall not count towards the five-minute limit;

(c) power-generating modules that do not have a permanent connection point and are used by the system operators to temporarily provide power when normal system capacity is partly or completely unavailable;

(d) storage devices except for pump-storage power-generating modules in accordance with Article 6(2).

Article 4

Application to existing power-generating modules

1. Existing power-generating modules are not subject to the requirements of this Regulation, except where:

(a) a type C or type D power-generating module has been modified to such an extent that its connection agreement must be substantially revised in accordance with the following procedure:

(i) power-generating facility owners who intend to undertake the modernisation of a plant or replacement of equipment impacting the technical capabilities of the power-generating module shall notify their plans to the relevant system operator in advance;

(ii) if the relevant system operator considers that the extent of the modernisation or replacement of

equipment is such that a new connection agreement is required, the system operator shall notify the relevant regulatory authority or, where applicable, the **Contracting Party**; and

(iii) the relevant regulatory authority or, where applicable, the **Contracting Party** shall decide if the existing connection agreement needs to be revised or a new connection agreement is required and which requirements of this Regulation shall apply; or

(b) a regulatory authority or, where applicable, a **Contracting Party** decides to make an existing power-generating module subject to all or some of the requirements of this Regulation, following a proposal from the relevant TSO in accordance with paragraphs 3, 4 and 5.

2. For the purposes of this Regulation, a power-generating module shall be considered existing if:

(a) it is already connected to the network on the date of **expiry of the deadline for transposition** of this Regulation; or

(b) the power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by two years after **the expiry of the deadline for transposition** of the Regulation. The power-generating facility owner must notify the relevant system operator and relevant TSO of conclusion of the contract within 30 months after the **expiry of the deadline for transposition**.

The notification submitted by the power-generating facility owner to the relevant system operator and to the relevant TSO shall at least indicate the contract title, its date of signature and date of entry into force and the specifications of the main generating plant to be constructed, assembled or purchased.

A **Contracting Party** may provide that in specified circumstances the regulatory authority may determine whether the power-generating module is to be considered an existing power-generating module or a new power-generating module.

3. Following a public consultation in accordance with Article 10 and in order to address significant factual changes in circumstances, such as the evolution of system requirements including penetration of renewable energy sources, smart grids, distributed generation or demand response, the relevant TSO may propose to the regulatory authority concerned, or where applicable, to the **Contracting Party** to extend the application of this Regulation to existing power-generating modules.

For that purpose a sound and transparent quantitative cost-benefit analysis shall be carried out, in accordance with Articles 38 and 39. The analysis shall indicate:

(a) the costs, in regard to existing power-generating modules, of requiring compliance with this Regulation;

(b) the socioeconomic benefit resulting from applying the requirements set out in this Regulation; and

(c) the potential of alternative measures to achieve the required performance.

4. Before carrying out the quantitative cost-benefit analysis referred to in paragraph 3, the relevant TSO shall:

(a) carry out a preliminary qualitative comparison of costs and benefits;

(b) obtain approval from the relevant regulatory authority or, where applicable, the **Contracting Party**.

5. The relevant regulatory authority or, where applicable, the **Contracting Party** shall decide on the extension of the applicability of this Regulation to existing power-generating modules within six months of receipt of the report and the recommendation of the relevant TSO in accordance with Article 38(4). The decision of the regulatory authority or, where applicable, the **Contracting Party** shall be published.

6. The relevant TSO shall take account of the legitimate expectations of power-generating facility owners as part of the assessment of the application of this Regulation to existing power-generating modules.

7. The relevant TSO may assess the application of some or all of the provisions of this Regulation to existing power-generating modules every three years in accordance with the criteria and process set out in paragraphs 3 to 5.

Article 5

Determination of significance

1. The power-generating modules shall comply with the requirements on the basis of the voltage level of their connection point and their maximum capacity according to the categories set out in paragraph 2.

2. Power-generating modules within the following categories shall be considered as significant:

(a) connection point below 110 kV and maximum capacity of 0,8 kW or more (type A);

(b) connection point below 110 kV and maximum capacity at or above a threshold proposed by each relevant TSO in accordance with the procedure laid out in paragraph 3 (type B). This threshold shall not be above the limits for type B power-generating modules contained in Table 1;

(c) connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO in accordance with paragraph 3 (type C). This threshold shall not be above the limits for type C power-generating modules contained in Table 1; or

(d) connection point at 110 kV or above (type D). A power-generating module is also of type D if its connection point is below 110 kV and its maximum capacity is at or above a threshold specified in accordance with paragraph 3. This threshold shall not be above the limit for type D power-generating modules contained in Table 1.

Table 1

Limits for thresholds for type B, C and D power-generating modules

Synchronous areas	**Limit for maximum capacity threshold from which a power-generating module is of type B**	**Limit for maximum capacity threshold from which a power-generating module is of type C**	**Limit for maximum capacity threshold from which a power-generating module is of type D**
Continental Europe, **Ukraine**	1 MW	50 MW	75 MW
Great Britain	1 MW	50 MW	75 MW
Nordic, **Georgia**	1,5 MW	10 MW	30 MW
Ireland and Northern Ireland	0,1 MW	5 MW	10 MW
Baltic, **Moldova**	0,5 MW	10 MW	15 MW

3. Proposals for maximum capacity thresholds for types B, C and D power-generating modules shall be subject to approval by the relevant regulatory authority or, where applicable, the **Contracting Party**. In forming proposals the relevant TSO shall coordinate with adjacent TSOs and DSOs and shall conduct a

public consultation in accordance with Article 10. A proposal by the relevant TSO to change the thresholds shall not be made sooner than three years after the previous proposal.

4. Power-generating facility owners shall assist this process and provide data as requested by the relevant TSO.

5. If, as a result of modification of the thresholds, a power-generating module qualifies under a different type, the procedure laid down in Article 4(3) concerning existing power-generating modules shall apply before compliance with the requirements for the new type is required.

Article 6

Application to power-generating modules, pump-storage power-generating modules, combined heat and power facilities, and industrial sites

1. Offshore power-generating modules connected to the interconnected system shall meet the requirements for onshore power-generating modules, unless the requirements are modified for this purpose by the relevant system operator or unless the connection of power park modules is via a high voltage direct current connection or via a network whose frequency is not synchronously coupled to that of the main interconnected system (such as via a back-to-back convertor scheme).

2. Pump-storage power-generating modules shall fulfil all the relevant requirements in both generating and pumping operation mode. Synchronous compensation operation of pump-storage power-generating modules shall not be limited in time by the technical design of power-generating modules. Pump-storage variable speed power-generating modules shall fulfil the requirements applicable to synchronous power-generating modules as well as those set out in point (b) of Article 20(2), if they qualify as type B, C or D.

3. With respect to power-generating modules embedded in the networks of industrial sites, power-generating facility owners, system operators of industrial sites and relevant system operators whose network is connected to the network of an industrial site shall have the right to agree on conditions for disconnection of such power-generating modules together with critical loads, which secure production processes, from the relevant system operator's network. The exercise of this right shall be coordinated with the relevant TSO.

4. Except for requirements under paragraphs 2 and 4 of Article 13 or where otherwise stated in the national framework, requirements of this Regulation relating to the capability to maintain constant active power output or to modulate active power output shall not apply to power-generating modules of facilities for combined heat and power production embedded in the networks of industrial sites, where all of the following criteria are met:

(a) the primary purpose of those facilities is to produce heat for production processes of the industrial site concerned;

(b) heat and power-generating is inextricably interlinked, that is to say any change of heat generation results inadvertently in a change of active power-generating and *vice versa*;

(c) the power-generating modules are of type A, B, C or, in the case of the Nordic synchronous area, type D in accordance with points (a) to (c) of Article 5(2).

5. Combined heat and power-generating facilities shall be assessed on the basis of their electrical maximum capacity.

Article 7

Regulatory aspects

1. Requirements of general application to be established by relevant system operators or TSOs under this Regulation shall be subject to approval by the entity designated by the **Contracting Party** and be published. The designated entity shall be the regulatory authority unless otherwise provided by the **Contracting Party**.

2. For site specific requirements to be established by relevant system operators or TSOs under this Regulation, **Contracting Party** may require approval by a designated entity.

3. When applying this Regulation, **Contracting Parties**, competent entities and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;

(e) consult with relevant DSOs and take account of potential impacts on their system;

(f) take into consideration agreed European standards and technical specifications.

4. The relevant system operator or TSO shall submit a proposal for requirements of general application, or the methodology used to calculate or establish them, for approval by the competent entity within two years of **expiry of the deadline for transposition** of this Regulation.

5. Where this Regulation requires the relevant system operator, relevant TSO, power-generating facility owner and/or the distribution system operator to seek agreement, they shall endeavour to do so within six months after a first proposal has been submitted by one party to the other parties. If no agreement has been found within this time frame, each party may request the relevant regulatory authority to issue a decision within six months.

6. Competent entities shall take decisions on proposals for requirements or methodologies within six months following the receipt of such proposals.

7. If the relevant system operator or TSO deems an amendment to requirements or methodologies as provided for and approved under paragraph 1 and 2 to be necessary, the requirements provided for in paragraphs 3 to 8 shall apply to the proposed amendment. System operators and TSOs proposing an amendment shall take into account the legitimate expectations, if any, of power-generating facility owners, equipment manufacturers and other stakeholders based on the initially specified or agreed requirements or methodologies.

8. Any party having a complaint against a relevant system operator or TSO in relation to that relevant system operator's or TSO's obligations under this Regulation may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months after receipt of the complaint. That period may be extended by two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall have binding effect unless and until overruled on appeal.

9. Where the requirements under this Regulation are to be established by a relevant system operator that

is not a TSO, **Contracting Parties** may provide that instead the TSO be responsible for establishing the relevant requirements.

Article 8

Multiple TSOs

1. Where more than one TSO exists in a **Contracting Party**, this Regulation shall apply to all those TSOs.

2. **Contracting Parties** may, under the national regulatory regime, provide that the responsibility of a TSO to comply with one or some or all obligations under this Regulation is assigned to one or more specific TSOs.

Article 9

Recovery of costs

1. The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms.

2. If requested by the relevant regulatory authorities, system operators referred to in paragraph 1 shall, within three months of the request, provide the information necessary to facilitate assessment of the costs incurred.

Article 10

Public consultation

1. Relevant system operators and relevant TSOs shall carry out consultation with stakeholders, including the competent authorities of each **Contracting Party**, on proposals to extend the applicability of this Regulation to existing power-generating modules in accordance with Article 4(3), for the proposal for thresholds in accordance with Article 5(3), and on the report prepared in accordance with Article 38(3) and the cost-benefit analysis undertaken in accordance with Article 63(2). The consultation shall last at least for a period of one month.

2. The relevant system operators or relevant TSOs shall duly take into account the views of the stakeholders resulting from the consultations prior to the submission of the draft proposal for thresholds, the report or cost benefit analysis for approval by the regulatory authority or, if applicable, the **Contracting Party**. In all cases, a sound justification for including or not the views of the stakeholders shall be provided and published in a timely manner before, or simultaneously with, the publication of the proposal.

Article 11

Stakeholder involvement

The **Energy Community Regulatory Board**, in close cooperation with the European Network of Transmission System Operators for Electricity (ENTSO for Electricity), shall organise stakeholder involvement regarding the requirements for grid connection of power-generating facilities, and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the requirements for grid connection of power-generating facilities.

Article 12

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons, regulatory authorities or entities subject to the provisions of this Regulation.

3. Confidential information received by the persons, regulatory authorities or entities referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **Energy Community** law.

4. Without prejudice to cases covered by national or **Energy Community** law, regulatory authorities, entities or persons who receive confidential information pursuant to this Regulation may use it only for the purpose of carrying out their duties under this Regulation.

TITLE II
REQUIREMENTS

CHAPTER 1
General requirements

Article 13

General requirements for type A power-generating modules

1. Type A power-generating modules shall fulfil the following requirements relating to frequency stability:

(a) With regard to frequency ranges:

(i) a power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Table 2;

(ii) the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating module, if it is required to preserve or to restore system security;

(iii) the power-generating facility owner shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation, taking account of their economic and technical feasibility.

(b) With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.

Table 2

Minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network.

Synchronous area	Frequency range	Time period for operation
Continental Europe	47,5 Hz–48,5 Hz	To be specified by each TSO, but not less than 30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz–48,5 Hz
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	30 minutes
Nordic	47,5 Hz–48,5 Hz	30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 30 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	30 minutes
Great Britain	47,0 Hz–47,5 Hz	20 seconds
	47,5 Hz–48,5 Hz	90 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	90 minutes
	51,5 Hz–52,0 Hz	15 minutes
Ireland and Northern Ireland	47,5 Hz–48,5 Hz	90 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	90 minutes

Baltic	47,5 Hz–48,5 Hz	To be specified by each TSO, but not less than 30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz–48,5 Hz
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	To be specified by each TSO, but not less than 30 minutes
Georgia	**47,0 Hz–47,5 Hz**	**20 seconds**
	47,5 Hz–48,5 Hz	**30 minutes**
	48,5 Hz–49,0 Hz	**60 minutes**
	49,0 Hz–51,0 Hz	**Unlimited**
	51,0 Hz–51,5 Hz	**30 minutes**

2. With regard to the limited frequency sensitive mode - overfrequency (LFSM-O), the following shall apply, as determined by the relevant TSO for its control area in coordination with the TSOs of the same synchronous area to ensure minimal impacts on neighbouring areas:

(a) the power-generating module shall be capable of activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings specified by the relevant TSO;

(b) instead of the capability referred to in paragraph (a), the relevant TSO may choose to allow within its control area automatic disconnection and reconnection of power-generating modules of Type A at randomised frequencies, ideally uniformly distributed, above a frequency threshold, as determined by the relevant TSO where it is able to demonstrate to the relevant regulatory authority, and with the cooperation of power-generating facility owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;

(c) the frequency threshold shall be between 50,2 Hz and 50,5 Hz inclusive;

(d) the droop settings shall be between 2% and 12%;

(e) the power-generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power-generating facility owner shall justify the delay, providing technical evidence to the relevant TSO;

(f) the relevant TSO may require that upon reaching minimum regulating level, the power-generating module be capable of either:

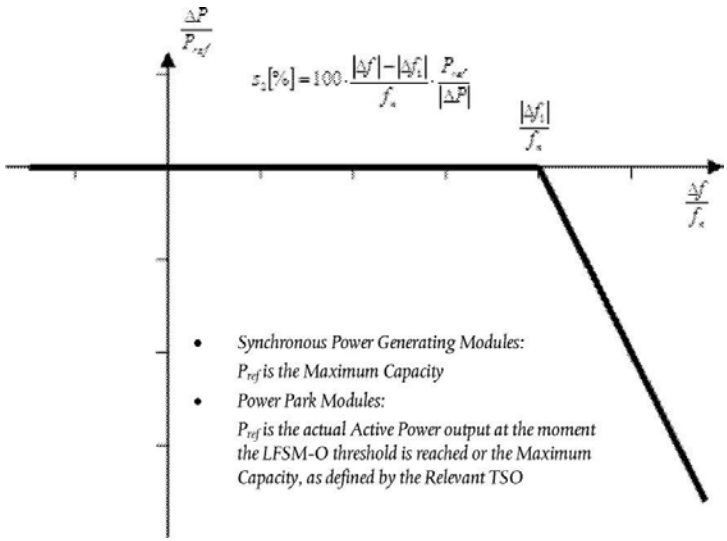
(i) continuing operation at this level; or

(ii) further decreasing active power output;

(g) the power-generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.

Figure 1

Active power frequency response capability of power-generating modules in LFSM-O



P_{ref} is the reference active power to which ΔP is related and may be specified differently for synchronous power-generating modules and power park modules. ΔP is the change in active power output from the power-generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At overfrequencies where Δf is above Δf1, the power-generating module has to provide a negative active power output change according to the droop S2.

3. The power-generating module shall be capable of maintaining constant output at its target active power value regardless of changes in frequency, except where output follows the changes specified in the context of paragraphs 2 and 4 of this Article or points (c) and (d) of Article 15(2) as applicable.

4. The relevant TSO shall specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 2:

(a) below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop;

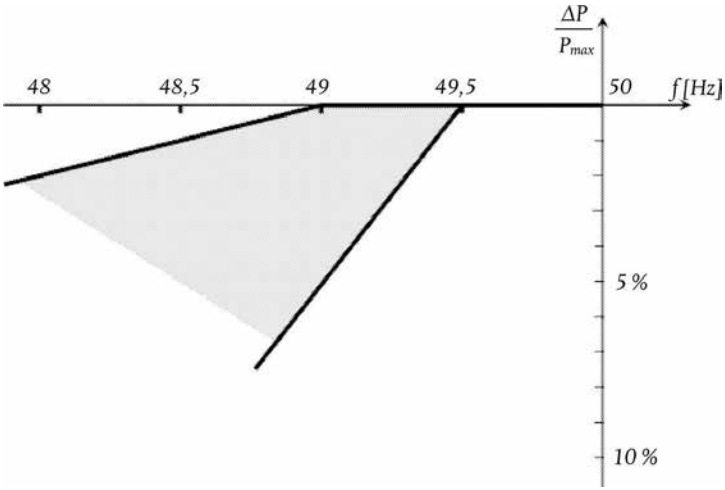
(b) below 49,5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop.

5. The admissible active power reduction from maximum output shall:

(a) clearly specify the ambient conditions applicable;

(b) take account of the technical capabilities of power-generating modules.

Figure 2



Maximum power capability reduction with falling frequency

The diagram represents the boundaries in which the capability can be specified by the relevant TSO.

6. The power-generating module shall be equipped with a logic interface (input port) in order to cease active power output within five seconds following an instruction being received at the input port. The relevant system operator shall have the right to specify requirements for equipment to make this facility operable remotely.

7. The relevant TSO shall specify the conditions under which a power-generating module is capable of connecting automatically to the network. Those conditions shall include:

(a) frequency ranges within which an automatic connection is admissible, and a corresponding delay time; and

(b) maximum admissible gradient of increase in active power output.

Automatic connection is allowed unless specified otherwise by the relevant system operator in coordination with the relevant TSO.

Article 14

General requirements for type B power-generating modules

1. Type B power-generating modules shall fulfil the requirements set out in Article 13, except for Article 13(2)(b).

2. Type B power-generating modules shall fulfil the following requirements in relation to frequency stability:

(a) to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and

(b) the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

3. Type B power-generating modules shall fulfil the following requirements in relation to robustness:

(a) with regard to fault-ride-through capability of power-generating modules:

(i) each TSO shall specify a voltage-against-time-profile in line with Figure 3 at the connection point for fault conditions, which describes the conditions in which the power-generating module is capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults on the transmission system;

(ii) the voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault;

(iii) the lower limit referred to in point (ii) shall be specified by the relevant TSO using the parameters set out in Figure 3, and within the ranges set out in Tables 3.1 and 3.2;

(iv) each TSO shall specify and make publicly available the pre-fault and post-fault conditions for the fault-ride-through capability in terms of:

- the calculation of the pre-fault minimum short circuit capacity at the connection point,

- pre-fault active and reactive power operating point of the power-generating module at the connection point and voltage at the connection point, and

- calculation of the post-fault minimum short circuit capacity at the connection point;

(v) at the request of a power-generating facility owner, the relevant system operator shall provide the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the connection point as specified in point (iv) regarding:

- pre-fault minimum short circuit capacity at each connection point expressed in MVA,

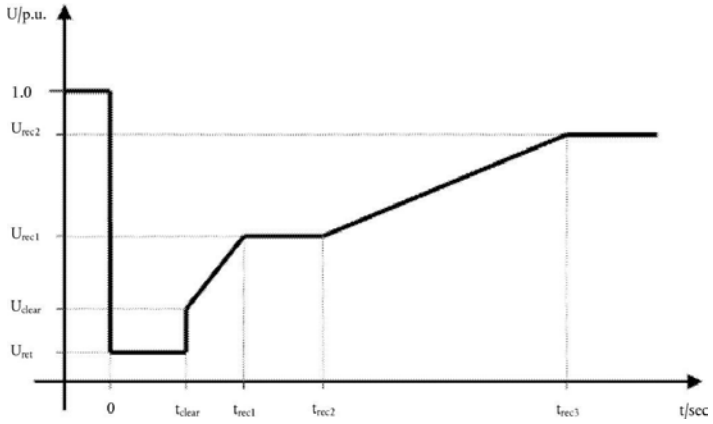
- pre-fault operating point of the power-generating module expressed in active power output and reactive power output at the connection point and voltage at the connection point, and

- post-fault minimum short circuit capacity at each connection point expressed in MVA.

Alternatively, the relevant system operator may provide generic values derived from typical cases;

Figure 3

Fault-ride-through profile of a power-generating module



The diagram represents the lower limit of a voltage-against-time profile of the voltage at the connection point, expressed as the ratio of its actual value and its reference 1 pu value before, during and after a fault. U_{ret} is the retained voltage at the connection point during a fault, t_{clear} is the instant when the fault has been cleared. $U_{rec}1$, $U_{rec}2$, $t_{rec}1$, $t_{rec}2$ and $t_{rec}3$ specify certain points of lower limits of voltage recovery after fault clearance.

Table 3.1

Parameters for Figure 3 for fault-ride-through capability of synchronous power-generating modules

Voltage parameters (pu)		**Time parameters (seconds)**	
U_{ret}:	0,05–0,3	t_{clear}:	0,14–0,15 (or 0,14–0,25 if system protection and secure operation so require)
U_{clear}:	0,7–0,9	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}-0,7
U_{rec2}:	0,85-0,9 and ≥ U_{clear}	t_{rec3}:	t_{rec2}-1,5

Table 3.2

Parameters for Figure 3 for fault-ride-through capability of power park modules

Voltage parameters (pu)		**Time parameters (seconds)**	
U_{ret}:	0,05–0,15	t_{clear}:	0,14–0,15 (or 0,14–0,25 if system protection and secure operation so require)
U_{clear}:	U_{ret}–0,15	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0,85	t_{rec3}:	1,5–3,0

(vi) the power-generating module shall be capable of remaining connected to the network and continuing to operate stably when the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, given the pre-fault and post-fault conditions in points (iv) and (v) of paragraph 3(a), remain above the lower limit specified in point (ii) of paragraph 3(a), unless the protection scheme for internal electrical faults requires the disconnection of the power-generating module from the network. The protection schemes and settings for internal electrical faults must not jeopardise fault-ride-through performance;

(vii) without prejudice to point (vi) of paragraph 3(a), undervoltage protection (either fault-ride-through capability or minimum voltage specified at the connection point voltage) shall be set by the power-generating facility owner according to the widest possible technical capability of the power-generating module, unless the relevant system operator requires narrower settings in accordance with point (b) of paragraph 5. The settings shall be justified by the power-generating facility owner in accordance with this principle;

(b) fault-ride-through capabilities in case of asymmetrical faults shall be specified by each TSO.

4. Type B power-generating modules shall fulfil the following requirements relating to system restoration:

(a) the relevant TSO shall specify the conditions under which a power-generating module is capable of reconnecting to the network after an incidental disconnection caused by a network disturbance; and

(b) installation of automatic reconnection systems shall be subject both to prior authorisation by the relevant system operator and to the reconnection conditions specified by the relevant TSO.

5. Type B power-generating modules shall fulfil the following general system management requirements:

(a) with regard to control schemes and settings:

(i) the schemes and settings of the different control devices of the power-generating module that are necessary for transmission system stability and for taking emergency action shall be coordinated and agreed between the relevant TSO, the relevant system operator and the power-generating facility owner;

(ii) any changes to the schemes and settings, mentioned in point (i), of the different control devices of the power-generating module shall be coordinated and agreed between the relevant TSO, the relevant system operator and the power-generating facility owner, in particular if they apply in the circumstances referred to in point (i) of paragraph 5(a);

(b) with regard to electrical protection schemes and settings:

(i) the relevant system operator shall specify the schemes and settings necessary to protect the network, taking into account the characteristics of the power-generating module. The protection schemes needed for the power-generating module and the network as well as the settings relevant to the power-generating module shall be coordinated and agreed between the relevant system operator and the power-generating facility owner. The protection schemes and settings for internal electrical faults must not jeopardise the performance of a power-generating module, in line with the requirements set out in this Regulation;

(ii) electrical protection of the power-generating module shall take precedence over operational controls, taking into account the security of the system and the health and safety of staff and of the public, as well as mitigating any damage to the power-generating module;

(iii) protection schemes may cover the following aspects:

- external and internal short circuit,
- asymmetric load (negative phase sequence),
- stator and rotor overload,
- over-/underexcitation,
- over-/undervoltage at the connection point,
- over-/undervoltage at the alternator terminals,
- inter-area oscillations,
- inrush current,
- asynchronous operation (pole slip),
- protection against inadmissible shaft torsions (for example, subsynchronous resonance),
- power-generating module line protection,
- unit transformer protection,
- back-up against protection and switchgear malfunction,
- overfluxing (U/f),
- inverse power,
- rate of change of frequency, and neutral voltage displacement.

(iv) changes to the protection schemes needed for the power-generating module and the network and to the settings relevant to the power-generating module shall be agreed between the system operator and the power-generating facility owner, and agreement shall be reached before any changes are made;

(c) the power-generating facility owner shall organise its protection and control devices in accordance with the following priority ranking (from highest to lowest):

(i) network and power-generating module protection;

(ii) synthetic inertia, if applicable;

(iii) frequency control (active power adjustment);

(iv) power restriction; and

(v) power gradient constraint;

(d) with regard to information exchange:

(i) power-generating facilities shall be capable of exchanging information with the relevant system operator or the relevant TSO in real time or periodically with time stamping, as specified by the relevant system operator or the relevant TSO;

(ii) the relevant system operator, in coordination with the relevant TSO, shall specify the content of information exchanges including a precise list of data to be provided by the power-generating facility.

Article 15

General requirements for type C power-generating modules

1. Type C power-generating modules shall fulfil the requirements laid down in Articles 13 and 14, except for Article 13(2)(b) and (6) and Article 14(2).

2. Type C power-generating modules shall fulfil the following requirements relating to frequency stability:

(a) with regard to active power controllability and control range, the power-generating module control system shall be capable of adjusting an active power setpoint in line with instructions given to the power-generating facility owner by the relevant system operator or the relevant TSO.

The relevant system operator or the relevant TSO shall establish the period within which the adjusted active power setpoint must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached;

(b) manual local measures shall be allowed in cases where the automatic remote control devices are out of service.

The relevant system operator or the relevant TSO shall notify the regulatory authority of the time required to reach the setpoint together with the tolerance for the active power;

(c) In addition to Article 13(2), the following requirements shall apply to type C power-generating modules with regard to limited frequency sensitive mode - underfrequency (LFSM-U):

(i) the power-generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows:

- the frequency threshold specified by the TSO shall be between 49,8 Hz and 49,5 Hz inclusive,

- the droop settings specified by the TSO shall be in the range 2-12%.

This is represented graphically in Figure 4;

(ii) the actual delivery of active power frequency response in LFSM-U mode shall take into account:

- ambient conditions when the response is to be triggered,

- the operating conditions of the power-generating module, in particular limitations on operation near maximum capacity at low frequencies and the respective impact of ambient conditions according to paragraphs 4 and 5 of Article 13, and

- the availability of the primary energy sources.

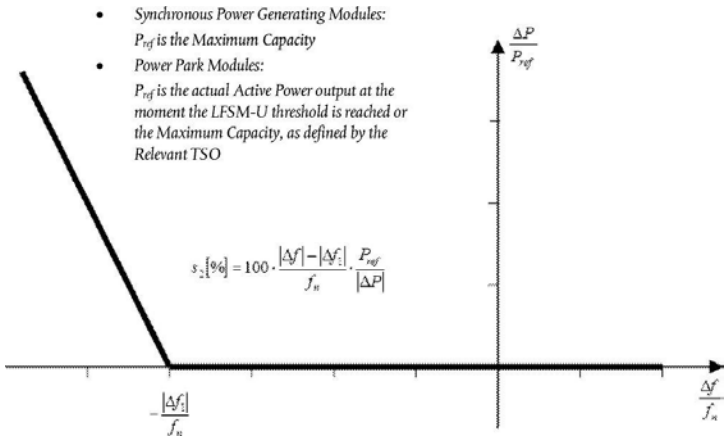
(iii) the activation of active power frequency response by the power-generating module shall not be unduly delayed. In the event of any delay greater than two seconds, the power-generating facility owner shall justify it to the relevant TSO;

(iv) in LFSM-U mode the power-generating module shall be capable of providing a power increase up to its maximum capacity;

(v) stable operation of the power-generating module during LFSM-U operation shall be ensured;

Figure 4

Active power frequency response capability of power-generating modules in LFSM-U



P_{ref} is the reference active power to which ΔP is related and may be specified differently for synchronous power-generating modules and power park modules. ΔP is the change in active power output from the power-generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At underfrequencies where Δf is below Δf1 the power-generating module has to provide a positive active power output change according to the droop S2.

(d) in addition to point (c) of paragraph 2, the following shall apply cumulatively when frequency sensitive mode ('FSM') is operating:

(i) the power-generating module shall be capable of providing active power frequency response in accordance with the parameters specified by each relevant TSO within the ranges shown in Table 4. In specifying those parameters, the relevant TSO shall take account of the following facts:

- in case of overfrequency, the active power frequency response is limited by the minimum regulating level,

- in case of underfrequency, the active power frequency response is limited by maximum capacity,

- the actual delivery of active power frequency response depends on the operating and ambient conditions of the power-generating module when this response is triggered, in particular limitations on operation near maximum capacity at low frequencies according to paragraphs 4 and 5 of Article 13 and available primary energy sources;

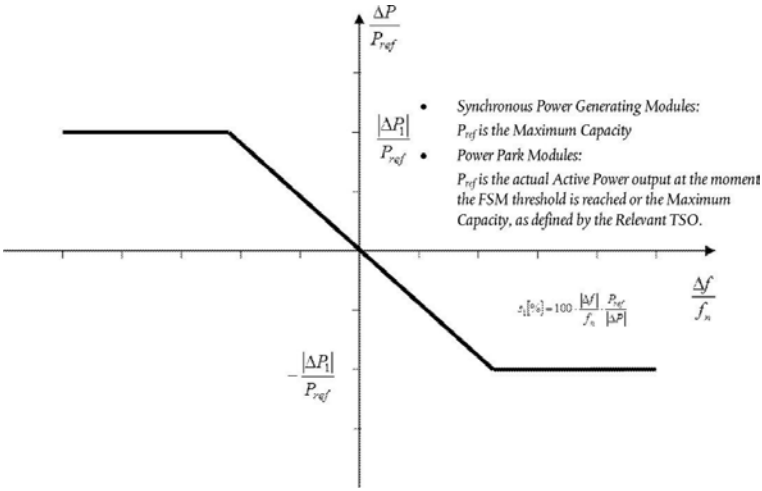
Table 4

Parameters for active power frequency response in FSM (explanation for Figure 5)

Parameters		Ranges
Active power range related to maximum capacity $\frac{\lvert\Delta P_1\rvert}{P_{max}}$		1,5–10%
Frequency response insensitivity	$\lvert\Delta f_i\rvert$	10–30 mHz
	$\frac{\lvert\Delta f_i\rvert}{f_n}$	0,02–0,06%
Frequency response deadband		0–500 mHz
Droop s_1		2–12%

Figure 5

Active power frequency response capability of power-generating modules in FSM illustrating the case of zero deadband and insensitivity



P_{ref} is the reference active power to which ΔP is related. ΔP is the change in active power output from the power-generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network.

(ii) the frequency response deadband of frequency deviation and droop must be able to be reselected repeatedly;

(iii) in the event of a frequency step change, the power-generating module shall be capable of activating full active power frequency response, at or above the full line shown in Figure 6 in accordance with the parameters specified by each TSO (which shall aim at avoiding active power oscillations for the power-generating module) within the ranges given in Table 5. The combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitations into account;

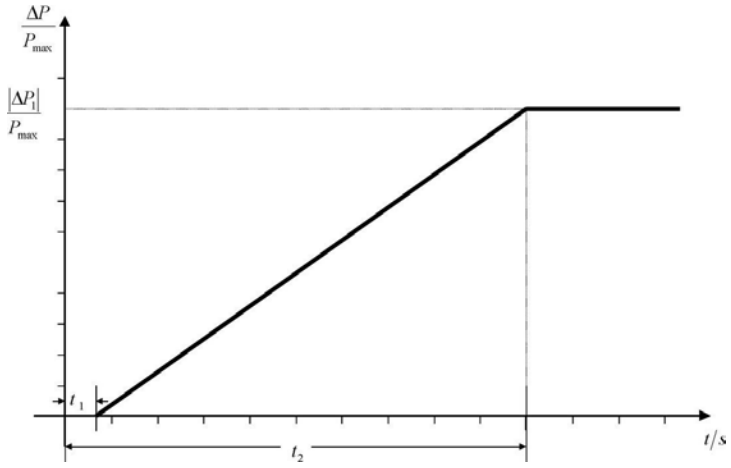
(iv) the initial activation of active power frequency response required shall not be unduly delayed.

If the delay in initial activation of active power frequency response is greater than two seconds, the power-generating facility owner shall provide technical evidence demonstrating why a longer time is needed.

For power-generating modules without inertia, the relevant TSO may specify a shorter time than two seconds. If the power-generating facility owner cannot meet this requirement they shall provide technical evidence demonstrating why a longer time is needed for the initial activation of active power frequency response;

Figure 6

Active power frequency response capability



P_{max} is the maximum capacity to which ΔP relates. ΔP is the change in active power output from the power-generating module. The power-generating module has to provide active power output ΔP up to the point ΔP_1 in accordance with the times t_1 and t_2 with the values of ΔP_1, $t_1$and t_2 being specified by the relevant TSO according to Table 5. t_1 is the initial delay. t_2 is the time for full activation.

(v) the power-generating module shall be capable of providing full active power frequency response for a period of between 15 and 30 minutes as specified by the relevant TSO. In specifying the period, the TSO shall have regard to active power headroom and primary energy source of the power-generating module;

(vi) within the time limits laid down in point (v) of paragraph 2(d), active power control must not have any adverse impact on the active power frequency response of power-generating modules;

(vii) the parameters specified by the relevant TSO in accordance with points (i), (ii), (iii) and (v) shall be notified to the relevant regulatory authority. The modalities of that notification shall be specified in accordance with the applicable national regulatory framework;

Table 5

Parameters for full activation of active power frequency response resulting from frequency step change (explanation for Figure 6)

Parameters	Ranges or values
Active power range related to maximum capacity (frequency response range) $\frac{\lvert\Delta P_1\rvert}{P_{max}}$	1,5–10%
For power-generating modules with inertia, the maximum admissible initial delay t_1 unless justified otherwise in line with Article 15(2)(d)(iv)	2 seconds
For power-generating modules without inertia, the maximum admissible initial delay t_1 unless justified otherwise in line with Article 15(2)(d)(iv)	as specified by the relevant TSO.
Maximum admissible choice of full activation time t_2, unless longer activation times are allowed by the relevant TSO for reasons of system stability	30 seconds

(e) with regard to frequency restoration control, the power-generating module shall provide functionalities complying with specifications specified by the relevant TSO, aiming at restoring frequency to its nominal value or maintaining power exchange flows between control areas at their scheduled values;

(f) with regard to disconnection due to underfrequency, power-generating facilities capable of acting as a load, including hydro pump-storage power-generating facilities, shall be capable of disconnecting their load in case of underfrequency. The requirement referred to in this point does not extend to auxiliary supply;

(g) with regard to real-time monitoring of FSM:

(i) to monitor the operation of active power frequency response, the communication interface shall be equipped to transfer in real time and in a secured manner from the power-generating facility to the network control centre of the relevant system operator or the relevant TSO, at the request of the relevant system operator or the relevant TSO, at least the following signals:

- status signal of FSM (on/off),
- scheduled active power output,
- actual value of the active power output,
- actual parameter settings for active power frequency response,
- droop and deadband;

(ii) the relevant system operator and the relevant TSO shall specify additional signals to be provided by

the power-generating facility by monitoring and recording devices in order to verify the performance of the active power frequency response provision of participating power-generating modules.

3. With regard to voltage stability, type C power-generating modules shall be capable of automatic disconnection when voltage at the connection point reaches levels specified by the relevant system operator in coordination with the relevant TSO.

The terms and settings for actual automatic disconnection of power-generating modules shall be specified by the relevant system operator in coordination with the relevant TSO.

4. Type C power-generating modules shall fulfil the following requirements relating to robustness:

(a) in the event of power oscillations, power-generating modules shall retain steady-state stability when operating at any operating point of the P-Q-capability diagram;

(b) without prejudice to paragraph 4 and 5 of Article 13, power-generating modules shall be capable of remaining connected to the network and operating without power reduction, as long as voltage and frequency remain within the specified limits pursuant to this Regulation;

(c) power-generating modules shall be capable of remaining connected to the network during single-phase or three-phase auto-reclosures on meshed network lines, if applicable to the network to which they are connected. The details of that capability shall be subject to coordination and agreements on protection schemes and settings as referred to in point (b) of Article 14(5).

5. Type C power-generating modules shall fulfil the following requirements relating to system restoration:

(a) with regard to black start capability:

(i) black start capability is not mandatory without prejudice to the **Contracting Party**'s rights to introduce obligatory rules in order to ensure system security;

(ii) power-generating facility owners shall, at the request of the relevant TSO, provide a quotation for providing black start capability. The relevant TSO may make such a request if it considers system security to be at risk due to a lack of black start capability in its control area;

(iii) a power-generating module with black start capability shall be capable of starting from shutdown without any external electrical energy supply within a time frame specified by the relevant system operator in coordination with the relevant TSO;

(iv) a power-generating module with black start capability shall be able to synchronise within the frequency limits laid down in point (a) of Article 13(1) and, where applicable, voltage limits specified by the relevant system operator or in Article 16(2);

(v) a power-generating module with black start capability shall be capable of automatically regulating dips in voltage caused by connection of demand;

(vi) a power-generating module with black start capability shall:

- be capable of regulating load connections in block load,

- be capable of operating in LFSM-O and LFSM-U, as specified in point (c) of paragraph 2 and Article 13(2),

- control frequency in case of overfrequency and underfrequency within the whole active power output range between minimum regulating level and maximum capacity as well as at houseload level,

- be capable of parallel operation of a few power-generating modules within one island, and

- control voltage automatically during the system restoration phase;

(b) with regard to the capability to take part in island operation:

(i) power-generating modules shall be capable of taking part in island operation if required by the relevant system operator in coordination with the relevant TSO and:

- the frequency limits for island operation shall be those established in accordance with point (a) of Article 13(1),

- the voltage limits for island operation shall be those established in accordance with Article 15(3) or Article 16(2), where applicable;

(ii) power-generating modules shall be able to operate in FSM during island operation, as specified in point (d) of paragraph 2.

In the event of a power surplus, power-generating modules shall be capable of reducing the active power output from a previous operating point to any new operating point within the P-Q-capability diagram. In that regard, the power-generating module shall be capable of reducing active power output as much as inherently technically feasible, but to at least 55% of its maximum capacity;

(iii) the method for detecting a change from interconnected system operation to island operation shall be agreed between the power-generating facility owner and the relevant system operator in coordination with the relevant TSO. The agreed method of detection must not rely solely on the system operator's switchgear position signals;

(iv) power-generating modules shall be able to operate in LFSM-O and LFSM-U during island operation, as specified in point (c) of paragraph 2 and Article 13(2);

(c) with regard to quick re-synchronisation capability:

(i) in case of disconnection of the power-generating module from the network, the power-generating module shall be capable of quick re-synchronisation in line with the protection strategy agreed between the relevant system operator in coordination with the relevant TSO and the power-generating facility;

(ii) a power-generating module with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be designed to trip to houseload from any operating point in its P-Q-capability diagram. In this case, the identification of houseload operation must not be based solely on the system operator's switchgear position signals;

(iii) power-generating modules shall be capable of continuing operation following tripping to houseload, irrespective of any auxiliary connection to the external network. The minimum operation time shall be specified by the relevant system operator in coordination with the relevant TSO, taking into consideration the specific characteristics of prime mover technology.

6. Type C power-generating modules shall fulfil the following general system management requirements:

(a) with regard to loss of angular stability or loss of control, a power-generating module shall be capable of disconnecting automatically from the network in order to help preserve system security or to prevent damage to the power-generating module. The power-generating facility owner and the relevant system operator in coordination with the relevant TSO shall agree on the criteria for detecting loss of angular stability or loss of control;

(b) with regard to instrumentation:

(i) power-generating facilities shall be equipped with a facility to provide fault recording and monitoring

of dynamic system behaviour. This facility shall record the following parameters:

- voltage,

- active power,

- reactive power, and

- frequency.

The relevant system operator shall have the right to specify quality of supply parameters to be complied with on condition that reasonable prior notice is given;

(ii) the settings of the fault recording equipment, including triggering criteria and the sampling rates shall be agreed between the power-generating facility owner and the relevant system operator in coordination with the relevant TSO;

(iii) the dynamic system behaviour monitoring shall include an oscillation trigger specified by the relevant system operator in coordination with the relevant TSO, with the purpose of detecting poorly damped power oscillations;

(iv) the facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the power-generating facility owner, and the relevant system operator and the relevant TSO to access the information. The communications protocols for recorded data shall be agreed between the power-generating facility owner, the relevant system operator and the relevant TSO;

(c) with regard to the simulation models:

(i) at the request of the relevant system operator or the relevant TSO, the power-generating facility owner shall provide simulation models which properly reflect the behaviour of the power-generating module in both steady-state and dynamic simulations (50 Hz component) or in electromagnetic transient simulations.

The power-generating facility owner shall ensure that the models provided have been verified against the results of compliance tests referred to in Chapters 2, 3 and 4 of Title IV, and shall notify the results of the verification to the relevant system operator or relevant TSO. **Contracting Parties** may require that such verification be carried out by an authorised certifier;

(ii) the models provided by the power-generating facility owner shall contain the following sub-models, depending on the existence of the individual components:

- alternator and prime mover,

- speed and power control,

- voltage control, including, if applicable, power system stabiliser ('PSS') function and excitation control system,

- power-generating module protection models, as agreed between the relevant system operator and the power-generating facility owner, and

- converter models for power park modules;

(iii) the request by the relevant system operator referred to in point (i) shall be coordinated with the relevant TSO. It shall include:

- the format in which models are to be provided,

- the provision of documentation on a model's structure and block diagrams,

- an estimate of the minimum and maximum short circuit capacity at the connection point, expressed in MVA, as an equivalent of the network;

(iv) the power-generating facility owner shall provide recordings of the power-generating module's performance to the relevant system operator or relevant TSO if requested. The relevant system operator or relevant TSO may make such a request, in order to compare the response of the models with those recordings;

(d) with regard to the installation of devices for system operation and devices for system security, if the relevant system operator or the relevant TSO considers that it is necessary to install additional devices in a power-generating facility in order to preserve or restore system operation or security, the relevant system operator or relevant TSO and the power-generating facility owner shall investigate that matter and agree on an appropriate solution;

(e) the relevant system operator shall specify, in coordination with the relevant TSO, minimum and maximum limits on rates of change of active power output (ramping limits) in both an up and down direction of change of active power output for a power-generating module, taking into consideration the specific characteristics of prime mover technology;

(f) earthing arrangement of the neutral-point at the network side of step-up transformers shall comply with the specifications of the relevant system operator.

Article 16

General requirements for type D power-generating modules

1. In addition to fulfilling the requirements listed in Article 13, except for Article 13(2)(b), (6) and (7), Article 14, except for Article 14(2), and Article 15, except for Article 15(3), type D power-generating modules shall fulfil the requirements set out in this Article.

2. Type D power-generating modules shall fulfil the following requirements relating to voltage stability:

(a) with regard to voltage ranges:

(i) without prejudice to point (a) of Article 14(3) and point (a) of paragraph 3 below, a power-generating module shall be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to the reference 1 pu voltage, and for the time periods specified in Tables 6.1 and 6.2;

(ii) the relevant TSO may specify shorter periods of time during which power-generating modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency;

(iii) notwithstanding the provisions of point (i), the relevant TSO in Spain may require power-generating modules to be capable of remaining connected to the network in the voltage range between 1,05 pu and 1,0875 pu for an unlimited period;

(iv) for the 400 kV grid voltage level (or alternatively commonly referred to as 380 kV level), the reference 1 pu value is 400 kV; for other grid voltage levels, the reference 1 pu voltage may differ for each system operator in the same synchronous area;

(v) notwithstanding the provisions of point (i), the relevant TSOs in the Baltic synchronous area may

require power-generating modules to remain connected to the 400 kV network in the voltage range limits and for the time periods that apply in the Continental Europe synchronous area;

Table 6.1

Synchronous area	Voltage range	Time period for operation
Continental Europe	0,85 pu–0,90 pu	60 minutes
	0,90 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	60 minutes
Great Britain	0,90 pu–1,10 pu	Unlimited
Ireland and Northern Ireland	0,90 pu–1,118 pu	Unlimited
Baltic	0,85 pu–0,90 pu	30 minutes
	0,90 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	20 minutes
Georgia	**0,85 pu–0,90 pu**	**60 minutes**
	0,90 pu–1,12 pu	**Unlimited**
	1,12 pu–1,15 pu	**20 minutes**

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network, where the voltage base for pu values is from 110 kV to 300 kV.

Table 6.2

Synchronous area	Voltage range	Time period for operation
Continental Europe	0,85 pu–0,90 pu	60 minutes
	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	To be specified by each TSO, but not more than 60 minutes
Great Britain	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	15 minutes
Ireland and Northern Ireland	0,90 pu–1,05 pu	Unlimited

Baltic	0,88 pu–0,90 pu	20 minutes
	0,90 pu–1,097 pu	Unlimited
	1,097 pu–1,15 pu	20 minutes
Georgia	**0,85 pu–0,90 pu**	**60 minutes**
	0,90 pu–1,10 pu	**Unlimited**
	1,10 pu–1,15 pu	**20 minutes**

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network where the voltage base for pu values is from 300 kV to 500 kV.

(b) wider voltage ranges or longer minimum time periods for operation may be agreed between the relevant system operator and the power-generating facility owner in coordination with the relevant TSO. If wider voltage ranges or longer minimum times for operation are economically and technically feasible, the power-generating facility owner shall not unreasonably withhold an agreement;

(c) without prejudice to point (a), the relevant system operator in coordination with the relevant TSO shall have the right to specify voltages at the connection point at which a power-generating module is capable of automatic disconnection. The terms and settings for automatic disconnection shall be agreed between the relevant system operator and the power-generating facility owner.

3. Type D power-generating modules shall fulfil the following requirements in relation to robustness:

(a) with regard to fault-ride-through capability:

(i) power-generating modules shall be capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults. That capability shall be in accordance with a voltage-against-time profile at the connection point for fault conditions specified by the relevant TSO.

The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault.

That lower limit shall be specified by the relevant TSO, using the parameters set out in Figure 3 and within the ranges set out in Tables 7.1 and 7.2 for type D power-generating modules connected at or above the 110 kV level.

That lower limit shall also be specified by the relevant TSO, using parameters set out in Figure 3 and within the ranges set out in Tables 3.1 and 3.2 for type D power-generating modules connected below the 110 kV level;

(ii) each TSO shall specify the pre-fault and post-fault conditions for the fault-ride-through capability referred to in point (iv) of Article 14(3)(a). The specified pre-fault and post-fault conditions for the fault-ride-through capability shall be made publicly available;

Table 7.1

Parameters for Figure 3 for fault-ride-through capability of synchronous power-generating modules

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0	t_{clear}:	0,14–0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	0,25	t_{rec1}:	t_{clear}–0,45
U_{rec1}:	0,5–0,7	t_{rec2}:	t_{rec1}–0,7
U_{rec2}:	0,85–0,9	t_{rec3}:	t_{rec2}–1,5

Table 7.2

Parameters for Figure 3 for fault-ride-through capability of power park modules

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0	t_{clear}:	0,14–0,15 (or 0,14–0,25 if system protection and secure operation so require)
U_{clear}:	U_{ret}	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0,85	t_{rec3}:	1,5-3,0

(b) at the request of a power-generating facility owner, the relevant system operator shall provide the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the connection point as specified in point (iv) of Article 14(3)(a) regarding:

(i) pre-fault minimum short circuit capacity at each connection point expressed in MVA;

(ii) pre-fault operating point of the power-generating module expressed as active power output and reactive power output at the connection point and voltage at the connection point; and

(iii) post-fault minimum short circuit capacity at each connection point expressed in MVA;

(c) fault-ride-through capabilities in case of asymmetrical faults shall be specified by each TSO.

4. Type D power-generating modules shall fulfil the following general system management requirements:

(a) with regard to synchronisation, when starting a power-generating module, synchronisation shall be performed by the power-generating facility owner only after authorisation by the relevant system operator;

(b) the power-generating module shall be equipped with the necessary synchronisation facilities;

(c) synchronisation of power-generating modules shall be possible at frequencies within the ranges set out in Table 2;

(d) the relevant system operator and the power-generating facility owner shall agree on the settings of synchronisation devices to be concluded prior to operation of the power-generating module. This agreement shall cover:

(i) voltage;

(ii) frequency;

(iii) phase angle range;

(iv) phase sequence;

(v) deviation of voltage and frequency.

CHAPTER 2
Requirements for synchronous power-generating modules

Article 17

Requirements for type B synchronous power-generating modules

1. Type B synchronous power-generating modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b), and 14.

2. Type B synchronous power-generating modules shall fulfil the following additional requirements relating to voltage stability:

(a) with regard to reactive power capability, the relevant system operator shall have the right to specify the capability of a synchronous power-generating module to provide reactive power;

(b) with regard to the voltage control system, a synchronous power-generating module shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the synchronous power-generating module.

3. With regard to robustness, type B synchronous power-generating modules shall be capable of providing post-fault active power recovery. The relevant TSO shall specify the magnitude and time for active power recovery.

Article 18

Requirements for type C synchronous power-generating modules

1. Type C synchronous power-generating modules shall fulfil the requirements laid down in Articles 13, 14, 15 and 17, except for Article 13(2)(b) and 13(6), Article 14(2) and Article 17(2)(a).

2. Type C synchronous power-generating modules shall fulfil the following additional requirements in relation to voltage stability:

(a) with regard to reactive power capability, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a synchronous power-generating module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the alternator terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the synchronous power-generating module or its alternator terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable;

(b) with regard to reactive power capability at maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power provision capability requirements in the context of varying voltage. For that purpose the relevant system operator shall specify a U-Q/P_{max}-profile within the boundaries of which the synchronous power-generating module shall be capable of providing reactive power at its maximum capacity. The specified U-Q/P_{max} profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;

(ii) the U-Q/P_{max}-profile shall be specified by the relevant system operator in coordination with the relevant TSO, in conformity with the following principles:

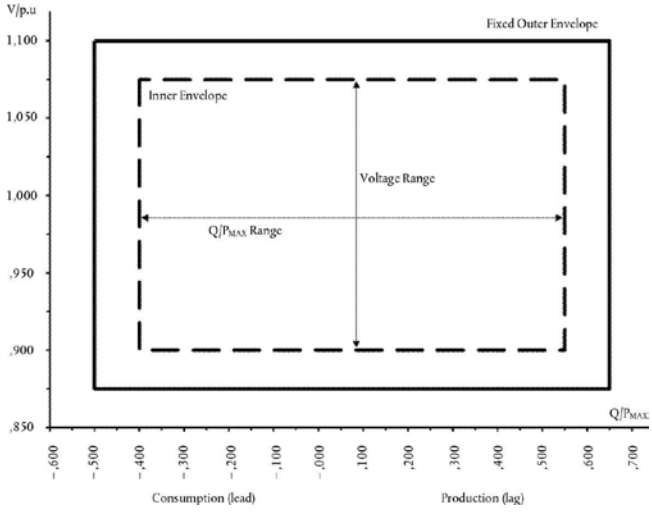
- the U-Q/P_{max}-profile shall not exceed the U-Q/P_{max}-profile envelope, represented by the inner envelope in Figure 7,

- the dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and voltage range) shall be within the range specified for each synchronous area in Table 8, and

- the position of the U-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope in Figure 7;

Figure 7

U-Q/P_{max}-profile of a synchronous power-generating module



The diagram represents boundaries of a U-Q/P_{max}-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1 pu value, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Table 8

Parameters for the inner envelope in Figure 7

Synchronous area	Maximum range of Q/P_{max}	Maximum range of wsteady-state voltage level in PU
Continental Europe	0,95	0,225
Nordic	0,95	0,150
Great Britain	0,95	0,225
Ireland and Northern Ireland	1,08	0,218
Baltic, **Georgia**	1,0	0,220

(iii) the reactive power provision capability requirement applies at the connection point. For profile shapes other than rectangular, the voltage range represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady-state voltages;

(iv) the synchronous power-generating module shall be capable of moving to any operating point within its U-Q/P_{max} profile in appropriate timescales to target values requested by the relevant system operator;

(c) with regard to reactive power capability below maximum capacity, when operating at an active power output below the maximum capacity ($P < P_{max}$), the synchronous power-generating modules shall be capable of operating at every possible operating point in the P-Q-capability diagram of the alternator of that synchronous power-generating module, at least down to minimum stable operating level. Even at reduced active power output, reactive power supply at the connection point shall correspond fully to the P-Q-capability diagram of the alternator of that synchronous power-generating module, taking the auxiliary supply power and the active and reactive power losses of the step-up transformer, if applicable, into account.

Article 19

Requirements for type D synchronous power-generating modules

1. Type D synchronous power-generating modules shall fulfil the requirements laid down in Article 13, except for Article 13(2)(b), (6) and (7), Article 14 except for Article 14(2), Article 15, except for Article 15(3), Article 16, Article 17, except for Article 17(2) and Article 18.

2. Type D synchronous power-generating modules shall fulfil the following additional requirements in relation to voltage stability:

(a) the parameters and settings of the components of the voltage control system shall be agreed between the power-generating facility owner and the relevant system operator, in coordination with the relevant TSO;

(b) the agreement referred to in subparagraph (a) shall cover the specifications and performance of an automatic voltage regulator ('AVR') with regard to steady-state voltage and transient voltage control and the specifications and performance of the excitation control system. The latter shall include:

(i) bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other power-generating modules connected to the network;

(ii) an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;

(iii) an overexcitation limiter to ensure that the alternator excitation is not limited to less than the maximum value that can be achieved whilst ensuring that the synchronous power-generating module is operating within its design limits;

(iv) a stator current limiter; and

(v) a PSS function to attenuate power oscillations, if the synchronous power-generating module size is above a value of maximum capacity specified by the relevant TSO.

3. The relevant TSO and the power-generating facility owner shall enter into an agreement regarding technical capabilities of the power-generating module to aid angular stability under fault conditions.

CHAPTER 3
Requirements for power park modules

Article 20
Requirements for type B power park modules

1. Type B power park modules shall fulfil the requirements laid down in Articles 13, except for Article 13(2)(b), and Article 14.

2. Type B power park modules shall fulfil the following additional requirements in relation to voltage stability:

(a) with regard to reactive power capability, the relevant system operator shall have the right to specify the capability of a power park module to provide reactive power;

(b) the relevant system operator in coordination with the relevant TSO shall have the right to specify that a power park module be capable of providing fast fault current at the connection point in case of symmetrical (3-phase) faults, under the following conditions:

(i) the power park module shall be capable of activating the supply of fast fault current either by:

- ensuring the supply of the fast fault current at the connection point, or

- measuring voltage deviations at the terminals of the individual units of the power park module and providing a fast fault current at the terminals of these units;

(ii) the relevant system operator in coordination with the relevant TSO shall specify:

- how and when a voltage deviation is to be determined as well as the end of the voltage deviation,

- the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current, for which current and voltage may be measured differently from the method specified in Article 2,

- the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance;

(c) with regard to the supply of fast fault current in case of asymmetrical (1-phase or 2-phase) faults, the relevant system operator in coordination with the relevant TSO shall have the right to specify a requirement

for asymmetrical current injection.

3. Type B power park modules shall fulfil the following additional requirements in relation to robustness:

(a) the relevant TSO shall specify the post-fault active power recovery that the power park module is capable of providing and shall specify:

(i) when the post-fault active power recovery begins, based on a voltage criterion;

(ii) a maximum allowed time for active power recovery; and

(iii) a magnitude and accuracy for active power recovery;

(b) the specifications shall be in accordance with the following principles:

(i) interdependency between fast fault current requirements according to points (b) and (c) of paragraph 2 and active power recovery;

(ii) dependence between active power recovery times and duration of voltage deviations;

(iii) a specified limit of the maximum allowed time for active power recovery;

(iv) adequacy between the level of voltage recovery and the minimum magnitude for active power recovery; and

(v) adequate damping of active power oscillations.

Article 21

Requirements for type C power park modules

1. Type C power park modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b) and (6), Article 14, except for Article 14(2), Article 15 and Article 20, except for Article 20(2)(a), unless referred to otherwise in point (v) of paragraph 3(d).

2. Type C power park modules shall fulfil the following additional requirements in relation to frequency stability:

(a) the relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations;

(b) the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO.

3. Type C power park modules shall fulfil the following additional requirements in relation to voltage stability:

(a) with regard to reactive power capability, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a power park module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the convertor terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the power park module or its convertor terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable.

(b) with regard to reactive power capability at maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power

provision capability requirements in the context of varying voltage. To that end, it shall specify a U-Q/P_{max}-profile that may take any shape within the boundaries of which the power park module shall be capable of providing reactive power at its maximum capacity;

(ii) the U-Q/P_{max}-profile shall be specified by each relevant system operator in coordination with the relevant TSO in conformity with the following principles:

- the U-Q/P_{max}-profile shall not exceed the U-Q/P_{max}-profile envelope, represented by the inner envelope in Figure 8,

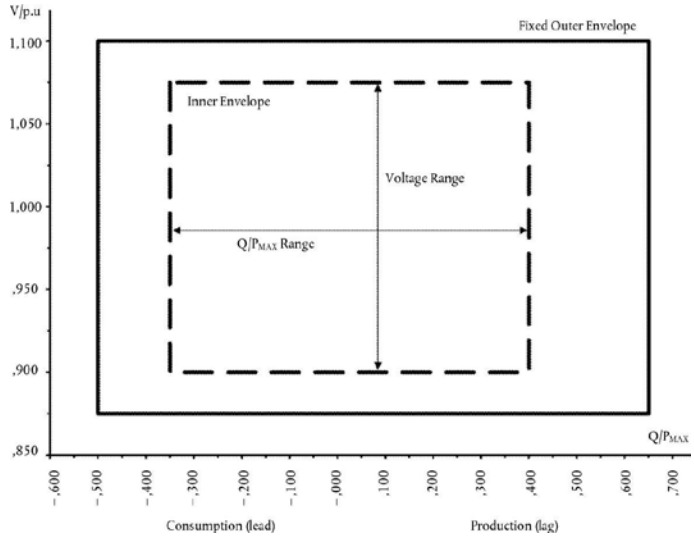
- the dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and voltage range) shall be within the values specified for each synchronous area in Table 9,

- the position of the U-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope set out in Figure 8, and

- the specified U-Q/P_{max} profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;

Figure 8

U-Q/P_{max}-profile of a power park module



The diagram represents boundaries of a U-Q/P_{max}-profile by the voltage at the connection point, expressed by the ratio of its actual value and its reference 1 pu value, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Table 9

Parameters for the inner envelope in Figure 8

Synchronous area	Maximum range of Q/P_{max}	Maximum range of steady-state voltage level in PU
Continental Europe	0,75	0,225
Nordic	0,95	0,150
Great Britain	0,66	0,225
Ireland and Northern Ireland	0,66	0,218
Baltic, **Georgia**	0,80	0,220

(iii) the reactive power provision capability requirement applies at the connection point. For profile shapes other than rectangular, the voltage range represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady-state voltages;

(c) with regard to reactive power capability below maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power provision capability requirements and shall specify a P-Q/P_{max}-profile that may take any shape within the boundaries of which the power park module shall be capable of providing reactive power below maximum capacity;

(ii) the P-Q/P_{max}-profile shall be specified by each relevant system operator in coordination with the relevant TSO, in conformity with the following principles:

- the P-Q/P_{max}-profile shall not exceed the P-Q/P_{max}-profile envelope, represented by the inner envelope in Figure 9,

- the Q/P_{max} range of the P-Q/P_{max}-profile envelope is specified for each synchronous area in Table 9,

- the active power range of the P-Q/P_{max}-profile envelope at zero reactive power shall be 1 pu,

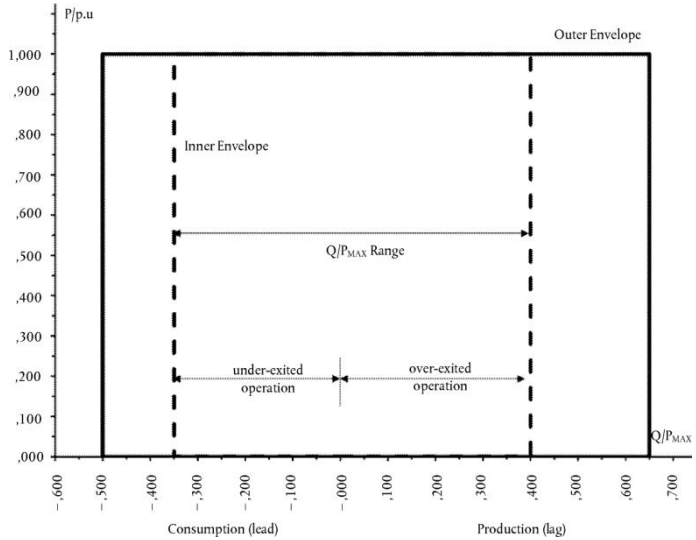
- the P-Q/P_{max}-profile can be of any shape and shall include conditions for reactive power capability at zero active power, and

- the position of the P-Q/P_{max}-profile envelope shall be within the limits of the fixed outer envelope set out in Figure 9;

(iii) when operating at an active power output below maximum capacity ($P<P_{max}$), the power park module shall be capable of providing reactive power at any operating point inside its P-Q/P_{max}-profile, if all units of that power park module which generate power are technically available that is to say they are not out of service due to maintenance or failure, otherwise there may be less reactive power capability, taking into consideration the technical availabilities;

Figure 9

P-Q/P_{max}-profile of a power park module



The diagram represents boundaries of a P-Q/P_{max}-profile at the connection point by the active power, expressed by the ratio of its actual value and the maximum capacity pu, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

(iv) the power park module shall be capable of moving to any operating point within its P-Q/P_{max} profile in appropriate timescales to target values requested by the relevant system operator;

(d) with regard to reactive power control modes:

(i) the power park module shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode;

(ii) for the purposes of voltage control mode, the power park module shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a setpoint voltage covering 0,95 to 1,05 pu in steps no greater than 0,01 pu, with a slope having a range of at least 2 to 7% in steps no greater than 0,5%. The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint;

(iii) the setpoint may be operated with or without a deadband selectable in a range from zero to ± 5% of reference 1 pu network voltage in steps no greater than 0,5%;

(iv) following a step change in voltage, the power park module shall be capable of achieving 90% of the change in reactive power output within a time t1 to be specified by the relevant system operator in the range of 1 to 5 seconds, and must settle at the value specified by the slope within a time t2 to be specified by the relevant system operator in the range of 5 to 60 seconds, with a steady-state reactive tolerance no greater than 5% of the maximum reactive power. The relevant system operator shall specify the time specifications;

(v) for the purpose of reactive power control mode, the power park module shall be capable of setting the reactive power setpoint anywhere in the reactive power range, specified by point (a) of Article 20(2)

and by points (a) and (b) of Article 21(3), with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full reactive power, controlling the reactive power at the connection point to an accuracy within plus or minus 5 MVAr or plus or minus 5% (whichever is smaller) of the full reactive power;

(vi) for the purpose of power factor control mode, the power park module shall be capable of controlling the power factor at the connection point within the required reactive power range, specified by the relevant system operator according to point (a) of Article 20(2) or specified by points (a) and (b) of Article 21(3), with a target power factor in steps no greater than 0,01. The relevant system operator shall specify the target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output. The tolerance of the target power factor shall be expressed through the tolerance of its corresponding reactive power. This reactive power tolerance shall be expressed by either an absolute value or by a percentage of the maximum reactive power of the power park module;

(vii) the relevant system operator, in coordination with the relevant TSO and with the power park module owner, shall specify which of the above three reactive power control mode options and associated setpoints is to apply, and what further equipment is needed to make the adjustment of the relevant setpoint operable remotely;

(e) with regard to prioritising active or reactive power contribution, the relevant TSO shall specify whether active power contribution or reactive power contribution has priority during faults for which fault-ride-through capability is required. If priority is given to active power contribution, this provision has to be established no later than 150 ms from the fault inception;

(f) with regard to power oscillations damping control, if specified by the relevant TSO a power park module shall be capable of contributing to damping power oscillations. The voltage and reactive power control characteristics of power park modules must not adversely affect the damping of power oscillations.

Article 22

Requirements for type D power park modules

Type D power park modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b), (6) and (7), Article 14, except for Article 14(2), Article 15, except for Article 15(3), Article 16, Article 20 except for Article 20(2)(a) and Article 21.

CHAPTER 4
Requirements for offshore power park modules

Article 23

General provisions

1. The requirements set out in this Chapter apply to the connection to the network of AC-connected power park modules located offshore. An AC-connected power park module located offshore which does not have an offshore connection point shall be considered as an onshore power park module and thus shall

comply with the requirements governing power park modules situated onshore.

2. The offshore connection point of an AC-connected offshore power park module shall be specified by the relevant system operator.

3. AC-connected offshore power park modules within the scope of this Regulation shall be categorised in accordance with the following offshore grid connection system configurations:

(a) configuration 1: AC connection to a single onshore grid interconnection point whereby one or more offshore power park modules that are interconnected offshore to form an offshore AC system are connected to the onshore system;

(b) configuration 2: meshed AC connections whereby a number of offshore power park modules are interconnected offshore to form an offshore AC system and the offshore AC system is connected to the onshore system at two or more onshore grid interconnection points.

Article 24

Frequency stability requirements applicable to AC-connected offshore power park modules

The frequency stability requirements laid down respectively in Article 13(1) to (5), except for Article 13(2) (b), Article 15(2) and Article 21(2) shall apply to any AC-connected offshore power park module.

Article 25

Voltage stability requirements applicable to AC-connected offshore power park modules

1. Without prejudice to point (a) of Article 14(3) and point (a) of Article 16(3), an AC-connected offshore power park module shall be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to reference 1 pu voltage, and for the time periods specified in Table 10.

2. Notwithstanding the provisions of paragraph 1, the relevant TSO in Spain may require AC-connected offshore power park modules to remain connected to the network in the voltage range between 1,05 pu and 1,0875 pu for an unlimited period.

3. Notwithstanding the provisions of paragraph 1, the relevant TSOs in the Baltic synchronous area may require AC-connected offshore power park modules to remain connected to the 400 kV network in the voltage range and for the time periods that apply to the Continental Europe synchronous area.

Table 10

Synchronous area	**Voltage range**	**Time period for operation**
Continental Europe	0,85 pu–0,90 pu	60 minutes
	0,9 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes
	0,90 pu-1,05 pu	Unlimited
	1,05 pu-1,10 pu	To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	60 minutes
	1,05 pu–1,10 pu	To be specified by each TSO, but not more than 60 minutes
Great Britain	0,90 pu–1,10 pu (*)	Unlimited
	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	15 minutes
Ireland and Northern Ireland	0,90 pu–1,10 pu	Unlimited
Baltic	0,85 pu–0,90 pu	30 minutes
	0,90 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	20 minutes
	0,88 pu–0,90 pu	20 minutes
	0,90 pu–1,097 pu	Unlimited
	1,097 pu–1,15 pu	20 minutes

The table shows the minimum period during which an AC-connected offshore power park module must be capable of operating over different voltage ranges deviating from the reference 1 pu value without disconnecting.

4. The voltage stability requirements specified respectively in points (b) and (c) of Article 20(2) as well as in Article 21(3) shall apply to any AC-connected offshore power park module.

5. The reactive power capability at maximum capacity specified in point (b) of Article 21(3) shall apply to AC-connected offshore power park modules, except for Table 9. Instead, the requirements of Table 11 shall apply.

Table 11

Parameters for Figure 8

Synchronous area	Maximum range of Q/P_{max}	Maximum range of steady-state voltage level in PU
Continental Europe	0,75	0,225
Nordic	0,95	0,150
Great Britain	0 0,33	0,225
Ireland and Northern Ireland	0,66	0,218
Baltic	0,8	0,22

Article 26

Robustness requirements applicable to AC-connected offshore power park modules

1. The robustness requirements of power-generating modules laid down in Article 15(4) and Article 20(3) shall apply to AC-connected offshore power park modules.

2. The fault-ride-through capability requirements laid down in point (a) of Article 14(3) and point (a) of Article 16(3) shall apply to AC-connected offshore power park modules.

Article 27

System restoration requirements applicable to AC-connected offshore power park modules

The system restoration requirements laid down respectively in Article 14(4) and Article 15(5) shall apply to AC-connected offshore power park modules.

Article 28

General system management requirements applicable to AC-connected offshore power park modules

The general system management requirements laid down in Article 14(5), Article 15(6) and Article 16(4) shall apply to AC-connected offshore power park modules.

TITLE III
OPERATIONAL NOTIFICATION PROCEDURE FOR CONNECTION

CHAPTER 1
Connection of new power-generating modules

Article 29
General provisions

1. The power-generating facility owner shall demonstrate to the relevant system operator that it has complied with the requirements set out in Title II of this Regulation by completing successfully the operational notification procedure for connection of each power-generating module described in Articles 30 to 37.

2. The relevant system operator shall clarify and make publicly available the details of the operational notification procedure.

Article 30
Operational notification of type A power-generating modules

1. The operational notification procedure for connection of each new type A power-generating module shall consist of submitting an installation document. The power-generating facility owner shall ensure that the required information is filled in on an installation document obtained from the relevant system operator and is submitted to the system operator. Separate installation documents shall be provided for each power-generating module within the power-generating facility.

The relevant system operator shall ensure that the required information can be submitted by third parties on behalf of the power-generating facility owner.

2. The relevant system operator shall specify the content of the installation document, which shall have at least the following information:

(a) the location at which the connection is made;

(b) the date of the connection;

(c) the maximum capacity of the installation in kW;

(d) the type of primary energy source;

(e) the classification of the power-generating module as an emerging technology according to Title VI of this Regulation;

(f) reference to equipment certificates issued by an authorised certifier used for equipment that is in the site installation;

(g) as regards equipment used, for which an equipment certificate has not been received, information shall be provided as directed by the relevant system operator; and

(h) the contact details of the power-generating facility owner and the installer and their signatures.

3. The power-generating facility owner shall ensure that the relevant system operator or the competent authority of the **Contracting Party** is notified about the permanent decommissioning of a power-generating module in accordance with national legislation.

The relevant system operator shall ensure that such notification can be made by third parties, including aggregators.

Article 31

Operational notification of type B, C and D power-generating modules

The operational notification procedure for connection of each new type B, C and D power-generating module shall allow the use of equipment certificates issued by an authorised certifier.

Article 32

Procedure for type B and C power-generating modules

1. For the purpose of operational notification for connection of each new type B and C power-generating module, a power-generating module document ('PGMD') shall be provided by the power-generating facility owner to the relevant system operator and shall include a statement of compliance.

For each power-generating module within the power-generating facility, separate independent PGMDs shall be provided.

2. The format of the PGMD and the information to be given therein shall be specified by the relevant system operator. The relevant system operator shall have the right to request that the power-generating facility owner include the following in the PGMD:

(a) evidence of an agreement on the protection and control settings relevant to the connection point between the relevant system operator and the power-generating facility owner;

(b) itemised statement of compliance;

(c) detailed technical data of the power-generating module with relevance to the grid connection as specified by the relevant system operator;

(d) equipment certificates issued by an authorised certifier in respect of power-generating modules, where these are relied upon as part of the evidence of compliance;

(e) for Type C power-generating modules, simulation models pursuant to point (c) of Article 15(6);

(f) compliance test reports demonstrating steady-state and dynamic performance as required by Chapters 2, 3 and 4 of Title IV, including use of actual measured values during testing, to the level of detail required by the relevant system operator; and

(g) studies demonstrating steady-state and dynamic performance as required by Chapters 5, 6 or 7 of Title IV, to the level of detail required by the relevant system operator.

3. The relevant system operator, on acceptance of a complete and adequate PGMD, shall issue a final operational notification to the power-generating facility owner.

4. The power-generating facility owner shall notify the relevant system operator or the competent authority of the **Contracting Party** about the permanent decommissioning of a power-generating module in accordance with national legislation.

5. Where applicable, the relevant system operator shall ensure that the commissioning and decommissioning of Type B and Type C power-generating modules can be notified electronically.

6. **Contracting Parties** may provide that the PGMD shall be issued by an authorised certifier.

Article 33

Procedure for type D power-generating modules

The operational notification procedure for connection of each new type D power-generating module shall comprise:

(a) energisation operational notification ('EON');

(b) interim operational notification ('ION'); and

(c) final operational notification ('FON').

Article 34

Energisation operational notification for type D power-generating modules

1. An EON shall entitle the power-generating facility owner to energise its internal network and auxiliaries for the power-generating modules by using the grid connection that is specified for the connection point.

2. An EON shall be issued by the relevant system operator, subject to completion of preparations including agreement on the protection and control settings relevant to the connection point between the relevant system operator and the power-generating facility owner.

Article 35

Interim operational notification for type D power-generating modules

1. An ION shall entitle the power-generating facility owner to operate the power-generating module and generate power by using the grid connection for a limited period of time.

2. An ION shall be issued by the relevant system operator, subject to completion of the data and study review process as required by this Article.

3. With regard to the data and study review, the relevant system operator shall have the right to request that the power-generating facility owner provide the following:

(a) itemised statement of compliance;

(b) detailed technical data on the power-generating module of relevance to the grid connection as specified by the relevant system operator;

(c) equipment certificates issued by an authorised certifier in respect of power-generating modules, where

they are relied upon as part of the evidence of compliance;

(d) simulation models, as specified by point (c) of Article 15(6) and required by the relevant system operator;

(e) studies demonstrating the expected steady-state and dynamic performance as required by Chapter 5, 6 or 7 of Title IV; and

(f) details of intended compliance tests in accordance with Chapters 2, 3 and 4 of Title IV.

4. The maximum period during which the power-generating facility owner may maintain ION status shall be 24 months. The relevant system operator is entitled to specify a shorter ION validity period. An extension of the ION shall be granted only if the power-generating facility owner has made substantial progress towards full compliance. Outstanding issues shall be clearly identified at the time of requesting extension.

5. An extension of the period during which the power-generating facility owner may maintain ION status, beyond the period established in paragraph 4, may be granted if a request for a derogation is made to the relevant system operator before the expiry of that period in accordance with the derogation procedure laid down in Article 60.

Article 36

Final operational notification for type D power-generating modules

1. A FON shall entitle the power-generating facility owner to operate a power-generating module by using the grid connection.

2. A FON shall be issued by the relevant system operator, upon prior removal of all incompatibilities identified for the purpose of ION status and subject to completion of the data and study review process as required by this Article.

3. For the purposes of the data and study review, the power-generating facility owner must submit the following to the relevant system operator:

(a) an itemised statement of compliance; and

(b) an update of applicable technical data, simulation models and studies as referred to in points (b), (d) and (e) of Article 35(3), including the use of actual measured values during testing.

4. If incompatibility is identified in connection with the issuing of the FON, a derogation may be granted upon a request made to the relevant system operator, in accordance with the derogation procedure described in Title V. A FON shall be issued by the relevant system operator if the power-generating module complies with the provisions of the derogation.

Where a request for a derogation is rejected, the relevant system operator shall have the right to refuse to allow the operation of the power-generating module until the power-generating facility owner and the relevant system operator resolve the incompatibility and the relevant system operator considers that the power-generating module complies with the provisions of this Regulation.

If the relevant system operator and the power-generating facility owner do not resolve the incompatibility within a reasonable time frame, but in any case not later than six months after the notification of the rejection of the request for a derogation, each party may refer the issue for decision to the regulatory authority.

Article 37

Limited operational notification for type D power-generating modules

1. Power-generating facility owners to whom a FON has been granted shall inform the relevant system operator immediately in the following circumstances:

(a) the facility is temporarily subject to either significant modification or loss of capability affecting its performance; or

(b) equipment failure leading to non-compliance with some relevant requirements.

2. The power-generating facility owner shall apply to the relevant system operator for a LON, if the power-generating facility owner reasonably expects the circumstances described in paragraph 1 to persist for more than three months.

3. A LON shall be issued by the relevant system operator and shall contain the following information which shall be clearly identifiable:

(a) the unresolved issues justifying the granting of the LON;

(b) the responsibilities and timescales for the expected solution; and

(c) a maximum period of validity which shall not exceed 12 months. The initial period granted may be shorter with the possibility of an extension if evidence is submitted to the satisfaction of the relevant system operator demonstrating that substantial progress has been made towards achieving full compliance.

4. The FON shall be suspended during the period of validity of the LON with regard to the items for which the LON has been issued.

5. A further extension of the period of validity of the LON may be granted upon a request for a derogation made to the relevant system operator before the expiry of that period, in accordance with the derogation procedure described in Title V.

6. The relevant system operator shall have the right to refuse to allow the operation of the power-generating module, once the LON is no longer valid. In such cases, the FON shall automatically become invalid.

7. If the relevant system operator does not grant an extension of the period of validity of the LON in accordance with paragraph 5 or if it refuses to allow the operation of the power-generating module once the LON is no longer valid in accordance with paragraph 6, the power-generating facility owner may refer the issue for decision to the regulatory authority within six months after the notification of the decision of the relevant system operator.

CHAPTER 2
Cost-benefit analysis

Article 38

Identification of costs and benefits of application of requirements to existing power-generating modules

1. Prior to the application of any requirement set out in this Regulation to existing power-generating modules in accordance with Article 4(3), the relevant TSO shall undertake a qualitative comparison of costs and benefits related to the requirement under consideration. This comparison shall take into account available network-based or market-based alternatives. The relevant TSO may only proceed to undertake a quantitative cost-benefit analysis in accordance with paragraphs 2 to 5, if the qualitative comparison indicates that the likely benefits exceed the likely costs. If, however, the cost is deemed high or the benefit is deemed low, then the relevant TSO shall not proceed further.

2. Following a preparatory stage undertaken in accordance with paragraph 1, the relevant TSO shall carry out a quantitative cost-benefit analysis of any requirement under consideration for application to existing power-generating modules that have demonstrated potential benefits as a result of the preparatory stage according to paragraph 1.

3. Within three months of concluding the cost-benefit analysis, the relevant TSO shall summarise the findings in a report which shall:

(a) include the cost-benefit analysis and a recommendation on how to proceed;

(b) include a proposal for a transitional period for applying the requirement to existing power-generating modules. That transitional period shall not be more than two years from the date of the decision of the regulatory authority or where applicable the **Contracting Party** on the requirement's applicability;

(c) be subject to public consultation in accordance with Article 10.

4. No later than six months after the end of the public consultation, the relevant TSO shall prepare a report explaining the outcome of the consultation and making a proposal on the applicability of the requirement under consideration to existing power-generating modules. The report and proposal shall be notified to the regulatory authority or, where applicable, the **Contracting Party**, and the power-generating facility owner or, where applicable, third party shall be informed on its content.

5. The proposal made by the relevant TSO to the regulatory authority or, where applicable, the **Contracting Party** pursuant to paragraph 4 shall include the following:

(a) an operational notification procedure for demonstrating the implementation of the requirements by the existing power-generating facility owner;

(b) a transitional period for implementing the requirements which shall take into account the category of the power-generating module as specified in Article 5(2) and Article 23(3) and any underlying obstacles to the efficient implementation of the equipment modification/refitting.

Article 39

Principles of cost-benefit analysis

1. Power-generating facility owners and DSOs including CDSOs shall assist and contribute to the cost-benefit analysis undertaken according to Articles 38 and 63 and provide the necessary data as requested by the relevant system operator or relevant TSO within three months of receiving a request, unless agreed otherwise by the relevant TSO. For the preparation of a cost-benefit-analysis by a power-generating facility owner, or prospective owner, assessing a potential derogation pursuant to Article 62, the relevant TSO and DSO, including CDSO, shall assist and contribute to the cost-benefit analysis and provide the necessary data as requested by the power-generating facility owner, or the prospective owner, within three months of receiving a request, unless agreed otherwise by the power-generating facility owner or the prospective owner.

2. A cost-benefit analysis shall be in line with the following principles:

(a) the relevant TSO, relevant system operator, power-generating facility owner or prospective owner shall base its cost-benefit analysis on one or more of the following calculating principles:

(i) the net present value;

(ii) the return on investment;

(iii) the rate of return;

(iv) the time needed to break even;

(b) the relevant TSO, relevant system operator, power-generating facility owner or prospective owner shall also quantify socioeconomic benefits in terms of improvement in security of supply and shall include at least:

(i) the associated reduction in probability of loss of supply over the lifetime of the modification;

(ii) the probable extent and duration of such loss of supply;

(iii) the societal cost per hour of such loss of supply;

(c) the relevant TSO, relevant system operator, power-generating facility owner or prospective owner shall quantify the benefits to the internal market in electricity, cross-border trade and integration of renewable energies, including at least:

(i) the active power frequency response;

(ii) the balancing reserves;

(iii) the reactive power provision;

(iv) congestion management;

(v) defence measures;

(d) the relevant TSO shall quantify the costs of applying the necessary rules to existing power-generating modules, including at least:

(i) the direct costs incurred in implementing a requirement;

(ii) the costs associated with attributable loss of opportunity;

(iii) the costs associated with resulting changes in maintenance and operation.

TITLE IV
COMPLIANCE

CHAPTER 1
Compliance monitoring

Article 40

Responsibility of the power-generating facility owner

1. The power-generating facility owner shall ensure that each power-generating module complies with the requirements applicable under this Regulation throughout the lifetime of the facility. For type A power-generating modules, the power-generating facility owner may rely upon equipment certificates **<...>**

2. The power-generating facility owner shall notify to the relevant system operator any planned modification of the technical capabilities of a power-generating module which may affect its compliance with the requirements applicable under this Regulation, before initiating that modification.

3. The power-generating facility owner shall notify the relevant system operator of any operational incidents or failures of a power-generating module that affect its compliance with the requirements of this Regulation, without undue delay, after the occurrence of those incidents.

4. The power-generating facility owner shall notify the relevant system operator of the planned test schedules and procedures to be followed for verifying the compliance of a power-generating module with the requirements of this Regulation, in due time and prior to their launch. The relevant system operator shall approve in advance the planned test schedules and procedures. Such approval by the relevant system operator shall be provided in a timely manner and shall not be unreasonably withheld.

5. The relevant system operator may participate in such tests and record the performance of the power-generating modules.

Article 41

Tasks of the relevant system operator

1. The relevant system operator shall assess the compliance of a power-generating module with the requirements applicable under this Regulation, throughout the lifetime of the power-generating facility. The power-generating facility owner shall be informed of the outcome of this assessment.

For type A power-generating modules, the relevant system operator may rely upon equipment certificates issued by an authorised certifier for this assessment.

2. The relevant system operator shall have the right to request that the power-generating facility owner carry out compliance tests and simulations according to a repeat plan or general scheme or after any failure, modification or replacement of any equipment that may have an impact on the power-generating module's compliance with the requirements of this Regulation.

The power-generating facility owner shall be informed of the outcome of those compliance tests and

simulations.

3. The relevant system operator shall make publicly available a list of information and documents to be provided as well as the requirements to be fulfilled by the power-generating facility owner within the framework of the compliance process. The list shall cover at least the following information, documents and requirements:

(a) all the documentation and certificates to be provided by the power-generating facility owner;

(b) details of the technical data on the power-generating module of relevance to the grid connection;

(c) requirements for models for steady-state and dynamic system studies;

(d) timeline for the provision of system data required to perform the studies;

(e) studies by the power-generating facility owner to demonstrate the expected steady-state and dynamic performance in accordance with the requirements set out in Chapters 5 and 6 of Title IV;

(f) conditions and procedures, including the scope, for registering equipment certificates; and

(g) conditions and procedures for the use of relevant equipment certificates issued by an authorised certifier by the power-generating facility owner.

4. The relevant system operator shall make public the allocation of responsibilities between the power-generating facility owner and the system operator for compliance testing, simulation and monitoring.

5. The relevant system operator may totally or partially delegate the performance of its compliance monitoring to third parties. In such cases, the relevant system operator shall continue ensuring compliance with Article 12, including entering into confidentiality commitments with the assignee.

6. If compliance tests or simulations cannot be carried out as agreed between the relevant system operator and the power-generating facility owner due to reasons attributable to the relevant system operator, then the relevant system operator shall not unreasonably withhold the operational notification referred to in Title III.

Article 42

Common provisions for compliance testing

1. Testing of the performance of individual power-generating modules within a power-generating facility shall aim at demonstrating that the requirements of this Regulation have been complied with.

2. Notwithstanding the minimum requirements for compliance testing set out in this Regulation, the relevant system operator is entitled to:

(a) allow the power-generating facility owner to carry out an alternative set of tests, provided that those tests are efficient and suffice to demonstrate that a power-generating module complies with the requirements of this Regulation;

(b) require the power-generating facility owner to carry out additional or alternative sets of tests in those cases where the information supplied to the relevant system operator in relation to compliance testing under the provisions of Chapter 2, 3 or 4 of Title IV, is not sufficient to demonstrate compliance with the requirements of this Regulation; and

(c) require the power-generating facility owner to carry out appropriate tests in order to demonstrate a

power-generating module's performance when operating on alternative fuels or fuel mixes. The relevant system operator and the power-generating facility owner shall agree on which types of fuel are to be tested.

3. The power-generating facility owner is responsible for carrying out the tests in accordance with the conditions laid down in Chapters 2, 3 and 4 of Title IV. The relevant system operator shall cooperate and not unduly delay the performance of the tests.

4. The relevant system operator may participate in the compliance testing either on site or remotely from the system operator's control centre. For that purpose, the power-generating facility owner shall provide the monitoring equipment necessary to record all relevant test signals and measurements as well as ensure that the necessary representatives of the power-generating facility owner are available on site for the entire testing period. Signals specified by the relevant system operator shall be provided if, for selected tests, the system operator wishes to use its own equipment to record performance. The relevant system operator has sole discretion to decide about its participation.

Article 43

Common provisions on compliance simulation

1. Simulation of the performance of individual power-generating modules within a power-generating facility shall aim at demonstrating that the requirements of this Regulation have been fulfilled.

2. Notwithstanding the minimum requirements set out in this Regulation for compliance simulation, the relevant system operator may:

(a) allow the power-generating facility owner to carry out an alternative set of simulations, provided that those simulations are efficient and suffice to demonstrate that a power-generating module complies with the requirements of this Regulation or with national legislation; and

(b) require the power-generating facility owner to carry out additional or alternative sets of simulations in those cases where the information supplied to the relevant system operator in relation to compliance simulation under the provisions of Chapter 5, 6 or 7 of Title IV, is not sufficient to demonstrate compliance with the requirements of this Regulation.

3. To demonstrate compliance with the requirements of this Regulation, the power-generating facility owner shall provide a report with the simulation results for each individual power-generating module within the power-generating facility. The power-generating facility owner shall produce and provide a validated simulation model for a given power-generating module. The scope of the simulation models is set out in point (c) of Article 15(6).

4. The relevant system operator shall have the right to check that a power-generating module complies with the requirements of this Regulation by carrying out its own compliance simulations based on the provided simulation reports, simulation models and compliance test measurements.

5. The relevant system operator shall provide the power-generating facility owner with technical data and a simulation model of the network, to the extent necessary to carry out the requested simulations in accordance with Chapter 5, 6 or 7 of Title IV.

CHAPTER 2
Compliance testing for synchronous power-generating modules

Article 44
Compliance tests for type B synchronous power-generating modules

1. Power-generating facility owners shall undertake LFSM-O response compliance tests in relation to type B synchronous power-generating modules.

Instead of carrying out the relevant test, power-generating facility owners may rely upon equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In such a case, the equipment certificates shall be provided to the relevant system operator.

2. The following requirements with regard to the LFSM-O response test shall apply:

(a) the power-generating module's technical capability to continuously modulate active power to contribute to frequency control in case of any large increase of frequency in the system shall be demonstrated. The steady-state parameters of regulations, such as droop and deadband, and dynamic parameters, including frequency step change response shall be verified;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to trigger at least 10% of maximum capacity change in active power, taking into account the droop settings and the deadband. If required, simulated frequency deviation signals shall be injected simultaneously at both the speed governor and load controller of the control systems, taking into account the scheme of those control systems;

(c) the test shall be deemed successful if the following conditions are fulfilled:

(i) the test results, for both dynamic and static parameters, meet the requirements set out in Article 13(2); and

(ii) undamped oscillations do not occur after the step change response.

Article 45
Compliance tests for type C synchronous power-generating modules

1. In addition to the compliance tests for type B synchronous power-generating modules described in Article 44, power-generating facility owners shall undertake the compliance tests set out in paragraphs 2, 3, 4 and 6 of this Article in relation to type C synchronous power-generating modules. Where a power-generating module provides black start capability, power-generating facility owners shall also undertake the tests referred to in paragraph 5. Instead of the relevant test, the power-generating facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In that case, the equipment certificates shall be provided to the relevant system operator.

2. The following requirements with regard to the LFSM-U response test shall apply:

(a) it shall demonstrate that the power-generating module is technically capable of continuously modulating active power at operating points below maximum capacity to contribute to frequency control in case of a large frequency drop in the system;

(b) the test shall be carried out by simulating appropriate active power load points, with low frequency steps and ramps big enough to trigger active power change of at least 10 % of maximum capacity, taking into account the droop settings and the deadband. If required, simulated frequency deviation signals shall be injected simultaneously into both the speed governor and the load controller references;

(c) the test shall be deemed successful if the following conditions are fulfilled:

(i) the test results, for both dynamic and static parameters, comply with point (c) of Article 15(2); and

(ii) undamped oscillations do not occur after the step change response.

3. The following requirements with regard to the FSM response test shall apply:

(a) it shall demonstrate that the power-generating module is technically capable of continuously modulating active power over the full operating range between maximum capacity and minimum regulating level to contribute to frequency control. The steady-state parameters of regulations, such as droop and deadband and dynamic parameters, including robustness through frequency step change response and large, fast frequency deviations shall be verified;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the settings of droop and deadband, as well as the capability to actually increase or decrease active power output from the respective operating point. If required, simulated frequency deviation signals shall be injected simultaneously into the references of both the speed governor and the load controller of the unit or plant control system;

(c) the test shall be deemed successful if the following conditions are fulfilled:

(i) the activation time of full active power frequency response range as a result of a frequency step change is no longer than required by point (d) of Article 15(2);

(ii) undamped oscillations do not occur after the step change response;

(iii) the initial delay time complies with point (d) of Article 15(2);

(iv) the droop settings are available within the range specified in point (d) of Article 15(2) and the deadband (threshold) is not higher than the value specified in that Article; and

(v) the insensitivity of active power frequency response at any relevant operating point does not exceed the requirements set out in point (d) of Article 15(2).

4. With regard to the frequency restoration control test the following requirements shall apply:

(a) the power-generating module's technical capability to participate in frequency restoration control shall be demonstrated and the cooperation of FSM and frequency restoration control shall be checked;

(b) the test shall be deemed successful if the results, for both dynamic and static parameters, comply with the requirements of point (e) of Article 15(2).

5. With regard to the black start capability test the following requirements shall apply:

(a) for power-generating modules with black start capability, this technical capability to start from shut down without any external electrical energy supply shall be demonstrated;

(b) the test shall be deemed successful if the start-up time is kept within the time frame set out in point (iii) of Article 15(5)(a).

6. With regard to the tripping to houseload test the following requirements shall apply:

(a) the power-generating modules' technical capability to trip to and stably operate on house load shall

be demonstrated;

(b) the test shall be carried out at the maximum capacity and nominal reactive power of the power-generating module before load shedding;

(c) the relevant system operator shall have the right to set additional conditions, taking into account point (c) of Article 15(5);

(d) the test shall be deemed successful if tripping to house load is successful, stable houseload operation has been demonstrated in the time period set out in point (c) of Article 15(5) and re-synchronisation to the network has been performed successfully.

7. With regard to the reactive power capability test the following requirements shall apply:

(a) the power-generating module's technical capability to provide leading and lagging reactive power capability in accordance with points (b) and (c) of Article 18(2) shall be demonstrated;

(b) the test shall be deemed successful if the following conditions are fulfilled:

(i) the power-generating module operates at maximum reactive power for at least one hour, both leading and lagging, at:

- minimum stable operating level,
- maximum capacity, and
- an active power operating point between those maximum and minimum levels;

(ii) the power-generating module's capability to change to any reactive power target value within the agreed or decided reactive power range shall be demonstrated.

Article 46

Compliance tests for type D synchronous power-generating modules

1. Type D synchronous power-generating modules are subject to the compliance tests for type B and C synchronous power-generating modules described in Articles 44 and 45.

2. Instead of the relevant test, the power-generating facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In such a case, the equipment certificates shall be provided to the relevant system operator.

CHAPTER 3
Compliance testing for power park modules

Article 47

Compliance tests for type B power park modules

1. Power-generating facility owners shall undertake LFSM-O response compliance tests in relation to type B power park modules.

Instead of the relevant test, the power-generating facility owner may use equipment certificates issued by an

authorised certifier to demonstrate compliance with the relevant requirement. In that case, the equipment certificates shall be provided to the relevant system operator.

2. With regard to type B power park modules, the LFSM-O response tests shall reflect the choice of control scheme selected by the relevant system operator.

3. With regard to the LFSM-O response tests the following requirements shall apply:

(a) the power park module's technical capability to continuously modulate active power to contribute to frequency control in case of increase of frequency in the system shall be demonstrated. The steady-state parameters of regulations, such as droop and deadband, and dynamic parameters shall be verified;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to trigger at least 10% of maximum capacity change in active power, taking into account the droop settings and the deadband. To perform this test simulated frequency deviation signals shall be injected simultaneously into the control system references;

(c) the test shall be deemed successful in the event that the test results, for both dynamic and static parameters, comply with the requirements set out in Article 13(2).

Article 48

Compliance tests for type C power park modules

1. In addition to the compliance tests for type B power park modules described in Article 47, power-generating facility owners shall undertake the compliance tests set out in paragraphs 2 to 9 in relation to type C power park modules. Instead of the relevant test, the power-generating facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In such a case, the equipment certificate shall be provided to the relevant system operator.

2. With regard to the active power controllability and control range test the following requirements shall apply:

(a) the power park module's technical capability to operate at a load level below the setpoint set by the relevant system operator or the relevant TSO shall be demonstrated;

(b) the test shall be deemed successful if the following conditions are fulfilled:

(i) the load level of the power park module is kept below the setpoint;

(ii) the setpoint is implemented according to the requirements laid down in Article 15(2)(a); and

(iii) the accuracy of the regulation complies with the value specified in point (a) of Article 15(2).

3. With regard to the LFSM-U response test the following requirements shall apply:

(a) the power park module's technical capability to continuously modulate active power to contribute to frequency control in case of a large frequency drop in the system shall be demonstrated;

(b) the test shall be carried out by simulating the frequency steps and ramps big enough to trigger at least 10% of maximum capacity active power change with a starting point of no more than 80% of maximum capacity, taking into account the droop settings and the deadband;

(c) the test shall be deemed successful if the following conditions are fulfilled:

(i) the test results, for both dynamic and static parameters, comply with the requirements laid down in Article 15(2)(c); and

(ii) undamped oscillations do not occur after the step change response.

4. With regard to the FSM response test the following requirements shall apply:

(a) the power park module's technical capability to continuously modulate active power over the full operating range between maximum capacity and minimum regulating level to contribute to frequency control shall be demonstrated. The steady-state parameters of regulations, such as insensitivity, droop, deadband and range of regulation, as well as dynamic parameters, including frequency step change response shall be verified;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the droop settings and the deadband. Simulated frequency deviation signals shall be injected to perform the test;

(c) the test shall be deemed successful if the following conditions are fulfilled:

(i) the activation time of the full active power frequency response range as a result of a frequency step change is no longer than that required by point (d) of Article 15(2);

(ii) undamped oscillations do not occur after the step change response;

(iii) the initial delay is in line with point (d) of Article 15(2);

(iv) the droop settings are available within the ranges specified in point (d) of Article 15(2) and the deadband (threshold) is not higher than the value chosen by the relevant TSO; and

(v) the insensitivity of active power frequency response does not exceed the requirement set out in point (d) of Article 15(2).

5. With regard to the frequency restoration control test the following requirements shall apply:

(a) the power park module's technical capability to participate in frequency restoration control shall be demonstrated. The cooperation of both FSM and frequency restoration control shall be checked;

(b) the test shall be deemed successful if the results for both dynamic and static parameters comply with the requirements of point (e) of Article 15(2).

6. With regard to the reactive power capability test the following requirements shall apply:

(a) the power park module's technical capability to provide leading and lagging reactive power capability in accordance with points (b) and (c) of Article 21(3) shall be demonstrated;

(b) it shall be carried out at maximum reactive power, both leading and lagging, and shall verify the following parameters:

(i) operation in excess of 60% of maximum capacity for 30 min;

(ii) operation within the range of 30-50% of maximum capacity for 30 min; and

(iii) operation within the range of 10-20% of maximum capacity for 60 min;

(c) the test shall be deemed successful if the following criteria are fulfilled:

(i) the power park module operates for a duration no shorter than the requested duration at maximum reactive power, both leading and lagging, in each parameter specified in paragraph 6(b);

(ii) the power park module's capability to change to any reactive power target value within the agreed or decided reactive power range is demonstrated; and

(iii) no protection action takes place within the operation limits specified by the reactive power capacity diagram.

7. With regard to the voltage control mode test the following requirements shall apply:

(a) the power park module's capability to operate in voltage control mode referred to in the conditions set out in points (ii) to (iv) of Article 21(3)(d) shall be demonstrated;

(b) The voltage control mode test shall verify the following parameters:

(i) the implemented slope and deadband according to Article 21(3)(d)(iii);

(ii) the accuracy of the regulation;

(iii) the insensitivity of the regulation; and

(iv) the time of reactive power activation;

(c) The test shall be deemed successful if the following conditions are fulfilled:

(i) the range of regulation and adjustable droop and deadband complies with the agreed or decided characteristic parameters set out in point (d) of Article 21(3);

(ii) the insensitivity of voltage control is not higher than 0,01 pu, in accordance with point (d) of Article 21(3); and

(iii) following a step change in voltage, 90% of the change in reactive power output has been achieved within the times and tolerances specified in point (d) of Article 21(3).

8. With regard to the reactive power control mode test the following requirements shall apply:

(a) the power park module's capability to operate in reactive power control mode, in accordance with point (v) of Article 21(3)(d), shall be demonstrated;

(b) the reactive power control mode test shall be complementary to the reactive power capability test;

(c) the reactive power control mode test shall verify the following parameters:

(i) the reactive power setpoint range and increment;

(ii) the accuracy of the regulation; and

(iii) the time of reactive power activation.

(d) the test shall be deemed successful if the following conditions are fulfilled:

(i) the reactive power setpoint range and increment are ensured in accordance with point (d) of Article 21(3); and

(ii) the accuracy of the regulation complies with the conditions set out in point (d) of Article 21(3).

9. With regard to the power factor control mode test the following requirements shall apply:

(a) the power park module's capability to operate in power factor control mode in accordance with point (vi) of Article 21(3)(d) shall be demonstrated;

(b) the power factor control mode test shall verify the following parameters:

(i) the power factor setpoint range;

(ii) the accuracy of the regulation; and

(iii) the response of reactive power due to step change of active power;

(c) the test shall be deemed successful if the following conditions are cumulatively fulfilled:

(i) the power factor setpoint range and increment are ensured in accordance with point (d) of Article 21(3);

(ii) the time of reactive power activation as a result of step active power change does not exceed the requirement laid down in point (d) of Article 21(3); and

(iii) the accuracy of the regulation complies with the value specified in point (d) of Article 21(3).

10. With regard to the tests referred to in paragraphs 7, 8 and 9, the relevant system operator may select only one of the three control options for testing.

Article 49

Compliance tests for type D power park modules

1. Type D power park modules are subject to the compliance tests for type B and C power park modules in accordance with the conditions set out in Articles 47 and 48.

2. Instead of the relevant test, the power-generating facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In that case, the equipment certificates shall be provided to the relevant system operator.

CHAPTER 4
Compliance testing for offshore power park modules

Article 50

Compliance tests for offshore power park modules

The compliance tests established in Article 44(2), as well as in paragraphs 2, 3, 4, 5, 7, 8 and 9 of Article 48 shall apply to offshore power park modules.

CHAPTER 5
Compliance simulations for synchronous power-generating modules

Article 51

Compliance simulations for type B synchronous power-generating modules

1. Power-generating facility owners shall undertake LFSM-O response simulations in relation to type B synchronous power-generating modules. Instead of the relevant simulations, the power-generating facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In that case, the equipment certificates shall be provided to the relevant system operator.

2. With regard to the LFSM-O response simulation the following requirements shall apply:

(a) the power-generating module's capability to modulate active power at high frequency in accordance with Article 13(2) shall be demonstrated by simulation;

(b) the simulation shall be carried out by means of high frequency steps and ramps reaching minimum regulating level, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power-generating module is validated against the compliance test for LFSM-O response described in Article 44(2); and

(ii) compliance with the requirement set out in Article 13(2) is demonstrated.

3. With regard to the simulation of fault-ride-through capability of type B synchronous power-generating modules, the following requirements shall apply:

(a) the power-generating module's capability to ride through faults in accordance with the conditions set out in subparagraph (a) of Article 14(3) shall be demonstrated by simulation;

(b) the simulation shall be deemed successful if compliance with the requirement set out in point (a) of Article 14(3) is demonstrated.

4. With regard to the post fault active power recovery simulation the following requirements shall apply:

(a) the power-generating module's capability to provide post fault active power recovery referred to in the conditions set out in Article 17(3) shall be demonstrated;

(b) the simulation shall be deemed successful if compliance with the requirement set out in Article 17(3) is demonstrated.

Article 52

Compliance simulations for type C synchronous power-generating modules

1. In addition to the compliance simulations for type B synchronous power-generating modules set out in Article 51, type C synchronous power-generating modules shall be subject to the compliance simulations detailed in paragraphs 2 to 5. Instead of all or part of those simulations, the power-generating facility owner may use equipment certificates issued by an authorised certifier, which must be provided to the relevant system operator.

2. With regard to the LFSM-U response simulation the following requirements shall apply:

(a) the power-generating module's capability to modulate active power at low frequencies in accordance with point (c) of Article 15(2) shall be demonstrated;

(b) the simulation shall be carried out by means of low frequency steps and ramps reaching maximum capacity, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power-generating module is validated against the compliance test for LFSM-U response described in of Article 45(2); and

(ii) compliance with the requirement of point (c) of Article 15(2) is demonstrated.

3. With regard to the FSM response simulation the following requirements shall apply:

(a) the power-generating module's capability to modulate active power over the full frequency range in accordance with point (d) of Article 15(2) shall be demonstrated;

(b) the simulation shall be carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power-generating module is validated against the compliance test for FSM response described in Article 45(3); and

(ii) compliance with the requirement of point (d) of Article 15(2) is demonstrated.

4. With regard to the island operation simulation the following requirements shall apply:

(a) the power-generating module's performance during island operation referred to in the conditions set out in point (b) of Article 15(5) shall be demonstrated;

(b) the simulation shall be deemed successful if the power-generating module reduces or increases the active power output from its previous operating point to any new operating point within the P-Q-capability diagram within the limits of point (b) of Article 15(5), without disconnection of the power-generating module from the island due to over- or underfrequency.

5. With regard to the reactive power capability simulation the following requirements shall apply:

(a) the power-generating module's capability to provide leading and lagging reactive power capability in accordance with the conditions set out in points (b) and (c) of Article 18(2) shall be demonstrated;

(b) the simulation shall be deemed successful if the following conditions are fulfilled:

(i) the simulation model of the power-generating module is validated against the compliance tests for reactive power capability described in Article 45(7); and

(ii) compliance with the requirements of points (b) and (c) of Article 18(2) is demonstrated.

Article 53

Compliance simulations for type D synchronous power-generating modules

1. In addition to the compliance simulations for type B and C synchronous power-generating modules set out in Articles 51 and 52, except for the simulation of fault-ride-through capability of type B synchronous power-generating modules referred to in Article 51(3), type D synchronous power-generating modules are subject to the compliance simulations set out in paragraphs 2 and 3. Instead of all or part of those simulations, the power-generating facility owner may use equipment certificates issued by an authorised certifier, which must be provided to the relevant system operator.

2. With regard to the power oscillations damping control simulation the following requirements shall apply:

(a) it shall be demonstrated that the power-generating module's performance in terms of its control system ('PSS function') is capable of damping active power oscillations in accordance with the conditions set out in paragraph 2 of Article 19;

(b) the tuning must result in improved damping of corresponding active power response of the AVR in combination with the PSS function, compared to the active power response of the AVR alone;

(c) the simulation shall be deemed successful if the following conditions are cumulatively fulfilled:

(i) the PSS function damps the existing active power oscillations of the power-generating module within a frequency range specified by the relevant TSO. That frequency range shall include the local mode

frequencies of the power-generating module and the expected network oscillations; and

(ii) a sudden load reduction of the power-generating module from 1 pu to 0,6 pu of the maximum capacity does not lead to undamped oscillations in active or reactive power of the power-generating module.

3. With regard to the simulation of fault-ride-through capability of type D synchronous power-generating modules, the following requirements shall apply:

(a) the power-generating module's capability to provide fault-ride-through in accordance with the conditions set out in point (a) of Article 16(3) shall be demonstrated;

(b) the simulation shall be deemed successful if compliance with the requirement laid down in point (a) of Article 16(3) is demonstrated.

CHAPTER 6
Compliance simulations for power park modules

Article 54
Compliance simulations for type B power park modules

1. Type B power park modules are subject to the compliance simulations in paragraphs 2 to 5. Instead of all or part of those simulations, the power-generating facility owner may use equipment certificates issued by an authorised certifier, which must be provided to the relevant system operator.

2. With regard to the LFSM-O response simulation the following requirements shall apply:

(a) the power park module's capability to modulate active power at high frequency in accordance with Article 13(2) shall be demonstrated;

(b) the simulation shall be carried out by means of high frequency steps and ramps reaching minimum regulating level, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power park module is validated against the compliance test for LFSM-O response set out in Article 47(3); and

(ii) compliance with the requirement laid down in Article 13(2) is demonstrated.

3. With regard to the fast fault current injection simulation the following requirements shall apply:

(a) the power park module's capability to provide fast fault current injection in accordance with the conditions set out in point (b) of Article 20(2) shall be demonstrated;

(b) the simulation shall be deemed successful if compliance with the requirement laid down in point (b) of Article 20(2) is demonstrated.

4. With regard to the fault-ride-through simulation capability of type B power park modules, the following requirements shall apply:

(a) the power park module's capability to ride through faults in accordance with the conditions set out in point (a) of Article 14(3) shall be demonstrated by simulation;

(b) the simulation shall be deemed successful if compliance with the requirement laid down in point (a) of Article 14(3) is demonstrated.

5. The following requirements with regard to the post fault active power recovery simulation shall apply:

(a) the power park module's capability to provide post fault active power recovery in accordance with the conditions set out in Article 20(3) shall be demonstrated;

(b) the simulation shall be deemed successful if compliance with the requirement laid down in Article 20(3) is demonstrated.

Article 55

Compliance simulations for type C power park modules

1. In addition to the compliance simulations for type B power park modules set out in Article 54, type C power park modules are subject to the compliance simulations set out in paragraphs 2 to 7. Instead of all or part of those simulations, the power-generating facility owner may use equipment certificates issued by an authorised certifier, which must be provided to the relevant system operator.

2. With regard to the LFSM-U response simulation the following requirements shall apply:

(a) the power park module's capability to modulate active power at low frequencies in accordance with point (c) of Article 15(2) shall be demonstrated;

(b) the simulation shall be carried out by simulating low frequency steps and ramps reaching maximum capacity, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power park module is validated against the compliance test for LFSM-U response set out in Article 48(3); and

(ii) compliance with the requirement laid down in point (c) of Article 15(2) is demonstrated.

3. With regard to the FSM response simulation the following requirements shall apply:

(a) the power park module's capability to modulate active power over the full frequency range as referred to in point (d) of Article 15(2) shall be demonstrated;

(b) the simulation shall be carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the droop settings and the deadband;

(c) the simulation shall be deemed successful in the event that:

(i) the simulation model of the power park module is validated against the compliance test for FSM response set out in Article 48(4); and

(ii) compliance with the requirement laid down in point (d) of Article 15(2) is demonstrated.

4. With regard to the island operation simulation, the following requirements shall apply:

(a) the power park module's performance during island operation in accordance with the conditions set out in point (b) of Article 15(5) shall be demonstrated;

(b) the simulation shall be deemed successful in the event that the power park module reduces or increases the active power output from its previous operating point to any new operating point, within the P-Q-ca-

pability diagram and within the limits set out in point (b) of Article 15(5), without disconnection of the power park module from the island due to over- or underfrequency.

5. With regard to the simulation of the capability of providing synthetic inertia, the following requirements shall apply:

(a) the model of the power park module's capability of providing synthetic inertia to a low frequency event as set out in point (a) of Article 21(2) shall be demonstrated;

(b) the simulation shall be deemed successful if the model demonstrates that it complies with the conditions set out in Article 21(2).

6. With regard to the reactive power capability simulation, the following requirements shall apply:

(a) the power park module shall demonstrate that it can provide leading and lagging reactive power capability as set out in points (b) and (c) of Article 21(3);

(b) the simulation shall be deemed successful if the following conditions are cumulatively fulfilled:

(i) the simulation model of the power park module is validated against the compliance tests for reactive power capability set out in paragraph 6 of Article 48; and

(ii) compliance with the requirements laid down in points (b) and (c) of Article 21(3) is demonstrated.

7. With regard to the power oscillations damping control simulation, the following requirements shall apply:

(a) the model of the power park module shall demonstrate that it can provide active power oscillations damping capability accordance with point (f) of Article 21(3);

(b) the simulation shall be deemed successful in the event that the model demonstrates compliance with the conditions described in point (f) of Article 21(3).

Article 56

Compliance simulations for type D power park modules

1. In addition to the compliance simulations for type B and C power park modules set out in Articles 54 and 55, except for the fault-ride-through capability of type B power park modules referred to in Article 54(4), type D power park modules are subject to the fault-ride-through capability of power park modules compliance simulation.

2. Instead of all or part of the simulations mentioned in paragraph 1, the power-generating facility owner may use equipment certificates issued by an authorised certifier, which must be provided to the relevant system operator.

3. The model of the power park module shall demonstrate that it is suitable for simulating the fault-ride-through capability in accordance with point (a) of Article 16(3).

4. The simulation shall be deemed successful if the model demonstrates compliance with the conditions set out in point (a) of Article 16(3).

CHAPTER 7
Compliance simulations for offshore power park modules

Article 57
Compliance simulations applicable to offshore power park modules

The compliance simulations specified in paragraphs 3 and 5 of Article 54 as well as in paragraphs 4, 5 and 7 of Article 55 shall apply to any offshore power park module.

CHAPTER 8
Non-binding guidance and monitoring of implementation

Article 58
Non-binding guidance on implementation

1. **<...>**

2. **<...>**

3. The non-binding guidance **published by ENTSO for Electricity** explains the technical issues, conditions and interdependencies which need to be considered when complying with the requirements of this Regulation at national level.

Article 59
Monitoring

1. ENTSO for Electricity shall monitor the implementation of this Regulation **<...> for the Contracting Parties whose TSOs are members of ENTSO for Electricity. The Secretariat and the Energy Community Regulatory Board shall monitor the implementation of this Regulation for the Contracting Parties whose TSOs are not members of ENTSO for Electricity'**. Monitoring **shall take into account the list of relevant information developed by the Agency for the Cooperation of Energy Regulators and it** shall cover in particular the following matters:

(a) identification of any divergences in the national implementation of this Regulation;

(b) assessment of whether the choice of values and ranges in the requirements applicable to power-generating modules under this Regulation continues to be valid.

ENTSO for Electricity shall report its findings to the Secretariat and the Energy Community Regulatory Board. The Secretariat and the Energy Community Regulatory Board shall make available the findings stemming from the monitoring of the implementation of this Regulation.

2. **<...>**

3. Relevant TSOs shall submit to the **Secretariat, the Energy Community Regulatory Board and** ENTSO for Electricity the information required to perform the tasks referred to in paragraph **1**.

Based on a request of the regulatory authority, DSOs shall provide TSOs with information under paragraph **1** unless the information is already obtained by regulatory authorities, **the Secretariat, Energy Community Regulatory Board** or ENTSO-E in relation to their respective implementation monitoring tasks, with the objective of avoiding duplication of information.

4. **<...>**

TITLE V
DEROGATIONS

Article 60

Power to grant derogations

1. Regulatory authorities may, at the request of a power-generating facility owner or prospective owner, relevant system operator or relevant TSO, grant power-generating facility owners or prospective owners, relevant system operators or relevant TSOs derogations from one or more provisions of this Regulation for new and existing power-generating modules in accordance with Articles 61 to 63.

2. Where applicable in a **Contracting Party**, derogations may be granted and revoked in accordance with Articles 61 to 63 by other authorities than the regulatory authority.

Article 61

General provisions

1. Each regulatory authority shall specify, after consulting relevant system operators and power-generating facility owners and other stakeholders whom it deems affected by this Regulation, the criteria for granting derogations pursuant to Articles 62 and 63. It shall publish those criteria on its website and notify them to the **Secretariat** within nine months of the **expiry of the deadline for transposition** of this Regulation. The **Secretariat** may require a regulatory authority to amend the criteria if it considers that they are not in line with this Regulation. This possibility to review and amend the criteria for granting derogations shall not affect the derogations already granted which shall continue to apply until the scheduled expiry date as detailed in the decision granting the exemption.

2. If the regulatory authority deems that it is necessary due to a change in circumstances relating to the evolution of system requirements, it may review and amend at most once every year the criteria for granting derogations in accordance with paragraph 1. Any changes to the criteria shall not apply to derogations for which a request has already been made.

3. The regulatory authority may decide that power-generating modules for which a request for a derogation has been filed pursuant to Articles 62 or 63 do not need to comply with the requirements of this Regulation from which a derogation has been sought from the day of filing the request until the regulatory authority's decision is issued.

Article 62

Request for a derogation by a power-generating facility owner

1. Power-generating facility owners, or prospective owners, may request a derogation to one or several requirements of this Regulation for power-generating modules within their facilities.

2. A request for a derogation shall be filed with the relevant system operator and include:

(a) an identification of the power-generating facility owner, or prospective owner, and a contact person for any communications;

(b) a description of the power-generating module or modules for which a derogation is requested;

(c) a reference to the provisions of this Regulation from which a derogation is requested and a detailed description of the requested derogation;

(d) detailed reasoning, with relevant supporting documents and cost-benefit analysis pursuant to the requirements of Article 39;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade.

3. Within two weeks of receipt of a request for a derogation, the relevant system operator shall confirm to the power-generating facility owner, or prospective owner, whether the request is complete. If the relevant system operator considers that the request is incomplete, the power-generating facility owner, or prospective owner, shall submit the additional required information within one month from the receipt of the request for additional information. If the power-generating facility owner, or prospective owner, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn.

4. The relevant system operator shall, in coordination with the relevant TSO and any affected adjacent DSO or DSOs, assess the request for a derogation and the provided cost-benefit analysis, taking into account the criteria determined by the regulatory authority pursuant to Article 61.

5. If a request for a derogation concerns a type C or D power-generating module connected to a distribution system, including a closed distribution system, the relevant system operator's assessment must be accompanied by an assessment of the request for a derogation by the relevant TSO. The relevant TSO shall provide its assessment within two months of being requested to do so by the relevant system operator.

6. Within six months of receipt of a request for a derogation, the relevant system operator shall forward the request to the regulatory authority and submit the assessment(s) prepared in accordance with paragraphs 4 and 5. That period may be extended by one month where the relevant system operator seeks further information from the power-generating facility owner, or prospective owner and by two months where the relevant system operator requests the relevant TSO to submit an assessment of the request for a derogation.

7. The regulatory authority shall adopt a decision concerning any request for a derogation within six months from the day after it receives the request. That time limit may be extended by three months before its expiry where the regulatory authority requires further information from the power-generating facility owner, or prospective owner, or from any other interested parties. The additional period shall begin when the complete information has been received.

8. The power-generating facility owner, or prospective owner, shall submit any additional information requested by the regulatory authority within two months of such request. If the power-generating facility

owner, or prospective owner, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn unless, before its expiry:

(a) the regulatory authority decides to provide an extension; or

(b) the power-generating facility owner, or prospective owner, informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

9. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants a derogation, it shall specify its duration.

10. The regulatory authority shall notify its decision to the relevant power-generating facility owner, or prospective owner, the relevant system operator and the relevant TSO.

11. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 65(2).

12. For Type A power-generating modules, a request for a derogation under this Article may be made by a third party on behalf of the power-generating facility owner, or prospective owner. Such a request may be for a single power-generating module or multiple, identical power-generating modules. In the case of the latter, and provided the cumulative maximum capacity is specified, the third party may substitute the details required by point (a) of paragraph 2 with their details.

Article 63

Request for a derogation by a relevant system operator or relevant TSO

1. Relevant system operators or relevant TSOs may request derogations for classes of power-generating modules connected or to be connected to their network.

2. Relevant system operators or relevant TSOs shall submit their requests for derogations to the regulatory authority. Each request for a derogation shall include:

(a) identification of the relevant system operator or relevant TSO, and a contact person for any communications;

(b) a description of the power-generating modules for which a derogation is requested and the total installed capacity and number of power-generating modules;

(c) the requirement or requirements of this Regulation for which a derogation is requested, with a detailed description of the requested derogation;

(d) detailed reasoning, with all relevant supporting documents;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade;

(f) a cost-benefit analysis pursuant to the requirements of Article 39. If applicable, the cost-benefit analysis shall be carried out in coordination with the relevant TSO and any adjacent DSO or DSOs.

3. Where the request for a derogation is submitted by a relevant DSO or CDSO, the regulatory authority shall, within two weeks from the day after receipt of that request, ask the relevant TSO to assess the request for a derogation in the light of the criteria determined by the regulatory authority pursuant to Article 61.

4. Within two weeks from the day after the receipt of such request for assessment, the relevant TSO shall

confirm to the relevant DSO or CDSO whether the request for a derogation is complete. If the relevant TSO considers that it is incomplete, the relevant DSO or CDSO shall submit the required additional information within one month from the receipt of the request for additional information.

5. Within six months of receipt of a request for a derogation, the relevant TSO shall submit to the regulatory authority its assessment, including any relevant documentation. The six-month time limit may be extended by one month where the relevant TSO seeks further information from the relevant DSO or from the relevant CDSO.

6. The regulatory authority shall adopt a decision concerning a request for a derogation within six months from the day after it receives the request. Where the request for a derogation is submitted by the relevant DSO or CDSO, the six-month time limit runs from the day following receipt of the relevant TSO's assessment pursuant to paragraph 5.

7. The six-month time limit referred to in paragraph 6 may, before its expiry, be extended by an additional three months where the regulatory authority requests further information from the relevant system operator requesting the derogation or from any other interested parties. That additional period shall run from the day following the date of receipt of the complete information.

The relevant system operator shall provide any additional information requested by the regulatory authority within two months from the date of the request. If the relevant system operator does not provide the requested additional information within that time limit, the request for a derogation shall be deemed withdrawn unless, before expiry of the time limit:

(a) the regulatory authority decides to provide an extension; or

(b) the relevant system operator informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

8. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants derogation, it shall specify its duration.

9. The regulatory authority shall notify its decision to the relevant system operator requesting the derogation, the relevant TSO, **the Energy Community Regulatory Board and the Secretariat.**

10. Regulatory authorities may lay down further requirements concerning the preparation of requests for derogation by relevant system operators. In doing so, regulatory authorities shall take into account the delineation between the transmission system and the distribution system at the national level and shall consult with system operators, power-generating facility owners and stakeholders, including manufacturers.

11. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 65(2).

Article 64

Register of derogations from the requirements of this Regulation

1. Regulatory authorities shall maintain a register of all derogations they have granted or refused and shall provide the **Energy Community Regulatory Board and the Secretariat** with an updated and consolidated register at least once every six months, a copy of which shall be given to ENTSO for Electricity.

2. The register shall contain, in particular:

(a) the requirement or requirements for which the derogation is granted or refused;

(b) the content of the derogation;

(c) the reasons for granting or refusing the derogation;

(d) the consequences resulting from granting the derogation.

Article 65

Monitoring of derogations

1. The **Energy Community Regulatory Board and the Secretariat** shall monitor the procedure of granting derogations with the cooperation of the regulatory authorities or relevant authorities of the **Contracting Party**. Those authorities or relevant authorities of the **Contracting Party** shall provide the **Energy Community Regulatory Board and the Secretariat** with all the information necessary for that purpose.

2. The **Energy Community Regulatory Board** may issue a reasoned recommendation to a regulatory authority to revoke a derogation due to a lack of justification. The **Secretariat** may issue a reasoned recommendation to a regulatory authority or relevant authority of the **Contracting Party** to revoke derogation due to a lack of justification.

3. The **Secretariat** may request the **Energy Community Regulatory Board** to report on the application of paragraphs 1 and 2 and to provide reasons for requesting or not requesting derogations to be revoked.

TITLE VI
TRANSITIONAL ARRANGEMENTS FOR EMERGING TECHNOLOGIES

Article 66

Emerging technologies

1. With the exception of Article 30, the requirements of this Regulation shall not apply to power-generating modules classified as an emerging technology, in accordance with the procedures set out in this Title.

2. A power-generating module shall be eligible to be classified as an emerging technology pursuant to Article 69, provided that:

(a) it is of type A;

(b) it is a commercially available power-generating module technology; and

(c) the accumulated sales of the power-generating module technology within a synchronous area at the time of application for classification as an emerging technology do not exceed 25 % of the maximum level of cumulative maximum capacity established pursuant to Article 67(1).

Article 67

Establishment of thresholds for classification as emerging technologies

1. The maximum level of cumulative maximum capacity of power-generating modules classified as emerging technologies in a synchronous area shall be 0.1% of the annual maximum load in 2014 in that synchronous area.

2. **Contracting Parties** shall ensure that their maximum level of cumulative maximum capacity of power-generating modules classified as emerging technologies is calculated by multiplying the maximum level of cumulative maximum capacity of power-generating modules classified as emerging technologies of a synchronous area with the ratio of annual electrical energy generated in 2014 in the **Contracting Party** to the total annual electrical energy generated in 2014 in the respective synchronous area to which the **Contracting Party** belongs.

For **Contracting Parties** belonging to parts of different synchronous areas, the calculation shall be carried out on a pro rata basis for each of those parts and combined to give the total allocation to that **Contracting Party**.

3. The source of the data for applying this Article shall be the ENTSO for Electricity's Statistical factsheet published in 2015.

Article 68

Application for classification as an emerging technology

1. Within six months of the **expiry of the deadline for transposition** of this Regulation manufacturers of Type A power-generating modules may submit to the relevant regulatory authority a request for classification of their power-generating module technology as an emerging technology.

2. In connection with a request pursuant to paragraph 1, the manufacturer shall inform the relevant regulatory authority of the accumulated sales of the respective power-generating module technology within each synchronous area at the time of application for classification as an emerging technology.

3. Proof that a request submitted pursuant to paragraph 1 complies with the eligibility criteria laid down in Articles 66 and 67 shall be provided by the manufacturer.

4. Where applicable in a **Contracting Party**, assessment of requests and approval and withdrawal of classification as an emerging technology may be undertaken by authorities other than the regulatory authority.

Article 69

Assessment and approval of requests for classification as an emerging technology

1. By 12 months of the **expiry of the deadline for transposition** of this Regulation, the relevant regulatory authority shall decide, in coordination with all the other regulatory authorities of a synchronous area, which power-generating modules, if any, should be classified as an emerging technology. Any regulatory authority of the relevant synchronous area may request a prior opinion from the **Energy Community**

Regulatory Board, which shall be issued within three months of receipt of the request. The decision of the relevant regulatory authority shall take into account the opinion of the **Energy Community Regulatory Board**.

2. A list of power-generating modules approved as emerging technologies shall be published by each regulatory authority of a synchronous area.

Article 70

Withdrawal of classification as an emerging technology

1. From the date of the decision of the regulatory authorities pursuant to Article 69(1), the manufacturer of any power-generating module classified as an emerging technology shall submit to the regulatory authority every two months an update of the sales of the module per **Contracting Party** for the past two months. The regulatory authority shall make publicly available the cumulative maximum capacity of power-generating modules classified as emerging technologies.

2. In the event that the cumulative maximum capacity of all power-generating modules classified as emerging technologies connected to networks exceeds the threshold established in Article 67, the classification as an emerging technology shall be withdrawn by the relevant regulatory authority. The withdrawal decision shall be published.

3. Without prejudice to the provisions of paragraphs 1 and 2, all regulatory authorities of a synchronous area may decide in a coordinated manner to withdraw a classification as an emerging technology. The regulatory authorities of the synchronous area concerned may request a prior opinion from the **Energy Community Regulatory Board** which shall be issued within three months of receipt of the request. Where applicable, the coordinated decision of the regulatory authorities shall take into account the opinion of the **Energy Community Regulatory Board**. The withdrawal decision shall be published by each regulatory authority of a synchronous area.

Power-generating modules classified as emerging technologies and connected to the network prior to the date of withdrawal of that classification as an emerging technology shall be considered as existing power-generating modules and shall therefore only be subject to the requirements of this Regulation pursuant to the provisions of Article 4(2) and Articles 38 and 39.

TITLE VII
FINAL PROVISIONS

Article 71

Amendment of contracts and general terms and conditions

1. Regulatory authorities shall ensure that all relevant clauses in contracts and general terms and conditions relating to the grid connection of new power-generating modules are brought into compliance with the requirements of this Regulation.

2. All relevant clauses in contracts and relevant clauses of general terms and conditions relating to the grid connection of existing power-generating modules subject to all or some of the requirements of this Regulation in accordance with Article 4(1) shall be amended in order to comply with the requirements of this Regulation. The relevant clauses shall be amended within three years following the decision of the regulatory authority or **Contracting Party** as referred to in Article 4(1).

3. Regulatory authorities shall ensure that national agreements between system operators and owners of new or existing power-generating facilities subject to this Regulation and relating to grid connection requirements for power-generating facilities, in particular in national network codes, reflect the requirements set out in this Regulation.

Article 72

Entry into force[1]

1. Each Contracting Party shall transpose Regulation (EU) 2016/631 by no later than by 12 June 2018.

2. Transposition shall be made without changes to the structure and text of Regulation (EU) 2016/1447 other than translation and the adaptations made by the present Decision [2018/03/PHLG-EnC].

3. Each Contracting Party shall notify the Energy Community Secretariat of completed transposition and of any subsequent changes made to the act transposing Regulation (EU) 2016/1447 within two weeks following the adoption of such measures.

4. Articles 4(2) points (a) and (b), 7(4), 58, 59, 61(1), 68(1) and Article 69(1) of Regulation (EU) 2016/631 shall apply as of the expiry of the transposition deadline.

5. Without prejudice to paragraph 4, Regulation (EU) 2016/631 shall be implemented no later than by 12 June 2021.

6. In transposing this Decision [2018/03/PHLG-EnC], Contracting Parties shall task national regulatory authorities with the monitoring of and enforcing compliance with this Decision [2018/03/PHLG-EnC].

1 Adapted by Article 1 of Permanent High Level Group Decision 2018/03/PHLG-EnC.

REGULATION (EU) 2016/1388 of 17 August 2016 establishing a network code on demand connection

Incorporated and adapted by Permanent High Level Group Decision 2018/05/PHLG-EnC of 12 January 2018

The adaptations made by Permanent High Level Group Decision 2018/05/PHLG-EnC are highlighted in **bold and blue**

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter

1. This Regulation establishes a network code which lays down the requirements for grid connection of:

(a) transmission-connected demand facilities;

(b) transmission-connected distribution facilities;

(c) distribution systems, including closed distribution systems;

(d) demand units, used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs.

2. This Regulation, therefore, helps to ensure fair conditions of competition in the internal electricity market, to ensure system security and the integration of renewable electricity sources, and to facilitate **Energy Community** -wide trade in electricity.

3. This Regulation also lays down the obligations for ensuring that system operators make appropriate use of the demand facilities' and distribution systems' capabilities in a transparent and non-discriminatory manner to provide a level playing field throughout the **Energy Community.**

Article 2
Definitions

For the purposes of this Regulation, the definitions in Article 2 of Directive 2012/27/EU of the European Parliament and of the Council, Article 2 of Regulation (EC) No 714/2009, **<...>**, Article 2 of Commission Regulation (EU) 2016/631, Article 2 of Commission Regulation (EU) No 543/2013 and Article 2 of Directive 2009/72/EC shall apply.

In addition, the following definitions shall apply:

(1) 'demand facility' means a facility which consumes electrical energy and is connected at one or more connection points to the transmission or distribution system. A distribution system and/or auxiliary supplies of a power generating module do not constitute a demand facility;

(2) 'transmission-connected demand facility' means a demand facility which has a connection point to a

transmission system;

(3) 'transmission-connected distribution facility' means a distribution system connection or the electrical plant and equipment used at the connection to the transmission system;

(4) 'demand unit' means an indivisible set of installations containing equipment which can be actively controlled by a demand facility owner or by a CDSO, either individually or commonly as part of demand aggregation through a third party;

(5) 'closed distribution system' means a distribution system classified pursuant to Article 28 of Directive 2009/72/EC as a closed distribution system by national regulatory authorities or by other competent authorities, where so provided by the **Contracting Party,** which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household customers, without prejudice to incidental use by a small number of households located within the area served by the system and with employment or similar associations with the owner of the system;

(6) 'main demand equipment' means at least one of the following equipment: motors, transformers, high voltage equipment at the connection point and at the process production plant;

(7) 'transmission-connected distribution system' means a distribution system connected to a transmission system, including transmission-connected distribution facilities;

(8) 'maximum import capability' means the maximum continuous active power that a transmission-connected demand facility or a transmission-connected distribution facility can consume from the network at the connection point, as specified in the connection agreement or as agreed between the relevant system operator and the transmission-connected demand facility owner or transmission-connected distribution system operator respectively;

(9) 'maximum export capability' means the maximum continuous active power that a transmission-connected demand facility or a transmission-connected distribution facility, can feed into the network at the connection point, as specified in the connection agreement or as agreed between the relevant system operator and the transmission-connected demand facility owner or transmission-connected distribution system operator respectively;

(10) 'low frequency demand disconnection' means an action where demand is disconnected during a low frequency event in order to recover the balance between demand and generation and restore system frequency to acceptable limits;

(11) 'low voltage demand disconnection' means a restoration action where demand is disconnected during a low voltage event in order to recover voltage to acceptable limits;

(12) 'on load tap changer' means a device for changing the tap of a winding, suitable for operation while the transformer is energised or on load;

(13) 'on load tap changer blocking' means an action that blocks the on load tap changer during a low voltage event in order to stop transformers from further tapping and suppressing voltages in an area;

(14) 'control room' means a relevant system operator's operation centre;

(15) 'block loading' means the maximum step active power loading of reconnected demand during system restoration after black-out;

(16) 'demand response active power control' means demand within a demand facility or closed distribution system that is available for modulation by the relevant system operator or relevant TSO, which results in

an active power modification;

(17) 'demand response reactive power control' means reactive power or reactive power compensation devices in a demand facility or closed distribution system that are available for modulation by the relevant system operator or relevant TSO;

(18) 'demand response transmission constraint management' means demand within a demand facility or closed distribution system that is available for modulation by the relevant system operator or relevant TSO to manage transmission constraints within the system;

(19) 'demand aggregation' means a set of demand facilities or closed distribution systems which can operate as a single facility or closed distribution system for the purposes of offering one or more demand response services;

(20) 'demand response system frequency control' means demand within a demand facility or closed distribution system that is available for reduction or increase in response to frequency fluctuations, made by an autonomous response from the demand facility or closed distribution system to diminish these fluctuations;

(21) 'demand response very fast active power control' means demand within a demand facility or closed distribution system that can be modulated very fast in response to a frequency deviation, which results in a very fast active power modification;

(22) 'demand response unit document' (DRUD) means a document, issued either by the demand facility owner or the CDSO to the relevant system operator for demand units with demand response and connected at a voltage level above 1 000 V, which confirms the compliance of the demand unit with the technical requirements set out in this Regulation and provides the necessary data and statements, including a statement of compliance.

Article 3

Scope of application

1. The connection requirements set out in this Regulation shall apply to:

(a) new transmission-connected demand facilities;

(b) new transmission-connected distribution facilities;

(c) new distribution systems, including new closed distribution systems;

(d) new demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs.

The relevant system operator shall refuse to allow the connection of a new transmission-connected demand facility, a new transmission-connected distribution facility, or a new distribution system, which does not comply with the requirements set out in this Regulation and which is not covered by a derogation granted by the regulatory authority, or other authority where applicable in a **Contracting Party** pursuant to Article 50. The relevant system operator shall communicate such refusal, by means of a reasoned statement in writing, to the demand facility owner, DSO, or CDSO and, unless specified otherwise by the regulatory authority, to the regulatory authority.

Based on compliance monitoring in accordance with Title III, the relevant TSO shall refuse demand response services subject to Articles 27 to 30 from new demand units not fulfilling the requirements set out in this

Regulation.

2. This Regulation shall not apply to:

(a) **<...>**

(b) storage devices except for pump-storage power generating modules in accordance with Article 5(2).

3. In case of demand facilities or closed distribution systems with more than one demand unit, these demand units shall together be considered as one demand unit if they cannot be operated independently from each other or can reasonably be considered in a combined manner.

Article 4

Application to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems 1and existing demand units used to provide demand response services

1. Existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units that are or can be used by a demand facility or a closed distribution system to provide demand response services to a relevant system operator or relevant TSO, are not subject to the requirements of this Regulation, except where:

(a) an existing transmission-connected demand facility, an existing transmission-connected distribution facility, an existing distribution system, or an existing demand unit within a demand facility at a voltage level above 1 000 V or a closed distribution system connected at a voltage level above 1 000 V, has been modified to such an extent that its connection agreement must be substantially revised in accordance with the following procedure:

(i) demand facility owners, DSOs, or CDSOs who intend to undertake the modernisation of a plant or replacement of equipment impacting the technical capabilities of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit shall notify their plans to the relevant system operator in advance;

(ii) if the relevant system operator considers that the extent of the modernisation or replacement of equipment is such that a new connection agreement is required, the system operator shall notify the relevant regulatory authority or, where applicable, the **Contracting Party**; and

(iii) the relevant regulatory authority or, where applicable, the **Contracting Party** shall decide if the existing connection agreement needs to be revised or a new connection agreement is required and which requirements of this Regulation shall apply; or

(b) a regulatory authority or, where applicable, a **Contracting Party** decides to make an existing transmission-connected demand facility, an existing transmission-connected distribution facility, an existing distribution system, or an existing demand unit subject to all or some of the requirements of this Regulation, following a proposal from the relevant TSO in accordance with paragraphs 3, 4 and 5.

2. For the purposes of this Regulation, a transmission-connected demand facility, a transmission-connected distribution facility, a distribution system, or a demand unit that is, or can be, used by a demand facility or a closed distribution system to provide demand response services to a relevant system operator or relevant TSO, shall be considered as existing if:

(a) it is already connected to the network on the date of **expiry of the deadline for transposition** of this Regulation; or

(b) the demand facility owner, DSO, or CDSO has concluded a final and binding contract for the purchase of the main demand equipment or the demand unit by two years after **expiry of the deadline for transposition of** the Regulation. The demand facility owner, DSO, or CDSO must notify the relevant system operator and relevant TSO of the conclusion of the contract within 30 months after **expiry of the deadline for transposition of** the Regulation.

The notification submitted by the demand facility owner, DSO, or CDSO to the relevant system operator and the relevant TSO shall at least indicate the contract title, its date of signature and date of entry into force, and the specifications of the main demand equipment or the demand unit to be constructed, assembled or purchased.

A **Contracting Party** may provide that in specified circumstances the regulatory authority may determine whether the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit is to be considered existing or new.

3. Following a public consultation in accordance with Article 9 and in order to address significant factual changes in circumstances, such as the evolution of system requirements including penetration of renewable energy sources, smart grids, distributed generation or demand response, the relevant TSO may propose to the regulatory authority concerned, or where applicable, to the **Contracting Party** to extend the application of this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems, or existing demand units used by a demand facility or a closed distribution system to provide demand response services to a relevant system operator or relevant TSO.

For that purpose a sound and transparent quantitative cost-benefit analysis shall be carried out, in accordance with Articles 48 and 49. The analysis shall indicate:

(a) the costs, in regard to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units, of requiring compliance with this Regulation;

(b) the socioeconomic benefit resulting from applying the requirements set out in this Regulation; and

(c) the potential of alternative measures to achieve the required performance.

4. Before carrying out the quantitative cost-benefit analysis referred to in paragraph 3, the relevant TSO shall:

(a) carry out a preliminary qualitative comparison of costs and benefits;

(b) obtain approval from the relevant regulatory authority or, where applicable, the **Contracting Party.**

5. The relevant regulatory authority or, where applicable, the **Contracting Party** shall decide on the extension of the applicability of this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems, or existing demand units, within six months of receipt of the report and the recommendation of the relevant TSO in accordance with paragraph 4 of Article 48. The decision of the regulatory authority or, where applicable, the **Contracting Party** shall be published.

6. The relevant TSO shall take account of the legitimate expectations of demand facility owners, DSOs and CDSOs as part of the assessment of the application of this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems, or

existing demand units.

7. The relevant TSO may assess the application of some or all of the provisions of this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems, or existing demand units, every three years in accordance with the requirements and process set out in paragraphs 3 to 5.

Article 5

Application to pump-storage power generating modules and industrial sites

1. This Regulation shall not apply to pump-storage power generating modules that have both generating and pumping operation mode.

2. Any pumping module within a pump-storage station that only provides pumping mode shall be subject to the requirements of this Regulation and shall be treated as a demand facility.

3. In the case of industrial sites with an embedded power generating module, the system operator of an industrial site, the demand facility owner, the power generating facility owner and the relevant system operator to whose system the industrial site is connected, may agree, in coordination with the relevant TSO, on conditions for disconnection of critical loads from the relevant system. The objective of the agreement shall be to secure production processes of the industrial site in case of disturbed conditions in the relevant system.

Article 6

Regulatory aspects

1. Requirements of general application to be established by relevant system operators or TSOs under this Regulation shall be subject to approval by the entity designated by the **Contracting Party** and be published. The designated entity shall be the regulatory authority unless otherwise provided by the **Contracting Party**.

2. For site specific requirements to be established by relevant system operators or TSOs under this Regulation, **Contracting Parties** may require approval by a designated entity.

3. When applying this Regulation, **Contracting Parties**, competent entities and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;

(e) consult with relevant DSOs and take account of potential impacts on their system;

(f) take into consideration agreed European standards and technical specifications

4. The relevant system operator or TSO shall submit a proposal for requirements of general application, or the methodology used to calculate or establish them, for approval by the competent entity within two years of **expiry of the deadline for transposition** of this Regulation.

5. Where this Regulation requires the relevant system operator, relevant TSO, demand facility owner, power generating facility owner, DSO and/or CDSO to seek agreement, they shall endeavour to do so within six months after a first proposal has been submitted by one party to the other parties. If no agreement has been found within this time frame, each party may request the relevant regulatory authority to issue a decision within six months.

6. Competent entities shall take decisions on proposals for requirements or methodologies within six months following the receipt of such proposals.

7. If the relevant system operator or TSO deems an amendment to requirements or methodologies as provided for and approved under paragraph 1 and 2 to be necessary, the requirements provided for in paragraphs 3 to 8 shall apply to the proposed amendment. System operators and TSOs proposing an amendment shall take into account the legitimate expectations, if any, of demand facility owners, DSOs, CDSOs, equipment manufacturers and other stakeholders based on the initially specified or agreed requirements or methodologies.

8. Any party having a complaint against a relevant system operator or a TSO in relation to that relevant system operator's or TSO's obligations under this Regulation may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months after receipt of the complaint. That period may be extended by two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall have binding effect unless and until overruled on appeal.

9. Where the requirements under this Regulation are to be established by a relevant system operator that is not a TSO, **Contracting Parties** may provide that instead the TSO be responsible for establishing the relevant requirements.

Article 7

Multiple TSOs

1. Where more than one TSO exists in a **Contracting Party**, this Regulation shall apply to all those TSOs.

2. **Contracting Parties** may, under the national regulatory regime, provide that the responsibility of a TSO to comply with one or some or all obligations under this Regulation is assigned to one or more specific TSOs.

Article 8

Recovery of costs

1. The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms.

2. If requested by the relevant regulatory authorities, system operators referred to in paragraph 1 shall, within three months of the request, provide the information necessary to facilitate assessment of the costs incurred.

Article 9

Public consultation

1. Relevant system operators and relevant TSOs shall carry out a consultation with stakeholders, including the competent authorities of each **Contracting Party** on:

(a) proposals to extend the applicability of this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units in accordance with Article 4(3);

(b) the report prepared in accordance with Article 48(3);

(c) the cost-benefit analysis undertaken in accordance with Article 53(2);

(d) the requirements for demand units specified in accordance with Article 28(2)(c),(e),(f),(k) and (l) and Article 29(2)(c) to (e).

The consultation shall last at least for a period of one month.

2. The relevant system operators or relevant TSOs shall duly take into account the views of the stakeholders resulting from the consultations, prior to the submission of the draft proposal, the report, the cost-benefit analysis, or the requirements for demand units, for approval by the regulatory authority, competent entity or, if applicable, the **Contracting Party**. In all cases, a sound justification for including or not the view of the stakeholders shall be provided and published in a timely manner before, or simultaneously with, the publication of the proposal, the report, the cost-benefit analysis, or the requirements for demand units specified in accordance with Article 28 and Article 29.

Article 10

Stakeholder involvement

The **Energy Community Regulatory Board**, in close cooperation with the European Network of Transmission System Operators for Electricity (ENTSO for Electricity), shall organise stakeholder involvement, regarding the requirements for the grid connection of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs, and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the requirements for grid connection of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs.

Article 11

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons, regulatory authorities, or entities subject to the provisions of this Regulation.

3. Confidential information received by the persons, regulatory authorities, or entities referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **Energy Community** law.

4. Without prejudice to cases covered by national or **Energy Community** law, regulatory authorities, entities, or persons who receive confidential information pursuant to this Regulation may use it only for the purpose of carrying out their duties under this Regulation.

TITLE II

CONNECTION OF TRANSMISSION-CONNECTED DEMAND FACILITIES, TRANSMISSION-CONNECTED DISTRIBUTION FACILITIES AND DISTRIBUTION SYSTEMS

CHAPTER 1

General requirements

Article 12

General frequency requirements

1. Transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems shall be capable of remaining connected to the network and operating at the frequency ranges and time periods specified in Annex I.

2. The transmission-connected demand facility owner or the DSO may agree with the relevant TSO on wider frequency ranges or longer minimum times for operation. If wider frequency ranges or longer minimum times for operation are technically feasible, the consent of the transmission-connected demand facility owner or DSO shall not be unreasonably withheld.

Article 13

General voltage requirements

1. Transmission-connected demand facilities, transmission-connected distribution facilities and transmission-connected distribution systems shall be capable of remaining connected to the network and operating at the voltage ranges and time periods specified in Annex II.

2. Equipment of distribution systems connected at the same voltage as the voltage of the connection point to the transmission system shall be capable of remaining connected to the network and operating at the voltage ranges and time periods specified in Annex II.

3. The voltage range at the connection point shall be expressed by the voltage at the connection point related to reference 1 per unit (pu) voltage. For the 400 kV grid voltage level (or alternatively commonly referred to as 380 kV level), the reference 1 pu value is 400 kV, for other grid voltage levels the reference 1 pu voltage may differ for each system operator in the same synchronous area.

4.**<...>**

5.**<...>**

6. If required by the relevant TSO, a transmission-connected demand facility, a transmission-connected distribution facility, or a transmission-connected distribution system shall be capable of automatic disconnection at specified voltages. The terms and settings for automatic disconnection shall be agreed between the relevant TSO and the transmission-connected demand facility owner or the DSO.

7. With regard to transmission-connected distribution systems with a voltage below 110 kV at the connection point, the relevant TSO shall specify the voltage range at the connection point that the distribution systems connected to that transmission system shall be designed to withstand. DSOs shall design the capability of their equipment, connected at the same voltage as the voltage of the connection point to the transmission system, to comply with this voltage range.

Article 14

Short-circuit requirements

1. Based on the rated short-circuit withstand capability of its transmission network elements, the relevant TSO shall specify the maximum short-circuit current at the connection point that the transmission-connected demand facility or the transmission-connected distribution system shall be capable of withstanding.

2. The relevant TSO shall deliver to the transmission-connected demand facility owner or the transmission-connected distribution system operator an estimate of the minimum and maximum short-circuit currents to be expected at the connection point as an equivalent of the network.

3. After an unplanned event, the relevant TSO shall inform the affected transmission-connected demand facility owner or the affected transmission-connected distribution system operator as soon as possible and no later than one week after the unplanned event, of the changes above a threshold for the maximum short-circuit current that the affected transmission-connected demand facility or the affected transmission-connected distribution system shall be able to withstand from the relevant TSO's network in accordance with paragraph 1.

4. The threshold set in paragraph 3 shall either be specified by the transmission-connected demand facility owner for its facility, or by the transmission-connected distribution system operator for its network.

5. Before a planned event, the relevant TSO shall inform the affected transmission-connected demand facility owner or the affected transmission-connected distribution system operator, as soon as possible and no later than one week before the planned event, of the changes above a threshold for the maximum short-circuit current that the affected transmission-connected demand facility or the affected transmission-connected distribution system shall be able to withstand from the relevant TSO's network, in accordance with paragraph 1.

6. The threshold set in paragraph 5 shall either be specified by the transmission-connected demand facility owner for its facility, or by the transmission-connected distribution system operator for its network.

7. The relevant TSO shall request information from a transmission-connected demand facility owner or a transmission-connected distribution system operator concerning the contribution in terms of short-circuit current from that facility or network. As a minimum, the equivalent modules of the network shall be delivered and demonstrated for zero, positive and negative sequences.

8. After an unplanned event, the transmission-connected demand facility owner or the transmission-connected distribution system operator shall inform the relevant TSO, as soon as possible and no later than one week after the unplanned event, of the changes in short-circuit contribution above the threshold set by the relevant TSO.

9. Before a planned event, the transmission-connected demand facility owner or the transmission-connected distribution system operator shall inform the relevant TSO, as soon as possible and no later than one week before the planned event, of the changes in short-circuit contribution above the threshold set by the relevant TSO.

Article 15

Reactive power requirements

1. Transmission-connected demand facilities and transmission-connected distribution systems shall be capable of maintaining their steady-state operation at their connection point within a reactive power range specified by the relevant TSO, according to the following conditions:

(a) for transmission-connected demand facilities, the actual reactive power range specified by the relevant TSO for importing and exporting reactive power shall not be wider than 48 percent of the larger of the maximum import capacity or maximum export capacity (0,9 power factor import or export of active power), except in situations where either technical or financial system benefits are demonstrated, for transmission-connected demand facilities, by the transmission-connected demand facility owner and accepted by the relevant TSO;

(b) for transmission-connected distribution systems, the actual reactive power range specified by the relevant TSO for importing and exporting reactive power shall not be wider than:

(i) 48 percent (i.e. 0,9 power factor) of the larger of the maximum import capability or maximum export capability during reactive power import (consumption); and

(ii) 48 percent (i.e. 0,9 power factor) of the larger of the maximum import capability or maximum export capability during reactive power export (production);

except in situations where either technical or financial system benefits are proved by the relevant TSO and the transmission-connected distribution system operator through joint analysis;

(c) the relevant TSO and the transmission-connected distribution system operator shall agree on the scope of the analysis, which shall address the possible solutions, and determine the optimal solution for reactive power exchange between their systems, taking adequately into consideration the specific system characteristics, variable structure of power exchange, bidirectional flows and the reactive power capabilities in the distribution system;

(d) the relevant TSO may establish the use of metrics other than power factor in order to set out equivalent reactive power capability ranges;

(e) the reactive power range requirement values shall be met at the connection point;

(f) by way of derogation from point (e), where a connection point is shared between a power generating module and a demand facility, equivalent requirements shall be met at the point defined in relevant agreements or national law.

2. The relevant TSO may require that transmission-connected distribution systems have the capability at the connection point to not export reactive power (at reference 1 pu voltage) at an active power flow of less than 25% of the maximum import capability. Where applicable, **Contracting Parties** may require the relevant TSO to justify its request through a joint analysis with the transmission-connected distribution system operator. If this requirement is not justified based on the joint analysis, the relevant TSO and the transmission-connected distribution system operator shall agree on necessary requirements according to the outcomes of a joint analysis.

3. Without prejudice to point (b) of paragraph 1, the relevant TSO may require the transmission-connected distribution system to actively control the exchange of reactive power at the connection point for the benefit of the entire system. The relevant TSO and the transmission-connected distribution system operator shall agree on a method to carry out this control, to ensure the justified level of security of supply for both parties. The justification shall include a roadmap in which the steps and the timeline for fulfilling the requirement are specified.

4. In accordance with paragraph 3, the transmission-connected distribution system operator may require the relevant TSO to consider its transmission-connected distribution system for reactive power management.

Article 16

Protection requirements

1. The relevant TSO shall specify the devices and settings required to protect the transmission network in accordance with the characteristics of the transmission-connected demand facility or the transmission-connected distribution system. The relevant TSO and the transmission-connected demand facility owner or the transmission-connected distribution system operator shall agree on protection schemes and settings relevant for the transmission-connected demand facility or the transmission-connected distribution system.

2. Electrical protection of the transmission-connected demand facility or the transmission-connected distribution system shall take precedence over operational controls while respecting system security, health and safety of staff and the public.

3. Protection scheme devices may cover the following elements:

(a) external and internal short circuit;

(b) over- and under-voltage at the connection point to the transmission system;

(c) over- and under-frequency;

(d) demand circuit protection;

(e) unit transformer protection;

(f) back-up against protection and switchgear malfunction.

4. The relevant TSO and the transmission-connected demand facility owner or the transmission-connected distribution system operator shall agree on any changes to the protection schemes relevant for the transmission-connected demand facility or the transmission-connected distribution system, and on the arrangements for the protection schemes of the transmission-connected demand facility or the transmission-connected distribution system.

Article 17

Control requirements

1. The relevant TSO and the transmission-connected demand facility owner or the transmission-connected distribution system operator shall agree on the schemes and settings of the different control devices of the transmission-connected demand facility or the transmission-connected distribution system relevant for system security.

2. The agreement shall cover at least the following elements:

(a) isolated (network) operation;

(b) damping of oscillations;

(c) disturbances to the transmission network;

(d) automatic switching to emergency supply and restoration to normal topology;

(e) automatic circuit-breaker re-closure (on 1-phase faults).

3. The relevant TSO and the transmission-connected demand facility owner or the transmission-connected distribution system operator shall agree on any changes to the schemes and settings of the different control devices of the transmission-connected demand facility or the transmission-connected distribution system relevant for system security.

4. With regard to priority ranking of protection and control, the transmission-connected demand facility owner or the transmission-connected distribution system operator shall set the protection and control devices of its transmission-connected demand facility or its transmission-connected distribution system respectively, in compliance with the following priority ranking, organised in decreasing order of importance:

(a) transmission network protection;

(b) transmission-connected demand facility or transmission-connected distribution system protection;

(c) frequency control (active power adjustment);

(d) power restriction.

Article 18

Information exchange

1. Transmission-connected demand facilities shall be equipped according to the standards specified by the relevant TSO in order to exchange information between the relevant TSO and the transmission-connected demand facility with the specified time stamping. The relevant TSO shall make the specified standards publicly available.

2. Transmission-connected distribution system shall be equipped according to the standards specified by the relevant TSO in order to exchange information between the relevant TSO and the transmission-connected distribution system with the specified time stamping. The relevant TSO shall make the specified standards publicly available.

3. The relevant TSO shall specify the information exchange standards. The relevant TSO shall make publicly available the precise list of data required.

Article 19

Demand disconnection and demand reconnection

1. All transmission-connected demand facilities and transmission-connected distribution systems shall fulfil the following requirements related to low frequency demand disconnection functional capabilities:

(a) each transmission-connected distribution system operator and, where specified by the TSO, transmission-connected demand facility owner, shall provide capabilities that enable automatic 'low frequency' disconnection of a specified proportion of their demand. The relevant TSO may specify a disconnection trigger based on a combination of low frequency and rate-of-change-of-frequency;

(b) the low frequency demand disconnection functional capabilities shall allow for disconnecting demand in stages for a range of operational frequencies;

(c) the low frequency demand disconnection functional capabilities shall allow for operation from a nominal Alternating Current ('AC') input to be specified by the relevant system operator, and shall meet the following requirements:

(i) frequency range: at least between 47-50 Hz, adjustable in steps of 0,05 Hz;

(ii) operating time: no more than 150 ms after triggering the frequency set point **and no more than 450 ms after triggering the frequency set point in Georgia**;

(iii) voltage lock-out: blocking of the functional capability shall be possible when the voltage is within a range of 30 to 90% of reference 1 pu voltage;

(iv) provide the direction of active power flow at the point of disconnection;

(d) the AC voltage supply used in providing low frequency demand disconnection functional capabilities, shall be provided from the network at the frequency signal measuring point, as used in providing functional capabilities in accordance with paragraph 1(c), so that the frequency of the low frequency demand disconnection functional capabilities supply voltage is the same as the one of the network.

2. With regard to low voltage demand disconnection functional capabilities, the following requirements

shall apply:

(a) the relevant TSO may specify, in coordination with the transmission-connected distribution system operators, low voltage demand disconnection functional capabilities for the transmission-connected distribution facilities;

(b) the relevant TSO may specify, in coordination with the transmission-connected demand facility owners, low voltage demand disconnection functional capabilities for the transmission-connected demand facilities;

(c) based on the TSO's assessment concerning system security, the implementation of on load tap changer blocking and low voltage demand disconnection shall be binding for the transmission-connected distribution system operators;

(d) if the relevant TSO decides to implement a low voltage demand disconnection functional capability, the equipment for both on load tap changer blocking and low voltage demand disconnection shall be installed in coordination with the relevant TSO;

(e) the method for low voltage demand disconnection shall be implemented by relay or control room initiation;

(f) the low voltage demand disconnection functional capabilities shall have the following features:

(i) the low voltage demand disconnection functional capability shall monitor the voltage by measuring all three phases;

(ii) blocking of the relays' operation shall be based on direction of either active power or reactive power flow.

3. With regard to blocking of on load tap changers, the following requirements shall apply:

(a) if required by the relevant TSO, the transformer at the transmission-connected distribution facility shall be capable of automatic or manual on load tap changer blocking;

(b) the relevant TSO shall specify the automatic on load tap changer blocking functional capability.

4. All transmission-connected demand facilities and transmission-connected distribution systems shall fulfil the following requirements related to disconnection or reconnection of a transmission-connected demand facility or a transmission-connected distribution system:

(a) with regard to the capability of reconnection after a disconnection, the relevant TSO shall specify the conditions under which a transmission-connected demand facility or a transmission-connected distribution system is entitled to reconnect to the transmission system. Installation of automatic reconnection systems shall be subject to prior authorisation by the relevant TSO;

(b) with regard to reconnection of a transmission-connected demand facility or a transmission-connected distribution system, the transmission-connected demand facility or the transmission-connected distribution system shall be capable of synchronisation for frequencies within the ranges set out in Article 12. The relevant TSO and the transmission-connected demand facility owner or the transmission-connected distribution system operator shall agree on the settings of synchronisation devices prior to connection of the transmission-connected demand facility or the transmission-connected distribution system, including voltage, frequency, phase angle range and deviation of voltage and frequency;

(c) a transmission-connected demand facility or a transmission-connected distribution facility shall be capable of being remotely disconnected from the transmission system when required by the relevant TSO. If required, the automated disconnection equipment for reconfiguration of the system in preparation for

block loading shall be specified by the relevant TSO. The relevant TSO shall specify the time required for remote disconnection.

Article 20

Power quality

Transmission-connected demand facility owners and transmission-connected distribution system operators shall ensure that their connection to the network does not result in a determined level of distortion or fluctuation of the supply voltage on the network, at the connection point. The level of distortion shall not exceed that allocated to them by the relevant TSO. TSOs shall coordinate their power quality requirements with the requirements of adjacent TSOs.

Article 21

Simulation models

1. Transmission-connected demand facilities and transmission-connected distribution systems shall fulfil the requirements set out in paragraphs 3 and 4 related to the simulation models or equivalent information.

2. Each TSO may require simulation models or equivalent information showing the behaviour of the transmission-connected demand facility, or the transmission-connected distribution system, or both, in steady and dynamic states.

3. Each TSO shall specify the content and format of those simulation models or equivalent information. The content and format shall include:

(a) steady and dynamic states, including 50 Hz component;

(b) electromagnetic transient simulations at the connection point;

(c) structure and block diagrams.

4. For the purpose of dynamic simulations, the simulation model or equivalent information referred to in paragraph 3(a) shall contain the following sub-models or equivalent information:

(a) power control;

(b) voltage control;

(c) transmission-connected demand facility and transmission-connected distribution system protection models;

(d) the different types of demand, that is to say electro technical characteristics of the demand; and

(e) converter models.

5. Each relevant system operator or relevant TSO shall specify the requirements of the performance of the recordings of transmission-connected demand facilities or transmission-connected distribution facilities, or both, in order to compare the response of the model with these recordings.

CHAPTER 2
Operational notification procedure

Article 22
General provisions

1. The operational notification procedure for the connection of each new transmission-connected demand facility, each new transmission-connected distribution facility and each new transmission-connected distribution system, shall comprise:

(a) an energisation operational notification (EON);

(b) an interim operational notification (ION);

(c) a final operational notification (FON).

2. Each transmission-connected demand facility owner or transmission-connected distribution system operator to which one or more of the requirements in Title II apply shall demonstrate to the relevant TSO that it has complied with the requirements set out in Title II of this Regulation by completing successfully the operational notification procedure for connection of each transmission-connected demand facility, each transmission-connected distribution facility and each transmission-connected distribution system described in Articles 23 to 26.

3. The relevant TSO shall specify and make publicly available further details concerning the operational notification procedure.

Article 23
Energisation operational notification

1. An EON shall entitle the transmission-connected demand facility owner or transmission-connected distribution system operator to energise its internal network and auxiliaries by using the grid connection that is specified for the connection point.

2. An EON shall be issued by the relevant TSO, subject to completion of preparations including agreement on the protection and control settings relevant to the connection point between the relevant TSO and the transmission-connected demand facility owner or transmission-connected distribution system operator.

Article 24
Interim operational notification

1. An ION shall entitle the transmission-connected demand facility owner or transmission-connected distribution system operator to operate the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system by using the grid connection for a limited period of time.

2. An ION shall be issued by the relevant TSO, subject to completion of the data and study review process as required by this Article.

3. With regard to the data and study review, the relevant TSO shall have the right to request that the transmission-connected demand facility owner or transmission-connected distribution system operator provide the following:

(a) an itemised statement of compliance;

(b) detailed technical data of the transmission-connected demand facility, the transmission-connected distribution facility or the transmission-connected distribution system relevant to the grid connection as specified by the relevant TSO;

(c) equipment certificates issued by an authorised certifier in respect of transmission-connected demand facilities, transmission-connected distribution facilities and transmission-connected distribution systems, where these are relied upon as part of the evidence of compliance;

(d) simulation models, as specified in Article 21 and required by the TSO;

(e) studies demonstrating expected steady-state and dynamic performance as required in Articles 43, 46 and 47;

(f) details of intended practical method of completing compliance tests according to Chapter 2 of Title IV.

4. The maximum period during which the transmission-connected demand facility owner or transmission-connected distribution system operator may maintain ION status shall be 24 months. The relevant TSO is entitled to specify a shorter ION validity period. An extension of the ION shall be granted only if the transmission-connected demand facility owner or transmission-connected distribution system operator has made substantial progress towards full compliance. Outstanding issues shall be clearly identified at the time of requesting extension.

5. An extension of the period during which the transmission-connected demand facility owner or transmission-connected distribution system operator may maintain ION status, beyond the period established in paragraph 4, may be granted if a request for a derogation is made to the relevant TSO before the expiry of that period in accordance with the derogation procedure laid down in Article 50.

Article 25

Final operational notification

1. A FON shall entitle the transmission-connected demand facility owner or transmission-connected distribution system operator to operate the transmission-connected demand facility, the transmission-connected distribution facility or the transmission-connected distribution system by using the grid connection.

2. A FON shall be issued by the relevant TSO, upon prior removal of all incompatibilities identified for the purposes of the ION status and subject to the completion of the data and study review process as required by this Article.

3. For the purposes of the data and study review, the transmission-connected demand facility owner or transmission-connected distribution system operator must submit the following to the relevant TSO:

(a) an itemised statement of compliance; and

(b) an update of the applicable technical data, simulation models and studies as referred to in points (b), (d) and (e) of Article 24(3), including the use of actual measured values during testing.

4. If incompatibility is identified in connection with the issuing of the FON, a derogation may be granted upon a request made to the relevant TSO, in accordance with the derogation procedure described in Chapter 2 of Title V. A FON shall be issued by the relevant TSO if the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system complies with the provisions of the derogation.

Where a request for a derogation is rejected, the relevant TSO shall have the right to refuse to allow the operation of the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system until the transmission-connected demand facility owner or transmission-connected distribution system operator and the relevant TSO resolve the incompatibility and the relevant TSO considers that the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system complies with the provisions of this Regulation.

If the relevant TSO and the transmission-connected demand facility owner or transmission-connected distribution system operator do not resolve the incompatibility within a reasonable time frame, but in any case not later than six months after the notification of the rejection of the request for a derogation, each party may refer the issue for decision to the regulatory authority.

Article 26

Limited operational notification

1. Transmission-connected demand facility owners or transmission-connected distribution system operators to whom a FON has been granted, shall inform the relevant TSO, no later than 24 hours after the incident has occurred, of the following circumstances:

(a) the facility is temporarily subject to either significant modification or loss of capability affecting its performance; or

(b) equipment failure leading to non-compliance with some relevant requirements.

A longer time period to inform the relevant TSO can be agreed with the transmission-connected demand facility owner or transmission-connected distribution system operator depending on the nature of the changes.

2. The transmission-connected demand facility owner or transmission-connected distribution system operator shall apply to the relevant TSO for a limited operational notification (LON), if the transmission-connected demand facility owner or transmission-connected distribution system operator expects the circumstances described in paragraph 1 to persist for more than three months.

3. A LON shall be issued by the relevant TSO and shall contain the following information which shall be clearly identifiable:

(a) the unresolved issues justifying the granting of the LON;

(b) the responsibilities and timescales for expected solution; and

(c) a maximum period of validity which shall not exceed 12 months. The initial period granted may be

shorter with the possibility of an extension if evidence is submitted to the satisfaction of the relevant TSO demonstrating that substantial progress has been made towards achieving full compliance.

4. The FON shall be suspended during the period of validity of the LON with regard to the items for which the LON has been issued.

5. A further extension of the period of validity of the LON may be granted upon a request for a derogation made to the relevant TSO before the expiry of that period, in accordance with the derogation procedure described in Chapter 2 of Title V.

6. The relevant TSO shall have the right to refuse to allow the operation of the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system once the LON is no longer valid. In such cases, the FON shall automatically become invalid.

7. If the relevant TSO does not grant an extension of the period of validity of the LON in accordance with paragraph 5 or if it refuses to allow the operation of the transmission-connected demand facility, the transmission-connected distribution facility, or the transmission-connected distribution system once the LON is no longer valid in accordance with paragraph 6, the transmission-connected demand facility owner or transmission-connected distribution system operator may refer the issue for decision to the regulatory authority within six months after the notification of the decision of the relevant TSO.

TITLE III

CONNECTION OF DEMAND UNITS USED BY A DEMAND FACILITY OR A CLOSED DISTRIBUTION SYSTEM TO PROVIDE DEMAND RESPONSE SERVICES TO SYSTEM OPERATORS

CHAPTER 1

General requirements

Article 27

General provisions

1. Demand response services provided to system operators shall be distinguished based on the following categories:

(a) remotely controlled:

(i) demand response active power control;

(ii) demand response reactive power control;

(iii) demand response transmission constraint management.

(b) autonomously controlled:

(i) demand response system frequency control;

(ii) demand response very fast active power control.

2. Demand facilities and closed distribution systems may provide demand response services to relevant

system operators and relevant TSOs. Demand response services can include, jointly or separately, upward or downward modification of demand.

3. The categories referred to in paragraph 1 are not exclusive and this Regulation does not prevent other categories from being developed. This Regulation does not apply to demand response services provided to other entities than relevant system operators or relevant TSOs.

Article 28

Specific provisions for demand units with demand response active power control, reactive power control and transmission constraint management

1. Demand facilities and closed distribution systems may offer demand response active power control, demand response reactive power control, or demand response transmission constraint management to relevant system operators and relevant TSOs.

2. Demand units with demand response active power control, demand response reactive power control, or demand response transmission constraint management shall comply with the following requirements, either individually or, where it is not part of a transmission-connected demand facility, collectively as part of demand aggregation through a third party:

(a) be capable of operating across the frequency ranges specified in Article 12(1) and the extended range specified in Article 12(2);

(b) be capable of operating across the voltage ranges specified in Article 13 if connected at a voltage level at or above 110 kV;

(c) be capable of operating across the normal operational voltage range of the system at the connection point, specified by the relevant system operator, if connected at a voltage level below 110 kV. This range shall take into account existing standards and shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(d) be capable of controlling power consumption from the network in a range equal to the range contracted, directly or indirectly through a third party, by the relevant TSO;

(e) be equipped to receive instructions, directly or indirectly through a third party, from the relevant system operator or the relevant TSO to modify their demand and to transfer the necessary information. The relevant system operator shall make publicly available the technical specifications approved to enable this transfer of information. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(f) be capable of adjusting its power consumption within a time period specified by the relevant system operator or the relevant TSO. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(g) be capable of full execution of an instruction issued by the relevant system operator or the relevant TSO to modify its power consumption to the limits of the electrical protection safeguards, unless a contractually agreed method is in place with the relevant system operator or relevant TSO for the replacement of their

contribution (including aggregated demand facilities' contribution through a third party);

(h) once a modification to power consumption has taken place and for the duration of the requested modification, only modify the demand used to provide the service if required by the relevant system operator or relevant TSO to the limits of the electrical protection safeguards, unless a contractually agreed method is in place with the relevant system operator or relevant TSO for the replacement of their contribution (including aggregated demand facilities' contribution through a third party). Instructions to modify power consumption may have immediate or delayed effects;

(i) notify the relevant system operator or relevant TSO of the modification of demand response capacity. The relevant system operator or relevant TSO shall specify the modalities of the notification;

(j) where the relevant system operator or the relevant TSO, directly or indirectly through a third party, command the modification of the power consumption, enable the modification of a part of its demand in response to an instruction by the relevant system operator or the relevant TSO, within the limits agreed with the demand facility owner or the CDSO and according to the demand unit settings;

(k) have the withstand capability to not disconnect from the system due to the rate-of-change-of-frequency up to a value specified by the relevant TSO. With regard to this withstand capability, the value of rate-of-change-of-frequency shall be calculated over a 500 ms time frame. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(l) where modification to the power consumption is specified via frequency or voltage control, or both, and via pre-alert signal sent by the relevant system operator or the relevant TSO, be equipped to receive, directly or indirectly through a third party, the instructions from the relevant system operator or the relevant TSO, to measure the frequency or voltage value, or both, to command the demand trip and to transfer the information. The relevant system operator shall specify and publish the technical specifications approved to enable this transfer of information. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1).

3. For voltage control with disconnection or reconnection of static compensation facilities, each transmission-connected demand facility or transmission-connected closed distribution system shall be able to connect or disconnect its static compensation facilities, directly or indirectly, either individually or commonly as part of demand aggregation through a third party, in response to an instruction transmitted by the relevant TSO, or in the conditions set forth in the contract between the relevant TSO and the demand facility owner or the CDSO.

Article 29

Specific provisions for demand units with demand response system frequency control

1. Demand facilities and closed distribution systems may offer demand response system frequency control to relevant system operators and relevant TSOs.

2. Demand units with demand response system frequency control shall comply with the following requirements, either individually or, where it is not part of a transmission-connected demand facility, collectively as part of demand aggregation through a third party:

(a) be capable of operating across the frequency ranges specified in Article 12(1) and the extended range

specified in Article 12(2);

(b) be capable of operating across the voltage ranges specified in Article 13 if connected at a voltage level at or above 110 kV;

(c) be capable of operating across the normal operational voltage range of the system at the connection point, specified by the relevant system operator, if connected at a voltage level below 110 kV. This range shall take into account existing standards, and shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(d) be equipped with a control system that is insensitive within a dead band around the nominal system frequency of 50,00 Hz, of a width to be specified by the relevant TSO in consultation with the TSOs in the synchronous area. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);

(e) be capable of, upon return to frequency within the dead band specified in paragraph 2(d), initiating a random time delay of up to 5 minutes before resuming normal operation.

The maximum frequency deviation from nominal value of 50,00 Hz to respond to shall be specified by the relevant TSO in coordination with the TSOs in the synchronous area. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1).

The demand shall be increased or decreased for a system frequency above or below the dead band of nominal (50,00 Hz) respectively;

(f) be equipped with a controller that measures the actual system frequency. Measurements shall be up-dated at least every 0,2 seconds;

(g) be able to detect a change in system frequency of 0,01 Hz, in order to give overall linear proportional system response, with regard to the demand response system frequency control's sensitivity and accuracy of the frequency measurement and the consequent modification of the demand. The demand unit shall be capable of a rapid detection and response to changes in system frequency, to be specified by the relevant TSO in coordination with the TSOs in the synchronous area. An offset in the steady-state measurement of frequency shall be acceptable up to 0,05 Hz.

Article 30

Specific provisions for demand units with demand response very fast active power control

1. The relevant TSO in coordination with the relevant system operator may agree with a demand facility owner or a CDSO (including, but not restricted to, through a third party) on a contract for the delivery of demand response very fast active power control.

2. If the agreement referred to in paragraph 1 takes place, the contract referred to in paragraph 1 shall specify:

(a) a change of active power related to a measure such as the rate-of-change-of-frequency for that portion of its demand;

(b) the operating principle of this control system and the associated performance parameters;

(c) the response time for very fast active power control, which shall not be longer than 2 seconds.

CHAPTER 2
Operational notification procedure

Article 31
General provisions

1. The operational notification procedure for demand units used by a demand facility or a closed distribution system to provide demand response to system operators shall be distinguished between:

(a) demand units within a demand facility or a closed distribution system connected at a voltage level of or below 1 000 V;

(b) demand units within a demand facility or a closed distribution system connected at a voltage level above 1 000 V.

2. Each demand facility owner or CDSO, providing demand response to a relevant system operator or a relevant TSO, shall confirm to the relevant system operator, or relevant TSO, directly or indirectly through a third party, its ability to satisfy the technical design and operational requirements as referred to in Chapter 1 of Title III of this Regulation.

3. The demand facility owner or the CDSO shall notify, directly or indirectly, through a third party, the relevant system operator or relevant TSO, in advance of any decision to cease offering demand response services and/or about the permanent removal of the demand unit with demand response. This information may be aggregated as specified by the relevant system operator or relevant TSO.

4. The relevant system operator shall specify and make publicly available further details concerning the operational notification procedure.

Article 32
Procedures for demand units within a demand facility or a closed distribution system connected at a voltage level of or below 1 000 V

1. The operational notification procedure for a demand unit within a demand facility or a closed distribution system connected at a voltage level of or below 1 000 V shall comprise an installation document.

2. The installation document template shall be provided by the relevant system operator, and the contents agreed with the relevant TSO, either directly or indirectly through a third party.

3. Based on an installation document, the demand facility owner or the CDSO shall submit information, directly or indirectly through a third party, to the relevant system operator or relevant TSO. The date of this submission shall be prior to the offer in the market of the capacity of the demand response by the demand unit. The requirements set in the installation document shall differentiate between different types of connections and between the different categories of demand response services.

4. For subsequent demand units with demand response, separate installation documents shall be provided.

5. The content of the installation document of individual demand units may be aggregated by the relevant system operator or relevant TSO.

6. The installation document shall contain the following items:

(a) the location at which the demand unit with demand response is connected to the network;

(b) the maximum capacity of the demand response installation in kW;

(c) the type of demand response services;

(d) the demand unit certificate and the equipment certificate as relevant for the demand response service, or if not available, equivalent information;

(e) the contact details of the demand facility owner, the closed distribution system operator or the third party aggregating the demand units from the demand facility or the closed distribution system.

Article 33

Procedures for demand units within a demand facility or a closed distribution system connected at a voltage level above 1 000 V

1. The operational notification procedure for a demand unit within a demand facility or a closed distribution system connected at a voltage level above 1 000 V shall comprise a DRUD. The relevant system operator, in coordination with the relevant TSO, shall specify the content required for the DRUD. The content of the DRUD shall require a statement of compliance which contains the information in Articles 36 to 47 for demand facilities and closed distribution systems, but the compliance requirements in Articles 36 to 47 for demand facilities and closed distribution systems can be simplified to a single operational notification stage as well as be reduced. The demand facility owner or CDSO shall provide the information required and submit it to the relevant system operator. Subsequent demand units with demand response shall provide separate DRUDs.

2. Based on the DRUD, the relevant system operator shall issue a FON to the demand facility owner or CDSO.

TITLE IV
COMPLIANCE

CHAPTER 1
General provisions

Article 34

Responsibility of the demand facility owner, the distribution system operator and the closed distribution system operator

1. Transmission-connected demand facility owners and DSOs shall ensure that their transmission-connected demand facilities, transmission-connected distribution facilities, or distribution systems comply with the requirements provided for in this Regulation. A demand facility owner or a CDSO providing demand response services to relevant system operators and relevant TSOs shall ensure that the demand unit complies

with the requirements provided for in this Regulation.

2. Where the requirements of this Regulation are applicable to demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs, the demand facility owner or the CDSO may totally or partially delegate to third parties tasks such as communicating with the relevant system operator or relevant TSO and gathering the documentation from the demand facility owner, the DSO or the CDSO evidencing compliance.

Third parties shall be treated as single users with the right to compile relevant documentation and demonstrate compliance of their aggregated demand facilities or aggregated closed distribution systems with the provisions of this Regulation. Demand facilities and closed distribution systems providing demand response services to relevant system operators and relevant TSOs may act collectively through third parties.

3. Where obligations are fulfilled through third parties, third parties shall only be required to inform the relevant system operator of changes to the total services being offered, taking account of location specific services.

4. Where the requirements are specified by the relevant TSO, or are for the purpose of the operation of the relevant TSO's system, alternative tests or requirements for test result acceptance for these requirements may be agreed with the relevant TSO.

5. Any intention to modify the technical capabilities of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit, which has impact on compliance with the requirements provided for in Chapters 2 to 4 of Title IV, shall be notified to the relevant system operator, directly or indirectly through a third party, prior to pursuing such modification, within the time frame provided by the relevant system operator.

6. Any operational incidents or failures of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system or the demand unit, which have an impact on compliance with the requirements provided for in Chapters 2 to 4 of Title IV, shall be notified to the relevant system operator, directly or indirectly through a third party, as soon as possible after the occurrence of such an incident.

7. Any planned test schedules and procedures to verify compliance of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit, with the requirements of this Regulation, shall be notified to the relevant system operator within the time frame specified by the relevant system operator and approved by the relevant system operator prior to their commencement.

8. The relevant system operator may participate in such tests and may record the performance of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, and the demand unit.

Article 35

Tasks of the relevant system operator

1. The relevant system operator shall assess the compliance of a transmission-connected demand facility, a transmission-connected distribution facility, a distribution system, or a demand unit, with the requirements of this Regulation throughout the lifetime of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit. The demand facility owner,

the DSO or the CDSO shall be informed of the outcome of this assessment.

The compliance of a demand unit used by a demand facility or a closed distribution system to provide demand response services to relevant TSOs, shall be jointly assessed by the relevant TSO and the relevant system operator, and if applicable in coordination with the third party involved in demand aggregation.

2. The relevant system operator shall have the right to request that the demand facility owner, the DSO or the CDSO carries out compliance tests and simulations according to a repeat plan or general scheme or after any failure, modification or replacement of any equipment that may have an impact on the compliance of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit with the requirements of this Regulation.

The demand facility owner, the DSO or the CDSO shall be informed of the outcome of those compliance tests and simulations.

3. The relevant system operator shall make publicly available the list of information and documents to be provided as well as the requirements to be fulfilled by the demand facility owner, the DSO or the CDSO in the frame of the compliance process. The list shall cover at least the following information, documents and requirements:

(a) all documentation and certificates to be provided by the demand facility owner, the DSO or the CDSO;

(b) details of the technical data required from the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit, with relevance to the grid connection or operation;

(c) requirements for models for steady-state and dynamic system studies;

(d) timeline for the provision of system data required to perform the studies;

(e) studies by the demand facility owner, the DSO or the CDSO for demonstrating expected steady-state and dynamic performance referring to the requirements set forth in Articles 43, 44 and 45;

(f) conditions and procedures including scope for registering equipment certificates;

(g) conditions and procedures for the use of relevant equipment certificates issued by an authorised certifier by the demand facility owner, the DSO or the CDSO.

4. The relevant system operator shall make public the allocation of responsibilities to the demand facility owner, the DSO or the CDSO and to the system operator for compliance testing, simulation and monitoring.

5. The relevant system operator may totally or partially delegate the performance of its compliance monitoring to third parties. In such cases, the relevant system operator shall continue ensuring compliance with Article 11, including entering into confidentiality commitments with the assignee.

6. If compliance tests or simulations cannot be carried out as agreed between the relevant system operator and the demand facility owner, the DSO or the CDSO due to reasons attributable to the relevant system operator, then the relevant system operator shall not unreasonably withhold the operational notification referred to in Title II and Title III.

CHAPTER 2
Compliance testing

Article 36

Common provisions for compliance testing

1. Testing of the performance of a transmission-connected demand facility, a transmission-connected distribution facility, or a demand unit with demand response active power control, demand response reactive power control or demand response transmission constraint management, shall aim at demonstrating that the requirements of this Regulation have been complied with.

2. Notwithstanding the minimum requirements for compliance testing set out in this Regulation, the relevant system operator is entitled to:

(a) allow the demand facility owner, the DSO or the CDSO to carry out an alternative set of tests, provided that those tests are efficient and suffice to demonstrate that a demand facility or a distribution system complies with the requirements of this Regulation; and

(b) require the demand facility owner, the DSO or the CDSO to carry out additional or alternative sets of tests in those cases where the information supplied to the relevant system operator in relation to compliance testing under the provisions of Articles 37 to 41, is not sufficient to demonstrate compliance with the requirements of this Regulation.

3. The demand facility owner, the DSO or the CDSO is responsible for carrying out the tests in accordance with the conditions laid down in Chapter 2 of Title IV. The relevant system operator shall cooperate and not unduly delay the performance of the tests.

4. The relevant system operator may participate in the compliance testing either on site or remotely from the system operator's control room. For that purpose, the demand facility owner, the DSO or the CDSO shall provide the monitoring equipment necessary to record all relevant test signals and measurements as well as ensure that the necessary representatives of the demand facility owner, the DSO or the CDSO are available on site for the entire testing period. Signals specified by the relevant system operator shall be provided if, for selected tests, the system operator wishes to use its own equipment to record performance. The relevant system operator has sole discretion to decide about its participation.

Article 37

Compliance testing for disconnection and reconnection of transmission-connected distribution facilities

1. The transmission-connected distribution facilities shall comply with the requirements for disconnection and reconnection referred in Article 19 and shall be subject to the following compliance tests.

2. With regard to testing of the capability of reconnection after an incidental disconnection due to a network disturbance, reconnection shall be achieved through a reconnection procedure, preferably by automation, authorised by the relevant TSO.

3. With regard to the synchronisation test, the technical synchronisation capabilities of the transmission-connected distribution facility shall be demonstrated. This test shall verify the settings of the synchronisation devices. This test shall cover the following matters: voltage, frequency, phase angle range, deviation of voltage and frequency.

4. With regard to the remote disconnection test, the transmission-connected distribution facility's technical capability for remote disconnection at the connection point or points from the transmission system when required by the relevant TSO and within the time specified by the relevant TSO shall be demonstrated.

5. With regard to the low frequency demand disconnection test, the transmission-connected distribution facility's technical capability of low frequency demand disconnection of a percentage of demand to be specified by the relevant TSO, in coordination with adjacent TSOs, where equipped as provided for in Article 19, shall be demonstrated.

6. With regard to the low frequency demand disconnection relays test, the transmission-connected distribution facility's technical capability to operate from a nominal AC supply input shall be demonstrated in accordance with Article 19(1) and (2). This AC supply input shall be specified by the relevant TSO.

7. With regard to the low voltage demand disconnection test, the transmission-connected distribution facility's technical capability to operate in a single action with on load tap changer blocking in Article 19(3) shall be demonstrated in accordance with Article 19(2).

8. An equipment certificate may be used instead of part of the tests provided for in paragraph 1, on the condition that it is provided to the relevant TSO.

Article 38

Compliance testing for information exchange of transmission-connected distribution facilities

1. With regard to information exchange between the relevant TSO and the transmission-connected distribution system operator in real time or periodically, the transmission-connected distribution facility's technical capability to comply with the information exchange standard established pursuant to Article 18(3) shall be demonstrated.

2. An equipment certificate may be used instead of part of the tests provided for in paragraph 1, on the condition that it is provided to the relevant TSO.

Article 39

Compliance testing for disconnection and reconnection of transmission-connected demand facilities

1. The transmission-connected demand facilities shall comply with the requirements for disconnection and reconnection referred to in Article 19 and shall be subject to the following compliance tests.

2. With regard to testing of the capability of reconnection after an incidental disconnection due to a network disturbance, reconnection shall be achieved through a reconnection procedure, preferably by automation, authorised by the relevant TSO.

3. With regard to the synchronisation test, the technical synchronisation capabilities of the transmission-connected demand facility shall be demonstrated. This test shall verify the settings of the synchronisation devices. This test shall cover the following matters: voltage, frequency, phase angle range, deviation of voltage and frequency.

4. With regard to the remote disconnection test, the transmission-connected demand facility's technical capability for remote disconnection at the connection point or points from the transmission system when required by the relevant TSO and within the time specified by the relevant TSO shall be demonstrated.

5. With regard to the low frequency demand disconnection relays test, the transmission-connected demand facility's technical capability to operate from a nominal AC input shall be demonstrated in accordance with Article 19(1) and (2). This AC supply input shall be specified by the relevant TSO.

6. With regard to the low voltage demand disconnection test, the transmission-connected demand facility's technical capability to operate in a single action with on load tap changer blocking in Article 19(3) shall be demonstrated in accordance with Article 19(2).

7. An equipment certificate may be used instead of part of the tests provided for in paragraph 1, on the condition that it is provided to the relevant TSO.

Article 40

Compliance testing for information exchange of transmission-connected demand facilities

1. With regard to information exchange between the relevant TSO and the transmission-connected demand facility owner in real time or periodically, the transmission-connected demand facility's technical capability to comply with the information exchange standard established pursuant to Article 18(3) shall be demonstrated.

2. An equipment certificate may be used instead of part of the tests provided for in paragraph 1, on the condition that it is provided to the relevant TSO.

Article 41

Compliance testing for demand units with demand response active power control, reactive power control and transmission constraint management

1. With regard to the demand modification test:

(a) the technical capability of the demand unit used by a demand facility or a closed distribution system to provide demand response active power control, demand response reactive power control or demand response transmission constraint management to modify its power consumption, after receiving an instruction from the relevant system operator or relevant TSO, within the range, duration and time frame previously agreed and established in accordance with Article 28, shall be demonstrated, either individually or collectively as part of demand aggregation through a third party;

(b) the test shall be carried out either by an instruction or alternatively by simulating the receipt of an instruction from the relevant system operator or relevant TSO and adjusting the power demand of the demand facility or the closed distribution system;

(c) the test shall be deemed passed, provided that the conditions specified by the relevant system operator or relevant TSO pursuant to Article 28(2)(d)(f)(g)(h)(k) and (l) are fulfilled;

(d) an equipment certificate may be used instead of part of the tests provided for in paragraph 1(b), on the condition that it is provided to the relevant system operator or relevant TSO.

2. With regard to the disconnection or reconnection of static compensation facilities test:

(a) the technical capability of the demand unit used by a demand facility owner or closed distribution system operator to provide demand response active power control, demand response reactive power control or demand response transmission constraint management to disconnect or reconnect, or both, its static compensation facility when receiving an instruction from the relevant system operator or relevant TSO, in the time frame expected in accordance with Article 28, shall be demonstrated, either individually or collectively as part of demand aggregation through a third party;

(b) the test shall be carried out by simulating the receipt of an instruction from the relevant system operator or relevant TSO and subsequently disconnecting the static compensation facility, and by simulating the receipt of an instruction from the relevant system operator or relevant TSO and subsequently reconnecting the facility;

(c) the test shall be deemed passed, provided that the conditions specified by the relevant system operator or relevant TSO pursuant to Article 28(2)(d)(f)(g)(h)(k) and (l) are fulfilled.

CHAPTER 3
Compliance simulation

Article 42
Common provisions on compliance simulations

1. Simulation of the performance of a transmission-connected demand facility, a transmission-connected distribution facility, or a demand unit with demand response very fast active power control within a demand facility or a closed distribution system shall result in demonstrating whether the requirements of this Regulation have been fulfilled or not.

2. Simulations shall be run in the following circumstances:

(a) a new connection to the transmission system is required;

(b) a new demand unit used by a demand facility or a closed distribution system to provide demand response very fast active power control to a relevant TSO has been contracted in accordance with Article 30;

(c) a further development, replacement or modernisation of equipment takes place;

(d) alleged incompliance by the relevant system operator with the requirements of this Regulation.

3. Notwithstanding the minimum requirements for compliance simulation set out in this Regulation, the relevant system operator is entitled to:

(a) allow the demand facility owner, the DSO or the CDSO to carry out an alternative set of simulations, provided that those simulations are efficient and suffice to demonstrate that a demand facility or a distribution system complies with the requirements of this Regulation or with national legislation; and

(b) require the demand facility owner, the DSO or the CDSO to carry out additional or alternative sets of simulations in those cases where the information supplied to the relevant system operator in relation to compliance simulation under the provisions of Articles 43, 44 and 45, is not sufficient to demonstrate compliance with the requirements of this Regulation.

4. The transmission-connected demand facility owner or the transmission-connected distribution system operator shall provide a report with the simulation results for each individual transmission-connected demand facility or transmission-connected distribution facility. The transmission-connected demand facility owner or the transmission-connected distribution system operator shall produce and provide a validated simulation model for a given transmission-connected demand facility or transmission-connected distribution facility. The scope of the simulation models is set out in Article 21(1) and (2).

5. The relevant system operator shall have the right to check that a demand facility or a distribution system complies with the requirements of this Regulation by carrying out its own compliance simulations based on the provided simulation reports, simulation models and compliance test measurements.

6. The relevant system operator shall provide the demand facility owner, the DSO or the CDSO with technical data and a simulation model of the network, to the extent necessary to carry out the requested simulations in accordance with Articles 43, 44 and 45.

Article 43

Compliance simulations for transmission-connected distribution facilities

1. With regard to the reactive power capability simulation of a transmission-connected distribution facility:

(a) a steady-state load flow simulation model of the network of the transmission-connected distribution system shall be used in order to calculate the reactive power exchange under different load and generation conditions;

(b) a combination of steady-state minimum and maximum load and generation conditions resulting in the lowest and highest reactive power exchange shall be part of the simulations;

(c) calculating the reactive power export at an active power flow of less than 25 % of the maximum import capability at the connection point shall be part of the simulations in accordance with Article 15.

2. The relevant TSO may specify the method for compliance simulation of the active control of reactive power set out in Article 15(3).

3. The simulation shall be deemed passed if the results demonstrate compliance with the requirements set out in Article 15.

Article 44

Compliance simulations for transmission-connected demand facilities

1. With regard to the reactive power capability simulation of a transmission-connected demand facility without onsite generation:

(a) the transmission-connected demand facility without onsite generation's reactive power capability at

the connection point shall be demonstrated;

(b) a load flow simulation model of the transmission-connected demand facility shall be used to calculate the reactive power exchange under different load conditions. Minimum and maximum load conditions resulting in the lowest and highest reactive power exchange at the connection point shall be part of the simulations;

(c) the simulation shall be deemed passed if the results demonstrate compliance with the requirements set out in Article 15(1) and (2).

2. With regard to the reactive power capability simulation of a transmission-connected demand facility with onsite generation:

(a) a load flow simulation model of the transmission-connected demand facility shall be used to calculate the reactive power exchange under different load conditions and under different generation conditions;

(b) a combination of minimum and maximum load and generation conditions resulting in the lowest and highest reactive power capability at the connection point shall be part of the simulations;

(c) the simulation shall be deemed passed if the results demonstrate compliance with the requirements set out in Article 15(1) and (2).

Article 45

Compliance simulations for demand units with demand response very fast active power control

1. The model of the demand unit used by a demand facility owner or a closed distribution system operator to provide demand response very fast active power control shall demonstrate the technical capability of the demand unit to provide very fast active power control to a low frequency event in the conditions set out in Article 30.

2. The simulation shall be deemed passed provided that the model demonstrates compliance with the conditions set out in Article 30.

CHAPTER 4
Compliance monitoring

Article 46

Compliance monitoring for transmission-connected distribution facilities

With regard to compliance monitoring of the reactive power requirements applicable to transmission-connected distribution facilities:

(a) the transmission-connected distribution facility shall be equipped with necessary equipment to measure the active and reactive power, in accordance with Article 15; and

(b) the relevant system operator shall specify the time frame for compliance monitoring.

Article 47

Compliance monitoring for transmission-connected demand facilities

With regard to compliance monitoring of the reactive power requirements applicable to transmission-connected demand facilities:

(a) the transmission-connected demand facility shall be equipped with necessary equipment to measure the active and reactive power, in accordance with Article 15; and

(b) the relevant system operator shall specify the time frame for compliance monitoring.

TITLE V
APPLICATIONS AND DEROGATIONS

CHAPTER 1
Cost-benefit analysis

Article 48

Identification of costs and benefits of application of requirements to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units

1. Prior to the application of any requirement set out in this Regulation to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units in accordance with Article 4(3), the relevant TSO shall undertake a qualitative comparison of costs and benefits related to the requirement under consideration. This comparison shall take into account available network-based or market-based alternatives. The relevant TSO may only proceed to undertake a quantitative cost-benefit analysis in accordance with paragraphs 2 to 5, if the qualitative comparison indicates that the likely benefits exceed the likely costs. If, however, the cost is deemed high or the benefit is deemed low, then the relevant TSO shall not proceed further.

2. Following a preparatory stage undertaken in accordance with paragraph 1, the relevant TSO shall carry out a quantitative cost-benefit analysis of any requirement under consideration for application to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units that have demonstrated potential benefits as a result of the preparatory stage according to paragraph 1.

3. Within three months of concluding the cost-benefit analysis, the relevant TSO shall summarise the findings in a report which shall:

(a) include the cost-benefit analysis and a recommendation on how to proceed;

(b) include a proposal for a transitional period for applying the requirement to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units. That transitional period shall not be more than two years from the date of

the decision of the regulatory authority or where applicable the **Contracting Party** on the requirement's applicability;

(c) be subject to public consultation in accordance with Article 9.

4. No later than six months after the end of the public consultation, the relevant TSO shall prepare a report explaining the outcome of the consultation and making a proposal on the applicability of the requirement under consideration to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units. The report and proposal shall be notified to the regulatory authority or, where applicable, the **Contracting Party**, and the demand facility owner, DSO, CDSO or, where applicable, third party shall be informed on its content.

5. The proposal made by the relevant TSO to the regulatory authority or, where applicable, the **Contracting Party** pursuant to paragraph 4 shall include the following:

(a) an operational notification procedure for demonstrating the implementation of the requirements by the existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs;

(b) a transitional period for implementing the requirements which shall take into account the classes of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs and any underlying obstacles to the efficient implementation of the equipment modification/refitting.

Article 49

Principles of cost-benefit analysis

1. Demand facility owners, DSOs and CDSOs shall assist and contribute to the cost-benefit analysis undertaken according to Articles 48 and 53 and provide the necessary data as requested by the relevant system operator or relevant TSO within three months of receiving a request, unless agreed otherwise by the relevant TSO. For the preparation of a cost-benefit-analysis by a demand facility owner or prospective owner, or by a DSO/CDSO or prospective operator, assessing a potential derogation pursuant to Article 52, the relevant TSO and DSO shall assist and contribute to the cost-benefit analysis and provide the necessary data as requested by the demand facility owner or prospective owner, or by the DSO/CDSO or prospective operator, within three months of receiving a request, unless agreed otherwise by the demand facility owner or prospective owner, or by the DSO/CDSO or prospective operator.

2. A cost-benefit analysis shall be in line with the following principles:

(a) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall base its cost-benefit analysis on one or more of the following calculating principles:

(i) the net present value;

(ii) the return on investment;

(iii) the rate of return;

(iv) the time needed to break even;

(b) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall also quantify socioeconomic benefits in terms of improvement in security of supply and shall include at least:

(i) the associated reduction in probability of loss of supply over the lifetime of the modification;

(ii) the probable extent and duration of such loss of supply;

(iii) the societal cost per hour of such loss of supply;

(c) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall quantify the benefits to the internal market in electricity, cross-border trade and integration of renewable energies, including at least:

(i) the active power frequency response;

(ii) the balancing reserves;

(iii) the reactive power provision;

(iv) congestion management;

(v) defence measures;

(d) the relevant TSO shall quantify the costs of applying the necessary rules to existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems, or existing demand units, including at least:

(i) the direct costs incurred in implementing a requirement;

(ii) the costs associated with attributable loss of opportunity;

(iii) the costs associated with resulting changes in maintenance and operation.

CHAPTER 2
Derogations

Article 50
Power to grant derogations

1. Regulatory authorities may, at the request of a demand facility owner or prospective owner, and a DSO/CDSO or prospective operator, relevant system operator or relevant TSO, grant demand facility owners or prospective owners, and DSOs/CDSOs or prospective operators, relevant system operators or relevant TSOs derogations from one or more provisions of this Regulation for new and existing transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units in accordance with Articles 51 to 53.

2. Where applicable in a **Contracting Party**, derogations may be granted and revoked in accordance with Articles 51 to 53 by other authorities than the regulatory authority.

Article 51

General provisions

1. Each regulatory authority shall specify, after consulting relevant system operators, demand facility owners, DSOs, CDSOs, and other stakeholders whom it deems affected by this Regulation, the criteria for granting derogations pursuant to Articles 52 and 53. It shall publish those criteria on its website and notify them to the **Secretariat** within nine months of **expiry of the deadline for transposition** of this Regulation. The **Secretariat** may require a regulatory authority to amend the criteria if it considers that they are not in line with this Regulation. This possibility to review and amend the criteria for granting derogations shall not affect the derogations already granted which shall continue to apply until the scheduled expiry date as detailed in the decision granting the exemption.

2. If the regulatory authority deems that it is necessary due to a change in circumstances relating to the evolution of system requirements, it may review and amend at most once every year the criteria for granting derogations in accordance with paragraph 1. Any changes to the criteria shall not apply to derogations for which a request has already been made.

3. The regulatory authority may decide that transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units for which a request for a derogation has been filed pursuant to Articles 52 or 53 do not need to comply with the requirements of this Regulation from which a derogation has been sought from the day of filing the request until the regulatory authority's decision is issued.

Article 52

Request for a derogation by a demand facility owner, a distribution system operator or a closed distribution system operator

1. Demand facility owners or prospective owners, and DSOs/CDSOs or prospective operators, may request a derogation to one or several requirements of this Regulation for transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems, or demand units used by a demand facility or a closed distribution system to provide demand response services to a relevant system operator and a relevant TSO.

2. A request for a derogation shall be filed with the relevant system operator and include:

(a) an identification of the demand facility owner or prospective owner, the DSO/CDSO or prospective operator, and a contact person for any communications;

(b) a description of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit for which a derogation is requested;

(c) a reference to the provisions of this Regulation from which a derogation is requested and a detailed description of the requested derogation;

(d) detailed reasoning, with relevant supporting documents and cost-benefit analysis pursuant to the requirements of Article 49;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade.

3. Within two weeks of receipt of a request for a derogation, the relevant system operator shall confirm to

the demand facility owner or prospective owner, or to the DSO/CDSO or prospective operator, whether the request is complete. If the relevant system operator considers that the request is incomplete, the demand facility owner or prospective owner, or the DSO/CDSO or prospective operator, shall submit the additional required information within one month from the receipt of the request for additional information. If the demand facility owner or prospective owner, or if the DSO/CDSO or prospective operator, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn.

4. The relevant system operator shall, in coordination with the relevant TSO and any affected adjacent DSO, assess the request for a derogation and the provided cost-benefit analysis, taking into account the criteria determined by the regulatory authority pursuant to Article 51.

5. Within six months of receipt of a request for a derogation, the relevant system operator shall forward the request to the regulatory authority and submit the assessment(s) prepared in accordance with paragraphs 4. That period may be extended by one month where the relevant system operator seeks further information from the demand facility owner or prospective owner, or from the DSO/CDSO or prospective operator, and by two months where the relevant system operator requests the relevant TSO to submit an assessment of the request for a derogation.

6. The regulatory authority shall adopt a decision concerning any request for a derogation within six months from the day after it receives the request. That time limit may be extended by three months before its expiry where the regulatory authority requires further information from the demand facility owner or prospective owner, or from the DSO/CDSO or prospective operator, or from any other interested parties. The additional period shall begin when the complete information has been received.

7. The demand facility owner or prospective owner, or the DSO/CDSO or prospective operator, shall submit any additional information requested by the regulatory authority within two months of such request. If the demand facility owner or prospective owner, or if the DSO/CDSO or prospective operator, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn unless, before its expiry:

(a) the regulatory authority decides to provide an extension; or

(b) the demand facility owner or prospective owner, or the DSO/CDSO or prospective operator, informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

8. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants a derogation, it shall specify its duration.

9. The regulatory authority shall notify its decision to the relevant demand facility owner or prospective owner, the DSO/CDSO or prospective operator, the relevant system operator and the relevant TSO.

10. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 55(2).

11. For demand units within a demand facility or a closed distribution system connected at a voltage level of or below 1 000 V, a request for a derogation under this Article may be made by a third party on behalf of the demand facility owner or prospective owner, or on behalf of the CDSO or prospective operator. Such a request may be for a single demand unit or multiple demand units within the same demand facility or closed distribution system. In the case of the latter, and provided the cumulative maximum capacity is specified, the third party may substitute the details required by point (a) of paragraph 2 with their details.

Article 53

Request for a derogation by a relevant system operator or relevant TSO

1. Relevant system operators or relevant TSOs may request derogations for transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems, or demand units within a demand facility or a closed distribution system connected or to be connected to their network.

2. Relevant system operators or relevant TSOs shall submit their requests for a derogation to the regulatory authority. Each request for a derogation shall include:

(a) identification of the relevant system operator or relevant TSO, and a contact person for any communications;

(b) a description of the transmission-connected demand facility, the transmission-connected distribution facility, the distribution system, or the demand unit for which a derogation is requested and the total installed capacity and number of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems, or demand units;

(c) the requirement or requirements of this Regulation for which a derogation is requested, with a detailed description of the requested derogation;

(d) detailed reasoning, with all relevant supporting documents;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade;

(f) a cost-benefit analysis pursuant to the requirements of Article 49. If applicable, the cost-benefit analysis shall be carried out in coordination with the relevant TSO and any adjacent DSO.

3. Where the request for a derogation is submitted by a relevant DSO, the regulatory authority shall, within two weeks from the day after receipt of that request, ask the relevant TSO to assess the request for a derogation in the light of the criteria determined by the regulatory authority pursuant to Article 51.

4. Within two weeks from the day after the receipt of such request for assessment, the relevant TSO shall confirm to the relevant DSO whether the request for a derogation is complete. If the relevant TSO considers that it is incomplete, the relevant DSO shall submit the required additional information within one month from the receipt of the request for additional information.

5. Within six months of receipt of a request for a derogation, the relevant TSO shall submit to the regulatory authority its assessment, including any relevant documentation. The six-month time limit may be extended by one month where the relevant TSO seeks further information from the relevant DSO.

6. The regulatory authority shall adopt a decision concerning a request for a derogation within six months from the day after it receives the request. Where the request for a derogation is submitted by the relevant DSO, the six-month time limit runs from the day following receipt of the relevant TSO's assessment pursuant to paragraph 5.

7. The six-month time limit referred to in paragraph 6 may, before its expiry, be extended by an additional three months where the regulatory authority requests further information from the relevant system operator requesting the derogation or from any other interested parties. That additional period shall run from the day following the date of receipt of the complete information.

The relevant system operator shall provide any additional information requested by the regulatory authority within two months from the date of the request. If the relevant system operator does not provide the requested additional information within that time limit, the request for a derogation shall be deemed

withdrawn unless, before expiry of the time limit:

(a) the regulatory authority decides to provide an extension; or

(b) the relevant system operator informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

8. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants derogation, it shall specify its duration.

9. The regulatory authority shall notify its decision to the relevant system operator requesting the derogation, the relevant TSO, **the Secretariat and the Energy Community Regulatory Board**.

10. Regulatory authorities may lay down further requirements concerning the preparation of requests for a derogation by relevant system operators. In doing so, regulatory authorities shall take into account the delineation between the transmission system and the distribution system at the national level and shall consult with system operators, demand facility owners and stakeholders, including manufacturers.

11. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 55(2).

Article 54

Register of derogations from the requirements of this Regulation

1. Regulatory authorities shall maintain a register of all derogations they have granted or refused and shall provide the **Secretariat and the Energy Community Regulatory Board** with an updated and consolidated register at least once every six months, a copy of which shall be given to ENTSO for Electricity.

2. The register shall contain, in particular:

(a) the requirement or requirements for which the derogation is granted or refused;

(b) the content of the derogation;

(c) the reasons for granting or refusing the derogation;

(d) the consequences resulting from granting the derogation.

Article 55

Monitoring of derogations

1. The **Secretariat and the Energy Community Regulatory Board** shall monitor the procedure of granting derogations with the cooperation of the regulatory authorities or relevant authorities of the **Contracting Party**. Those authorities or relevant authorities of the **Contracting Party** shall provide the **Secretariat and Energy Community Regulatory Board** with all the information necessary for that purpose.

2. The **Energy Community Regulatory Board** may issue a reasoned recommendation to a regulatory authority to revoke a derogation due to a lack of justification. The **Secretariat** may issue a reasoned

recommendation to a regulatory authority or relevant authority of the **Contracting Party** to revoke a derogation due to a lack of justification.

3. The **Secretariat** may request the **Energy Community Regulatory Board** to report on the application of paragraphs 1 and 2 and to provide reasons for requesting or not requesting derogations to be revoked.

TITLE VI
NON-BINDING GUIDANCE AND MONITORING OF IMPLEMENTATION

Article 56
Non-binding guidance on implementation

1. **<...>**

2. **<...>**

3. The non-binding guidance **published by ENTSO for Electricity** explains the technical issues, conditions and interdependencies which need to be considered when complying with the requirements of this Regulation at national level.

Article 57
Monitoring

1. ENTSO for Electricity shall monitor the implementation of this Regulation **for the Contracting Parties whose TSOs are members of ENTSO for Electricity. The Secretariat and the Energy Community Regulatory Board shall monitor the implementation of this Regulation for the Contracting Parties whose TSOs are not members of ENTSO for Electricity**.... Monitoring **shall take into account the list of relevant information developed by the Agency for the Cooperation of Energy Regulators and it** shall cover in particular the following matters:

(a) identification of any divergences in the national implementation of this Regulation;

(b) assessment of whether the choice of values and ranges in the requirements applicable to transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units under this Regulation continues to be valid.

ENTSO for Electricity shall report its findings to the Secretariat and the Energy Community Regulatory Board. The Secretariat and the Energy Community Regulatory Board shall make available the findings stemming from the monitoring of the implementation of this Regulation.

2. **<...>**

3. Relevant TSOs shall submit to **the Secretariat, the Energy Community Regulatory Board and** ENTSO for Electricity the information required to perform the tasks referred to in paragraph 1**<...>**

Based on a request of the regulatory authority, DSOs shall provide TSOs with information under paragraph 1 unless the information is already obtained by regulatory authorities, the **Secretariat, the Energy Com-**

munity Regulatory Board or ENTSO-E in relation to their respective implementation monitoring tasks, with the objective of avoiding duplication of information.

4. **<...>**

TITLE VII
FINAL PROVISIONS

Article 58

Amendment of contracts and general terms and conditions

1. Regulatory authorities shall ensure that all relevant clauses in contracts and general terms and conditions relating to the grid connection of new transmission-connected demand facilities, new transmission-connected distribution facilities, new distribution systems and new demand units are brought into compliance with the requirements of this Regulation.

2. All relevant clauses in contracts and relevant clauses of general terms and conditions relating to the grid connection of existing transmission-connected demand facilities, existing transmission-connected distribution facilities, existing distribution systems and existing demand units subject to all or some of the requirements of this Regulation in accordance with paragraph 1 of Article 4 shall be amended in order to comply with the requirements of this Regulation. The relevant clauses shall be amended within three years following the decision of the regulatory authority or **Contracting Party** as referred to in Article 4(1).

3. Regulatory authorities shall ensure that agreements between system operators and owners of new or existing demand facilities or operators of new or existing distribution systems subject to this Regulation and relating to grid connection requirements for transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs, in particular in national network codes, reflect the requirements set out in this Regulation.

Article 59

Entry into force[1]

1. Each Contracting Party shall transpose Regulation (EU) 2016/1388 no later than by 12 June 2018.

2. Transposition shall be made without changes to the structure and text of Regulation (EU) 2016/1388 other than translation and the adaptations made by the present Decision [2018/05/PHLG-EnC]

3. Each Contracting Party shall notify the Energy Community Secretariat of completed transposition and of any subsequent changes made to the act transposing Regulation (EU) 2016/1388 within two weeks following the adoption of such measures.

1 Adapted by Article 1 of Decision 2018/05/PHLG-EnC of the Permanent High Level Group

4. Articles 4(2) points (a) and (b), 6(4), 51(1), 56 and 57 of Regulation (EU) 2016/1388 shall be implemented as of the expiry of the transposition deadline.

5. Without prejudice to paragraph 4, Regulation (EU) 2016/1388 shall be implemented no later than by 12 June 2021.

6. In transposing this Decision, Contracting Parties shall task their national regulatory authorities with the monitoring of and enforcing compliance with this Decision [2018/05/PHLG-EnC].

ANNEX I

Frequency ranges and time periods referred to in Article 12(1)

Synchronous area	Frequency range	Time period for operation
Continental Europe, Ukraine	47,5 Hz–48,5 Hz	To be specified by each TSO, but not less than 30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz-48,5 Hz
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	30 minutes
Nordic	47,5 Hz–48,5 Hz	30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 30 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	30 minutes
Great Britain	47,0 Hz–47,5 Hz	20 seconds
	47,5 Hz–48,5 Hz	90 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	90 minutes
	51,5 Hz–52,0 Hz	15 minutes
Ireland and Northern Ireland	47,5 Hz–48,5 Hz	90 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	90 minutes
Baltic, Moldova	47,5 Hz–48,5 Hz	To be specified by each TSO, but not less than 30 minutes
	48,5 Hz–49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz–48,5 Hz
	49,0 Hz–51,0 Hz	Unlimited
	51,0 Hz–51,5 Hz	To be specified by each TSO, but not less than 30 minutes
Georgia	**47,5 Hz–48,5 Hz**	**Not less than 30 minutes**
	48,5 Hz–49,0 Hz	**Not less than 60 minutes**
	49,0 Hz–51,0 Hz	**Unlimited**
	51,0 Hz–51,5 Hz	**Not less than 30 minutes**

The table shows the minimum time periods for which a transmission-connected demand facility, a transmission-connected distribution facility or a distribution system has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network.

ANNEX II

Voltage ranges and time periods referred to in Article 13(1)

Synchronous area	Voltage range	Time period for operation
Continental Europe, Ukraine	0,90 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	To be specified by each TSO but not less than 20 minutes and not more than 60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	60 minutes
Great Britain	0,90 pu–1,10 pu	Unlimited
Ireland and Northern Ireland	0,90 pu–1,118 pu	Unlimited
Baltic, Moldova	0,90 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	20 minutes
Georgia	**0,85 pu–0,90 pu**	**30 minutes**
	0,90 pu–1,12 pu	**Unlimited**
	1,12 pu–1,15 pu	**20 minutes**

The table shows the minimum time periods during which a transmission-connected demand facility, a transmission-connected distribution facility or a transmission-connected distribution system has to be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network where the voltage base for pu values is at or above 110 kV and up to (not including) 300 kV.

Synchronous area	Voltage range	Time period for operation
Continental Europe, Ukraine	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	To be specified by each TSO but not less than 20 minutes and not more than 60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	To be specified by each TSO but not more than 60 minutes
Great Britain	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	15 minutes
Ireland and Northern Ireland	0,90 pu–1,05 pu	Unlimited
Baltic, Moldova	0,90 pu–1,097 pu	Unlimited
	1,097 pu–1,15 pu	20 minutes

Georgia	**0,85 pu–0,90 pu**	**20 minutes**
	0,90 pu–1,10 pu	**Unlimited**
	1,10 pu–1,15 pu	**20 minutes**

The table shows the minimum time periods during which a transmission-connected demand facility, a transmission-connected distribution facility or a transmission-connected distribution system has to be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network, where the voltage base for pu values is from 300 kV to **500** kV (including).

REGULATION (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules

Incorporated and adapted by Permanent High Level Group Decision 2018/04/PHLG-EnC of 12 January 2018

The adaptations made by Permanent High Level Group Decision 2018/04/PHLG-EnC are highlighted in **bold and blue**.

TITLE I
GENERAL PROVISIONS

Article 1
Subject matter

This Regulation establishes a network code which lays down the requirements for grid connections of high-voltage direct current (HVDC) systems and DC-connected power park modules. It, therefore, helps to ensure fair conditions of competition in the internal electricity market, to ensure system security and the integration of renewable electricity sources, and to facilitate **Energy Community**-wide trade in electricity.

This regulation also lays down the obligations for ensuring that system operators make appropriate use of HVDC systems and DC-connected power park modules capabilities in a transparent and non-discriminatory manner to provide a level playing field throughout the **Energy Community**.

Article 2
Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No 714/2009, <...>, Article 2 of Commission Regulation (EU) No 543/2013 , Article 2 of Commission Regulation (EU) 2016/631, Article 2 of Commission Regulation (EU) 2016/1388 and Article 2 of Directive 2009/72/EC shall apply. In addition, the following definitions shall apply:

(1) 'HVDC system' means an electrical power system which transfers energy in the form of high-voltage direct current between two or more alternating current (AC) buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations;

(2) 'DC-connected power park module' means a power park module that is connected via one or more HVDC interface points to one or more HVDC systems;

(3) 'embedded HVDC system' means an HVDC system connected within a control area that is not installed for the purpose of connecting a DC-connected power park module at the time of installation, nor installed for the purpose of connecting a demand facility;

(4) 'HVDC converter station' means part of an HVDC system which consists of one or more HVDC converter

units installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment;

(5) 'HVDC interface point' means a point at which HVDC equipment is connected to an AC network, at which technical specifications affecting the performance of the equipment can be prescribed;

(6) 'DC-connected power park module owner' means a natural or legal entity owning a DC-connected power park module;

(7) 'maximum HVDC active power transmission capacity' (P_{max}) means the maximum continuous active power which an HVDC system can exchange with the network at each connection point as specified in the connection agreement or as agreed between the relevant system operator and the HVDC system owner;

(8) 'minimum HVDC active power transmission capacity' (Pmin) means the minimum continuous active power which an HVDC system can exchange with the network at each connection point as specified in the connection agreement or as agreed between the relevant system operator and the HVDC system owner;

(9) 'HVDC system maximum current' means the highest phase current, associated with an operating point inside the U-Q/P_{max}-profile of the HVDC converter station at maximum HVDC active power transmission capacity;

(10) 'HVDC converter unit' means a unit comprising one or more converter bridges, together with one or more converter transformers, reactors, converter unit control equipment, essential protective and switching devices and auxiliaries, if any, used for the conversion.

Article 3

Scope of application

1. The requirements of this Regulation shall apply to:

(a) HVDC systems connecting synchronous areas or control areas, including back-to-back schemes;

(b) HVDC systems connecting power park modules to a transmission network or a distribution network, pursuant to paragraph 2;

(c) embedded HVDC systems within one control area and connected to the transmission network; and

(d) embedded HVDC systems within one control area and connected to the distribution network when a cross-border impact is demonstrated by the relevant transmission system operator (TSO). The relevant TSO shall consider the long-term development of the network in this assessment.

2. Relevant system operators, in coordination with relevant TSOs, shall propose to competent regulatory authorities the application of this Regulation for DC-connected power park modules with a single connection point to a transmission network or distribution network which is not part of a synchronous area for approval in accordance with Article 5. All other power park modules which are AC-collected but are DC-connected to a synchronous area are considered DC-connected power park modules and fall within the scope of this Regulation.

3. Articles 55 to 59, 69 to 74 and 84 shall not apply to HVDC systems within one control area referred to in points (c) and (d) of paragraph 1 where:

(a) the HVDC system has at least one HVDC converter station owned by the relevant TSO;

(b) the HVDC system is owned by an entity which exercises control over the relevant TSO;

(c) the HVDC system is owned by an entity directly or indirectly controlled by an entity which also exercises control over the relevant TSO.

4. The connection requirements for HVDC systems provided for in Title II shall apply at the AC connection points of such systems, except the requirements provided for in Article 29(4) and (5) and Article 31(5), which can apply at other connection points, and Article 19(1) which may apply at the terminals of the HVDC converter station.

5. The connection requirements for DC-connected power park modules and remote-end HVDC converter stations provided for in Title III shall apply at the HVDC interface point of such systems, except the requirements provided for in Article 39(1)(a) and Article 47(2), which apply at the connection point in the synchronous area to which frequency response is being provided.

6. The relevant system operator shall refuse to allow the connection of a new HVDC system or DC-connected power park module which does not comply with the requirements set out in this Regulation and which is not covered by a derogation granted by the regulatory authority, or other authority where applicable in a **Contracting Party** pursuant to Title VII. The relevant system operator shall communicate such refusal, by means of a reasoned statement in writing, to the HVDC system owner or DC-connected power park module owner and, unless specified otherwise by the regulatory authority, to the regulatory authority.

7. This Regulation shall not apply to:

(a) HVDC systems whose connection point is below 110 kV unless a cross-border impact is demonstrated by the relevant TSO. The relevant TSO shall consider the long-term development of the network in this assessment;

(b) **<...>**

Article 4

Application to existing HVDC systems and DC-connected power park modules

1. Except for Articles 26, 31, 33 and 50, existing HVDC systems and existing DC-connected power park modules are not subject to the requirements of this Regulation, unless:

(a) the HVDC system or DC-connected power park module has been modified to such an extent that its connection agreement must be substantially revised in accordance with the following procedure:

(i) the HVDC system or DC-connected power park module owners who intend to undertake the modernisation of a plant or replacement of equipment impacting the technical capabilities of the HVDC system or DC-connected power park module shall notify their plans to the relevant system operator in advance;

(ii) if the relevant system operator considers that the extent of the modernisation or replacement of equipment is such that a new connection agreement is required, the system operator shall notify the relevant regulatory authority or, where applicable, the **Contracting Party**; and

(iii) the relevant regulatory authority or, where applicable, the **Contracting Party** shall decide if the existing connection agreement needs to be revised or a new connection agreement is required and which requirements of this Regulation shall apply; or

(b) a regulatory authority or, where applicable, a **Contracting Party** decides to make an existing HVDC system or existing DC-connected power park module subject to all or some of the requirements of this Regulation, following a proposal from the relevant TSO in accordance with paragraphs 3, 4 and 5.

2. For the purposes of this Regulation, an HVDC system or DC-connected power park module shall be considered existing if:

(a) it is already connected to the network on the date of **expiry of the deadline for transposition** of this Regulation; or

(b) the HVDC system owner or DC-connected power park module owner has concluded a final and binding contract for the purchase of the main generating plant or HVDC equipment by two years after the **expiry of the deadline for transposition** of the Regulation. The HVDC system owner or DC-connected power park module owner must notify the relevant system operator and relevant TSO of conclusion of the contract within 30 months after the **expiry of the deadline for transposition** of the Regulation.

The notification submitted by the HVDC system owner or DC-connected power park module owner to the relevant system operator and to the relevant TSO shall at least indicate the contract title, its date of signature and date of entry into force and the specifications of the main generating plant or HVDC equipment to be constructed, assembled or purchased.

A **Contracting Party** may provide that in specified circumstances the regulatory authority may determine whether the HVDC system or DC-connected power park module is to be considered an existing or new HVDC system or DC-connected power park module.

3. Following a public consultation in accordance to Article 8 and in order to address significant factual changes in circumstances, such as the evolution of system requirements including penetration of renewable energy sources, smart grids, distributed generation or demand response, the relevant TSO may propose to the regulatory authority concerned, or where applicable, to the **Contracting Party** to extend the application of this Regulation to existing HVDC systems and/or DC-connected power park modules.

For that purpose a sound and transparent quantitative cost-benefit analysis shall be carried out, in accordance with Articles 65 and 66. The analysis shall indicate:

(a) the costs, in regard to existing HVDC systems and DC-connected power park modules, of requiring compliance with this Regulation;

(b) the socioeconomic benefit resulting from applying the requirements set out in this Regulation; and

(c) the potential of alternative measures to achieve the required performance.

4. Before carrying out the quantitative cost-benefit analysis referred to in paragraph 3, the relevant TSO shall:

(a) carry out a preliminary qualitative comparison of costs and benefits;

(b) obtain approval from the relevant regulatory authority or, where applicable, the **Contracting Party**.

5. The relevant regulatory authority or, where applicable, the **Contracting Party** shall decide on the extension of the applicability of this Regulation to existing HVDC systems or DC-connected power park modules within six months of receipt of the report and the recommendation of the relevant TSO in accordance with paragraph 4 of Article 65. The decision of the regulatory authority or, where applicable, the **Contracting Party** shall be published.

6. The relevant TSO shall take account of the legitimate expectations of HVDC system owners and DC-connected power park modules owners as part of the assessment of the application of this Regulation to

existing HVDC systems or DC-connected power park modules.

7. The relevant TSO may assess the application of some or all of the provisions of this Regulation to existing HVDC systems or DC-connected power park modules every three years in accordance with the criteria and process set out in paragraphs 3 to 5.

Article 5

Regulatory aspects

1. Requirements of general application to be established by relevant system operators or TSOs under this Regulation shall be subject to approval by the entity designated by the **Contracting Party** and be published. The designated entity shall be the regulatory authority unless otherwise provided by the **Contracting Party**.

2. For site specific requirements to be established by relevant system operators or TSOs under this Regulation, **Contracting Parties** may require approval by a designated entity.

3. When applying this Regulation, **Contracting Parties**, competent entities and system operators shall:

(a) apply the principles of proportionality and non-discrimination;

(b) ensure transparency;

(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;

(d) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;

(e) consult with relevant DSOs and take account of potential impacts on their system;

(f) take into consideration agreed European standards and technical specifications.

4. The relevant system operator or TSO shall submit a proposal for requirements of general application, or the methodology used to calculate or establish them, for approval by the competent entity within two years of **expiry of the deadline for transposition** of this Regulation.

5. Where this Regulation requires the relevant system operator, relevant TSO, HVDC system owner, DC-connected power park module owner and/or the distribution system operator to seek agreement, they shall endeavour to do so within six months after a first proposal has been submitted by one party to the other parties. If no agreement has been found within this timeframe, each party may request the relevant regulatory authority to issue a decision within six months.

6. Competent entities shall take decisions on proposals for requirements or methodologies within six months following the receipt of such proposals.

7. If the relevant system operator or TSO deems an amendment to requirements or methodologies as provided for and approved under paragraph 1 and 2 to be necessary, the requirements provided for in paragraphs 3 to 8 shall apply to the proposed amendment. System operators and TSOs proposing an amendment shall take into account the legitimate expectations, if any, of HVDC system owners, DC-connected power park module owners, equipment manufacturers and other stakeholders based on the initially specified or agreed requirements or methodologies.

8. Any party having a complaint against a relevant system operator or TSO in relation to that relevant system operator's or TSO's obligations under this Regulation may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within two months after receipt of the complaint. That period may be extended by two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall have binding effect unless and until overruled on appeal.

9. Where the requirements under this Regulation are to be established by a relevant system operator that is not a TSO, **Contracting Parties** may provide that instead the TSO be responsible for establishing the relevant requirements.

Article 6

Multiple TSOs

1. Where more than one TSO exists in a **Contracting Party**, this Regulation shall apply to all those TSOs.

2. **Contracting Parties** may, under the national regulatory regime, provide that the responsibility of a TSO to comply with one or some or all obligations under this Regulation is assigned to one or more specific TSOs.

Article 7

Recovery of costs

1. The costs borne by system operators subject to network tariff regulation and stemming from the obligations laid down in this Regulation shall be assessed by the relevant regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered through network tariffs or other appropriate mechanisms.

2. If requested by the relevant regulatory authorities, system operators referred to in paragraph 1 shall, within three months of the request, provide the information necessary to facilitate assessment of the costs incurred.

Article 8

Public consultation

1. Relevant system operators and relevant TSOs shall carry out consultation with stakeholders, including the competent authorities of each **Contracting Party**, on proposals to extend the applicability of this Regulation to existing HVDC systems and DC-connected power park modules, in accordance with Article 4(3), on the report prepared in accordance with Article 65(3), and the cost-benefit analysis undertaken in accordance with Article 80(2). The consultation shall last at least for a period of one month.

2. The relevant system operators or relevant TSOs shall duly take into account the views of the stakeholders resulting from the consultations prior to the submission of the draft proposal or the report or cost benefit analysis for approval by the regulatory authority or, if applicable, the **Contracting Party**. In all cases, a

sound justification for including or not the views of the stakeholders shall be provided and published in a timely manner before, or simultaneously with, the publication of the proposal.

Article 9

Stakeholder involvement

The **Energy Community Regulatory Board**, in close cooperation with the European Network of Transmission System Operators for Electricity (ENTSO for Electricity), shall organise stakeholder involvement regarding the requirements for grid connection of HVDC systems and DC-connected power park modules, and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the requirements for grid connection of HVDC systems and DC-connected power park modules.

Article 10

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any persons, regulatory authorities or entities subject to the provisions of this Regulation.

3. Confidential information received by the persons, regulatory authorities or entities referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant **Energy Community** law.

4. Without prejudice to cases covered by national or **Energy Community** law, regulatory authorities, entities or persons who receive confidential information pursuant to this Regulation may use it only for the purpose of carrying out their duties under this Regulation.

TITLE II
GENERAL REQUIREMENTS FOR HVDC CONNECTIONS

CHAPTER 1
Requirements for active power control and frequency support

Article 11
Frequency ranges

1. An HVDC system shall be capable of staying connected to the network and remaining operable within the frequency ranges and time periods specified in Table 1, Annex I for the short circuit power range as specified in Article 32(2).

2. The relevant TSO and HVDC system owner may agree on wider frequency ranges or longer minimum times for operation if needed to preserve or to restore system security. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the HVDC system owner shall not unreasonably withhold consent.

3. Without prejudice to paragraph 1, an HVDC system shall be capable of automatic disconnection at frequencies specified by the relevant TSO.

4. The relevant TSO may specify a maximum admissible active power output reduction from its operating point if the system frequency falls below 49 Hz.

Article 12
Rate-of-change-of-frequency withstand capability

An HVDC system shall be capable of staying connected to the network and operable if the network frequency changes at a rate between – 2,5 and + 2,5 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 s).

Article 13
Active power controllability, control range and ramping rate

1. With regard to the capability of controlling the transmitted active power:

(a) an HVDC system shall be capable of adjusting the transmitted active power up to its maximum HVDC active power transmission capacity in each direction following an instruction from the relevant TSO.

The relevant TSO:

(i) may specify a maximum and minimum power step size for adjusting the transmitted active power;

(ii) may specify a minimum HVDC active power transmission capacity for each direction, below which

active power transmission capability is not requested; and

(iii) shall specify the maximum delay within which the HVDC system shall be capable of adjusting the transmitted active power upon receipt of request from the relevant TSO.

(b) the relevant TSO shall specify how an HVDC system shall be capable of modifying the transmitted active power infeed in case of disturbances into one or more of the AC networks to which it is connected. If the initial delay prior to the start of the change is greater than 10 milliseconds from receiving the triggering signal sent by the relevant TSO, it shall be reasonably justified by the HVDC system owner to the relevant TSO.

(c) the relevant TSO may specify that an HVDC system be capable of fast active power reversal. The power reversal shall be possible from the maximum active power transmission capacity in one direction to the maximum active power transmission capacity in the other direction as fast as technically feasible and reasonably justified by the HVDC system owner to the relevant TSOs if greater than 2 seconds.

(d) for HVDC systems linking various control areas or synchronous areas, the HVDC system shall be equipped with control functions enabling the relevant TSOs to modify the transmitted active power for the purpose of cross-border balancing.

2. An HVDC system shall be capable of adjusting the ramping rate of active power variations within its technical capabilities in accordance with instructions sent by relevant TSOs. In case of modification of active power according to points (b) and (c) of paragraph 1, there shall be no adjustment of ramping rate.

3. If specified by a relevant TSO, in coordination with adjacent TSOs, the control functions of an HVDC system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM-O, LFSM-U and frequency control. The triggering and blocking criteria shall be specified by relevant TSO and subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework.

Article 14

Synthetic inertia

1. If specified by a relevant TSO, an HVDC system shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency. The requirement shall at least take account of the results of the studies undertaken by TSOs to identify if there is a need to set out minimum inertia.

2. The principle of this control system and the associated performance parameters shall be agreed between the relevant TSO and the HVDC system owner.

Article 15

Requirements relating to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency

Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency shall be as set out in Annex II.

Article 16

Frequency control

1. If specified by the relevant TSO, an HVDC system shall be equipped with an independent control mode to modulate the active power output of the HVDC converter station depending on the frequencies at all connection points of the HVDC system in order to maintain stable system frequencies.

2. The relevant TSO shall specify the operating principle, the associated performance parameters and the activation criteria of the frequency control referred to in paragraph 1.

Article 17

Maximum loss of active power

1. An HVDC system shall be configured in such a way that its loss of active power injection in a synchronous area shall be limited to a value specified by the relevant TSOs for their respective load frequency control area, based on the HVDC system's impact on the power system.

2. Where an HVDC system connects two or more control areas, the relevant TSOs shall consult each other in order to set a coordinated value of the maximum loss of active power injection as referred to in paragraph 1, taking into account common mode failures.

CHAPTER 2

Requirements for reactive power control and voltage support

Article 18

Voltage ranges

1. Without prejudice to Article 25, an HVDC converter station shall be capable of staying connected to the network and capable of operating at HVDC system maximum current, within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to reference 1 pu voltage, and the time periods specified in Tables 4 and 5, Annex III. The establishment of the reference 1 pu voltage shall be subject to coordination between the adjacent relevant system operators.

2. The HVDC system owner and the relevant system operator, in coordination with the relevant TSO, may agree on wider voltage ranges or longer minimum times for operation than those specified in paragraph 1 in order to ensure the best use of the technical capabilities of an HVDC system if needed to preserve or to restore system security. If wider voltage ranges or longer minimum times for operation are economically and technically feasible, the HVDC system owner shall not unreasonably withhold consent.

3. An HVDC converter station shall be capable of automatic disconnection at connection point voltages specified by the relevant system operator, in coordination with the relevant TSO. The terms and settings for automatic disconnection shall be agreed between the relevant system operator, in coordination with the relevant TSO, and the HVDC system owner.

4. For connection points at reference 1 pu AC voltages not included in the scope set out in Annex III, the relevant system operator, in coordination with relevant TSOs, shall specify applicable requirements at the connection points.

5. Notwithstanding the provisions of paragraph 1, the relevant TSOs in **Moldova and Ukraine shall**, following consultation with relevant neighbouring TSOs, require HVDC converter stations to **operate** in the voltage ranges and for time periods that apply in the Continental Europe synchronous area.

Article 19

Short circuit contribution during faults

1. If specified by the relevant system operator, in coordination with the relevant TSO, an HVDC system shall have the capability to provide fast fault current at a connection point in case of symmetrical (3-phase) faults.

2. Where an HVDC system is required to have the capability referred to in paragraph 1, the relevant system operator, in coordination with the relevant TSO, shall specify the following:

(a) how and when a voltage deviation is to be determined as well as the end of the voltage deviation;

(b) the characteristics of the fast fault current;

(c) the timing and accuracy of the fast fault current, which may include several stages.

3. The relevant system operator, in coordination the relevant TSO, may specify a requirement for asymmetrical current injection in the case of asymmetrical (1-phase or 2-phase) faults.

Article 20

Reactive power capability

1. The relevant system operator, in coordination with the relevant TSO, shall specify the reactive power capability requirements at the connection points, in the context of varying voltage. The proposal for those requirements shall include a U-Q/P_{max}-profile, within the boundary of which the HVDC converter station shall be capable of providing reactive power at its maximum HVDC active power transmission capacity.

2. The U-Q/P_{max}-profile referred to in paragraph 1 shall comply with the following principles:

(a) the U-Q/P_{max}-profile shall not exceed the U-Q/P_{max}-profile envelope represented by the inner envelope in the figure set out in Annex IV, and does not need to be rectangular;

(b) the dimensions of the U-Q/P_{max}-profile envelope shall respect the values established for each synchronous area in the table set out in Annex IV. **The dimensions of the profile envelope applied in Moldova and Ukraine shall correspond to the values that apply in the Continental Europe synchronous area**; and

(c) the position of the U-Q/P_{max}-profile envelope shall lie within the limits of the fixed outer envelope in the figure set out in Annex IV.

3. An HVDC system shall be capable of moving to any operating point within its U-Q/P_{max} profile in timescales specified by the relevant system operator in coordination with the relevant TSO.

4. When operating at an active power output below the maximum HVDC active power transmission capacity ($P < P_{max}$), the HVDC converter station shall be capable of operating in every possible operating point, as specified by the relevant system operator in coordination with the relevant TSO and in accordance with the reactive power capability set out by the U-Q/P_{max} profile specified in paragraphs 1 to 3.

Article 21

Reactive power exchanged with the network

1. The HVDC system owner shall ensure that the reactive power of its HVDC converter station exchanged with the network at the connection point is limited to values specified by the relevant system operator in coordination with the relevant TSO.

2. The reactive power variation caused by the reactive power control mode operation of the HVDC converter Station, referred to in Article 22(1), shall not result in a voltage step exceeding the allowed value at the connection point. The relevant system operator, in coordination with the relevant TSO, shall specify this maximum tolerable voltage step value.

Article 22

Reactive power control mode

1. An HVDC converter station shall be capable of operating in one or more of the three following control modes, as specified by the relevant system operator in coordination with the relevant TSO:

(a) voltage control mode;

(b) reactive power control mode;

(c) power factor control mode.

2. An HVDC converter station shall be capable of operating in additional control modes specified by the relevant system operator in coordination with the relevant TSO.

3. For the purposes of voltage control mode, each HVDC converter station shall be capable of contributing to voltage control at the connection point utilising its capabilities, while respecting Articles 20 and 21, in accordance with the following control characteristics:

(a) a setpoint voltage at the connection point shall be specified to cover a specific operation range, either continuously or in steps, by the relevant system operator, in coordination with the relevant TSO;

(b) the voltage control may be operated with or without a deadband around the setpoint selectable in a range from zero to +/– 5% of reference 1 pu network voltage. The deadband shall be adjustable in steps as specified by the relevant system operator in coordination with the relevant TSO;

(c) following a step change in voltage, the HVDC converter station shall be capable of:

(i) achieving 90% of the change in reactive power output within a time t1 specified by the relevant system operator in coordination with the relevant TSO. The time t1 shall be in the range of 0,1-10 seconds; and

(ii) settling at the value specified by the operating slope within a time t2 specified by the relevant system

operator in coordination with the relevant TSO. The time t2 shall be in the range of 1-60 seconds, with a specified steady-state tolerance given in % of the maximum reactive power.

(d) voltage control mode shall include the capability to change reactive power output based on a combination of a modified setpoint voltage and an additional instructed reactive power component. The slope shall be specified by a range and step specified by the relevant system operator in coordination with the relevant TSO.

4. With regard to reactive power control mode, the relevant system operator shall specify a reactive power range in MVAr or in % of maximum reactive power, as well as its associated accuracy at the connection point, using the capabilities of the HVDC system, while respecting Articles 20 and 21.

5. For the purposes of power factor control mode, the HVDC converter station shall be capable of controlling the power factor to a target at the connection point, while respecting Articles 20 and 21. The available setpoints shall be available in steps no greater than a maximum allowed step specified by the relevant system operator.

6. The relevant system operator in coordination with the relevant TSO shall specify any equipment needed to enable the remote selection of control modes and relevant setpoints.

Article 23

Priority to active or reactive power contribution

Taking into account the capabilities of the HVDC system specified in accordance with this Regulation, the relevant TSO shall determine whether active power contribution or reactive power contribution shall have priority during low or high voltage operation and during faults for which fault-ride-through capability is required. If priority is given to active power contribution, its provision shall be established within a time from the fault inception as specified by relevant TSO.

Article 24

Power quality

An HVDC system owner shall ensure that its HVDC system connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network, at the connection point, exceeding the level specified by the relevant system operator in coordination with the relevant TSO. The process for necessary studies to be conducted and relevant data to be provided by all grid users involved, as well as mitigating actions identified and implemented, shall be in accordance with the process in Article 29.

CHAPTER 3
Requirements for fault ride through capability

Article 25
Fault ride through capability

1. The relevant TSO shall specify, while respecting Article 18, a voltage-against time profile as set out in Annex V and having regard to the voltage-against-time-profile specified for power park modules according to Regulation (EU) 2016/631. This profile shall apply at connection points for fault conditions, under which the HVDC converter station shall be capable of staying connected to the network and continuing stable operation after the power system has recovered following fault clearance. The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault. Any ride through period beyond t_{rec2} shall be specified by the relevant TSO consistent with Article 18.

2. On request by the HVDC system owner, the relevant system operator shall provide the pre-fault and post-fault conditions as provided for in Article 32 regarding:

(a) pre-fault minimum short circuit capacity at each connection point expressed in MVA;

(b) pre-fault operating point of the HVDC converter station expressed as active power output and reactive power output at the connection point and voltage at the connection point; and

(c) post-fault minimum short circuit capacity at each connection point expressed in MVA.

Alternatively, generic values for the above conditions derived from typical cases may be provided by the relevant system operator.

3. The HVDC converter station shall be capable of staying connected to the network and continue stable operation when the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, given the pre-fault and post-fault conditions provided for in Article 32, remain above the lower limit set out in the figure in Annex V, unless the protection scheme for internal faults requires the disconnection of the HVDC converter station from the network. The protection schemes and settings for internal faults shall be designed not to jeopardise fault-ride-through performance.

4. The relevant TSO may specify voltages (Ublock) at the connection points under specific network conditions whereby the HVDC system is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a time frame that shall be as short as technically feasible and which shall be agreed between the relevant TSOs and the HVDC system owner.

5. In accordance Article 34, undervoltage protection shall be set by the HVDC system owner to the widest possible technical capability of the HVDC converter station. The relevant system operator, in coordination with the relevant TSO, may specify narrower settings pursuant to Article 34.

6. The relevant TSO shall specify fault-ride-through capabilities in case of asymmetrical faults.

Article 26

Post fault active power recovery

The relevant TSO shall specify the magnitude and time profile of active power recovery that the HVDC system shall be capable of providing, in accordance with Article 25.

Article 27

Fast recovery from DC faults

HVDC systems, including DC overhead lines, shall be capable of fast recovery from transient faults within the HVDC system. Details of this capability shall be subject to coordination and agreements on protection schemes and settings pursuant to Article 34.

CHAPTER 4
Requirements for control

Article 28

Energisation and synchronisation of HVDC converter stations

Unless otherwise instructed by the relevant system operator, during the energisation or synchronisation of an HVDC converter station to the AC network or during the connection of an energised HVDC converter station to an HVDC system, the HVDC converter station shall have the capability to limit any voltage changes to a steady-state level specified by the relevant system operator in coordination with the relevant TSO. The level specified shall not exceed 5 per cent of the pre-synchronisation voltage. The relevant system operator, in coordination with the relevant TSO, shall specify the maximum magnitude, duration and measurement window of the voltage transients.

Article 29

Interaction between HVDC systems or other plants and equipment

1. When several HVDC converter stations or other plants and equipment are within close electrical proximity, the relevant TSO may specify that a study is required, and the scope and extent of that study, to demonstrate that no adverse interaction will occur. If adverse interaction is identified, the studies shall identify possible mitigating actions to be implemented to ensure compliance with the requirements of this Regulation.

2. The studies shall be carried out by the connecting HVDC system owner with the participation of all other parties identified by the TSOs as relevant to each connection point. **Contracting Parties** may provide that the responsibility for undertaking the studies in accordance with this Article lies with the TSO. All parties shall be informed of the results of the studies.

3. All parties identified by the relevant TSO as relevant to each connection point, including the relevant TSO, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. The relevant TSO shall collect this input and, where applicable, pass it on to the party responsible for the studies in accordance with Article 10.

4. The relevant TSO shall assess the result of the studies based on their scope and extent as specified in accordance with paragraph 1. If necessary for the assessment, the relevant TSO may request the HVDC system owner to perform further studies in line with the scope and extent specified in accordance with paragraph 1.

5. The relevant TSO may review or replicate some or all of the studies. The HVDC system owner shall provide the relevant TSO all relevant data and models that allow such study to be performed.

6. Any necessary mitigating actions identified by the studies carried out in accordance with paragraphs 2 to 5 and reviewed by the relevant TSO shall be undertaken by the HVDC system owner as part of the connection of the new HVDC converter station.

7. The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and that of grid users in a manner consistent with its national code.

Article 30

Power oscillation damping capability

The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations. The relevant TSO shall specify a frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by TSOs to identify the stability limits and potential stability problems in their transmission systems. The selection of the control parameter settings shall be agreed between the relevant TSO and the HVDC system owner.

Article 31

Subsynchronous torsional interaction damping capability

1. With regard to subsynchronous torsional interaction (SSTI) damping control, the HVDC system shall be capable of contributing to electrical damping of torsional frequencies.

2. The relevant TSO shall specify the necessary extent of SSTI studies and provide input parameters, to the extent available, related to the equipment and relevant system conditions in its network. The SSTI studies shall be provided by the HVDC system owner. The studies shall identify the conditions, if any, where SSTI exists and propose any necessary mitigation procedure. **Contracting Parties** may provide that the responsibility for undertaking the studies in accordance with this Article lies with the TSO. All parties shall be informed of the results of the studies.

3. All parties identified by the relevant TSO as relevant to each connection point, including the relevant TSO, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. The relevant TSO shall collect this input and, where applicable, pass it on to the party responsible for the studies in accordance with Article 10.

4. The relevant TSO shall assess the result of the SSTI studies. If necessary for the assessment, the relevant TSO may request that the HVDC system owner perform further SSTI studies in line with this same scope and extent.

5. The relevant TSO may review or replicate the study. The HVDC system owner shall provide the relevant TSO all relevant data and models that allow such study to be performed.

6. Any necessary mitigating actions identified by the studies carried out in accordance with paragraphs 2 or 4, and reviewed by the relevant TSOs, shall be undertaken by the HVDC system owner as part of the connection of the new HVDC converter station.

Article 32

Network characteristics

1. The relevant system operator shall specify and make publicly available the method and the pre-fault and post-fault conditions for the calculation of at least the minimum and maximum short circuit power at the connection points.

2. The HVDC system shall be capable of operating within the range of short circuit power and network characteristics specified by the relevant system operator.

3. Each relevant system operator shall provide the HVDC system owner with network equivalents describing the behaviour of the network at the connection point, enabling the HVDC system owners to design their system with regard to at least, but not limited to, harmonics and dynamic stability over the lifetime of the HVDC system.

Article 33

HVDC system robustness

1. The HVDC system shall be capable of finding stable operation points with a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system or AC network to which it is connected. The relevant TSO shall specify the changes in the system conditions for which the HVDC systems shall remain in stable operation.

2. The HVDC system owner shall ensure that the tripping or disconnection of an HVDC converter station, as part of any multi-terminal or embedded HVDC system, does not result in transients at the connection point beyond the limit specified by the relevant TSO.

3. The HVDC system shall withstand transient faults on HVAC lines in the network adjacent or close to the HVDC system, and shall not cause any of the equipment in the HVDC system to disconnect from the network due to auto-reclosure of lines in the network.

4. The HVDC system owner shall provide information to the relevant system operator on the resilience of the HVDC system to AC system disturbances.

CHAPTER 5
Requirements for protection devices and settings

Article 34
Electrical protection schemes and settings

1. The relevant system operator shall specify, in coordination with the relevant TSO, the schemes and settings necessary to protect the network taking into account the characteristics of the HVDC system. Protection schemes relevant for the HVDC system and the network, and settings relevant for the HVDC system, shall be coordinated and agreed between the relevant system operator, the relevant TSO and the HVDC system owner. The protection schemes and settings for internal electrical faults shall be designed so as not to jeopardise the performance of the HVDC system in accordance with this Regulation.

2. Electrical protection of the HVDC system shall take precedence over operational controls taking into account system security, health and safety of staff and the public and mitigation of the damage to the HVDC system.

3. Any change to the protection schemes or their settings relevant to the HVDC system and the network shall be agreed between the relevant system operator, the relevant TSO and the HVDC system owner before being implemented by the HVDC system owner.

Article 35
Priority ranking of protection and control

1. A control scheme, specified by the HVDC system owner consisting of different control modes, including the settings of the specific parameters, shall be coordinated and agreed between the relevant TSO, the relevant system operator and the HVDC system owner.

2. With regard to priority ranking of protection and control, the HVDC system owner shall organise its protections and control devices in compliance with the following priority ranking, listed in decreasing order of importance, unless otherwise specified by the relevant TSOs, in coordination with the relevant system operator:

(a) network system and HVDC system protection;

(b) active power control for emergency assistance;

(c) synthetic inertia, if applicable;

(d) automatic remedial actions as specified in Article 13(3);

(e) LFSM;

(f) FSM and frequency control; and

(g) power gradient constraint.

Article 36

Changes to protection and control schemes and settings

1. The parameters of the different control modes and the protection settings of the HVDC system shall be able to be changed in the HVDC converter station, if required by the relevant system operator or the relevant TSO, and in accordance with paragraph 3.

2. Any change to the schemes or settings of parameters of the different control modes and protection of the HVDC system, including the procedure, shall be coordinated and agreed between the relevant system operator, the relevant TSO and the HVDC system owner.

3. The control modes and associated setpoints of the HVDC system shall be capable of being changed remotely, as specified by the relevant system operator, in coordination with the relevant TSO.

CHAPTER 6
Requirements for power system restoration

Article 37

Black start

1. The relevant TSO may obtain a quote for black start capability from an HVDC system owner.

2. An HVDC system with black start capability shall be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a time-frame after shut down of the HVDC system determined by the relevant TSOs. The HVDC system shall be able to synchronise within the frequency limits set out in Article 11 and within the voltage limits specified by the relevant TSO or as provided for in Article 18, where applicable. Wider frequency and voltage ranges can be specified by the relevant TSO where needed in order to restore system security.

3. The relevant TSO and the HVDC system owner shall agree on the capacity and availability of the black start capability and the operational procedure.

TITLE III

REQUIREMENTS FOR DC-CONNECTED POWER PARK MODULES AND REMOTE-END HVDC CONVERTER STATIONS

CHAPTER 1

Requirements for DC-connected power park modules

Article 38

Scope

The requirements applicable to offshore power park modules under Articles 13 to 22 of Regulation (EU) 2016/631 shall apply to DC-connected power park modules subject to specific requirements provided for in Articles 41 to 45 of this Regulation. These requirements shall apply at the HVDC interface points of the DC-connected power park module and the HVDC systems. The categorisation in Article 5 of Regulation (EU) 2016/631 shall apply to DC-connected power park modules.

Article 39

Frequency stability requirements

1. With regards to frequency response:

(a) a DC-connected power park module shall be capable of receiving a fast signal from a connection point in the synchronous area to which frequency response is being provided, and be able to process this signal within 0,1 second from sending to completion of processing the signal for activation of the response. Frequency shall be measured at the connection point in the synchronous area to which frequency response is being provided;

(b) DC-connected power park modules connected via HVDC systems which connect with more than one control area shall be capable of delivering coordinated frequency control as specified by the relevant TSO.

2. With regard to frequency ranges and response:

(a) a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operating within the frequency ranges and time periods specified in Annex VI for the 50 Hz nominal system. Where a nominal frequency other than 50 Hz, or a frequency variable by design is used, subject to agreement with the relevant TSO, the applicable frequency ranges and time periods shall be specified by the relevant TSO taking into account specificities of the system and the requirements set out in Annex VI;

(b) wider frequency ranges or longer minimum times for operation can be agreed between the relevant TSO and the DC-connected power park module owner to ensure the best use of the technical capabilities of a DC-connected power park module if needed to preserve or to restore system security. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the DC-connected power park module owner shall not unreasonably withhold consent;

(c) while respecting the provisions of point (a) of paragraph 2, a DC-connected power park module shall be capable of automatic disconnection at specified frequencies, if specified by the relevant TSO. Terms and settings for automatic disconnection shall be agreed between the relevant TSO and the DC-connected power park module owner.

3. With regards to rate-of-change-of-frequency withstand capability, a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operable if the system frequency changes at a rate up to +/– 2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second) at the HVDC interface point of the DC-connected power park module at the remote end HVDC converter station for the 50 Hz nominal system.

4. DC-connected power park modules shall have limited frequency sensitive mode-overfrequency (LFSM-O) capability in accordance with Article 13(2) of Regulation (EU) 2016/631, subject to fast signal response as specified in paragraph 1 for the 50 Hz nominal system.

5. A capability for DC-connected power park modules to maintain constant power shall be determined in accordance with Article 13(3) of Regulation (EU) 2016/631 for the 50 Hz nominal system.

6. A capability for active power controllability of DC-connected power park modules shall be determined in accordance with Article 15(2)(a) of Regulation (EU) 2016/631 for the 50 Hz nominal system. Manual control shall be possible in the case that remote automatic control devices are out of service.

7. A capability for limited frequency sensitive mode-underfrequency (LFSM-U) for a DC-connected power park module shall be determined in accordance with Article 15(2)(c) of Regulation (EU) 2016/631, subject to fast signal response as specified in paragraph 1 for the 50 Hz nominal system.

8. A capability for frequency sensitive mode for a DC-connected power park module shall be determined in accordance with Article 15(2)(d) of Regulation (EU) 2016/631, subject to a fast signal response as specified in paragraph 1 for the 50 Hz nominal system.

9. A capability for frequency restoration for a DC-connected power park module shall be determined in accordance with Article 15(2)(e) of Regulation (EU) 2016/631 for the 50 Hz nominal system.

10. Where a constant nominal frequency other than 50 Hz, a frequency variable by design or a DC system voltage is used, subject to the agreement of the relevant TSO, the capabilities listed in paragraphs 3 to 9 and the parameters associated with such capabilities shall be specified by the relevant TSO.

Article 40

Reactive power and voltage requirements

1. With respect to voltage ranges:

(a) a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operating within the voltage ranges (per unit), for the time periods specified in Tables 9 and 10, Annex VII. The applicable voltage range and time periods specified are selected based on the reference 1 pu voltage;

(b) wider voltage ranges or longer minimum times for operation can be agreed between the relevant system operator, the relevant TSO and the DC-connected power park module owner to ensure the best use of the technical capabilities of a DC-connected power park module if needed to preserve or to restore system

security. If wider voltage ranges or longer minimum times for operation are economically and technically feasible, the DC-connected power park module owner shall not unreasonably withhold consent;

(c) for DC-connected power park modules which have an HVDC interface point to the remote-end HVDC converter station network, the relevant system operator, in coordination with the relevant TSO may specify voltages at the HVDC interface point at which a DC-connected power park module shall be capable of automatic disconnection. The terms and settings for automatic disconnection shall be agreed between the relevant system operator, the relevant TSO and the DC-connected power park module owner;

(d) for HVDC interface points at AC voltages that are not included in the scope of Annex VII, the relevant system operator, in coordination with the relevant TSO shall specify applicable requirements at the connection point;

(e) where frequencies other than nominal 50 Hz are used, subject to relevant TSO agreement, the voltage ranges and time periods specified by the relevant system operator, in coordination with the relevant TSO, shall be proportional to those in Tables 9 and 10, Annex VII.

2. With respect to reactive power capability for DC-connected power park modules:

(a) if the DC-connected power park module owner can obtain a bilateral agreement with the owners of the HVDC systems connecting the DC-connected power park module to a single connection point on a AC network, it shall fulfil all of the following requirements:

(i) it shall have the ability with additional plant or equipment and/or software, to meet the reactive power capabilities prescribed by the relevant system operator, in coordination with the relevant TSO, according to point (b), and it shall either:

- have the reactive power capabilities for some or all of its equipment in accordance with point (b) already installed as part of the connection of the DC-connected power park module to the AC network at the time of initial connection and commissioning; or

- demonstrate to, and then reach agreement with, the relevant system operator and the relevant TSO on how the reactive power capability will be provided when the DC-connected power park module is connected to more than a single connection point in the AC network, or the AC network at the remote-end HVDC converter station network has either another DC-connected power park module or HVDC system with a different owner connected to it. This agreement shall include a contract by the DC-connected power park module owner (or any subsequent owner), that it will finance and install reactive power capabilities required by this Article for its power park modules at a point in time specified by the relevant system operator, in coordination with the relevant TSO. The relevant system operator, in coordination with the relevant TSO shall inform the DC-connected power park module owner of the proposed completion date of any committed development which will require the DC-connected power park module owner to install the full reactive power capability.

(ii) the relevant system operator, in coordination with the relevant TSO shall account for the development time schedule of retrofitting the reactive power capability to the DC-connected power park module in specifying the point in time by which this reactive power capability retrofitting is to take place. The development time schedule shall be provided by the DC-connected power park module owner at the time of connection to the AC network.

(b) DC-connected power park modules shall fulfil the following requirements relating to voltage stability either at the time of connection or subsequently, according to the agreement as referred to in point (a):

(i) with regard to reactive power capability at maximum HVDC active power transmission capacity, DC-connected power park modules shall meet the reactive power provision capability requirements specified by the relevant system operator, in coordination with the relevant TSO, in the context of varying voltage. The relevant system operator shall specify a U-Q/P_{max}-profile that may take any shape with ranges in accordance with Table 11, Annex VII, within which the DC-connected power park module shall be capable of providing reactive power at its maximum HVDC active power transmission capacity. The relevant system operator, in coordination with the relevant TSO, shall consider the long term development of the network when determining these ranges, as well as the potential costs for power park modules of delivering the capability of providing reactive power production at high voltages and reactive power consumption at low voltages.

If the Ten-Year Network Development Plan, where applicable, or a national plan developed and approved in accordance with Article 22 of Directive 2009/72/EC specifies that a DC-connected power park module will become AC-connected to the synchronous area, the relevant TSO may specify that either:

- the DC-connected power park module shall have the capabilities prescribed in Article 25(4) of Regulation (EU) 2016/631 for that synchronous area installed at the time of initial connection and commissioning of the DC-connected power park module to the AC-network; or

- the DC-connected power park module owner shall demonstrate to, and then reach agreement with, the relevant system operator and the relevant TSO on how the reactive power capability prescribed in Article 25(4) of Regulation (EU) 2016/631 for that synchronous area will be provided in the event that the DC-connected power park module becomes AC-connected to the synchronous area.

(ii) With regard to reactive power capability, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a DC-connected power park module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the alternator terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power exchange of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the DC-connected power park module or its alternator terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable.

3. With regard to priority to active or reactive power contribution for DC-connected power park modules, the relevant system operator, in coordination with the relevant TSO shall specify whether active power contribution or reactive power contribution has priority during faults for which fault-ride-through capability is required. If priority is given to active power contribution, its provision shall be established within a time from the fault inception as specified by the relevant system operator, in coordination with the relevant TSO.

Article 41

Control requirements

1. During the synchronisation of a DC-connected power park module to the AC collection network, the DC-connected power park module shall have the capability to limit any voltage changes to a steady-state level specified by the relevant system operator, in coordination with the relevant TSO. The level specified shall not exceed 5 per cent of the pre-synchronisation voltage. The relevant system operator, in coordi-

nation with the relevant TSO, shall specify the maximum magnitude, duration and measurement window of the voltage transients.

2. The DC-connected power park module owner shall provide output signals as specified by the relevant system operator, in coordination with the relevant TSO.

Article 42

Network characteristics

With regard to the network characteristics, the following shall apply for the DC-connected power park modules:

(a) each relevant system operator shall specify and make publicly available the method and the pre-fault and post-fault conditions for the calculation of minimum and maximum short circuit power at the HVDC interface point;

(b) the DC-connected power park module shall be capable of stable operation within the minimum to maximum range of short circuit power and network characteristics of the HVDC interface point specified by the relevant system operator, in coordination with the relevant TSO;

(c) each relevant system operator and HVDC system owner shall provide the DC-connected power park module owner with network equivalents representing the system, enabling the DC-connected power park module owners to design their system with regard to harmonics;

Article 43

Protection requirements

1. Electrical protection schemes and settings of DC-connected power park modules shall be determined in accordance with Article 14(5)(b) of Regulation (EU) 2016/631, where the network refers to the synchronous area network. The protection schemes have to be designed taking into account the system performance, grid specificities as well as technical specificities of the power park module technology and agreed with the relevant system operator, in coordination with the relevant TSO.

2. Priority ranking of protection and control of DC-connected power park modules shall be determined in accordance with Article 14(5)(c) of Regulation (EU) 2016/631, where the network refers to the synchronous area network, and agreed with the relevant system operator, in coordination with the relevant TSO.

Article 44

Power quality

DC-connected power park modules owners shall ensure that their connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network, at the connection point, exceeding the level specified by the relevant system operator, in coordination with the relevant TSO. The necessary contribution from grid users to associated studies, including, but not limited to, existing DC-con-

nected power park modules and existing HVDC systems, shall not be unreasonably withheld. The process for necessary studies to be conducted and relevant data to be provided by all grid users involved, as well as mitigating actions identified and implemented, shall be in accordance with the process in Article 29.

Article 45

General system management requirements applicable to DC-connected power park modules

With regard to general system management requirements, Articles 14(5), 15(6) and 16(4) of Regulation (EU) 2016/631 shall apply to any DC-connected power park module.

CHAPTER 2
Requirements for remote-end HVDC converter stations

Article 46

Scope

The requirements of Articles 11 to 39 apply to remote-end HVDC converter stations, subject to specific requirements provided for in Articles 47 to 50.

Article 47

Frequency stability requirements

1. Where a nominal frequency other than 50 Hz, or a frequency variable by design is used in the network connecting the DC-connected power park modules, subject to relevant TSO agreement, Article 11 shall apply to the remote-end HVDC converter station with the applicable frequency ranges and time periods specified by the relevant TSO, taking into account specificities of the system and the requirements laid down in Annex I.

2. With regards to frequency response, the remote-end HVDC converter station owner and the DC-connected power park module owner shall agree on the technical modalities of the fast signal communication in accordance with Article 39(1). Where the relevant TSO requires, the HVDC system shall be capable of providing the network frequency at the connection point as a signal. For an HVDC system connecting a power park module the adjustment of active power frequency response shall be limited by the capability of the DC-connected power park modules.

Article 48

Reactive power and voltage requirements

1. With respect to voltage ranges:

(a) a remote-end HVDC converter station shall be capable of staying connected to the remote-end HVDC converter station network and operating within the voltage ranges (per unit) and time periods specified in Tables 12 and 13, Annex VIII. The applicable voltage range and time periods specified are selected based on the reference 1 pu voltage;

(b) wider voltage ranges or longer minimum times for operation may be agreed between the relevant system operator, in coordination with the relevant TSO, and the DC-connected power park module owner in accordance with Article 40;

(c) for HVDC interface points at AC voltages that are not included in the scope of Table 12 and Table 13, Annex VIII, the relevant system operator, in coordination with the relevant TSO shall specify applicable requirements at the connection points;

(d) where frequencies other than nominal 50 Hz are used, subject to agreement by the relevant TSO, the voltage ranges and time periods specified by the relevant system operator, in coordination with the relevant TSO, shall be proportional to those in Annex VIII.

2. A remote-end HVDC converter station shall fulfil the following requirements referring to voltage stability, at the connection points with regard to reactive power capability:

(a) the relevant system operator, in coordination with the relevant TSO shall specify the reactive power provision capability requirements for various voltage levels. In doing so, the relevant system operator, in coordination with the relevant TSO shall specify a U-Q/P_{max}-profile of any shape and within the boundaries of which the remote-end HVDC converter station shall be capable of providing reactive power at its maximum HVDC active power transmission capacity;

(b) the U-Q/P_{max}-profile shall be specified by each relevant system operator, in coordination with the relevant TSO. The U-Q/P_{max}-profile shall be within the range of Q/P_{max} and steady-state voltage specified in Table 14, Annex VIII, and the position of the U-Q/P_{max}-profile envelope shall lie within the limits of the fixed outer envelope specified in Annex IV. The relevant system operator, in coordination with the relevant TSO, shall consider the long term development of the network when determining these ranges.

Article 49

Network characteristics

With regard to the network characteristics, the remote-end HVDC converter station owner shall provide relevant data to any DC-connected power park module owner in accordance with Article 42.

Article 50

Power quality

Remote-end HVDC converter station owners shall ensure that their connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network, at the connection point, exceeding the level allocated to them by the relevant system operator, in coordination with the relevant TSO. The necessary contribution from grid users to the associated studies shall not be unreasonably withheld, including from, but not limited to, existing DC-connected power park modules and existing HVDC systems. The process for necessary studies to be conducted and relevant data to be provided by all grid users involved, as well as mitigating actions identified and implemented shall be in accordance with the process provided for in Article 29.

TITLE IV
INFORMATION EXCHANGE AND COORDINATION

Article 51

Operation of HVDC systems

1. With regard to instrumentation for the operation, each HVDC converter unit of an HVDC system shall be equipped with an automatic controller capable of receiving instructions from the relevant system operator and from the relevant TSO. This automatic controller shall be capable of operating the HVDC converter units of the HVDC system in a coordinated way. The relevant system operator shall specify the automatic controller hierarchy per HVDC converter unit.

2. The automatic controller of the HVDC system referred to in paragraph 1 shall be capable of sending the following signal types to the relevant system operator:

(a) operational signals, providing at least the following:

(i) start-up signals;

(ii) AC and DC voltage measurements;

(iii) AC and DC current measurements;

(iv) active and reactive power measurements on the AC side;

(v) DC power measurements;

(vi) HVDC converter unit level operation in a multi-pole type HVDC converter;

(vii) elements and topology status; and

(viii) FSM, LFSM-O and LFSM-U active power ranges.

(b) alarm signals, providing at least the following:

(i) emergency blocking;

(ii) ramp blocking;

(iii) fast active power reversal.

3. The automatic controller referred to in paragraph 1 shall be capable of receiving the following signal types from the relevant system operator:

(a) operational signals, receiving at least the following:

(i) start-up command;

(ii) active power setpoints;

(iii) frequency sensitive mode settings;

(iv) reactive power, voltage or similar setpoints;

(v) reactive power control modes;

(vi) power oscillation damping control; and

(vii) synthetic inertia.

(b) alarm signals, receiving at least the following:

(i) emergency blocking command;

(ii) ramp blocking command;

(iii) active power flow direction; and

(iv) fast active power reversal command.

4. With regards to each signal, the relevant system operator may specify the quality of the supplied signal.

Article 52

Parameters and settings

The parameters and settings of the main control functions of an HVDC system shall be agreed between the HVDC system owner and the relevant system operator, in coordination with the relevant TSO. The parameters and settings shall be implemented within such a control hierarchy that makes their modification possible if necessary. Those main control functions are at least:

(a) synthetic inertia, if applicable as referred to in Articles 14 and 41;

(b) frequency sensitive modes (FSM, LFSM-O, LFSM-U) referred to in Articles 15, 16 and 17;

(c) frequency control, if applicable, referred to in Article 16;

(d) reactive power control mode, if applicable as referred to in Article 22;

(e) power oscillation damping capability, referred to Article 30;

(f) subsynchronous torsional interaction damping capability, referred to Article 31.

Article 53

Fault recording and monitoring

1. An HVDC system shall be equipped with a facility to provide fault recording and dynamic system behaviour monitoring of the following parameters for each of its HVDC converter stations:

(a) AC and DC voltage;

(b) AC and DC current;

(c) active power;

(d) reactive power; and

(e) frequency.

2. The relevant system operator may specify quality of supply parameters to be complied with by the HVDC system, provided a reasonable prior notice is given.

3. The particulars of the fault recording equipment referred to in paragraph 1, including analogue and digital channels, the settings, including triggering criteria and the sampling rates, shall be agreed between the HVDC system owner, the relevant system operator and the relevant TSO.

4. All dynamic system behaviour monitoring equipment shall include an oscillation trigger, specified by the relevant system operator, in coordination with the relevant TSO, with the purpose of detecting poorly damped power oscillations.

5. The facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the HVDC system owner and the relevant system operator to access the information electronically. The communications protocols for recorded data shall be agreed between the HVDC system owner, the relevant system operator and the relevant TSO.

Article 54

Simulation models

1. The relevant system operator in coordination with the relevant TSO may specify that an HVDC system owner deliver simulation models which properly reflect the behaviour of the HVDC system in both steady-state, dynamic simulations (fundamental frequency component) and in electromagnetic transient simulations.

The format in which models shall be provided and the provision of documentation of models structure and block diagrams shall be specified by the relevant system operator in coordination with the relevant TSO.

2. For the purpose of dynamic simulations, the models provided shall contain at least, but not limited to the following sub-models, depending on the existence of the mentioned components:

(a) HVDC converter unit models;

(b) AC component models;

(c) DC grid models;

(d) Voltage and power controller;

(e) Special control features if applicable e.g. power oscillation damping (POD) function, subsynchronous torsional interaction (SSTI) control;

(f) Multi terminal control, if applicable;

(g) HVDC system protection models as agreed between the relevant TSO and the HVDC system owner.

3. The HVDC system owner shall verify the models against the results of compliance tests carried out according to Title VI and a report of this verification shall be submitted to the relevant TSO. The models shall then be used for the purpose of verifying compliance with the requirements of this Regulation including, but not limited to, compliance simulations as provided for in Title VI and used in studies for continuous

evaluation in system planning and operation.

4. An HVDC system owner shall submit HVDC system recordings to the relevant system operator or relevant TSO if requested in order to compare the response of the models with these recordings.

5. An HVDC system owner shall deliver an equivalent model of the control system when adverse control interactions may result with HVDC converter stations and other connections in close electrical proximity if requested by the relevant system operator or relevant TSO. The equivalent model shall contain all necessary data for the realistic simulation of the adverse control interactions.

TITLE V
OPERATIONAL NOTIFICATION PROCEDURE FOR CONNECTION

CHAPTER 1
Connection of new HVDC systems

Article 55
General provisions

1. The HVDC system owner shall demonstrate to the relevant system operator that it has complied with the requirements set out in Title II to Title IV at the respective connection point by successfully completing the operational notification procedure for connection of the HVDC system as described in Articles 56 to 59.

2. The relevant system operator shall specify any detailed provisions of the operational notification procedure and make the details publicly available.

3. The operational notification procedure for connection for each new HVDC system shall comprise:

(a) energisation operational notification (EON);

(b) interim operational notification (ION); and

(c) final operational notification (FON).

Article 56
EON for HVDC systems

1. An EON shall entitle the HVDC system owner to energise its internal network and auxiliaries and connect it to the network at its specified connection points.

2. An EON shall be issued by the relevant system operator, subject to completion of preparation and the fulfilment of the requirements specified by the relevant system operator in the relevant operational procedures. This preparation will include agreement on the protection and control settings relevant to the connection points between the relevant system operator and the HVDC system owner.

Article 57

ION for HVDC systems

1. An ION shall entitle a HVDC system owner or HVDC converter unit owner to operate the HVDC system or HVDC converter unit by using the network connections specified for the connection points for a limited period of time.

2. An ION shall be issued by the relevant system operator subject to the completion of the data and study review process.

3. For the purpose of the completion of data and study review, the HVDC system owner or HVDC converter unit owner shall provide the following upon request from the relevant system operator:

(a) itemised statement of compliance;

(b) detailed technical data of the HVDC system with relevance to the network connection, that is specified with respect to the connection points, as specified by the relevant system operator, in coordination with the relevant TSOs;

(c) equipment certificates of HVDC systems or HVDC converter units where these are relied upon as part of the evidence of compliance;

(d) simulation models or a replica of the exact control system as specified by Article 54 and by the relevant system operator in coordination with the relevant TSOs;

(e) studies demonstrating expected steady-state and dynamic performance as required by Titles II, III and IV;

(f) details of intended compliance tests according to Article 72;

(g) details of intended practical method of completing compliance tests pursuant to Title VI.

4. Except where paragraph 5 applies, the maximum period for the HVDC system owner or HVDC converter unit owner to remain in the ION status shall not exceed twenty four months. The relevant system operator may specify a shorter ION validity period. The ION validity period shall be notified to the regulatory authority in accordance with the applicable national regulatory framework. ION extension shall be granted only if the HVDC system owner demonstrates substantial progress towards full compliance. At the time of ION extension, the outstanding issues shall be explicitly identified.

5. The maximum period for an HVDC system owner or HVDC converter unit owner to remain in the ION status may be extended beyond 24 months upon request for a derogation made to the relevant system operator in accordance with the procedure in Title VII. The request shall be made before the expiry of the twenty four month period.

Article 58

FON for HVDC systems

1. A FON shall entitle an HVDC system owner to operate the HVDC system or HVDC converter units by using the grid connection points.

2. A FON shall be issued by the relevant system operator upon prior removal of all incompatibilities identified for the purpose of the ION status and subject to the completion of the data and study review process.

3. For the purpose of the completion of data and study review, the HVDC system owner shall provide the following upon request from the relevant system operator in coordination with the relevant TSO:

(a) itemised statement of compliance; and

(b) update of applicable technical data, simulation models, a replica of the exact control system and studies as referred to in Article 57, including use of actual measured values during testing.

4. In case of incompatibility identified for the purpose of the granting of the FON, a derogation may be granted upon a request to the relevant system operator, in accordance with Articles 79 and 80. A FON shall be issued by the relevant system operator, if the HVDC system is compliant with the provisions of the derogation.

Where a request for a derogation is rejected, the relevant system operator shall have the right to refuse the operation of the HVDC system or HVDC converter units, whose owner's request for a derogation was rejected, until the HVDC system owner and the relevant system operator have resolved the incompatibility and the relevant system operator considers that the HVDC system complies with the provisions of this Regulation.

If the relevant system operator and the HVDC system owner do not resolve the incompatibility within a reasonable timeframe, but in any case not later than six months after the notification of the rejection of the request for a derogation, each party may refer the issue for decision to the regulatory authority.

Article 59

Limited operational notification for HVDC systems/derogations

1. HVDC system owners to whom a FON has been granted shall inform the relevant system operator immediately in the following circumstances:

(a) the HVDC system is temporarily subject to either a significant modification or loss of capability, due to implementation of one or more modifications of significance to its performance; or

(b) in case of equipment failures leading to non-compliance with some relevant requirements.

2. The HVDC system owner shall apply to the relevant system operator for a limited operational notification (LON) if the HVDC system owner reasonably expects the circumstances detailed in paragraph 1 to persist for more than three months.

3. A LON shall be issued by the relevant system operator with a clear identification of:

(a) the unresolved issues justifying the granting of the LON;

(b) the responsibilities and timescales for expected solution; and

(c) a maximum period of validity which shall not exceed 12 months. The initial period granted may be shorter with the possibility for extension if evidence to the satisfaction of the relevant system operator demonstrates that substantial progress has been made towards achieving full compliance.

4. The FON shall be suspended during the period of validity of the LON with regard to the subjects for which the LON has been issued.

5. A further prolongation of the period of validity of the LON may be granted upon request for a derogation made to the relevant system operator before the expiry of that period, in accordance with Articles 79 and 80.

6. The relevant system operator may refuse the operation of the HVDC system if the LON terminates and the circumstance which caused it to be issued remains. In such a case the FON shall automatically be invalid.

7. If the relevant system operator does not grant an extension of the period of validity of the LON in accordance with paragraph 5 or if it refuses to allow the operation of the HVDC system once the LON is no longer valid in accordance with paragraph 6, the HVDC system owner may refer the issue for decision to the regulatory authority within six months after the notification of the decision of the relevant system operator.

CHAPTER 2
Connection of new DC-connected power park modules

Article 60
General provisions

1. The provisions of this Chapter shall apply to new DC-connected power park modules only.

2. The DC-connected power park module owner shall demonstrate to the relevant system operator its compliance with the requirements referred to in Title III at the respective connection points by successfully completing the operational notification procedure for connection of the DC-connected power park module in accordance with Articles 61 through to 66.

3. The relevant system operator shall specify further details of the operational notification procedure and make those details publically available.

4. The operational notification procedure for connection for each new DC-connected power park module shall comprise:

(a) energisation operational notification (EON);

(b) interim operational notification (ION); and

(c) final operational notification (FON).

Article 61
EON for DC-connected power park modules

1. An EON shall entitle the owner of a DC-connected power park module to energise its internal network and auxiliaries by using the grid connection that is specified by the connection points.

2. An EON shall be issued by the relevant system operator, subject to completion of preparation including agreement on the protection and control settings relevant to the connection points between the relevant system operator and the DC-connected power park module.

Article 62

ION for DC-connected power park modules

1. An ION shall entitle the DC-connected power park module owner to operate the DC-connected power park module and generate power by using the grid connection for a limited period of time.

2. An ION shall be issued by the relevant system operator, subject to the completion of the data and study review process.

3. With respect to data and study review, the DC-connected power park module owner shall provide the following upon request from the relevant system operator:

(a) itemised statement of compliance;

(b) detailed technical data of the DC-connected power park module with relevance to the grid connection, that is specified by the connection points, as specified by the relevant system operator in coordination with the relevant TSO;

(c) equipment certificates of DC-connected power park module, where these are relied upon as part of the evidence of compliance;

(d) simulation models as specified in Article 54 and as required by the relevant system operator in coordination with the relevant TSO;

(e) studies demonstrating expected steady-state and dynamic performance as required by Title III; and

(f) details of intended compliance tests in accordance with Article 73.

4. Except where paragraph 5 applies, the maximum period for the DC-connected power park module owner to remain in the ION status shall not exceed twenty-four months. The relevant system operator may specify shorter ION validity. The ION validity period shall be notified to the regulatory authority in accordance with the applicable national regulatory framework. ION extensions shall be granted only if the DC-connected power park module owner demonstrates substantial progress towards full compliance. At the time of ION extension, any outstanding issues shall be explicitly identified.

5. The maximum period for a DC-connected power park module owner to remain in the ION status may be extended beyond 24 months upon request for a derogation made to the relevant system operator in accordance with the procedure in Title VII.

Article 63

FON for DC-connected power park modules

1. A FON shall entitle the DC-connected power park module owner to operate the DC-connected power park module by using the grid connection that is specified by the connection point.

2. A FON shall be issued by the relevant system operator, upon prior removal of all incompatibilities identified for the purpose of the ION status and subject to the completion of the data and study review process as required by this Regulation.

3. For the purpose of the completion of data and study review, the DC-connected power park module owner shall provide the following upon request from the relevant system operator:

(a) itemised statement of compliance; and

(b) update of applicable technical data, simulation models and studies as referred to in Article 62(3), including use of actual measured values during testing.

4. In case of incompatibility identified for the purpose of the granting of the FON, a derogation may be granted upon request made to the relevant system operator, in accordance with the derogation procedure according to Title VII. A FON shall be issued by the relevant system operator, if the DC-connected power park module is compliant with the provisions of the derogation. The relevant system operator shall have the right to refuse the operation of the DC-connected power park module, whose owner's request for a derogation was rejected, until the DC-connected power park module owner and the relevant system operator have resolved the incompatibility and the DC-connected power park module is considered to be compliant by the relevant system operator.

Article 64

Limited operational notification for DC-connected power park modules

1. DC-connected power park module owners to whom a FON has been granted shall inform the relevant system operator immediately in the following circumstances:

(a) the DC-connected power park module is temporarily subject to either a significant modification or loss of capability, due to implementation of one or more modifications of significance to its performance; or

(b) in case of equipment failures leading to non-compliance with some relevant requirements.

2. The DC-connected power park module owner shall apply to the relevant system operator for a limited operational notification (LON), if the DC-connected power park module owner reasonably expects the circumstances detailed in paragraph 1 to persist for more than three months.

3. A LON shall be issued by the relevant TSO with a clear identification of:

(a) the unresolved issues justifying the granting of the LON;

(b) the responsibilities and timescales for expected solution; and

(c) a maximum period of validity which shall not exceed 12 months. The initial period granted may be shorter with the possibility for extension if evidence to the satisfaction of the relevant system operator demonstrating that substantial progress has been made towards achieving full compliance.

4. The FON shall be suspended during the period of validity of the LON with regard to the subjects for which the LON has been issued.

5. A further prolongation of the period of validity of the LON may be granted upon request for a derogation made to the relevant system operator, before the expiry of that period, in accordance with the derogation procedure described in Title VII.

6. The relevant system operator may refuse the operation of the DC-connected power park module if the LON terminates and the circumstance which caused it to be issued remains. In such a case the FON shall automatically be invalid.

CHAPTER 3
Cost benefit analysis

Article 65

Identification of costs and benefits of application of requirements to existing HVDC systems or DC-connected power park modules

1. Prior to the application of any requirement set out in this Regulation to existing HVDC systems or DC-connected power park modules in accordance with paragraph 3 of Article 4, the relevant TSO shall undertake a qualitative comparison of costs and benefits related to the requirement under consideration. This comparison shall take into account available network-based or market-based alternatives. The relevant TSO may only proceed to undertake a quantitative cost-benefit analysis in accordance with paragraphs 2 to 5, if the qualitative comparison indicates that the likely benefits exceed the likely costs. If, however, the cost is deemed high or the benefit is deemed low, then the relevant TSO shall not proceed further.

2. Following a preparatory stage undertaken in accordance with paragraph 1, the relevant TSO shall carry out a quantitative cost-benefit analysis of any requirement under consideration for application to existing HVDC systems or DC-connected power park modules that have demonstrated potential benefits as a result of the preparatory stage according to paragraph 1.

3. Within three months of concluding the cost-benefit analysis, the relevant TSO shall summarise the findings in a report which shall:

(a) include the cost-benefit analysis and a recommendation on how to proceed;

(b) include a proposal for a transitional period for applying the requirement to existing HVDC systems or DC-connected power park modules. That transitional period shall not be more than two years from the date of the decision of the regulatory authority or where applicable the **Contracting Party** on the requirement's applicability;

(c) be subject to public consultation in accordance with Article 8.

4. No later than six months after the end of the public consultation, the relevant TSO shall prepare a report explaining the outcome of the consultation and making a proposal on the applicability of the requirement under consideration to existing HVDC systems or DC-connected power park modules. The report and proposal shall be notified to the regulatory authority or, where applicable, the **Contracting Party**, and the HVDC system owner, DC-connected power park module owner or, where applicable, third party shall be informed on its content.

5. The proposal made by the relevant TSO to the regulatory authority or, where applicable, the **Contracting Party** pursuant to paragraph 4 shall include the following:

(a) an operational notification procedure for demonstrating the implementation of the requirements by the owner of the existing HVDC system or DC-connected power park module;

(b) a transitional period for implementing the requirements which shall take into account the category of HVDC system or DC-connected power park module and any underlying obstacles to the efficient implementation of the equipment modification/refitting.

Article 66

Principles of cost-benefit analysis

1. HVDC system owners, DC-connected power park module owners and DSOs, including CDSOs, shall assist and contribute to the cost-benefit analysis undertaken according to Article 65 and 80 and provide the necessary data as requested by the relevant system operator or relevant TSO within three months of receiving a request, unless agreed otherwise by the relevant TSO. For the preparation of a cost-benefit-analysis by a HVDC system owner or DC-connected power park module owner, or their prospective owner, assessing a potential derogation pursuant to Article 79, the relevant TSO and DSO, including CDSO, shall assist and contribute to the cost-benefit analysis and provide the necessary data as requested by the HVDC system owner or DC-connected power park module owner, or their prospective owner, within three months of receiving a request, unless agreed otherwise by the HVDC system owner or DC-connected power park module owner, or their prospective owner.

2. A cost-benefit analysis shall be in line with the following principles:

(a) the relevant TSO, or HVDC system owner or DC-connected power park module owner, or their prospective owner, shall base its cost-benefit analysis on one or more of the following calculating principles:

(i) the net present value;

(ii) the return on investment;

(iii) the rate of return;

(iv) the time needed to break even.

(b) the relevant TSO, or HVDC system owner or DC-connected power park module owner, or their prospective owner, shall also quantify socioeconomic benefits in terms of improvement in security of supply and shall include at least:

(i) the associated reduction in probability of loss of supply over the lifetime of the modification;

(ii) the probable extent and duration of such loss of supply;

(iii) the societal cost per hour of such loss of supply.

(c) the relevant TSO, or HVDC system owner or DC-connected power park module owner, or their prospective owner, shall quantify the benefits to the internal market in electricity, cross-border trade and integration of renewable energies, including at least:

(i) the active power frequency response;

(ii) the balancing reserves;

(iii) the reactive power provision;

(iv) congestion management;

(v) defence measures.

(d) the relevant TSO shall quantify the costs of applying the necessary rules to existing HVDC systems or DC-connected power park modules, including at least:

(i) the direct costs incurred in implementing a requirement;

(ii) the costs associated with attributable loss of opportunity;

(iii) the costs associated with resulting changes in maintenance and operation.

TITLE VI
COMPLIANCE

CHAPTER 1
Compliance monitoring

Article 67
Common provisions for compliance testing

1. Testing of the performance of HVDC systems and DC-connected power park modules shall aim at demonstrating that the requirements of this Regulation have been complied with.

2. Notwithstanding the minimum requirements for compliance testing set out in this Regulation, the relevant system operator is entitled to:

(a) allow the HVDC system owner or DC-connected power park module owner to carry out an alternative set of tests, provided that those tests are efficient and suffice to demonstrate that a HVDC system or DC-connected power park module complies with the requirements of this Regulation; and

(b) require the HVDC system owner or DC-connected power park module owner to carry out additional or alternative sets of tests in those cases where the information supplied to the relevant system operator in relation to compliance testing under the provisions of Chapter 2 of Title VI, is not sufficient to demonstrate compliance with the requirements of this Regulation.

3. The HVDC system owner or DC-connected power park module owner is responsible for carrying out the tests in accordance with the conditions laid down in Chapter 2 of Title VI. The relevant system operator shall cooperate and not unduly delay the performance of the tests.

4. The relevant system operator may participate in the compliance testing either on site or remotely from the system operator's control centre. For that purpose, the HVDC system owner or DC-connected power park module owner shall provide the monitoring equipment necessary to record all relevant test signals and measurements as well as ensure that the necessary representatives of the HVDC system owner or DC-connected power park module owner available on site for the entire testing period. Signals specified by the relevant system operator shall be provided if, for selected tests, the system operator wishes to use its own equipment to record performance. The relevant system operator has sole discretion to decide about its participation.

Article 68
Common provisions on compliance simulation

1. Simulation of the performance of HVDC systems and DC-connected power park modules shall aim at demonstrating that the requirements of this Regulation have been fulfilled.

2. Notwithstanding the minimum requirements set out in this Regulation for compliance simulation, the relevant system operator may:

(a) allow the HVDC system owner or DC-connected power park module owner to carry out an alternative set of simulations, provided that those simulations are efficient and suffice to demonstrate that a HVDC system or DC-connected power park module complies with the requirements of this Regulation or with national legislation; and

(b) require the HVDC system owner or DC-connected power park module owner to carry out additional or alternative sets of simulations in those cases where the information supplied to the relevant system operator in relation to compliance simulation under the provisions of Chapter 3 of Title VI, is not sufficient to demonstrate compliance with the requirements of this Regulation.

3. To demonstrate compliance with the requirements of this Regulation, the HVDC system owner and DC-connected power park module owner shall provide a report with the simulation results. The HVDC system owner and DC-connected power park module owner shall produce and provide a validated simulation model for a given HVDC system or DC-connected power park module. The scope of the simulation models is set out in Articles 38 and 54.

4. The relevant system operator shall have the right to check that a HVDC system and DC-connected power park module complies with the requirements of this Regulation by carrying out its own compliance simulations based on the provided simulation reports, simulation models and compliance test measurements.

5. The relevant system operator shall provide the HVDC system owner or DC-connected power park module owner with technical data and a simulation model of the network, to the extent necessary to carry out the requested simulations in accordance with Chapter 3 of Title VI.

Article 69

Responsibility of the HVDC system owner and DC-connected power park module owner

1. The HVDC system owner shall ensure that the HVDC system and HVDC converter stations are compliant with the requirements provided for by this Regulation. This compliance shall be maintained throughout the lifetime of the facility.

2. The DC-connected power park module owner shall ensure that the DC-connected power park module is compliant with the requirements under this Regulation. This compliance shall be maintained throughout the lifetime of the facility.

3. Planned modifications of the technical capabilities of the HVDC system, HVDC converter station or DC-connected power park module with possible impact on its compliance to the requirements under this Regulation shall be notified to the relevant system operator by the HVDC system owner or DC-connected power park module owner before initiating such modification.

4. Any operational incidents or failures of an HVDC system, HVDC converter station or DC-connected power park module that have impact on its compliance to the requirements of this Regulation shall be notified to the relevant system operator by the HVDC system owner or DC-connected power park module owner as soon as possible without any delay after the occurrence of such an incident.

5. Any foreseen test schedules and procedures to verify compliance of an HVDC system, HVDC converter station or DC-connected power park module with the requirements of this Regulation shall be notified to the relevant system operator by the HVDC system owner or DC-connected power park module owner in due time and prior to their launch and shall be approved by the relevant system operator.

6. The relevant system operator shall be facilitated to participate in such tests and may record the performance of the HVDC systems, HVDC converter stations or DC-connected power park modules.

Article 70

Tasks of the relevant system operator

1. The relevant system operator shall assess the compliance of an HVDC system, HVDC converter station and DC-connected power park module with the requirements under this Regulation throughout the lifetime of the HVDC system, HVDC converter station or DC-connected power park module. The HVDC system owner or DC-connected power park module owner shall be informed of the outcome of this assessment.

2. Where requested by the relevant system operator, the HVDC system owner or DC-connected power park module owner shall carry out compliance tests and simulations, not only during the operational notification procedures according to Title V, but repeatedly throughout the lifetime of the HVDC system, HVDC converter station or DC-connected power park module according to a plan or general scheme for repeated tests and specified simulations or after any failure, modification or replacement of any equipment that may have impact on the compliance with the requirements under this Regulation. The HVDC system owner or DC-connected power park module owner shall be informed of the outcome of these compliance tests and simulations.

3. The relevant system operator shall make publicly available the list of information and documents to be provided as well as the requirements to be fulfilled by the HVDC system owner or DC-connected power park module owner in the frame of the compliance process. Such list shall cover at least the following information, documents and requirements:

(a) all documentation and certificates to be provided by the HVDC system owner or DC-connected power park module owner;

(b) details of the technical data of the HVDC system, HVDC converter station or DC-connected power park module with relevance to the grid connection;

(c) requirements for models for steady-state and dynamic system studies;

(d) timeline for the provision of system data required to perform the studies;

(e) studies by the HVDC system owner or DC-connected power park module owner to demonstrate the expected steady-state and dynamic performance in accordance with the requirements set out in Titles II, III and IV;

(f) conditions and procedures including the scope for registering equipment certificates; and

(g) conditions and procedures for use of relevant equipment certificates, issued by an authorised certifier, by the DC-connected power park module owner.

4. The relevant system operator shall make publicly available the allocation of responsibilities to the HVDC system owner or DC-connected power park module owner and to the system operator for compliance testing, simulation and monitoring.

5. The relevant system operator may partially or totally assign the performance of its compliance monitoring to third parties. In this case, the relevant system operator shall ensure compliance with Article 10 by appropriate confidentiality commitments with the assignee.

6. The relevant system operator shall not unreasonably withhold any operational notification in accordance with Title V, if compliance tests or simulations cannot be performed as agreed between the relevant system operator and the HVDC system owner or DC-connected power park module owner due to reasons which are in the sole control of the relevant system operator.

7. The relevant system operator shall provide the relevant TSO when requested the compliance test and simulation results referred to in this Chapter.

CHAPTER 2
Compliance testing

Article 71
Compliance testing for HVDC systems

1. Equipment certificates may be used instead of part of the tests below, on the condition that they are provided to the relevant system operator.

2. With regard to the reactive power capability test:

(a) the HVDC converter unit or the HVDC converter station shall demonstrate its technical capability to provide leading and lagging reactive power capability according to Article 20;

(b) the reactive power capability test shall be carried out at maximum reactive power, both leading and lagging, and concerning the verification of the following parameters:

(i) Operation at minimum HVDC active power transmission capacity;

(ii) Operation at maximum HVDC active power transmission capacity;

(iii) Operation at active power setpoint between those minimum and maximum HVDC active power transmission capacity.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC converter unit or the HVDC converter station has been operating no shorter than 1 hour at maximum reactive power, both leading and lagging, for each parameter as referred to in point (b);

(ii) the HVDC converter unit or the HVDC converter station demonstrates its capability to change to any reactive power setpoint within the applicable reactive power range within the specified performance targets of the relevant reactive power control scheme; and

(iii) no action of any protection within the operation limits specified by reactive power capacity diagram occurs.

3. With regard to the voltage control mode test:

(a) the HVDC converter unit or the HVDC converter station shall demonstrate its capability to operate in voltage control mode in the conditions set forth in Article 22(3);

(b) the voltage control mode test shall apply concerning the verification of the following parameters:

(i) the implemented slope and deadband of the static characteristic;

(ii) the accuracy of the regulation;

(iii) the insensitivity of the regulation;

(iv) the time of reactive power activation.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the range of regulation and adjustable droop and deadband is compliant with agreed or decided characteristic parameters, according to Article 22(3);

(ii) the insensitivity of voltage control is not higher than 0,01 pu;

(iii) following a step change in voltage, 90% of the change in reactive power output has been achieved within the times and tolerances according to Article 22(3).

4. With regard to the reactive power control mode test:

(a) the HVDC converter unit or the HVDC converter station shall demonstrate its capability to operate in reactive power control mode, according to the conditions referred to in Article 22(4);

(b) the reactive power control mode test shall be complementary to the reactive power capability test;

(c) the reactive power control mode test shall apply concerning the verification of the following parameters:

(i) the reactive power setpoint range and step;

(ii) the accuracy of the regulation; and

(iii) the time of reactive power activation.

(d) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the reactive power setpoint range and step is ensured according to Article 22(4);

(ii) the accuracy of the regulation is compliant with the conditions as referred to in Article 22(3).

5. With regard to the power factor control mode test:

(a) the HVDC converter unit or the HVDC converter station shall demonstrate its capability to operate in power factor control mode according to the conditions referred to in Article 22(5);

(b) the power factor control mode test shall apply concerning the verification of the following parameters:

(i) the power factor setpoint range;

(ii) the accuracy of the regulation;

(iii) the response of reactive power due to step change of active power.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the power factor setpoint range and step is ensured according to Article 22(5);

(ii) the time of reactive power activation as result of step active power change does not exceed the requirements specified in accordance with Article 22(5);

(iii) the accuracy of the regulation is compliant with the value, as referred to in Article 22(5).

6. With regard to the FSM response test:

(a) the HVDC system shall demonstrate its technical capability to continuously modulate active power over the full operating range between maximum HVDC active power transmission capacity and minimum HVDC active power transmission capacity to contribute to frequency control and shall verify the steady-state parameters of regulations, such as droop and deadband and dynamic parameters, including robustness during frequency step change response and large, fast frequency changes;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to activate at least 10% of the full active power frequency response range in each direction, taking into account the droop settings and the deadband. Simulated frequency deviation signals shall be injected into the controller of the HVDC converter unit or the HVDC converter station;

(c) the test shall be deemed to be passed, provided that the following conditions are all fulfilled:

(i) activation time of full active power frequency response range as result of a step frequency change has been no longer than required by Annex II;

(ii) undamped oscillations do not occur after the step change response;

(iii) the initial delay time has been according to Annex II;

(iv) the droop settings are available within the range provided for in Annex II and deadband (thresholds) is not more than the value in Annex II;

(v) insensitivity of active power frequency response at any relevant operating point does not exceed the requirements set forth in Annex II.

7. With regard to the LFSM-O response test:

(a) the HVDC system shall demonstrate its technical capability to continuously modulate active power to contribute to frequency control in case of large increase of frequency in the system and shall verify the steady-state parameters of regulations, such as droop and deadband, and dynamic parameters, including frequency step change response;

(b) the test shall be carried out by simulating frequency steps and ramps big enough to activate at least 10% of the full operating range for active power, taking into account the droop settings and the deadband. Simulated frequency deviation signals shall be injected into the controller of the HVDC converter unit or the HVDC converter station;

(c) the test shall be deemed passed, provided that the following conditions are both fulfilled:

(i) the test results, for both dynamic and static parameters, are in line with the requirements as referred to in Annex II;

(ii) undamped oscillations do not occur after the step change response.

8. With regard to the LFSM-U response test:

(a) the HVDC system shall demonstrate its technical capability to continuously modulate active power at operating points below maximum HVDC active power transmission capacity to contribute to frequency control in case of large drop of frequency in the system;

(b) the test shall be carried out by simulating at appropriate active power load points with low frequency steps and ramps big enough to activate at least 10% of the full operating range for active power, taking into account the droop settings and the deadband. Simulated frequency deviation signals shall be injected into the controller of the HVDC converter unit or the HVDC converter station;

(c) the test shall be deemed passed, provided that the following conditions are both fulfilled:

(i) the test results, for both dynamic and static parameters, are in line with the requirements as referred to in Annex II;

(ii) undamped oscillations do not occur after the step change response.

9. With regard to the active power controllability test:

(a) the HVDC system shall demonstrate its technical capability to continuously modulate active power over the full operating range according to Article 13(1)(a) and (d);

(b) the test shall be carried out by sending manual and automatic instructions by the relevant TSO;

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC system has demonstrated stable operation;

(ii) the time of adjustment of the active power is shorter than the delay specified pursuant to Article 13(1)(a);

(iii) the dynamic response of the HVDC system when receiving instructions for the purposes of exchange or sharing of reserves, or for participating in imbalance netting processes, if capable of fulfilling the requirements for these products, as specified by the relevant TSO, has been demonstrated.

10. With regard to the ramping rate modification test:

(a) the HVDC system shall demonstrate its technical capability to adjust the ramping rate according to Article 13(2);

(b) the test shall be carried out by relevant TSO sending instructions of ramping modifications;

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) ramping rate is adjustable;

(ii) the HVDC system has demonstrated stable operation during ramping periods.

11. With regard to the black start test, if applicable:

(a) the HVDC system shall demonstrate its technical capability to energise the busbar of the remote AC sub-station to which it is connected, within a time frame specified by the relevant TSO, according to Article 37(2);

(b) the test shall be carried out while the HVDC system starts from shut down;

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC system has demonstrated being able to energise the busbar of the remote AC-substation to which it is connected;

(ii) the HVDC system operates from a stable operating point at agreed capacity, according to the procedure of Article 37(3).

Article 72

Compliance testing for DC-connected power park modules and remote-end HVDC converter units

1. Equipment certificates may be used instead of part of the tests below, on the condition that they are provided to the relevant system operator.

2. With regard to the reactive power capability test of DC-connected power park modules:

(a) the DC-connected power park module shall demonstrate its technical capability to provide leading and lagging reactive power capability according to Article 40(2);

(b) the reactive power capability test shall be carried out at maximum reactive power, both leading and lagging, and concerning the verification of the following parameters:

(i) operation in excess of 60% of maximum capacity for 30 minutes;

(ii) operation within the range of 30-50% of maximum capacity for 30 minutes; and

(iii) operation within the range of 10-20% of maximum capacity for 60 minutes.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the DC-connected power park module has been operating no shorter than requested duration at maximum reactive power, both leading and lagging, in each parameter as referred to in point (b);

(ii) the DC-connected power park module has demonstrated its capability to change to any reactive power setpoint within the agreed or decided reactive power range within the specified performance targets of the relevant reactive power control scheme; and

(iii) no action of any protection within the operation limits specified by reactive power capacity diagram occurs.

3. With regard to the reactive power capability test of remote-end HVDC converter units:

(a) the HVDC converter unit or the HVDC converter station shall demonstrate its technical capability to provide leading and lagging reactive power capability according to Article 48(2);

(b) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC converter unit or the HVDC converter station has been operating no shorter than 1 hour at maximum reactive power, both leading and lagging, at:

- minimum HVDC active power transmission capacity;

- maximum HVDC active power transmission capacity; and

- an active power operating point between those maximum and minimum ranges.

(ii) the HVDC converter unit or the HVDC converter station demonstrates its capability to change to any reactive power setpoint within the agreed or decided reactive power range within the specified performance targets of the relevant reactive power control scheme; and

(iii) no action of any protection within the operation limits specified by reactive power capacity diagram occurs.

4. With regard to the voltage control mode test:

(a) the DC-connected power park module shall demonstrate its capability to operate in voltage control mode in the conditions set forth in Article 21 of Regulation (EU) 2016/631;

(b) the voltage control mode test shall apply concerning the verification of the following parameters:

(i) the implemented slope and deadband of the static characteristic;

(ii) the accuracy of the regulation;

(iii) the insensitivity of the regulation;

(iv) the time of reactive power activation.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the range of regulation and adjustable the droop and deadband is compliant with agreed or decided characteristic parameters, according to Article 21(3)(d) of Regulation (EU) 2016/631;

(ii) the insensitivity of voltage control is not higher than 0,01 pu, according to Article 21(3)(d) of Regulation (EU) 2016/631;

(iii) following a step change in voltage, 90% of the change in reactive power output has been achieved

within the times and tolerances according to Article 21(3)(d) of Regulation (EU) 2016/631.

5. With regard to the reactive power control mode test:

(a) the DC-connected power park module shall demonstrate its capability to operate in reactive power control mode, according to the conditions referred to in Article 21(3)(d)(iii) of Regulation (EU) 2016/631;

(b) the reactive power control mode test shall be complementary to the reactive power capability test;

(c) the reactive power control mode test shall apply concerning the verification of the following parameters:

(i) the reactive power setpoint range and step;

(ii) the accuracy of the regulation;

(iii) the time of reactive power activation.

(d) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the reactive power setpoint range and step is ensured according to Article 21(3)(d) of Regulation (EU) 2016/631;

(ii) the accuracy of the regulation is compliant with the conditions as referred to in Article 21(3)(d) of Regulation (EU) 2016/631.

6. With regard to the power factor control mode test:

(a) the DC-connected power park module shall demonstrate its capability to operate in power factor control mode according to the conditions referred to in Article 21(3)(d)(iv) of Regulation (EU) 2016/631;

(b) the power factor control mode test shall apply concerning the verification of the following parameters:

(i) the power factor setpoint range;

(ii) the accuracy of the regulation;

(iii) the response of reactive power due to step change of active power.

(c) the test shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the power factor setpoint range and step is ensured according to Article 21(3)(d) of Regulation (EU) 2016/631;

(ii) the time of reactive power activation as result of step active power change does not exceed the requirement according to Article 21(3)(d) of Regulation (EU) 2016/631;

(iii) the accuracy of the regulation is compliant with the value, as referred to in Article 21(3)(d) of Regulation (EU) 2016/631.

7. With regard to the tests identified in paragraphs 4, 5 and 6 the relevant TSO may select only two of the three control options for testing.

8. With regard to LFSM-O response of DC-connected power park module, the tests shall be carried out in accordance with Article 47(3) of Regulation (EU) 2016/631.

9. With regard to LFSM-U response of DC-connected power park module, the tests shall be carried out in accordance with Article 48(3) of Regulation (EU) 2016/631.

10. With regard to active power controllability of DC-connected power park module, the tests shall be carried out in accordance with 48(2) of Regulation (EU) 2016/631.

11. With regard to FSM response of DC-connected power park module, the tests shall be carried out in accordance with Article 48(4) of Regulation (EU) 2016/631.

12. With regard to frequency restoration control of DC-connected power park module, the tests shall be carried out in accordance with Article 45(5) of Regulation (EU) 2016/631.

13. With regard to fast signal response of DC-connected power park module, the test shall be deemed passed if the DC-connected power park module can demonstrate its response within the time specified in Article 39(1)(a).

14. With regard to tests for DC-connected power park modules where the AC collection network is not at nominal 50 Hz frequency, the relevant system operator, in coordination with the relevant TSO, shall agree with the DC-connected power park module owner the compliance tests required.

CHAPTER 3
Compliance simulations

Article 73
Compliance simulations for HVDC systems

1. Equipment certificates may be used instead of part of the simulations below, on the condition that they are provided to the relevant system operator.

2. With regard to the fast fault current injection simulation:

(a) the HVDC converter unit owner or the HVDC converter station owner shall simulate fast fault current injection in the conditions set forth in Article 19;

(b) the simulation is deemed passed, provided that compliance with the requirements specified in accordance with Article 19 is demonstrated.

3. With regard to the fault-ride-through capability simulation:

(a) the HVDC system owner shall simulate the capability for fault-ride-through in the conditions set forth in Article 25; and

(b) the simulation is deemed passed, provided that compliance with the requirements specified in accordance with Article 25 is demonstrated.

4. With regard to the post fault active power recovery simulation:

(a) the HVDC system owner shall simulate the capability for post fault active power recovery in the conditions set forth in Article 26;

(b) the simulation is deemed passed, provided that compliance with the requirements specified in accordance with Article 26 is demonstrated.

5. With regard to the reactive power capability simulation:

(a) the HVDC converter unit owner or the HVDC converter station owner shall simulate the capability for leading and lagging reactive power capability in the conditions referred to in Article 20(2) to (4);

(b) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the simulation model of the HVDC converter unit or the HVDC converter station is validated against the compliance tests for reactive power capability as referred to in Article 71;

(ii) compliance with the requirements as referred to in Article 20(2) to (4) is demonstrated.

6. With regard to the power oscillations damping control simulation:

(a) the HVDC system owner shall demonstrate the performance of its control system (POD function) to damp power oscillations in the conditions set forth in Article 30;

(b) the tuning shall result in improved damping of corresponding active power response of the HVDC system in combination with the POD function compared to the active power response of the HVDC system without POD;

(c) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the POD function damps the existing power oscillations of the HVDC system within a frequency range specified by the relevant TSO. This frequency range shall include the local mode frequency of the HVDC system and the expected network oscillations; and

(ii) a change of active power transfer of the HVDC system as specified by the relevant TSO does not lead to undamped oscillations in active or reactive power of the HVDC system.

7. With regard to the simulation of active power modification in case of disturbance:

(a) the HVDC system owner shall simulate the capability to quickly modify active power according to Article 13(1)(b); and

(b) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC system has demonstrated stable operation when following the pre-specified sequence of active power variation;

(ii) the initial delay of the adjustment of the active power is shorter than the value specified in Article 13(1)(b) or reasonably justified if greater.

8. With regard to the fast active power reversal simulation, as applicable:

(a) the HVDC system owner shall simulate the capability to quickly reverse active power according to Article 13(1)(c);

(b) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the HVDC system has demonstrated stable operation;

(ii) the time of adjustment of the active power is shorter than the value specified in Article 13(1)(c) or reasonably justified if greater.

Article 74

Compliance simulations for DC-connected power park modules and remote-end HVDC converter units

1. DC-connected power park modules are subject to the compliance simulations detailed in this Article. Equipment certificates may be used instead of part of the simulations described below, on the condition that they are provided to the relevant system operator.

2. With regard to the fast fault current injection simulation:

(a) the DC-connected power park module owner shall simulate the capability for fast fault current injection

in the conditions set forth in Article 20(2)(b) of Regulation (EU) 2016/631; and

(b) the simulation shall be deemed passed, provided that compliance with the requirement according to Article 20(2)(b) of Regulation (EU) 2016/631 is demonstrated.

3. With regard to the post fault active power recovery simulation:

(a) the DC-connected power park module owner shall simulate the capability for post fault active power recovery in the conditions set forth in Article 20(3)(a) of Regulation (EU) 2016/631; and

(b) the simulation shall be deemed passed, provided that compliance with the requirement according to Article 20(3)(a) of Regulation (EU) 2016/631 is demonstrated.

4. With regard to the reactive power capability simulation of DC-connected power park modules:

(a) the DC-connected power park module owner shall simulate the capability for leading and lagging reactive power capability in the conditions referred to in Article 40(2); and

(b) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the simulation model of the DC-connected power park module is validated against the compliance tests for reactive power capability as referred to in Article 72(2);

(ii) compliance with the requirements as referred to in Article 40(2) is demonstrated.

5. With regard to the reactive power capability simulation of remote-end HVDC converter units:

(a) the remote-end HVDC converter unit owner or the remote-end HVDC converter station owner shall simulate the capability for leading and lagging reactive power capability in the conditions referred to in Article 48(2); and

(b) the simulation shall be deemed passed, provided that the following conditions are cumulatively fulfilled:

(i) the simulation model of the remote-end HVDC converter unit or the remote-end HVDC converter station is validated against the compliance tests for reactive power capability at the as referred to in Article 72(3);

(ii) compliance with the requirements as referred to in Article 48(2) is demonstrated.

6. With regard to the power oscillations damping control simulation:

(a) the DC-connected power park module owner shall simulate the capability for power oscillations damping under the conditions as referred to in Article 21(3)(f) of Regulation (EU) 2016/631; and

(b) the simulation shall be deemed passed, provided that the model demonstrates compliance with the conditions of Article 21(3)(f) of Regulation (EU) 2016/631.

7. With regard to fault-ride-through capability simulation:

(a) the DC-connected power park module owner shall simulate the capability for fault-ride-through under the conditions as referred to in Article 16(3)(a) of Regulation (EU) 2016/631;

(b) the simulation shall be deemed passed, provided that the model demonstrates compliance with the conditions of Article 16(3)(a) of Regulation (EU) 2016/631.

CHAPTER 4
Non-binding guidance and monitoring of implementation

Article 75
Non-binding guidance on implementation

1 **<...>**

2 **<...>**

3. The non-binding guidance **published by ENTSO for Electricity** explains the technical issues, conditions and interdependencies which need to be considered when complying with the requirements of this Regulation at national level.

Article 76
Monitoring

1. ENTSO for Electricity shall monitor the implementation of this Regulation **for the Contracting Parties whose TSOs are members of ENTSO for Electricity. The Secretariat and the Energy Community Regulatory Board shall monitor the implementation of this Regulation for the Contracting Parties whose TSOs are not members of ENTSO for Electricity <...>**. Monitoring **shall take into account the list of relevant information developed by the Agency for the Cooperation of Energy Regulators and** it shall cover in particular the following matters:

(a) identification of any divergences in the national implementation of this Regulation;

(b) assessment of whether the choice of values and ranges in the requirements applicable to HVDC systems and DC-connected power park modules under this Regulation continues to be valid.

ENTSO for Electricity shall report its findings to the Secretariat and the Energy Community Regulatory Board The Secretariat and the Energy Community Regulatory Board shall make available the findings stemming from the monitoring of the implementation of this Regulation.

2. **<...>**

3. Relevant TSOs shall submit to **the Secretariat, the Energy Community Regulatory Board and** ENTSO for Electricity the information required to perform the tasks referred to in paragraph 1 **<...>**.

Based on a request of the regulatory authority, DSOs shall provide TSOs with information under paragraph **1** unless the information is already obtained by regulatory authorities, the **Secretariat**, **Energy Community Regulatory Board** or ENTSO-E in relation to their respective implementation monitoring tasks, with the objective of avoiding duplication of information.

4. **<...>**

TITLE VII
DEROGATIONS

Article 77

Power to grant derogations

1. Regulatory authorities may, at the request of a HVDC system owner or DC-connected power park module owner, or their prospective owner, relevant system operator or relevant TSO, grant HVDC system owners or DC-connected power park module owners, or their prospective owner, relevant system operators or relevant TSOs derogations from one or more provisions of this Regulation for new and existing HVDC system and/or DC-connected power park modules in accordance with Articles 78 to 82.

2. Where applicable in a **Contracting Party**, derogations may be granted and revoked in accordance with Articles 78 to 81 by other authorities than the regulatory authority.

Article 78

General provisions

1. Each regulatory authority shall specify, after consulting relevant system operators, HVDC system owners and DC-connected power park module owners and other stakeholders whom it deems affected by this Regulation, the criteria for granting derogations pursuant to Articles 79 to 81. It shall publish those criteria on its website and notify them to the **Secretariat** within nine months of the **expiry of the deadline for transposition** of this Regulation. The **Secretariat** may require a regulatory authority to amend the criteria if it considers that they are not in line with this Regulation. This possibility to review and amend the criteria for granting derogations shall not affect the derogations already granted which shall continue to apply until the scheduled expiry date as detailed in the decision granting the exemption.

2. If the regulatory authority deems that it is necessary due to a change in circumstances relating to the evolution of system requirements, it may review and amend at most once every year the criteria for granting derogations in accordance with paragraph 1. Any changes to the criteria shall not apply to derogations for which a request has already been made.

3. The regulatory authority may decide that HVDC systems or DC-connected power park modules for which a request for a derogation has been filed pursuant to Articles 79 to 81 do not need to comply with the requirements of this Regulation from which a derogation has been sought from the day of filing the request until the regulatory authority's decision is issued.

Article 79

Request for derogations by an HVDC system owner or DC-connected power park module owner

1. HVDC system owners and DC-connected power park module owners, or their prospective owner, may request a derogation to one or several requirements of this Regulation.

2. A request for a derogation shall be filed with the relevant system operator and include:

(a) an identification of the HVDC system owner or DC-connected power park module owner, or their prospective owner, and a contact person for any communications;

(b) a description of the HVDC system or DC-connected power park module for which a derogation is requested;

(c) a reference to the provisions of this Regulation from which a derogation is requested and a detailed description of the requested derogation;

(d) detailed reasoning, with relevant supporting documents, and cost-benefit analysis pursuant to the requirements of Article 66;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade;

(f) in the case of a DC-connected power park module connected to one or more remote-end HVDC converter stations, evidence that the converter station will not be affected by the derogation or, alternatively, agreement from the converter station owner to the proposed derogation.

3. Within two weeks of receipt of a request for a derogation, the relevant system operator shall confirm to the HVDC system owner or DC-connected power park module owner, or their prospective owner, whether the request is complete. If the relevant system operator considers that the request is incomplete, the HVDC system owner or DC-connected power park module owner, or their prospective owner, shall submit the additional required information within one month from the receipt of the request for additional information. If the HVDC system owner or DC-connected power park module owner, or their prospective owner, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn.

4. The relevant system operator shall, in coordination with the relevant TSO and any affected adjacent DSO or DSOs, assess the request for a derogation and the provided cost-benefit analysis, taking into account the criteria determined by the regulatory authority pursuant to Article 78.

5. If a request for a derogation concerns a HVDC system or DC-connected power park module connected to a distribution system, including a closed distribution system, the relevant system operator's assessment must be accompanied by an assessment of the request for a derogation by the relevant TSO. The relevant TSO shall provide its assessment within two months of being requested to do so by the relevant system operator.

6. Within six months of receipt of a request for a derogation, the relevant system operator shall forward the request to the regulatory authority and submit the assessment(s) prepared in accordance with paragraphs 4 and 5. That period may be extended by one month where the relevant system operator seeks further information from the HVDC system owner or DC-connected power park module owner, or their prospective owner, and by two months where the relevant system operator requests the relevant TSO to submit an assessment of the request for a derogation.

7. The regulatory authority shall adopt a decision concerning any request for a derogation within six months from the day after it receives the request. That time limit may be extended by three months before its expiry where the regulatory authority requires further information from the HVDC system owner or DC-connected power park module owner, or their prospective owner, or from any other interested parties. The additional period shall begin when the complete information has been received.

8. The HVDC system owner or DC-connected power park module owner, or their prospective owner, shall submit any additional information requested by the regulatory authority within two months of such request. If the HVDC system owner or DC-connected power park module owner, or the prospective owner, does not supply the requested information within that time limit, the request for a derogation shall be deemed withdrawn unless, before its expiry:

(a) the regulatory authority decides to provide an extension; or

(b) the HVDC system owner or DC-connected power park module owner, or their prospective owner, informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

9. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants a derogation, it shall specify its duration.

10. The regulatory authority shall notify its decision to the HVDC system owner or DC-connected power park module owner, or their prospective owner, the relevant system operator and the relevant TSO.

11. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 83(2).

Article 80

Request for a derogation by a relevant system operator or relevant TSO

1. Relevant system operators or relevant TSOs may request a derogation for classes of HVDC systems or DC-connected power park modules connected or to be connected to their network.

2. Relevant system operators or relevant TSOs shall submit their requests for a derogation to the regulatory authority. Each request for a derogation shall include:

(a) identification of the relevant system operator or relevant TSO, and a contact person for any communications;

(b) a description of the HVDC systems or DC-connected power park modules for which a derogation is requested and the total installed capacity and number of HVDC systems or DC-connected power park modules;

(c) the requirement or requirements of this Regulation for which a derogation is requested, with a detailed description of the requested derogation;

(d) detailed reasoning, with all relevant supporting documents;

(e) demonstration that the requested derogation would have no adverse effect on cross-border trade;

(f) a cost-benefit analysis pursuant to the requirements of Article 66. If applicable, the cost-benefit analysis

shall be carried out in coordination with the relevant TSO and any adjacent DSOs.

3. Where the request for a derogation is submitted by a relevant DSO or CDSO, the regulatory authority shall, within two weeks from the day after receipt of that request, ask the relevant TSO to assess the request for a derogation in the light of the criteria determined by the regulatory authority pursuant to Article 78.

4. Within two weeks from the day after the receipt of such request for assessment, the relevant TSO shall confirm to the relevant DSO or CDSO whether the request for a derogation is complete. If the relevant TSO considers that it is incomplete, the relevant DSO or CDSO shall submit the required additional information within one month from the receipt of the request for additional information.

5. Within six months of receipt of a request for a derogation, the relevant TSO shall submit to the regulatory authority its assessment, including any relevant documentation. The six-month time limit may be extended by one month where the relevant TSO seeks further information from the relevant DSO or from the relevant CDSO.

6. The regulatory authority shall adopt a decision concerning a request for a derogation within six months from the day after it receives the request. Where the request for a derogation is submitted by the relevant DSO or CDSO, the six-month time limit runs from the day following receipt of the relevant TSO's assessment pursuant to paragraph 5.

7. The six-month time limit referred to in paragraph 6 may, before its expiry, be extended by an additional three months where the regulatory authority requests further information from the relevant system operator requesting the derogation or from any other interested parties. That additional period shall run from the day following the date of receipt of the complete information.

The relevant system operator shall provide any additional information requested by the regulatory authority within two months from the date of the request. If the relevant system operator does not provide the requested additional information within that time limit, the request for a derogation shall be deemed withdrawn unless, before expiry of the time limit:

(a) the regulatory authority decides to provide an extension; or

(b) the relevant system operator informs the regulatory authority by means of a reasoned submission that the request for a derogation is complete.

8. The regulatory authority shall issue a reasoned decision concerning a request for a derogation. Where the regulatory authority grants a derogation, it shall specify its duration.

9. The regulatory authority shall notify its decision to the relevant system operator requesting the derogation, the relevant TSO and the **Secretariat and Energy Community Regulatory Board**.

10. Regulatory authorities may lay down further requirements concerning the preparation of requests for derogations by relevant system operators. In doing so, regulatory authorities shall take into account the delineation between the transmission system and the distribution system at the national level and shall consult with system operators, HVDC system owners, DC-connected power park module owners and stakeholders, including manufacturers.

11. A regulatory authority may revoke a decision granting a derogation if the circumstances and underlying reasons no longer apply or upon a reasoned recommendation of the **Secretariat** or reasoned recommendation by the **Energy Community Regulatory Board** pursuant to Article 83(2).

Article 81

Request for derogations from the provisions of Title III by a DC-connected power park module owner

1. A request for a derogation to the provisions of Article 40(1)(b) and (c), Article 40(2)(a) and (b), and Articles 41 to 45 shall not be subject to Article 79(2)(d) and (e) where it relates to a DC-connected power park module that has, or will have, a single connection to a single synchronous area.

2. The regulatory authority may attach any conditions to a decision concerning request for a derogation referred to in paragraph 1. This may include a condition that the development of the connection into a multi-terminal network, or that connection of a further power park module at the same point, will cause the derogation to be evaluated by the regulatory authority or to expire. The regulatory authority shall take into account the need to optimise the configuration between the DC-connected power park module and the remote-end HVDC converter station, as well as the legitimate expectations of the DC-connected power park module owner when adopting a decision concerning a request for a derogation.

Article 82

Register of derogations from the requirements of this Regulation

1. Regulatory authorities shall maintain a register of all derogations they have granted or refused and shall provide the **Energy Community Regulatory Board and the Secretariat** with an updated and consolidated register at least once every six months, a copy of which shall be given to ENTSO for Electricity.

2. The register shall contain, in particular:

(a) the requirement or requirements for which the derogation is granted or refused;

(b) the content of the derogation;

(c) the reasons for granting or refusing the derogation;

(d) the consequences resulting from granting the derogation.

Article 83

Monitoring of derogations

1. The **Energy Community Regulatory Board** and the **Secretariat** shall monitor the procedure of granting derogations with the cooperation of the regulatory authorities or relevant authorities of the **Contracting Party**. Those authorities or relevant authorities of the **Contracting Party** shall provide the **Energy Community Regulatory Board** and the **Secretariat** with all the information necessary for that purpose.

2. The **Energy Community Regulatory Board** may issue a reasoned recommendation to a regulatory authority to revoke a derogation due to a lack of justification. The **Secretariat** may issue a reasoned recommendation to a regulatory authority or relevant authority of the **Contracting Party** to revoke a derogation due to a lack of justification.

3. The **Secretariat** may request the **Energy Community Regulatory Board** to report on the application of paragraphs 1 and 2 and to provide reasons for requesting or not requesting derogations to be revoked.

TITLE VIII
FINAL PROVISIONS

Article 84

Amendment of contracts and general terms and conditions

1. Regulatory authorities shall ensure that all relevant clauses in contracts and general terms and conditions relating to the grid connection of new HVDC systems or new DC-connected power park modules are brought into compliance with the requirements of this Regulation.

2. All relevant clauses in contracts and relevant clauses of general terms and conditions relating to the grid connection of existing HVDC systems or existing DC-connected power park modules subject to all or some of the requirements of this Regulation in accordance with paragraph 1 of Article 4 shall be amended in order to comply with the requirements of this Regulation. The relevant clauses shall be amended within three years following the decision of the regulatory authority or **Contracting Party** as referred to in Article 4(1).

3. Regulatory authorities shall ensure that national agreements between system operators and owners of new or existing HVDC systems and DC-connected power park modules subject to this Regulation and relating to grid connection requirements for HVDC systems and DC-connected power park modules, in particular in national network codes, reflect the requirements set out in this Regulation.

Article 85

HVDC System or DC-connected power park modules connecting with synchronous areas or control areas not bound by EU legislation

1. Where an HVDC system to which the requirements of this Regulation apply is connecting synchronous areas or control areas, with at least one synchronous area or one control area not falling under the scope of application of **Energy Community** legislation, the relevant TSO or, where applicable, the HVDC system owner shall endeavour to implement an agreement to ensure that the owners of HVDC systems with no legal obligation to comply with this Regulation also cooperate to fulfil the requirements.

2. If an agreement as referred to in paragraph 1 cannot be implemented, the relevant TSO or, as the case may be, the HVDC system owner concerned shall use all available means to comply with the requirements of this Regulation.

Article 86[1]

Entry into force

1. Each Contracting Party shall transpose Regulation (EU) 2016/1447 by no later than by 12 June 2018.

2. Transposition shall be made without changes to the structure and text of Regulation (EU) 2016/1447 other than translation and the adaptations made by the present Decision [2018/04/PHLG-EnC].

3. Each Contracting Party shall notify the Energy Community Secretariat of completed transposition and of any subsequent changes made to the act transposing Regulation (EU) 2016/1447 within two weeks following the adoption of such measures.

4. Articles 4(2) points (a) and (b), 5(4), 75, 76 and 78(1) of Regulation (EU) 2016/1447 shall apply as of the expiry of the transposition deadline.

5. Without prejudice to paragraph 4, Regulation (EU) 2016/1447 shall be implemented no later than 12 June 2021.

6. In transposing this Decision [2018/04/PHLG-EnC], Contracting Parties shall task national regulatory authorities with the monitoring of and enforcing compliance with this Decision [2018/04/PHLG-EnC].

1 Adapted by Article 1 of Permanent High Level Group Decision 2018/04/PHLG-EnC.

ANNEX I

Frequency ranges referred to in Article 11

Frequency range	Time period for operation
47,0 Hz–47,5 Hz	60 seconds **Georgia: 20 seconds**
47,5 Hz–48,5 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively, and longer than for DC-connected PPMs according to Article 39
48,5 Hz–49,0 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively, and longer than for DC-connected PPMs according to Article 39
49,0 Hz–51,0 Hz	Unlimited
51,0 Hz–51,5 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively, and longer than for DC-connected PPMs according to Article 39
51,5 Hz–52,0 Hz	To be specified by each relevant TSO, but longer than for DC-connected PPMs according to Article 39

Table 1: Minimum time periods an HVDC system shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the network.

ANNEX II

Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency

A. Frequency sensitive mode

1. When operating in frequency sensitive mode (FSM):

(a) the HVDC system shall be capable of responding to frequency deviations in each connected AC network by adjusting the active power transmission as indicated in Figure 1 and in accordance with the parameters specified by each TSO within the ranges shown in Table 2. This specification shall be subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework;

(b) the adjustment of active power frequency response shall be limited by the minimum HVDC active power transmission capacity and maximum HVDC active power transmission capacity of the HVDC system (in each direction);

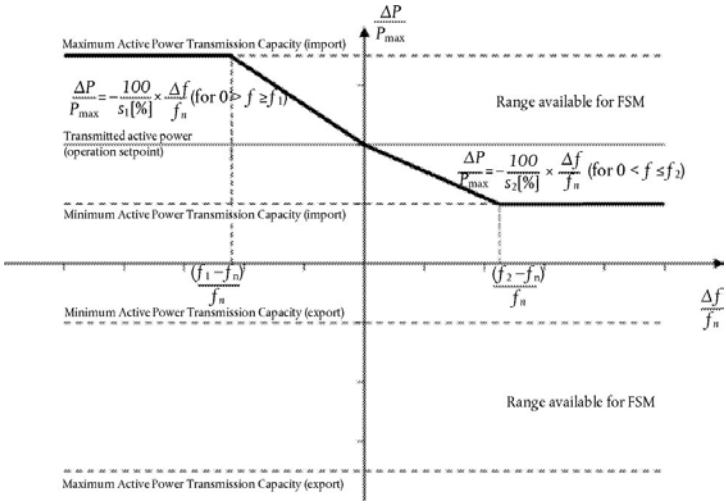


Figure 1: Active power frequency response capability of an HVDC system in FSM illustrating the case of zero deadband and insensitivity with a positive active power setpoint (import mode). ΔP is the change in active power output from the HVDC system. fn is the target frequency in the AC network where the FSM service is provided and Δf is the frequency deviation in the AC network where the FSM service is provided.

Parameters	Ranges
Frequency response deadband	0-±500 mHz
Droop s 1 (upward regulation)	Minimum 0,1%
Droop s 2 (downward regulation)	Minimum 0,1%
Frequency response insensitivity	Maximum 30 mHz

Table 2: Parameters for active power frequency response in FSM

(c) the HVDC system shall be capable, following an instruction from the relevant TSO, of adjusting the droops for upward and downward regulation, the frequency response deadband and the operational range of variation within the active power range available for FSM, set out in Figure 1 and more generally within the limits set by points (a) and (b). These values shall be subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework;

(d) as a result of a frequency step change, the HVDC system shall be capable of adjusting active power to the active power frequency response defined in Figure 1, in such a way that the response is:

(i) as fast as inherently technically feasible; and

(ii) at or above the solid line according to Figure 2 in accordance with the parameters specified by each relevant TSO within the ranges according to Table 3:

- the HVDC system shall be able to adjust active power output ΔP up to the limit of the active power range requested by the relevant TSO in accordance with the times t1 and t2 according to the ranges in Table 3, where t1 is the initial delay and t2 is the time for full activation. The values of t1 and t2 shall be specified by the relevant TSO, subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework;

- if the initial delay of activation is greater than 0,5 second, the HVDC system owner shall reasonably justify it to the relevant TSO.

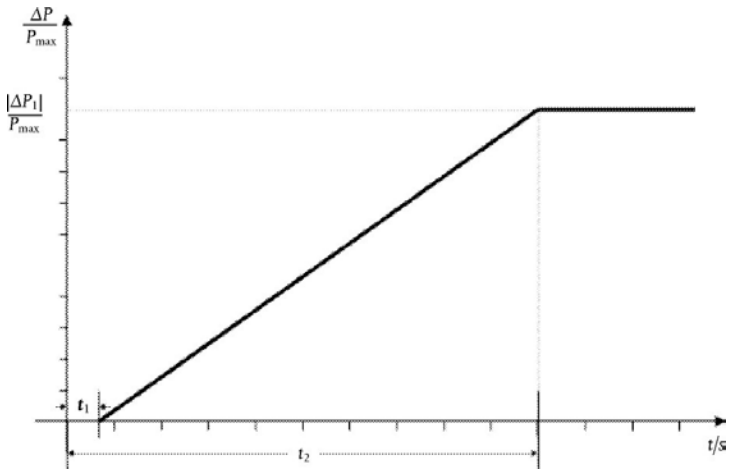


Figure 2: Active power frequency response capability of an HVDC system. ΔP is the change in active power triggered by the step change in frequency.

Parameters	**Time**
Maximum admissible initial delay t 1	0,5 seconds
Maximum admissible time for full activation t 2, unless longer activation times are specified by the relevant TSO	30 seconds

Table 3: Parameters for full activation of active power frequency response resulting from frequency step change.

(e) for HVDC systems linking various control areas or synchronous areas, in frequency sensitive mode operation the HVDC system shall be capable of adjusting full active power frequency response at any time and for a continuous time period;

(f) as long as a frequency deviation continues active power control shall not have any adverse impact on the active power frequency response.

B. Limited frequency sensitive mode overfrequency

1. In addition to the requirements of Article 11 the following shall apply with regard to limited frequency sensitive mode - overfrequency (LFSM-O):

(a) the HVDC system shall be capable of adjusting active power frequency response to the AC network or networks, during both import and export, according to Figure 3 at a frequency threshold f 1 between and including 50,2 Hz and 50,5 Hz with a droop S3 adjustable from 0,1% upwards;

(b) the HVDC system shall be capable of adjusting active power down to its minimum HVDC active power transmission capacity;

(c) the HVDC system shall be capable of adjusting active power frequency response as fast as inherently technically feasible, with an initial delay and time for full activation determined by the relevant TSO and notified to the regulatory authority in accordance with the applicable national regulatory framework;

(d) the HVDC system shall be capable of stable operation during LFSM-O operation. When LFSM-O is active, hierarchy of control functions shall be organised in accordance with Article 35.

2. The frequency threshold and droop settings referred to in point (a) of paragraph 1 shall be determined by the relevant TSO and be notified to the regulatory authority in accordance with the applicable national regulatory framework.

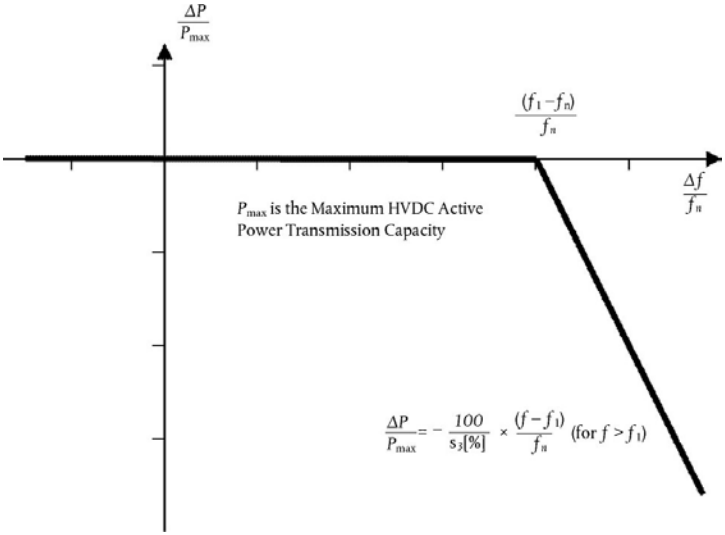


Figure 3: Active power frequency response capability of HVDC systems in LFSM-O. ΔP is the change in active power output from the HVDC system and, depending on the operational conditions, either a decrease of import power or an increase of export power. f n is the nominal frequency of the AC network or networks the HVDC system is connected to and Δf is the frequency change in the AC network or networks the HVDC is connected to. At overfrequencies where f is above f 1 the HVDC system shall reduce active power according to the droop setting.

C. Limited frequency sensitive mode underfrequency

1. In addition to the requirements of Article 11, the following shall apply with regard to limited frequency sensitive mode - underfrequency (LFSM-U):

(a) the HVDC system shall be capable of adjusting active power frequency response to the AC network or networks, during both import and export, according to Figure 4 at a frequency threshold f2 between and including 49,8 Hz and 49,5 Hz with a droop S4 adjustable from 0,1% upwards;

(b) in the LFSM-U mode the HVDC system shall be capable of adjusting active power up to its maximum HVDC active power transmission capacity;

(c) the active power frequency response shall be activated as fast as inherently technically feasible, with an initial delay and time for full activation determined by the relevant TSO and notified to regulatory authority in accordance with the applicable national regulatory framework;

(d) the HVDC system shall be capable of stable operation during LFSM-U operation. When LFSM-U is active, hierarchy of control functions shall be organised in accordance with Article 35.

2. The frequency threshold and droop settings referred to in point (a) of paragraph 1 shall be determined by the relevant TSO and be notified to the regulatory authority in accordance with the applicable national regulatory framework.

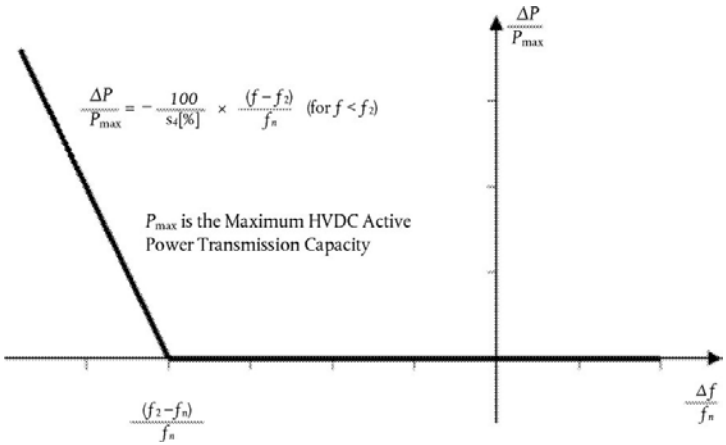


Figure 4: Active power frequency response capability of HVDC systems in LFSM-U. ΔP is the change in active power output from the HVDC system, depending on the operation condition a decrease of import power or an increase of export power. fn is the nominal frequency in the AC network or networks the HVDC system is connected and Δf is the frequency change in the AC network or networks the HVDC is connected. At underfrequencies where f is below f2, the HVDC system has to increase active power output according to the droop s4.

ANNEX III

Voltage ranges referred to in Article 18

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0,85 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	To be established by each relevant system operator, in coordination with the relevant TSO but not less than 20 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	60 minutes
Great Britain	0,90 pu–1,10 pu	Unlimited
Ireland and Northern Ireland	0,90 pu–1,118 pu	Unlimited
Baltic, **Georgia**	0,85 pu–1,118 pu	Unlimited
	1,118 pu–1,15 pu	20 minutes

Table 4: Minimum time periods an HVDC system shall be capable of operating for voltages deviating from the reference 1 pu value at the connection points without disconnecting from the network. This table applies in case of pu voltage base values at or above 110 kV and up to (not including) 300 kV.

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0,85 pu–1,05 pu	Unlimited
	1,05 pu–1,0875 pu	To be specified by each TSO, but not less than 60 minutes
	1,0875 pu–1,10 pu	60 minutes
Nordic	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	To be specified by each TSO, but not more than 60 minutes
Great Britain	0,90 pu–1,05 pu	Unlimited
	1,05 pu–1,10 pu	15 minutes
Ireland and Northern Ireland	0,90 pu–1,05 pu	Unlimited
Baltic, **Georgia**	0,88 pu–1,097 pu	Unlimited
	1,097 pu–1,15 pu	20 minutes

Table 5: Minimum time periods an HVDC system shall be capable of operating for voltages deviating from the reference 1 pu value at the connection points without disconnecting from the network. This table applies in case of pu voltage base values from 300 kV to 400 kV (included).

ANNEX IV

Requirements for U-Q/P_{max}-profile referred to in Article 20

Figure 5: The diagram represents boundaries of a U-Q/P_{max}-profile with U being the voltage at the connection points expressed by the ratio of its actual value to its reference 1 pu value in per unit, and Q/P_{max} the ratio of the reactive power to the maximum HVDC active power transmission capacity. The position, size and shape of the inner envelope are indicative and shapes other than rectangular may be used within the inner envelope. For profile shapes other than rectangular, the voltage range represents the highest and lowest voltage points in this shape. Such a profile would not give rise to the full reactive power range being available across the range of steady-state voltages.

Synchronous Area	**Maximum range of Q/P_{max}**	**Maximum range of steady-state Voltage level in PU**
Continental Europe	0,95	0,225
Nordic	0,95	0,15
Great Britain	0,95	0,225
Ireland and Northern Ireland	1,08	0,218
Baltic States, **Georgia**	1,0	0,220

Table 6: Parameters for the Inner Envelope in the Figure.

ANNEX V

Voltage-against-time-profile referred to in Article 25

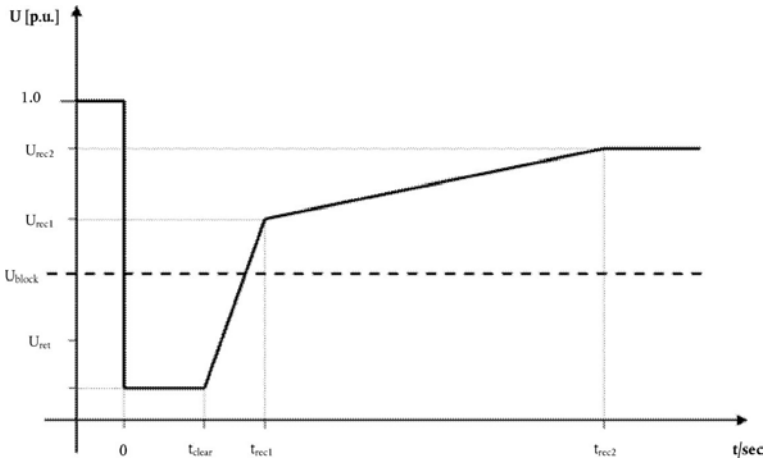


Figure 6: Fault-ride-through profile of an HVDC converter station. The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference 1 pu value in per unit before, during and after a fault. Uret is the retained voltage at the connection point during a fault, tclear is the instant when the fault has been cleared, Urec1 and trec1 specify a point of lower limits of voltage recovery following fault clearance. Ublock is the blocking voltage at the connection point. The time values referred to are measured from tfault.

Voltage parameters [pu]		**Time parameters [seconds]**	
U_{ret}	0,00–0,30	t_{clear}	0,14–0,25
U_{rec1}	0,25–0,85	t_{rec1}	1,5–2,5
U_{rec2}	0,85–0,90	t_{rec2}	T_{rec1}–10,0

Table 7: Parameters for Figure 6 for the fault-ride-through capability of an HVDC converter station.

ANNEX VI

Frequency ranges and time periods referred to in Article 39(2)(a)

Frequency range	Time period for operation
47,0 Hz–47,5 Hz	20 seconds
47,5 Hz–49,0 Hz	90 minutes
49,0 Hz–51,0 Hz	Unlimited
51,0 Hz–51,5 Hz	90 minutes
51,5 Hz–52,0 Hz	15 minutes

Table 8: Minimum time periods for the 50 Hz nominal system for which a PPM shall be capable of operating for different frequencies deviating from a nominal value without disconnecting from the network.

ANNEX VII

Voltage ranges and time periods referred to in Article 40

Voltage Range	Time period for operation
0,85 pu–0,90 pu	60 minutes
0,90 pu–1,10 pu	Unlimited
1,10 pu–1,118 pu	Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO.
1,118 pu–1,15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO.

Table 9: Minimum time periods for which a DC-connected power park module shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network where the voltage base for pu values is from 110 kV to (not including) 300 kV.

Voltage Range	Time period for operation
0,85 pu–0,90 pu	60 minutes
0,90 pu–1,05 pu	Unlimited
1,05 pu–1,15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub-ranges of voltage withstand capability can be specified.

Table 10: Minimum time periods for which a DC-connected power park module shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network where the voltage base for pu values is from 300 kV to 400 kV (included).

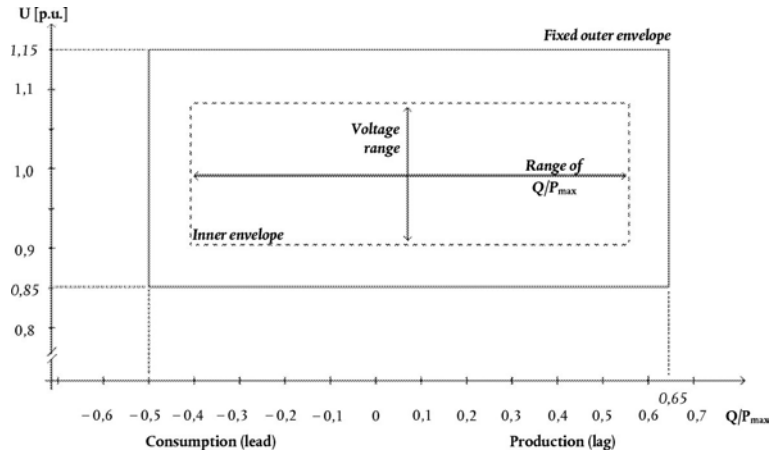


Figure 7: U-Q/P_{max}-profile of a DC-connected power park module at the connection point. The diagram represents boundaries of a U-Q/P_{max}-profile of the voltage at the connection point[s], expressed by the ratio of its actual value to its reference 1 pu value in per unit, against the ratio of the reactive power (Q) to the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative and other than rectangular may be used within the inner envelope. For profile shapes other than rectangular, the voltage range represents the highest and lowest voltage points. Such a profile would not give rise to the full

reactive power range being available across the range of steady-state voltages.

Range of width of Q/P_{max} profile	**Range of steady-state Voltage level in pu**
0–0,95	0,1–0,225

Table 11: Maximum and minimum range of both Q/P_{max} and steady-state voltage for a DC-connected PPM

ANNEX VIII

Reactive power and voltage requirements referred to in Article 48

Voltage range	Time period for operation
0,85 pu–0,90 pu	60 minutes
0,90 pu–1,10 pu	Unlimited
1,10 pu–1,12 pu	Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO.
1,12 pu–1,15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO.

Table 12: Minimum time periods for which a remote-end HVDC converter station shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network where the voltage base for pu values is from 110 kV to (not including) 300 kV.

Voltage range	Time period for operation
0,85 pu–0,90 pu	60 minutes
0,90 pu–1,05 pu	Unlimited
1,05 pu–1,15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub-ranges of voltage withstand capability may be specified.

Table 13: Minimum time periods for which a remote-end HVDC converter station shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network where the voltage base for pu values is from 300 kV to 400 kV (included).

Maximum range of Q/P_{max}	Maximum range of steady-state voltage level in PU
0,95	0,225

Table 14: Maximum range of both Q/P_{max} and steady-state voltage for a remote-end HVDC converter station.

REGULATION (EU) 543/2013 of 14 June 2013 on submission and publication of data in electricity markets

Incorporated and adapted by Permanent High Level Group Decision 2015/01/PHLG-EnC of 24 June 2015.

The adaptations made by Permanent High Level Group Decision 2015/01/PHLG-EnC are highlighted in **bold and blue**.

Article 1

Subject matter

This Regulation lays down the minimum common set of data relating to generation, transportation and consumption of electricity to be made available to market participants. It also provides for a central collection and publication of the data.

Article 2

Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No 714/2009 shall apply. In addition, the following definitions shall apply:

(1) ‚balancing reserves' mean all resources, if procured *ex ante* or in real time, or according to legal obligations, which are available to the TSO for balancing purposes;

(2) 'balancing time unit' means the time period for which the price for balancing reserves is established;

(3) 'bidding zone' means the largest geographical area within which market participants are able to exchange energy without capacity allocation;

(4) 'capacity allocation' means the attribution of cross zonal capacity;

(5) 'consumption unit' means a resource which receives electrical energy for its own use, excluding TSOs and Distribution Systems Operators (DSOs);

(6) 'control area' means a coherent part of the interconnected system, operated by a single system operator and shall include connected physical loads and/or generation units if any;

(7) 'coordinated net transmission capacity' means a capacity calculation method based on the principle of assessing and defining ex ante a maximum energy exchange between adjacent bidding zones;

(8) 'critical network element' means a network element either within a bidding zone or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged;

(9) 'cross-control area balancing' means a balancing scheme where a TSO can receive bids for activation coming from other TSOs' areas. It does not include re-dispatching or the delivery of emergency energy;

(10) 'cross zonal capacity' means the capability of the interconnected system to accommodate energy transfer between bidding zones;

(11) 'currency' is euro if at least one part of the bidding zone(s) concerned is part of a country in which euro is a legal tender. In any other case it is the local currency;

(12) 'cut-off time' means the point in time where TSOs have to confirm all matched nominations to the market. The cut-off time refers not only to daily or intra daily markets but also to the different markets that cover imbalance adjustments and reserve allocation;

(13) 'countertrading' means a cross zonal exchange initiated by system operators between two bidding zones to relieve physical congestion;

(14) 'data provider' means the entity that is sending the data to the central information transparency platform;

(15) 'explicit allocation' means the allocation of cross zonal capacity only, without the energy transfer;

(16) 'flow based parameters' mean the available margins on critical network elements with associated power transfer distribution factors;

(17) 'generation unit' means a single electricity generator belonging to a production unit;

(18) 'implicit allocation' means a congestion management method in which energy is obtained at the same time as cross zonal capacity;

(19) 'market time unit' means the period for which the market price is established or the shortest possible common time period for the two bidding zones, if their market time units are different;

(20) 'offered capacity' means the cross zonal capacity offered by the transmission capacity allocator to the market;

(21) 'planned' means an event known ex ante by the primary owner of the data;

(22) 'power transfer distribution factor' means a representation of the physical flow on a critical network element induced by the variation of the net position of a bidding zone;

(23) 'primary owner of the data' means the entity which creates the data;

(24) 'production unit' means a facility for generation of electricity made up of a single generation unit or of an aggregation of generation units;

(25) 'profile' means a geographical boundary between one bidding zone and several neighbouring bidding zones;

(26) 'redispatching' means a measure activated by one or several system operators by altering the generation and/or load pattern in order to change physical flows in the transmission system and relieve a physical congestion;

(27) 'total load', including losses without power used for energy storage, means a load equal to generation and any imports deducting any exports and power used for energy storage;

(28) 'transmission capacity allocator' means the entity empowered by TSOs to manage the allocation of cross zonal capacities;

(29) 'vertical load' means the total amount of power flowing out of the transmission network to the distribution networks, to directly connected final customers or to the consuming part of generation;

(30) 'year-ahead forecast margin' means the difference between the yearly forecast of available generation capacity and the yearly forecast of maximum total load taking into account the forecast of total generation capacity, the forecast of availability of generation and the forecast of reserves contracted for system services;

(31) 'time' means the local time in Brussels.

Article 3[1]

Establishment of a central information transparency platform

1. A central information transparency platform shall be established and operated in an efficient and cost effective manner within the European Network of Transmission System Operators for Electricity (the 'ENTSO for Electricity'). The ENTSO for Electricity shall publish on the central information transparency platform all data which TSOs are required to submit to the ENTSO for Electricity in accordance with this Regulation.

The central information transparency platform shall be available to the public free of charge through the internet and shall be available at least in English.

The data shall be up to date, easily accessible, downloadable and available for at least five years. Data updates shall be time-stamped, archived and made available to the public.

2. <...>

3. <...>

Article 4

Submission and publication of data

1. Primary owners of data shall submit data to TSOs in accordance with Articles 6 to 17. They shall ensure that the data they provide to TSOs, or where provided for in accordance with paragraph 2 to data providers, are complete, of the required quality and provided in a manner that allows TSOs or data providers to process and deliver the data to the ENTSO for Electricity in sufficient time to allow the ENTSO for Electricity to meet its obligations under this Regulation in relation to the timing of the publication of information.

TSOs, and where relevant data providers, shall process the data they receive and provide them to the ENTSO for Electricity in due time for publication.

2. Primary owners of data may fulfil their obligation laid down in paragraph 1 by submitting data directly to the central information transparency platform provided they use a third party acting as data provider on their behalf. This way of submitting data shall be subject to the prior agreement of the TSO in whose control area the primary owner is located. When providing its agreement the TSO shall assess whether the data provider fulfils the requirements referred to in points (b) and (c) of Article 5, first subparagraph.

3. TSOs shall be considered as primary owners of data for the purposes of Articles 6 to 17, except when stated otherwise.

4. In case a bidding zone consists of several control areas in different **Contracting Parties**, the ENTSO for Electricity shall publish the data referred to in paragraph 1 separately for the concerned **Contracting Parties**.

5. Without prejudice to the obligations of the TSOs and of the ENTSO for Electricity laid down in paragraph 1 and Article 3, data can also be published on TSOs' or other parties' websites.

6. National regulatory authorities shall ensure that the primary owners of the data, TSOs and data providers comply with their obligations under this Regulation.

1 Adapted by Article 3(1) of Decision 2015/01/PHLG-EnC.

Article 5[2]

Manual of procedures

The ENTSO for Electricity shall develop a manual specifying:

(a) details and format of the submission of data laid down in Article 4(1);

(b) standardised ways and formats of data communication and exchange between primary owners of data, TSOs, data providers and the ENTSO for Electricity;

(c) technical and operational criteria which data providers would need to fulfil when providing data to the central information transparency platform;

(d) appropriate classification of production types referred to in Articles 14(1), 15(1) and 16(1).

<...>

Article 6

Information on total load

1. For their control areas, TSOs shall calculate and submit the following data to the ENTSO for Electricity for each bidding zone:

(a) the total load per market time unit;

(b) a day-ahead forecast of the total load per market time unit;

(c) a week-ahead forecast of the total load for every day of the following week, which shall for each day include a maximum and a minimum load value;

(d) a month-ahead forecast of the total load for every week of the following month, which shall include, for a given week, a maximum and a minimum load value;

(e) a year-ahead forecast of the total load for every week of the following year, which shall for a given week include a maximum and a minimum load value.

2. The information referred to:

(a) in point (a) of paragraph 1 shall be published no later than one hour after the operating period;

(b) in point (b) of paragraph 1 shall be published no later than two hours before the gate closure of the day-ahead market in the bidding zone and be updated when significant changes occur;

(c) in point (c) of paragraph 1 shall be published each Friday no later than two hours before the gate closure of the day-ahead market in the bidding zone and be updated when significant changes occur;

(d) in point (d) of paragraph 1 shall be published no later than one week before the delivery month and be updated when significant changes occur;

(e) in point (e) of paragraph 1 shall be published no later than the 15th calendar day of the month before the year to which the data relates.

3. Generation units located within a TSO's control area shall provide that TSO with all the relevant information required to calculate the data referred to in point (a) of paragraph 1.

2 Adapted by Article 3(2) of Decision 2015/01/PHLG-EnC.

Generation units shall be considered as primary owners of the relevant information they provide.

4. Distribution system operators (DSO), located within a TSO's control area shall provide that TSO with all the relevant information required to calculate the data referred to in points (b) to (e) of paragraph 1.

DSOs shall be considered as primary owners of the relevant information they provide.

Article 7

Information relating to the unavailability of consumption units

1. For their control areas, TSOs shall provide the following information to the ENTSO for Electricity:

(a) the planned unavailability of 100 MW or more of a consumption unit, including changes of 100 MW or more in the planned unavailability of consumption units, lasting at least one market time unit, specifying:

- bidding zone,
- available capacity per market time unit during the event,
- reason for the unavailability,
- the estimated start and end date (day, hour) of the change in availability;

(b) changes in actual availability of a consumption unit with a power rating of 100 MW or more, specifying:

- bidding zone,
- available capacity per market time unit during the event,
- reason for the unavailability,
- the start date and the estimated end date (day, hour) of the change in availability.

2. The information laid down in point (a) of paragraph 1 shall be published in aggregated form per bidding zone indicating the sum of unavailable consumption capacity per market time unit during a given period as soon as possible but no later than one hour after the decision regarding the planned unavailability is made.

The information laid down point (b) of paragraph 1 shall be published in aggregated form per bidding zone indicating the sum of unavailable consumption capacity per market time unit during a given period as soon as possible but no later than one hour after the change in actual availability.

3. Consumption units located in a TSO's control area shall calculate and submit the data laid down in paragraph 1 to that TSO.

The consumption units shall be considered as primary owner of the data they submit.

Article 8

Year-ahead forecast margin

1. For their control areas, TSOs shall calculate and provide for each bidding zone the year-ahead forecast margin evaluated at the local market time unit to the ENTSO for Electricity.

The information shall be published one week before the yearly capacity allocation but no later than the 15th calendar day of the month before the year to which the data relates.

2. Generation units and DSOs, located within a TSO's control area shall provide that TSO with any relevant information required to calculate the data referred to in paragraph 1.

Generation units and DSOs shall be considered as primary owners of the data they submit.

Article 9

Transmission infrastructure

TSOs shall establish and provide information on future changes to network elements and interconnector projects including expansion or dismantling in their transmission grids within the next three years, to the ENTSO for Electricity. This information shall only be given for measures expected to have an impact of at least 100 MW on cross zonal capacity between bidding zones or on profiles at least during one market time unit. The information shall include:

(a) the identification of the assets concerned;

(b) the location;

(c) type of asset;

(d) the impact on interconnection capacity per direction between the bidding zones;

(e) the estimated date of completion. The information shall be published one week before the yearly capacity allocation but no later than the 15th calendar day of the month before the year to which the allocation relates. The information shall be updated with relevant changes before the end of March, the end of June and the end of September of the year to which the allocation relates.

Article 10

Information relating to the unavailability of transmission infrastructure

1. For their control areas TSOs shall calculate and provide to the ENTSO for Electricity:

(a) the planned unavailability, including changes in the planned unavailability of interconnections and in the transmission grid that reduce cross zonal capacities between bidding zones by 100 MW or more during at least one market time unit, specifying:

- the identification of the assets concerned,
- the location,
- the type of asset,
- the estimated impact on cross zonal capacity per direction between bidding zones,
- reasons for the unavailability,
- the estimated start and end date (day, hour) of the change in availability;

(b) changes in the actual availability of interconnections and in the transmission grid that reduce cross zonal capacities between bidding zones by 100 MW or more during at least one market time unit, specifying:

- the identification of the assets concerned,
- the location,

- the type of asset,
- the estimated impact on cross zonal capacity per direction between bidding zones,
- reasons for the unavailability,
- the start and estimated end date (day, hour) of the change in availability;

(c) changes in the actual availability of off-shore grid infrastructure that reduce wind power feed-in by 100 MW or more during at least one market time unit, specifying:

- the identification of the assets concerned,
- the location,
- the type of asset,
- the installed wind power generation capacity (MW) connected to the asset,
- wind power fed in (MW) at the time of the change in the availability,
- reasons for the unavailability,
- the start and estimated end date (day, hour) of the change in availability.

2. The information laid down in point (a) of paragraph 1 shall be published as soon as possible, but no later than one hour after the decision regarding the planned unavailability is made.

3. The information laid down in points (b) and (c) of paragraph 1 shall be published as soon as possible but no later than one hour after the change in actual availability.

4. For the information laid down in points (a) and (b) of paragraph 1 TSOs may choose not to identify the asset concerned and specify its location if it is classified as sensitive critical infrastructure protection related information in their **Contracting Parties** as provided for in point (d) of Article 2 of Council Directive 2008/114/EC. This is without prejudice to their other obligations laid down in paragraph 1 of this Article.

Article 11

Information relating to the estimation and offer of cross zonal capacities

1. For their control areas TSOs or, if applicable, transmission capacity allocators, shall calculate and provide the following information to the ENTSO for Electricity sufficiently in advance of the allocation process:

(a) the forecasted and offered capacity (MW) per direction between bidding zones in case of coordinated net transmission capacity based capacity allocation; or

(b) the relevant flow based parameters in case of flow based capacity allocation.

TSOs or, if applicable, transmission capacity allocators shall be considered as the primary owners of the information they calculate and provide.

2. The information laid down in paragraph 1(a) shall be published as set out in the Annex.

3. In relation to direct current links, TSOs shall provide updated information on any restrictions placed on the use of available cross-border capacity including through the application of ramping restrictions or intraday transfer limits not later than one hour after the information is known to the ENTSO for Electricity.

Operators of direct current links shall be considered as primary owners of the updated information they provide.

4. TSOs or, if applicable, transmission capacity allocators, shall provide a yearly report to the ENTSO for Electricity indicating:

(a) the main critical network elements limiting the offered capacity;

(b) the control area(s) which the critical network elements belong to;

(c) the extent to which relieving the critical network elements would increase the offered capacity;

(d) all possible measures that could be implemented to increase the offered capacity, together with their estimated costs.

When preparing the report TSOs may choose not to identify the asset concerned and specify its location if it is classified as sensitive critical infrastructure protection related information in their **Contracting Parties** as provided for in point (d) of Article 2 of Directive 2008/114/EC.

TSOs or, if applicable, transmission capacity allocators shall be considered as primary owners of the report they provide.

Article 12

Information relating to the use of cross zonal capacities

1. For their control areas TSOs shall calculate and provide the following information to the ENTSO for Electricity:

(a) in case of explicit allocations, for every market time unit and per direction between bidding zones:

- the capacity (MW) requested by the market,

- capacity (MW) allocated to the market,

- the price of the capacity (Currency/MW),

- the auction revenue (in Currency) per border between bidding zones;

(b) for every market time unit and per direction between bidding zones the total capacity nominated;

(c) prior to each capacity allocation the total capacity already allocated through previous allocation procedures per market time unit and per direction;

(d) for every market time unit the day-ahead prices in each bidding zone (Currency/MWh);

(e) in case of implicit allocations, for every market time unit the net positions of each bidding zone (MW) and the congestion income (in Currency) per border between bidding zones;

(f) scheduled day-ahead commercial exchanges in aggregated form between bidding zones per direction and market time unit;

(g) physical flows between bidding zones per market time unit;

(h) cross zonal capacities allocated between bidding zones in **Contracting Parties** and third countries per direction, per allocated product and period.

2. The information laid down:

(a) in points (a) and (e) of paragraph 1 shall be published no later than one hour after each capacity allocation;

(b) in point (b) of paragraph 1 shall be published no later than one hour after each round of nomination;

(c) in point (c) of paragraph 1 shall be published at the latest when publication of offered capacity figures become due as set out in the Annex;

(d) in point (d) of paragraph 1 shall be published no later than one hour after gate closure;

(e) in point (f) of paragraph 1 shall be published every day no later than one hour after the last cutoff time and, if applicable, shall be updated no later than two hours after each intra-day nomination process;

(f) in point (g) of paragraph 1 shall be published for each market time unit as closely as possible to real time but no later than one hour after the operational period;

(g) in point (h) of paragraph 1 shall be published no later than one hour after the allocation.

3. Transmission capacity allocators, or where applicable power exchanges, shall provide the TSOs with all the relevant information required to calculate the data laid down in paragraph 1.

Transmission capacity allocators shall be considered as primary owners of the information they provide.

Power exchanges shall be considered primary owners of the information they provide.

Article 13

Information relating to congestion management measures

1. For their control areas TSOs shall provide the following information to the ENTSO for Electricity:

(a) information relating to redispatching per market time unit, specifying:

- the action taken (that is to say production increase or decrease, load increase or decrease),
- the identification, location and type of network elements concerned by the action,
- the reason for the action,
- capacity affected by the action taken (MW);

(b) information relating to countertrading per market time unit, specifying:

- the action taken (that is to say cross-zonal exchange increase or decrease),
- the bidding zones concerned,
- the reason for the action,
- change in cross-zonal exchange (MW);

(c) the costs incurred in a given month from actions referred to in points (a) and (b) and from any other remedial action.

2. The information laid down:

(a) in points (a) and (b) of paragraph 1 shall be published as soon as possible but no later than one hour after the operating period, except for the reasons which shall be published as soon as possible but not later than one day after the operating period;

Article 14

Forecast generation

1. For their control areas, TSOs shall calculate and provide the following information to the ENTSO for Electricity:

(a) the sum of generation capacity (MW) installed for all existing production units equalling to or exceeding 1 MW installed generation capacity, per production type;

(b) information about production units (existing and planned) with an installed generation capacity equalling to or exceeding 100 MW. The information shall contain:

- the unit name,

- the installed generation capacity (MW),

- the location,

- the voltage connection level,

- the bidding zone,

- the production type;

(c) an estimate of the total scheduled generation (MW) per bidding zone, per each market time unit of the following day;

(d) a forecast of wind and solar power generation (MW) per bidding zone, per each market time unit of the following day.

2. The information laid down:

(a) in point (a) of paragraph 1 shall be published annually no later than one week before the end of the year;

(b) in point (b) of paragraph 1 shall be published annually for the three following years no later than one week before the beginning of the first year to which the data relates;

(c) in point (c) of paragraph 1 shall be published no later than 18.00 Brussels time, one day before actual delivery takes place;

(d) in point (d) of paragraph 1 shall be published no later than 18.00 Brussels time, one day before actual delivery takes place. The information shall be regularly updated and published during intra-day trading with at least one update to be published at 8.00 Brussels time on the day of actual delivery. The information shall be provided for all bidding zones only in Contracting Parties with more than 1% feed-in of wind or solar power generation per year or for bidding zones with more than 5% feed-in of wind or solar power generation per year.

3. Production units located in a TSO's control area shall provide that TSO with all the relevant information required to calculate the data laid down in paragraph 1.

Production units shall be considered as primary owners of the relevant information they provide.

Article 15

Information relating to the unavailability of generation and production units

1. For their control areas, TSOs shall provide the following information to the ENTSO for Electricity:

(a) the planned unavailability of 100 MW or more of a generation unit including changes of 100 MW or more in the planned unavailability of that generation unit, expected to last for at least one market time unit up to three years ahead, specifying:

- the name of the production unit,
- the name of the generation unit,
- location,
- bidding zone,
- installed generation capacity (MW),
- the production type,
- available capacity during the event,
- reason for the unavailability,
- start date and estimated end date (day, hour) of the change in availability;

(b) changes of 100 MW or more in actual availability of a generation unit, expected to last for at least one market time unit, specifying:

- the name of the production unit,
- the name of the generation unit,
- location,
- bidding zone,
- installed generation capacity (MW),
- the production type,
- available capacity during the event,
- reason for the unavailability, and
- start date and estimated end date (day, hour) of the change in availability;

(c) the planned unavailability of a production unit of 200 MW or more including changes of 100 MW or more in the planned unavailability of that production unit, but not published in accordance with subparagraph (a), expected to last for at least one market time unit up to three years ahead, specifying:

- the name of the production unit,
- location,
- bidding zone,
- installed generation capacity (MW),
- the production type,
- available capacity during the event,

- reason for the unavailability,

- start date and estimated end date (day, hour) of the change in availability;

(d) changes of 100 MW or more in actual availability of a production unit with an installed generation capacity of 200 MW or more, but not published in accordance with subparagraph (b), expected to last for at least one market time unit, specifying:

- the name of the production unit,

- location,

- bidding zone,

- installed generation capacity (MW),

- the production type,

- available capacity during the event,

- reason for the unavailability, and

- start date and estimated end date (day, hour) of the change in availability.

2. The information laid down in points (a) and (c) of paragraph 1 shall be published as soon as possible, but no later than one hour after the decision regarding the planned unavailability is made.

The information laid down in points (b) and (d) of paragraph 1 shall be published as soon as possible but no later than one hour after the change in actual availability.

3. Generation units located in a TSO's control area shall provide that TSO with the data laid down in paragraph 1.

Generation units shall be considered as primary owners of the data they provide.

Article 16

Actual generation

1. For their control areas, TSOs shall calculate and provide the following information to the ENTSO for Electricity:

(a) actual generation output (MW) per market time unit and per generation unit of 100 MW or more installed generation capacity;

(b)aggregated generation output per market time unit and per production type;

(c) actual or estimated wind and solar power generation (MW) in each bidding zone per market time unit;

(d) aggregated weekly average filling rate of all water reservoir and hydro storage plants (MWh) per bidding zone including the figure for the same week of the previous year.

2. The information laid down:

(a) in point (a) of paragraph 1 shall be published five days after the operational period;

(b) in point (b) of paragraph 1 shall be published no later than one hour after the operational period;

(c) in point (c) of paragraph 1 shall be published no later than one hour after the operational period and be updated on the basis of measured values as soon as they become available. The information shall

be provided for all bidding zones only in **Contracting Parties** with more than 1% feed-in of wind or solar power generation per year or for bidding zones with more than 5% feed-in of wind or solar power generation per year;

(d) in point (d) of paragraph 1 shall be published on the third working day following the week to which the information relates. The information shall be provided for all bidding zones only in **Contracting Parties** with more than 10% feed-in of this type of generation per year or for bidding zones with more than 30% feed-in of this type of generation per year.

3. Generation units and production units located within a TSOs' control area shall provide that TSO with all the relevant information to calculate the data laid down in paragraph 1.

Generation units and production units respectively shall be considered as primary owners of the relevant information they provide.

Article 17

Balancing

1. For their control areas, TSOs or where applicable operators of balancing markets, where such markets exist shall provide the following information to the ENTSO for Electricity:

(a) rules on balancing including:

- processes for the procurement of different types of balancing reserves and of balancing energy,

- the methodology of remuneration for both the provision of reserves and activated energy for balancing,

- the methodology for calculating imbalance charges,

- if applicable, a description on how cross-border balancing between two or more control areas is carried out and the conditions for generators and load to participate;

(b) the amount of balancing reserves under contract (MW) by the TSO, specifying:

- the source of reserve (generation or load),

- the type of reserve (e.g. Frequency Containment Reserve, Frequency Restoration Reserve, Replacement Reserve),

- the time period for which the reserves are contracted (e.g. hour, day, week, month, year, etc.);

(c) prices paid by the TSO per type of procured balancing reserve and per procurement period (Currency/MW/period);

(d) accepted aggregated offers per balancing time unit, separately for each type of balancing reserve;

(e) the amount of activated balancing energy (MW) per balancing time unit and per type of reserve;

(f) prices paid by the TSO for activated balancing energy per balancing time unit and per type of reserve; price information shall be provided separately for up and down regulation;

(g) imbalance prices per balancing time unit;

(h) total imbalance volume per balancing time unit;

(i) monthly financial balance of the control area, specifying:

- the expenses incurred to the TSO for procuring reserves and activating balancing energy,

- the net income to the TSO after settling the imbalance accounts with balance responsible parties;

(j) if applicable, information regarding Cross Control Area Balancing per balancing time unit, specifying:

- the volumes of exchanged bids and offers per procurement time unit,

- maximum and minimum prices of exchanged bids and offers per procurement time unit,

- volume of balancing energy activated in the control areas concerned. Operators of balancing markets shall be considered as primary owners of the information they provide.

2. The information laid down:

(a) in point (b) of paragraph 1 shall be published as soon as possible but no later than two hours before the next procurement process takes place;

(b) in point (c) of paragraph 1 shall be published as soon as possible but no later than one hour after the procurement process ends;

(c) in point (d) of paragraph 1 shall be published as soon as possible but no later than one hour after the operating period;

(d) in point (e) of paragraph 1 shall be published as soon as possible but no later than 30 minutes after the operating period. In case the data are preliminary, the figures shall be updated when the data become available;

(e) in point (f) of paragraph 1 shall be published as soon as possible but no later than one hour after the operating period;

(f) in point (g) of paragraph 1 shall be published as soon as possible;

(g) in point (h) of paragraph 1 shall be published as soon as possible but no later than 30 minutes after the operating period. In case the data are preliminary, the figures shall be updated when the data become available;

(h) in point (i) of paragraph 1 shall be published no later than three months after the operational month. In case the settlement is preliminary, the figures shall be updated after the final settlement;

(i) in point (j) of paragraph 1 shall be published no later than one hour after the operating period.

Article 18

Liability

The liability of the primary owner of the data, the data provider and the ENTSO for Electricity under this Regulation shall be limited to cases of gross negligence and/or wilful misconduct. In any event they shall not be liable to compensate the person who uses the data for any loss of profit, loss of business, or any other indirect incidental, special or consequential damages of any kind arising from a breach of their obligations under this Regulation.

Article 19

Amendment to Regulation (EC) No 714/2009

Points 5.5 to 5.9 of Annex I to Regulation (EC) No 714/2009 are deleted with effect from 5 January 2015.

Article 20[3]

This Regulation shall enter into force on the twentieth day following that of its publication in a **dedicated section of the website of the Energy Community.**

Article 4(1) shall apply 18 months after the entry into force of Decision 2015/01/PHLG-EnC.[4]

This Regulation shall be binding in its entirety and directly applicable in all **Contracting Parties**.

The references to the obligations of the ENTSO for Electricity are applicable upon the agreement of ENTSO for Electricity.[5]

3 Adapted by Article 4(3) of Decision 2011/02/MC-EnC.
4 Decision 2015/01/PHLG-EnC entered into force on 24 June 2015.
5 According to Article 2(1)(c) of Decision 2015/01/PHLG-EnC.

ANNEX

Publication of the information referred to in Article 11(2)

Capacity allocation period	**Forecasted cross zonal capacity to be published**	**Offered capacity to be published**
Yearly	One week before the yearly allocation process but no later than 15 December, for all months of the following year	One week before the yearly allocation process but no later than 15 December
Monthly	Two working days before the monthly allocation process for all days of the following month	Two working days before the monthly allocation process
Weekly	Each Friday, for all days of the following week	One day before the weekly allocation process
Day-ahead		One hour before spot market gate closure, for each market time unit
Intra-day		One hour before the first intra-day allocation and then real-time, for each market time unit

REGULATION (EU) 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

Incorporated and adapted by Permanent High Level Group Decision 2013/01/PHLG-EnC of 23 October 2013 on the incorporation of the Commission Regulation (EU) 838/2010 in the Energy Community, and amended by Permanent High Level Group Decision 2021/01/PHLG-EnC of 29 November 2021 amending Decision 2013/01-PHLG-EnC.

The adaptations made by Permanent High Level Group Decisions 2013/01/PHLG-EnC and 2021/01/PHLG-EnC are highlighted in **bold and blue.**

Article 1

Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks on the basis of the guidelines set out in Part A of the Annex.

Article 2

Charges applied by network operators for access to the transmission system shall be in accordance with guidelines set out in Part B of the Annex.

Article 3

This Decision [2013/01/PHLG-EnC] enters into force upon its adoption and is addressed to the Contracting Parties.

Each Contracting Party shall transpose and implement Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator comprehension mechanism and a common regulatory approach to transmission charging by 1 January 2014.

The transposition shall be made without changes to the structure and text of Commission Regulation (EU) No 838/2010 other than translation.

Commission Regulation (EU) No 838/2010 shall be made binding on market participants.

The national regulatory authorities shall be tasked with monitoring and enforcing compliance with Commission Regulation (EU) No 838/2010.

Contracting Parties shall notify the Secretariat of the measures transposing this Decision, and of any subsequent changes made to those measures, within two weeks of the adoption of such measures.

ANNEX

PART A
Guidelines on the Inter-Transmission System Operator Compensation Mechanism

1. General Provisions

1.1. The Inter-Transmission System Operator Compensation (ITC) mechanism shall provide for compensation for the costs of hosting cross-border flows of electricity including providing cross-border access to the interconnected system.

1.2. The European Network of Transmission System Operators for Electricity (ENTSO for Electricity) set up in accordance with Article 5 of Regulation (EC) 714/2009 shall establish an ITC fund for the purpose of compensating transmission system operators for the costs of hosting cross-border flows of electricity.

The ITC fund shall provide compensation for:

(1) the costs of losses incurred national transmission systems as a result of hosting cross-border flows of electricity; and,

(2) the costs of making infrastructure available to host cross-border flows of electricity.

1.3. Contributions to the ITC Fund shall be calculated in accordance with points 6 and 7. Payments from the ITC Fund shall be calculated in accordance with points 4 and 5.

ENTSO for Electricity shall be responsible for establishing arrangements for the collection and disbursement of all payments relating to the ITC Fund, and shall also be responsible for determining the timing of payments. All contributions and payments shall be made as soon as possible, and at the latest within six months of the end of the period to which they apply.

1.4. The Agency shall oversee the implementation of the ITC mechanism and report to the Commission each year on the implementation of the ITC mechanism and the management of the ITC fund.

ENTSO for Electricity shall co-operate with the Commission and with the Agency in this task and shall provide the Agency with all information necessary for this purpose.

Each transmission system operator shall provide ENTSO for Electricity and the Agency with all information necessary for the implementation of the ITC Mechanism.

1.5. Until such time as ENTSO for Electricity has been established, transmission system operators shall co-operate amongst themselves to carry out the tasks assigned to ENTSO for Electricity in relation to the ITC mechanism.

1.6. Transit of electricity shall be calculated, normally on an hourly basis, by taking the lower of the absolute amount of imports of electricity and the absolute amount of exports of electricity on interconnections between national transmission systems.

For the purpose of calculating transits of electricity the amount of imports and the amount of exports at each interconnection between national transmission systems shall be reduced in proportion to the share of capacity allocated in a manner which is not compatible with Point 2 of the guidelines on congestion

management set out in Annex I of Regulation (EC) No 714/2009.

Notwithstanding the provisions of the second subparagraph of this point imports and exports of electricity on interconnections with third countries to which the provisions of point 7.1 apply shall be included in the calculation of transit of electricity.

1.7. For the purposes of this part of the Annex, the net flow of electricity shall mean the absolute value of the difference between total exports of electricity from a given national transmission system to countries where the TSOs participate in the ITC Mechanism and total imports of electricity from countries where the TSOs participate in the ITC Mechanism to the same transmission system.

For ITC mechanism parties with a common border with at least one third country to which the provisions of Point 7.1 apply the following adjustments to the calculation of net flow shall be made:

(1) if total exports of electricity to countries where the TSOs participate in the ITC Mechanism are greater than total imports of electricity from countries where the TSOs participate in the ITC Mechanism, net flows shall be reduced by the lower of:

(a) net import flows from those third countries; or

(b) net export flows to countries where the transmission system operator participates in the ITC Mechanism.

(2) if total imports of electricity from countries where the TSOs participate in the ITC Mechanism are greater than total exports of electricity to countries where the TSOs participate in the ITC Mechanism then net flows shall be reduced by the lower of

(a) net export flows to those third countries; or

(b) net import flows from countries where the transmission system operator participates in the ITC mechanism.

1.8. For the purposes of this annex load shall mean the total amount of electricity which exits the national transmission system to connected distribution systems, end consumers connected to the transmission system and to electricity producers for consumption in the generation of electricity.

2. Participation in the ITC mechanism

2.1. Each regulatory authority shall ensure that transmission system operators in its area of competence participate in the ITC mechanism and that no additional charges for hosting cross-border flows of electricity are included in charges applied by transmission system operators for access to networks.

2.2. Transmission system operators from third countries which have concluded agreements with the Union whereby they have adopted and are applying Union law in the field of electricity shall be entitled to participate in the ITC mechanism.

In particular, the transmission system operators operating in the territories referred to in Article 9 of the Energy Community Treaty shall be entitled to participate in the ITC mechanism.

Each transmission system operator from a third country participating in the ITC mechanism shall be treated on an equivalent basis to a transmission system operator of a Member State.

3. Multi-Party Agreements

3.1. ENTSO for Electricity shall facilitate the conclusion of multi-party agreements relating to the compensation for the costs of hosting cross-border flows of electricity between transmission system operators participating in the ITC mechanism and those transmission system operators from third countries which have not concluded agreements with the Union whereby they have adopted and are applying Union law in the field of electricity, and which, on 16 December 2009, signed the voluntary agreement between transmission system operators on inter-transmission system operator compensation.

3.2. Such multi-party agreements shall aim at ensuring that the transmission system operator from the third country be treated on an equivalent basis to a transmission system operator in a country participating in the ITC Mechanism.

3.3. Where necessary such multi-party agreements may recommend appropriate adjustment to total compensation for the compensation for making infrastructure available to host cross-border flows of electricity determined in accordance with point 5. Any such adjustment shall be subject to approval by the Commission, taking account of the opinion of the Agency.

3.4. The treatment of the transmission system operator from the third country shall not be more favourable in comparison to that which would apply to a transmission system operator participating in the ITC Mechanism.

3.5. ENTSO for Electricity shall submit all such multi-party agreements to the Commission for its opinion as to whether continuation of the multi-party agreement promotes the completion and functioning of the internal market in electricity and cross-border trade. The opinion of the Commission shall address in particular:

(1) whether the agreement relates only to compensation between transmission system operators (TSOs) for the costs of hosting cross-border flows of electricity;

(2) whether the requirements of points 3.2 and 3.4 are respected.

3.6. In preparing the opinion referred to in point 3.5 the Commission shall consult all the Member States, taking particular account of the views of those Member States sharing a border with the relevant third country.

In preparing its opinion the Commission may consult the Agency.

4. Compensation for Losses

4.1. Compensation for losses incurred on national transmission systems as a result of hosting cross-border flows of electricity shall be calculated separately from compensation for costs incurred associated with making infrastructure available to host cross-border flows of electricity.

4.2. The amount of losses incurred on a national transmission system shall be established by calculating the difference between:

(1) the amount of losses actually incurred on the transmission system during the relevant period; and,

(2) the estimated amount of losses on the transmission system which would have been incurred on the system during the relevant period if no transits of electricity had occurred.

4.3. ENTSO for Electricity shall be responsible for carrying out the calculation referred to in point 4.2 and shall publish this calculation and its method in an appropriate format. This calculation may be derived from estimates for a number of points of time during the relevant period.

4.4. The value of losses incurred by a national transmission system as a result of the cross-border flow of electricity shall be calculated on the same basis as that approved by the regulatory authority in respect of all losses on the national transmission systems. The Agency shall verify the criteria for the valuation of losses at national level taking particular account that losses are valued in a fair and non-discriminatory way.

Where the relevant regulatory authority has not approved a basis for the calculation of losses for a period of time for which the ITC mechanism applies, the value of losses for the purposes of the ITC mechanism shall be estimated by ENTSO for Electricity.

5. Compensation for provision of infrastructure for cross-border flows of electricity

5.1. Following a proposal from the Agency made in accordance with point 5.3, the Commission shall determine the annual cross-border infrastructure compensation sum which shall be apportioned among TSOs as compensation for the costs incurred as a result of making infrastructure available to host cross-border flows of electricity. If the Commission disagrees with the proposal of the Agency, it shall ask the Agency for a second opinion.

5.2. The annual cross-border infrastructure compensation sum shall be apportioned amongst transmission system operators responsible for national transmission systems in proportion to:

(1) transit factor, referring to transits on that national transmission system state as a proportion of total transits on all national transmission systems;

(2) load factor, referring to the square of transits of electricity, in proportion to load plus transits on that national transmission system relative to the square of transits of electricity in proportion to load plus transit for all national transmission systems.

The transit factor shall be weighted 75% and the load factor 25%.

5.3. The Agency shall make the proposal on the annual cross-border infrastructure compensation sum referred to in point 5.1 based on a Union-wide assessment of the infrastructure of electricity transmission associated with facilitating cross-border flows of electricity. The Agency shall undertake its best endeavours to carry out an assessment within two years of the date of application of this Regulation. ENTSO for Electricity shall provide the Agency with all assistance necessary for the purposes of carrying out this assessment.

This assessment shall consist of a technical and economic assessment of the forward-looking longrun average incremental costs on an annual basis of making such electricity transmission infrastructure available for cross-border flows of electricity over the relevant period, and shall be based on recognised standard-costing methodologies.

Where infrastructure is financed by sources other than charges for access to networks applied in accordance with Article 14 of Regulation (EC) No 714/2009 the assessment of costs of making infrastructure available for cross-border flows of electricity shall be appropriately adjusted to reflect this.

This Union-wide assessment of the electricity transmission infrastructure shall include infrastructure in all Member States and third countries participating in the ITC mechanism and in systems operated by trans-

mission system operators who have concluded multi-party agreements referred to in point 3.

5.4. Until such time as the Agency has carried out the assessment referred to in point 5.3 and the Commission has determined the annual cross-border infrastructure compensation sum in accordance with point 5.1, the annual cross-border infrastructure compensation sum shall be EUR 100 000 000.

5.5. When making the proposal referred to in point 5.1, the Agency shall also provide its opinion to the Commission as to suitability of using long run average incremental costs for the assessment of the costs of making infrastructure available for hosting cross-border flows of electricity.

6. Contributions to the ITC Fund

6.1. The transmission system operators shall contribute to the ITC fund in proportion to the absolute value of net flows onto and from their national transmission system as a share of the sum of the absolute value of net flows onto and from all national transmission systems.

7. Transmission system use fee on third country imports and exports of electricity

7.1. A transmission system use fee shall be paid on all scheduled imports and exports of electricity from all third countries where:

(1) that country has not concluded agreement with the Union whereby it has adopted and is applying Union law in the field of electricity; or,

(2) the transmission system operator responsible for the system from which electricity is imported or to which electricity is exported has not concluded a multi-party agreement referred to in point 3.

This fee shall be expressed in Euros per megawatt hour.

7.2. Each participant in the ITC Mechanism shall levy the transmission system use fee on scheduled imports and exports of electricity between the national transmission system and the transmission system of the third country.

7.3. The transmission system use fee for each year shall be calculated in advance by ENTSO for Electricity. It shall be set at the estimated contribution per megawatt hour transmission system operators from a participating country would make to the ITC Fund based on projected cross-border flows of electricity for the relevant year.

PART B

Guidelines for A Common Regulatory Approach to Transmission Charging

1. Annual average transmission charges paid by producers in each **Contracting Party**[1] shall be within the ranges set out in point 3.

2. Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a **Contracting Party**.

For the calculation set out at Point 3, transmission charges shall exclude:

(1) charges paid by producers for physical assets required for connection to the system or the upgrade of the connection;

(2) charges paid by producers related to ancillary services;

(3) specific system loss charges paid by producers.

3. The value of the annual average transmission charges paid by producers shall be within a range of 0 to 0,5 EUR/MWh, except those applying in Denmark, Sweden, Finland, Romania, Ireland, **Montenegro,** Great Britain and Northern Ireland.

The value of the annual average transmission charges paid by producers in Denmark, Sweden and Finland shall be within a range of 0 to 1,2 EUR/MWh.

Annual average transmission charges paid by producers in Ireland, **Montenegro,** Great Britain and Northern Ireland shall be within a range of 0 to 2,5 EUR/MWh, and in Romania within a range of 0 to 2,0 EUR/MWh.

4. The Agency shall monitor the appropriateness of the ranges of allowable transmission charges, taking particular account of their impact on the financing of transmission capacity needed for Member States to achieve their targets under the Directive 2009/28/EC of the European Parliament and of the Council and their impact on system users in general.

5. By 1 January 2014 the Agency shall provide its opinion to the Commission as to the appropriate range or ranges of charges for the period after 1 January 2015.

1 Decision 2013/01/PHLG-EnC, incorporating this Regulation is addressed to the Contracting Parties.