Network Code for Demand Response

EDP Comments to DSO Entity & ENTSO-E Public consultation

November 2023

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Contents

1 Key Messages

Demand response is currently covered in some of the existing network codes and in the Directive (EU) 2019/944, where it is foreseen demand should be able to participate, including though aggregators, in all electricity markets.

However, the truth is that, whether due to incomplete implementation at Member States' level, or to the fact that existing Network Codes are more fit to large resources (as a result of the context where they were drafted), there is still a gap to be filled. Even in the CEP provisions (both the Directive (EU) 2019/944 and the Regulation (EU) 2019/943), some elements could benefit from further detail to support national implementation.

This consultation covers this gap in current regulation and is therefore crucial to further enable demand response towards a more active role and participation in overall electricity markets.

For EDP, demand response should always be framed under very basic principles:

- **Allow participation in all electricity markets:** demand response means the ability for demand (and other relevant resources) to provide a response in all electricity markets, which is also quite clear in the European legislation.

  Electricity markets are not limited to balancing, voltage control and congestion management, thus we consider this network code should evolve in that regard.

  Considering this is the network code for demand response, it should frame the rules for overall demand response, considering all electricity markets. Currently, it limits all provisions to balancing, voltage control and congestion management, which is quite narrow, and excludes other relevant markets such as day-ahead, intraday, and even other types of ancillary services.

- **Enable all relevant resources and ensure technology neutrality:** considering that previous network codes were more focused on large resources, new rules shall be adapted to allow for the participation of overall distributed resources.

  Thus, the Network Code shall apply to load, storage (in particular when combined with load), and distributed generation, aggregated or not.

  This is in line with the framework guidelines setting the tone for this Network Code, where these are referred to as "demand response and other relevant resources".

- **Marked-based as first approach:** flexibility shall, by default, be incentivised/procured under market-based rules, unless in particular circumstances rule-based is considered more fit for purpose.

  We acknowledge there are situations which may arise where a system operator may need to rely on rules-based procurement; however, this Network Code should be explicitly stated that market-based procurement shall be, as far as possible, the default. Where rules-based procurement may need to apply, there must be a robust justification (e.g. cost-effectiveness, competition issues, ...);

- **Align responsibilities and incentives:** when it comes to the aggregation models, it is important to stress the task set by the framework guidelines, to set an exhaustive list of models, taking as a starting point imbalance responsibility and (where applicable) due compensations for different incurred costs. The same applies for situations where market participants are limited to bid or are redispatched, and for which a proper compensation mechanism shall also be in place.

- **Ensure transparency:** rules, methodologies, and data exchange should be very clear to all relevant stakeholders and overall subject to public consultation, engagement of participants, and proper visibility on planning.
- **Ensure a robust governance (the role of regulators):** the NRA shall have a strong role to promote the dialogue and engagement, supervise, propose amendments, approve methodologies based on which the rules set in this network code operate; ACER must ensure a proper monitoring of the implementation status at EU level, promote best practice examples and enable dialogue for further harmonization (where applicable) and improvements to the framework that will be adopted.
- **The Network Code on DR as a complementary piece in the regulatory "puzzle", with the right fit:** The Network Code on Demand Response shall complement (and not overlap or infringe) existing legislation, other network codes and guidelines.

  Consistency and stability must be ensured. Therefore, this Network Code shall not try to address gaps in topics that should be under the scope of other Network Codes, but rather to adapt those, where needed, namely CACM GL, EB GL, SO GL, DCC and RfG).

2 Specific comments to whereas

2.1 Whereas (b)

The way the proposal is framed, leaves out distributed generation, and it is also restrictive on demand as it only foresees demand curtailment (which refers to demand response in only one direction).

The Framework Guidelines foresee a similar text but is also state that: *"the new rules shall be technology neutral and non-discriminatory and shall thus not favour demand response and storage to the detriment of other resource providers. (...) The new rules shall thus be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not (hereafter referred to as "demand response and other relevant resources" or in general "resources"). No resource provider shall be excluded and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers."*

In that regard we propose to review as follow, in line with the stated intention in the Framework Guidelines for this network code:

> *(b) Whilst having due regard to the particularities of demand response, this Regulation respects the principles of non-discrimination and technology neutrality, ~~whilst having due regard to the particularities of demand response,~~ applying to load, storage (in particular when combined with load), and distributed generation, aggregated or not (hereafter referred to as "demand response and other relevant resources" or in general "resources") ~~including aggregation, energy storage, and demand curtailment~~, and considering the potential needs resulting thereof for adapting current and future rules.*

2.2 Whereas (d)

This text refers to the "evolution of the bid granularity" in balancing products, to facilitate the participation of smaller resources. However, in only foresees such evolution for aggregated participation, thus excluding direct participation of those smaller resources.

In that regard we propose to review the last sentence as follow:

> (d) (...) This Regulation requires an evolution of the bid granularity of standard balancing products intended to facilitate the participation of smaller resources in balancing services either directly or by means of aggregation.

2.3 Whereas (o)

The proposed wording seems to suggest that, besides the existing ToE which would ensure the same type of requirements for equivalent products, different system operators could still require different things. The example provided is that the TSO could ask for activation tests for aFRR while a DSO requires different steps for congestion management.

If products are considered as equivalent in the ToE, this possibility to ask for different requirements seems to contradict the purpose behind the definition of the ToE in itself, and even the definition of 'product prequalification' in article 2 (32), which foresee technical and data exchange requirements.

In that regard we propose to delete whereas (o).

Otherwise, the text would need to be clarified in a way this won't imply an additional layer of differentiated requirements on top of a framework that was meant to avoid duplication and simplify the access to the market and existing products, and therefore allowing for value staking as correctly foreseen in whereas (n).

2.4 Whereas (q)

Suggest eliminating whereas (q), which is not clear in the purpose, and refers to situations that are not exclusive from small controllable units such as the "location in critical grid areas".

2.5 Whereas (u)

The proposed wording seems to imply that article 13 of Regulation (EU) 2019/943, might not always apply, according to the national choices of implementation.

In our view Member States shall apply the options they consider nationally suited, as long as they comply with European legislation, which means to always apply article 13 of Regulation (EU) 2019/943, regarding rules for redispatch, namely on financial compensation rights.

Making the reference to article 13 of this Regulation may be adequate to frame the rules on redispatch, but it shall refrain from making consideration on whether article 13 is applicable or not and affected or not.

In that regard we propose to review as follow:

> *(u) Congestion management is to some ~~a large~~ extent ruled by Article 13 of Regulation (EU) 2019/943, regarding redispatch, namely on the circumstances for which non-market-based may apply, and the rules on financial compensation, whether redispatch is market-based or not, by the system operator requesting the redispatching to the operator of the redispatched resource.~~, and Member states have implemented options considered nationally suitable. The applicability and implementation of the Regulation (EU) 2019/943 shall only be affected where necessary to reach the goals of this Regulation~~*

2.6 Whereas (w) and (x)

Price limits in wholesale electricity markets are, by definition, not allowed in Regulation (EU) 2019/943, article 10.

In that regard we suggest eliminating the reference to "(potentially limited by price caps)", in market-based procurement.

Additionally, whereas (w) have inconsistencies that contradicts whereas (x). For instance, whereas (w) refers to market-based procurement but if states that remuneration **may (which implies it also may not)** be determined by a market-mechanism which is inconsistent to a procurement that is supposed to be market-based, and it extends into what is supposed to be covered in whereas (x).

In that regard we propose to review as follow, to clarify:

> *(w) Market-based procurement is understood as a mechanism whereby a service is procured by soliciting market participants to place an offer for the service. ~~The market participants choose the amount they are offering and the prices (potentially limited by price caps)~~ . The remuneration is determined by a market-based pricing ~~may be determined by a market-mechanism (supply vs demand) pay as bid or pay as cleared. Examples, which may be labelled "market-based" based on assessment of national regulatory authority in Member State: Marketplace/Exchange for service (includes service specific market or taking offers from another market such as Energy-only-markets, balancing)~~.*
>
> *(x) Market-based pricing is understood as a pricing and remuneration mechanism determined through a market-mechanism by means of demand and supply. The quantity of the demand may be fixed in advance, or be determined by a mechanism.*

2.7 Whereas (y)

Demand connection rules also derive from Network Codes for grid connection such as the Demand Connection Code, which doesn't necessarily requires transposition into national law to be applicable.

In that regard we propose to review as follow:

> *(y) Member States, through national applicable law and in line with the applicable Network Codes for grid connection, prescribe how distribution and transmission system operators should connect customers or group of customers. This includes connection conditions applicable to the access to network capacity, as conditions for guaranteed capacity or firm connection.*

2.8 Whereas (z)

We propose to eliminate whereas (z) as system operators always have different options to choose and decide from, for grid management and this is not adequate to introduce under which conditions there could be connection limits and how these would be handled. This is out of scope for this Network Code, which shall not define rules regarding limits to grid connection.

2.9 Whereas (ff)

The proposed text only covers energy (not capacity), doesn't cover overall ancillary services (e.g. inertia), and is unclear on what may be considered "long-term". There is a definition for electricity markets in the Directive that should be used.

In that regard we propose to review as follow:

> *(ff) Market participants can trade in all electricity markets 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, as defined in the Directive (EU) 2019/944. ~~their volumes in long-term, day-ahead, intraday or continuous market process, pursuant to Regulation (EU) 2015/1222 and Regulation (EU) 2016/1719; which are also known as 'wholesale markets'. Additionally, market participants may become service providers in balancing markets developed pursuant to Regulation (EU) 2017/2195.~~ This Regulation states principles applicable for the use of bids and for the coordination for those ~~wholesale and balancing~~ markets and for the local markets for congestion management and voltage control.*

2.10 Whereas (ll)

In alignment to what is foreseen in SO NC, and in the framework guidelines (104), suggest to reword to emphasise that market-based should be the preferred option and rule-based shall only apply where market-based is economically not efficient.

The Directive 2019/944 is also clear by stating that system operators 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.

change as following: "procurement by system operators should make use of market-based mechanisms as far as possible"

In that regard we propose to review as follow:

(II) ~~In each Member State, grid users have a set mandatory technical requirements for the voltage control, including reactive power capacities, whose~~ Procurement of voltage control by system operators, including reactive power capacities, should make use of market-based mechanisms as far as possible, as foreseen in Directive 2019/944 ~~might be under ruled or market-based mechanisms~~.

3 Article 1 (Subject Matter)

Paragraph 1 leaves out distributed generation, and it is also restrictive on demand as it only foresees demand curtailment (which refers to demand response in only one direction).

The Framework Guidelines foresee a similar text but is also state that: *"the new rules shall be technology neutral and non-discriminatory and shall thus not favour demand response and storage to the detriment of other resource providers. (…) The new rules shall thus be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not (hereafter referred to as "demand response and other relevant resources" or in general "resources"). No resource provider shall be excluded and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers."*

In that regard we propose to review as follow, in line with the stated intention in the Framework Guidelines for this network code:

> *1. This Regulation establishes a network code which lays down the requirements in relation to demand response and other relevant resources as defined in article 2, including rules on aggregation, ~~energy storage, and demand curtailment rules,~~ to contribute to market integration, non-discrimination, effective competition and the efficient functioning of the market pursuant to Article 59(1) of Regulation (EU) 2019/943.*

Paragraph 3, seems to imply that some system operators do not have to comply with this NC, as it states Member States may determine which system operators need to comply if some system operators may not properly fulfil one or more obligations.

In a more extreme situation one might infer that the the procurement of demand response for those connected to the grids of other system operators (that are not the ones assigned with the responsibility to comply) could not be possible at all.

In that regard we propose to delete paragraph 3.

4 Article 2 (Definitions)

4.1 New definitions' proposal

4.1.1 'Other relevant sources'

There are several references to the scope of this Network Code that leave out distributed generation and it might be perceived as restrictive on demand as it only foresees demand curtailment (which refers to demand response in only one direction).

The Framework Guidelines state that: *"the new rules shall be technology neutral and non-discriminatory and shall thus not favour demand response and storage to the detriment of other resource providers. (...) The new rules shall thus be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not* ***(hereafter referred to as "demand response and other relevant resources" or in general "resources")****. No resource provider shall be excluded and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers."*

The same expression of "demand response and other relevant resources" is then also included in other parts of the Framework Guidelines.

In that regard we propose to add a definition of "other relevant resources" in line with the stated intention in the Framework Guidelines for this network code, and as a reference to other proposals in other articles/whereas:

> *(# tbd) 'Other relevant resources' means storage (in particular when combined with load), and distributed generation, aggregated or not.*

4.1.2 'Virtual Metering Point'

As foreseen in the proposal for the definition of the 'metering point', some physical metering points refer to multiple demand "sides" as is the case for electric vehicles that charge in different charging points. A charging point can than be of private access (as in the customer's home) or of public or semi-public access, which mean that the metered data is disaggregated amongst different consumers and suppliers. The same way, the total demand for such electric vehicle is than provided by the sum of metered data in different physical metering points (charging points) and is thus a virtual metering point.

As a complement to definition (1) in article 2 ('metering point') a definition of 'virtual metering point' must also be added to clarify what is meant as "calculated" in the definition of 'metering point'.

In that regard we propose the following definition of "virtual metering point":

(#tbd) 'Virtual metering point' means the sum of metered data, which can include metered data from different physical metering points, either withdrawal or injection, referring to mobile loads from electric vehicles, that connect to multiple 'connection points', namely of public or semi-public access.

4.1.3 'Accounting Point'

In the current definition of 'Locational information' the accounting point is referred but it is not defined anywhere.

We therefore suggest including a definition for 'accounting point' which we consider to be referring to situations where the accounting point might be in a physical location that doesn't match with the connection point to the public grid.

4.1.4 'SP Prequalification'

The current definition of 'SP qualifying responsible' (article 2, 34) refers to the entity responsible by SP prequalification, the same way the definition of 'Product qualifying responsible' (article 2, 35) refers to the entity responsible for product prequalification.

However, unlike 'Product prequalification' which is also defined (article 2, 33), 'SP prequalification' is not defined.

We therefore suggest including a definition for 'SP prequalification'.

4.1.5 'Normal operating conditions'

The current definition of 'Activation test' (article 2, 42) foresees an activation signal as a test to ensure the service provider can deliver under normal operating conditions.

However, there is no definition of what 'normal operating conditions' are.

We therefore suggest including a definition for 'normal operating conditions' which shall refer both to the status of the grid but also of the technical asset itself. For instance, the SP must be able to communicate maintenance situations that should be excluded of such normal operating conditions to avoid triggering such activation tests in maintenance periods.

4.2 Proposal of rewording in current definitions

We also suggest reviewing some definitions as follow:

4.2.1 'Metering Point'

(1) 'Metering point' means a physical location where the withdrawal or injection of electrical quantities is measured or calculated, in the case of a virtual metering point.

Why? To clarify the addition of situations where this is to be calculated. This must be complemented with a new definition for the virtual metering point, referring to mobile demand (electric vehicles) whose consumption is metered in several places and where a connection point serves multiple consumers (charging points with public or semi-public access), each with their chosen supplier (or suppliers, as even the same consumer may have more than one charging card from different entities).

4.2.2 'Submetering'

(2) 'Submeter' means a metering device (embedded in a particular asset or an autonomous meter) on customer's side, without its own connection agreement, which is placed behind the meter of the connection point with the transmission or distribution system operator as is defined in the connection agreement.

Why? The purpose is to clarify that an autonomous submeter should not be imposed if an embedded meter is already in place and complies with the requirements.

4.2.3 'Baseline'

(3) 'Baseline' means a counterfactual reference about the electrical quantities that were expected to ~~would~~ have been withdrawn or injected ~~if there had been no activation of any balancing or congestion management and voltage control services~~ in the absence of the activation for the provision of the respective service.

Why? In line with the FGs definition by covering **all** flexibility services, and adding that this is a forecast, which means an **expected** withdrawn or injection.

4.2.4 'Congestion Issue'

(7) 'Congestion issue' means a situation where the physical or structural congestion, as defined by the Regulation (EU) 2015/1222 are likely to occur ~~when the electric current flows through a physical asset exceeds operational limits~~.

Why? To ensure consistency with the definitions already in place for congestion and avoid create different scopes and understanding of congestion issues needed to be managed.

4.2.5 'Connecting System Operator'

(11)'Connecting system operator' means in this Network Code the DSO or TSO responsible for the grid to which a grid user or controllable unit is connected, directly or indirectly.

Why? A controllable unit may be a particular asset of set of assets behind the main-meter and the connection point.

4.2.6 'Affected system operator'

(14)'Affected system operator' means any DSO or TSO significantly affected by congestion or voltage issues, or whose data on its grid and the connected grid user ~~on the grid of another systems operator, or whose grid may provide solutions to these issues or that data on the grid or the grid users~~ are necessary to forecast, detect or solve such issues.

Why? For clarification purposes.

4.2.7 'Non-firm connection agreement'

(16) 'Non-firm connection agreement means a connection agreement where the grid user has agreed to not being ~~been~~ granted with ~~a firm~~ access to firm capacity for parts or the entirety of the grid connection.

Why? For clarification purposes, we suggest to either review this definition and proposed above or to replace it by a 'Flexible connection agreement' definition from the EMD review.

4.2.8 'Flexibility register'

(17) 'Flexibility Register' means an information system consisting of one or multiple and diverse platforms operated by one or multiple national actors to support the registration and prequalification for the provision of balancing, congestion management, ~~and~~ voltage control services and other relevant flexibility services, using a common front-door at least at Member State level.

Why? To set the link with the definition of common front-door and widen the scope for other services (e.g. inertia and other non-balancing ancillary services).

4.2.9 'Small controllable unit'

(21)'Small controllable unit' means a controllable unit connected below 1000 V with an installed capacity lower than a predefined threshold set at national level, but not higher than 1MW.

Why? In articles 45 and 84 there are specific rules and exemptions for such units. There should be a maximum threshold to avoid that the definition at national level result in very different thresholds across Member States, which would create an unlevel playing field.

4.2.10 'Controllable unit' or 'CU'

(22)'Controllable unit' or 'CU', means a single technical resource or an ensemble of technical resources behind the same single connection point, to be decided by the customer (or asset owner), if these technical resources ~~are~~ can be commonly controlled.

Why? To specify in the definition that the set of CUs can be defined by the customer itself.

4.2.11 'Full delivery time' or 'FDT'

(26)'Full Delivery Time' or 'FDT', means the time period between the receipt of an activation request setting of a new delivery or set point value and the corresponding full delivery of the relevant product by the SPU or SPG, which, in the case of balancing, means the 'full activation time' and the 'delivery period' combined, as defined in Regulation (EU) 2017/2195, of 23 November 2017.

Why? In order to link with existing definitions from EB GL Network Code.

4.2.12 'Product prequalification'

(32)'Product prequalification' means the ex-ante process, where applicable, prior to participation of a potential SPU or SPG in balancing or congestion management or voltage control market, to verify the compliance of a potential SPU or SPG with the technical and data exchange requirements for the provision of a balancing, congestion management or voltage control product. In the product prequalification the PPR may require the potential SPU or SPG to pass an activation test.

Why? Product pre-qualification, as an ex-ante process, is not necessarily a condition prior to participation, as for local and non-standard balancing services it is foreseen that an ex-post verification may apply and the ex-ante prequalification always applicable. Therefore it's not accurate to define this as an element prior to the participation as some products might only apply an ex-post verification.

4.2.13 'Product verification'

(33)'Product verification' means the process after the delivery of specific balancing, congestion management or voltage control services to verify the compliance of an SPU or SPG with the technical and data exchange requirements for the provision of such services ~~a of specific balancing, congestion management or voltage control product~~.

Why? For simplification as the products are already mentioned in the beginning of the definition.

4.2.14 'Table of equivalences' or 'ToEq'

(40)'Table of equivalences' or 'ToEq', means a mechanism defined in the national or European terms and conditions for service providers to simplify the participation of SPUs and SPGs in multiple markets. It provides a single national or European point of reference to store a common list of 'comparable qualification attributes' and defines how to make necessary data available to systems operators and market platform operators in the process of registering new SPUs or SPGs for the provision of particular products.

Why? Even if for some products it might be premature to already define an European common view of comparable qualification attributes, this should not be excluded. Additionally, for some products it doesn't make sense to already consider it just at national level, namely for standard balancing products, based on pan-European platforms with European implementation frameworks. Therefore, the definition in itself should not restrict this to just a national view and national terms and conditions, but to open the scope so that it can consider both national and European.

4.2.15 'Rebound effect'

(47)'Rebound effect' means the alteration of injection or withdrawal of electricity ~~generation or /consumption~~ of an activated technical resource before or after the time frame of its delivery, as a recovery effect resulting from ~~due~~ to the activation ~~provision~~ of a local or balancing service product.

Why? For clarification purposes, namely that this is a recovery from an activation and regarding the concepts used (e.g. activation instead of provision, injection/withdrawal instead of generation/consumption as this also applies to storage).

4.2.16 'Compensation effect'

(47)'Compensation effect' means the alteration of injection or withdrawal of electricity ~~generation or /consumption~~ of other non- activated technical resources in the time frame of a delivery of a local or balancing product, behind the same connection point, that compensate for the effects that the activation implies.

Why? For concept clarification (injection/withdrawal instead of generation/consumption as this also applies to storage) and to clarify what these changes are in non-activated technical resources, assuming those refer to assets behind the connection point that may counteract the activation effects on specific activate assets. If this compensation effect from non-activated resources refers to a different thing than it should be properly clarified considering this refers to assets that are not to be somehow activated.

4.2.17 'Temporary qualification'

(49)'Temporary qualification' means the default ~~preliminary~~ status granted to a SPU or SPG for provision of specific balancing or congestion management or voltage control services to allow their participation on the market, when an ex-ante prequalification is not required and this is based on an ex-post ~~until the~~ product verification process ~~is concluded~~.

Why? The proposed definition seems to imply that once the product verification is concluded the SPU or SPG is no longer qualified, which would be an obstacle to DR. In products where ex-ante prequalification is not required, this should be a default state that should only stops applying if product verification is systematically not concluded with success.

4.2.18 'Technical aggregator'

~~(51)'Technical aggregator' means a third party, delegated by the final customer, who combines and controls multiple CUs and interacts with a SP.~~

Why? The delegation by the consumer is done to an aggregator (which can or not be an independent aggregator) which is already defined in legislation, and can provide a service as a service provider, based on an aggregated portfolio of different CUs. Any relation between the SP and an IT supplier or other on which the aggregator supports their actions should not be regulated under the scope of this NC and risks create confusion in the concepts and in the defined roles and responsibilities.

5 Article 4 (Objectives and Regulatory Aspects)

Paragraph 1, (a) and paragraph 2 leaves out distributed generation, and it is also restrictive on demand as it only foresees demand curtailment (which refers to demand response in only one direction).

The Framework Guidelines foresee a similar text but is also state that: *"the new rules shall be technology neutral and non-discriminatory and shall thus not favour demand response and storage to the detriment of other resource providers. (...) The new rules shall thus be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not (hereafter referred to as "demand response and other relevant resources" or in general "resources"). No resource provider shall be excluded and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers."*

In that regard we propose to review, as follow, in line with the stated intention in the Framework Guidelines for this network code:

> *1. This Regulation aims at:*
>
> *(a) setting out clear and objective principles for the development of rules regarding demand response and other relevant resources as defined in article 2, including rules on aggregation~~, energy storage and demand curtailment~~.*
>
> *~~2.~~ (b) Respecting the principles of non-discrimination and technology neutrality, whilst having due regard to the particularities of demand response, including rules on aggregation, energy storage and demand curtailment, and the potential needs resulting thereof for adapting current and future rules.*

6 Article 5 (National process to develop national terms and conditions)

Paragraph 1 foresees a deadline of three months, after the publication of the legislation, for all the DSO and TSO within a Member State to present a process proposal for the development of national terms and conditions. Given that some states have many TSO and DSO, which takes some time to coordinate, a larger deadline is advisable.

For TSO and DSO to have the necessary time to coordinate a six-month period would increase the probability of a successful national debate and to the establishment of consensual process for the national terms and conditions.

In that regard we propose to review, as follow:

> *1. By ~~three~~ six months following the entry into force of this Regulation, all systems operators shall jointly submit to the competent national regulatory authority a proposal for a national process to develop national terms and conditions referred to in Article 6 (Common national terms and conditions). This is without prejudice to the right of the Member State or NRAs to define the national process on how systems operators jointly develop national terms and conditions pursuant to this Regulation.*

7 Article 6 and 7 (Common national terms and conditions)

In article 6, no description of the points that constitute the "National Terms and Conditions" is provided. However, in article 7 ("Approval of common national terms and conditions") there is such description in number 2.

For clarity purposes there should be a list of points that constitute the "National Terms and Conditions" in article 6. Therefore, we propose placing the description provided in article 7 number 2 in a new number 3 of article 6.

Also, article 7 should consider the consultation of system operators but also market participants, and it should also consider, for transparency purposes the yearly publication of the status of implementation and content of national terms and conditions.

In that regard we propose to review, as follow:

Article 6

Common national terms and conditions

> *(...)*
>
> *3. National Terms and Conditions are constituted by:*
>
> *(a) the terms and conditions for service providers in accordance with Article 38 (Principles for national implementation);*
>
> *(b) the terms and conditions for the market design for congestion management and voltage control services in accordance with Article 48(4) (National terms and conditions for17 market design for congestion management and voltage control services through active power); and*

(c) the terms and conditions for TSO-DSO and DSO-DSO coordination in accordance with Article 69 (National implementation and condition for coordination)

Article 7

Approval of common national terms and conditions

1. The competent national regulatory authority shall be responsible for approving the common national terms and conditions referred to in paragraph 2. Before approving the common national terms and conditions, the competent national regulatory authority shall revise the proposals where necessary, including proposed amendments, after consulting all systems operators and market participants, in order to ensure that they are in line with the purpose of this Regulation.

2. The proposals for the following common national terms and conditions and any amendments thereof shall be subject to approval by the competent national regulatory authority in each of the Member States, or where applicable, by another entity designated by the Member State.~~:~~

~~*(a) the terms and conditions for service providers in accordance with Article 38 (Principles for national implementation);*~~

~~*(b) the terms and conditions for the market design for congestion management and voltage control services in accordance with Article 48(4) (National terms and conditions for*~~

~~*market design for congestion management and voltage control services through active power); and*~~

~~*(c) the terms and conditions for TSO-DSO and DSO-DSO coordination in accordance with Article 69 (National implementation and condition for coordination).*~~

8 Article 9 (Union-wide terms and conditions or methodologies)

There is a mismatch between the referred article 9 number 1 (article 77) which the text refers to as concerning monitoring and the actual article referring to this topic, which is article 83 of this proposal.

In that regard we propose to review, as follow:

1. ENTSO-E and EU DSO Entity shall develop the Union-wide terms and conditions or methodologies, in case the relevant monitoring report produced pursuant to Article 83 ~~77~~ (Monitoring Reports ~~Harmonisation~~ – title X) identifies the need for harmonisation. ENTSO-E and EU DSO Entity shall submit them for approval to the Agency.

Also, while paragraph 1 foresees that ENTSO-E and the EU DSO Entity shall develop T&Cs or methodologies for topics identified for harmonization, paragraph 2 only foresees TSOs (not ENTSO-E) may (instead of shall) develop a Union-wide proposal for the harmonisation of processes for prequalification of standard balancing products.

Considering that standard balancing products are already mature and pan-european platforms for energy balancing products are already in place (or expected) for different Member States to join, this should be more binding and clearer.

In that regard we propose to review, as follow:

2. Without prejudice to paragraph 1, ENTSO-E ~~All TSOs~~ shall ~~may~~ develop a Union-wide proposal for the harmonisation of processes for prequalification of standard balancing products pursuant to Article 29, by no longer than 6 months after entry into force of this Regulation.

9 Article 11 (Amendments to Union-wide terms and conditions or methodologies)

Paragraph 1 foresees a period of 6 months, after ACER request for amendments, for ENTSO-E and the EU DSO Entity propose an amended version of the terms and conditions, which seems excessive.

In that regard we propose to review from 6 to 3 months, as follow:

1. In the event that the Agency requests an amendment to approve the Union-wide terms and conditions or methodologies submitted in accordance with Article 10(2) (Approval of Union-wide terms and conditions or methodologies), ENTSO-E and EU DSO Entity shall submit a proposal for amended terms and conditions or methodologies for approval within 3 ~~6~~ months following the request from the Agency. The Agency shall decide on the amended terms and conditions or methodologies within 2 months following their submission.

10 Article 13 (Public consultation for common national terms and conditions)

Besides NRA approval of the proposed terms and conditions, this article shall also foresee that the NRA can propose amendments and the period for system operators to incorporate such request in a new proposal.

This article should also set clear deadlines.

In that regard we propose to review as follow:

> *1. All systems operators responsible for jointly submitting proposals for the common national terms and conditions or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of the Member State, on the draft proposals for common national terms and conditions set out in this Regulation. The consultation shall last for a period of not less than one month.*
>
> *2. The proposals for the common national terms and conditions or their amendments in accordance with this Regulation shall be published and submitted to consultation at least at Member State level, by no longer than 6 months after entry into force of this Regulation.*
>
> *3. All systems operators, responsible for developing the joint proposal for the common national terms and conditions shall duly consider the views of stakeholders resulting from the consultations prior to its submission for regulatory approval, by no longer than 3 months after the end of the consultation period foreseen in paragraph 1 of this article. In all cases, a justification for including or not 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.*
>
> *4. In the event the NRA request for an amendment to, according to the previous paragraph, approve the common national terms and conditions, national DSOs and TSOs shall submit a proposal for amended terms and conditions, for regulatory approval, within 3 months following the request from the NRA. The NRA shall decide on the amended terms and conditions within 2 months following their submission, after which those shall be published.*

11 Article 16 (Delegation and assignments of tasks)

In article 16 number 4, it is stated that the Member State or the NRA may assign tasks or obligations entrusted to systems operators under this Regulation to one or more assigned parties. Given the particularities of each Member State and regulatory framework it is important to state that this redistribution must be carried out under the terms defined by national legislation.

In that regard we propose to review as follow:

> *2. Without prejudice to the tasks entrusted to systems operators pursuant to Directive (EU) 2019/944, a Member State, or where applicable a relevant regulatory authority, may assign tasks or obligations entrusted to systems operators under this Regulation to one or more assigned parties, including a TSO or a DSO, under the terms defined by national legislation. Prior to the assignment, the party concerned shall demonstrate to the Member State, or where applicable the relevant regulatory authority, its ability to meet the task to be assigned.*

12 Article 19 (Aggregation Models)

While the Framework Guidelines foresee the Network Code to present an exhaustive list of aggregation models, including financial compensations where applicable, this proposal only differentiates aggregation models based on the existence or not of meters.

The main elements of aggregation models, which should be at the base of the distinction between the models, is the imbalance settlement (to ensure each market participant is financially responsible for its imbalances), potential financial compensations and contractual relationships.

These are the elements broadly recognized in different aggregation models and are the elements considered in the Member States were aggregation models are already in place.

In that regard we propose to review as follow:

Article 19

Aggregation models

> *1. The aggregation models that are described below aim at defining how the participation of service providers are allowed by limiting the impact on other parties, based on different ways to do imbalance settlement and on contractual relationships, while ensuring each market participant is responsible for the imbalances it cause.*
>
> *2. Member States shall allow the aggregation models defined in the articles 13.4 and 13.5 for each flexibility services in the scope of this regulation, either one or the other or the combination of both.*
>
> *3. Every aggregation model presumes the following base assumptions:*

a. Aggregators (including independent) do not require consent from other market parties to participate in electricity markets;

b. Aggregators (including independent) are financially responsible for the imbalances they cause (which they may delegate under contractual agreement), apart from possible derogations foreseen in article 5 of the Regulation (EU) 2019/943;

c. Compensations to suppliers may apply, regarding costs proven to be incurred as a result of demand response activation;

d. Compensations may also take into account the benefits brought by the independent aggregators, which means the compensation may only apply where and to the extent that costs exceed the benefits. This calculation method is subject to approval of the regulatory authority or another competent authority.

4. Besides the situation where the aggregator and the supplier are the same market participant, which can be considered as an integrated model, there can be four base models:

a. Model A – Corrected model

b. Model B – Central settlement model

c. Model C – Contractual model

d. Model D – Information before day-ahead

5. Model A – Corrected model – assumes the following:

a. The allocated volume is corrected from the activation request, thus it neutralise the imbalance volumes;

b. Additional costs may apply referring to rebound effects or hedging costs;

6. Model B – Central settlement model – assumes the following:

a. There is no correction of volumes but a financial correction of the imbalances in which the system operator charges the aggregator and pays the supplier an equivalent compensation to neutralize the imbalance effect caused by the activation, under a methodology to be approved by the NRA;

b. This compensation should be calculated based on the harmonized imbalance settlement methodology approved by ACER, and the decision adopted by the Member State in using single or dual price.

c. Additional costs may apply referring to rebound effects or hedging costs;

7. Model C – Contractual model – assumes the following:

a. There is no correction of volumes;

b. Any financial correction of the imbalances or compensation, which can also include additional costs, is established contractually between the two parties;

c. Costs included in the compensation may refer to imbalance costs, rebound effects or hedging costs.

8. Model D – information before day-ahead – assumes the following:

a. This model is only applicable for products whose activation is timely requested before gate closure time of day-ahead;

b. The supplier's BRP is informed from activation requests in a timely manner ahead of day-ahead, and thus can review the final position;

c. This information can be provided directly by the aggregator, by the SO requiring for activation, or by a central entity;

d. Additional costs may apply referring to rebound effects or hedging costs;

9. Relevant changes in the volumes may be considered for additional compensation (other the referring to imbalance settlement) when associated to fixed prices with hedged volumes, and where price variations result in a loss incurred by the supplier.

10. Changes in profile may refer to a rebound effect, where there is the load is merely shifted to a different time period, thus causing an imbalance that is indirectly caused by an activation request for another time period. Such effect may be considered for additional compensation.

11. The methodology to calculate the compensation shall be approved by the NRA and include:

a. Thresholds for relevant variations in the volumes;

b. Reference prices against price variations are determined

c. Maximum time window where rebound effects are to be considered and reference baseline methodologies associated to load variations (injection or withdraw) from activation in specific technical units

12. All these different models can exist or co-exist in each Member State or as a combined version.

13. In any aggregation model:

a. The supplier shall receive the metered data without any adjustment from any activation request, so that it can bill the consumer.

b. The supplier shall be informed of activation requests so that it can incorporate such information in its forecasting tools, to provide accurate final positions and thus be able to strive to be balanced or help the electricity system to be balanced.

c. Each market participant shall be able to delegate their balance responsibility under contractual terms agreed by both parties. NRAs may define and approve minimum requirements for those contracts and, notwithstanding the parties may agree differently, the NRA may also define and approve standard templates to be used on a voluntary basis.

d. In case of contractual delegation of responsibilities, BRPs shall receive all the data necessary to be able to determine and validate each position associated to the respective settlement.

e. The rebound effect shall be included as one of the variables to be considered in the baselining methodologies, namely for thermal appliances or electric vehicles or charging stations where a variation for the baseline is likely to simply trigger a shift to a different time period.

f. The compensation mechanism for the transfer of energy or rebound effect shall be based on clear market price references, set by a methodology approved and published by the NRA.

14. Each of these models will also depend on whether the technical resource has a measurement equipment [according to the MID/EMD]. The following variants can be considered:

15. Variant 1 prescribes all the following requirements:

a. there is no additional metering equipment for the technical resources which is involved in providing the balancing, congestion management and voltage control services; and

b. the only metering equipment is the smart meter at the connection point, which is the only meter to perform measurements of the energy injected or withdrawn used by both the supplier(s) and by the service provider(s);

16. Variant 2 prescribes all the following requirements:

a. there is an additional metering equipment, being either a submeter or a dedicated measurement device (DMD, as considered in the EMDR), for each technical resources which are involved in providing the balancing, congestion management and voltage control services. The metering equipment of the technical resource measures the withdrawals and/or the injections of the technical resources involved in the provision of such services; and *b. the metering equipment at the connection point can be a conventional meter or smart meter;*

17. For simplification purposes, a simple version is assumed but the possibility of multiple suppliers and service providers behind the connection point providing balance or congestion management and voltage control services from different technical resources is possible. When multiple suppliers are active at the connection point, the allocation of imbalance between different BRPs of multiple suppliers is performed following national rules. The configurations and the responsibilities shall remain as they are in the simple version.

18. The interactions and data exchange remain the same in case of several service providers as it is in the simple version. Direct interaction and data exchange between the service providers are not envisaged.

~~1. The aggregation models that are described below aim at defining how the participation of service providers is allowed, based on the configuration of the meter equipment and by the relationships established between the BRPs and market entities present at and behind any connection point.~~

~~2. Member States shall allow the aggregation models defined in the Articles 13(6) and 13(7) for each balancing or congestion management and voltage control services in the scope of this regulation, either one or the other or the combination of both.~~

~~3. The aggregation model will depend on whether the controllable unit has a measurement equipment [according to the MID/EMD].~~

~~4. For each model, the service provider can either take his balance responsibility or contractually delegate his balance responsibility to an entity that is not the BRP of the supplier, in line with the national terms and conditions, or the service provider can contractually delegate its balance responsibility to the supplier's BRP (according to Article 17(3) of Directive (EU) 2019/944 and Art. 5(1) of Regulation (EU) 2019/943).~~

~~5. Each technical resource assigned to a controllable unit shall be allocated to the same supplier, the same BRP and, where applicable, to the same balance group.~~

~~6. The aggregation model A prescribes all the following requirements:~~

~~(d) the performance of the controllable units involved in providing the balancing, congestion management and voltage control services is assessed only through the metering equipment at the connection point;~~

~~(e) the only metering equipment is the smart meter at the connection point, which is the only meter to perform measurements of the energy injected or withdrawn used by both the supplier(s) and by the service provider(s); and~~

~~*(f) there must only be one BRP responsible for the activations of any service provider for each ISP, even if there are multiple service providers behind a connection point.*~~

~~*7. The aggregation model B prescribes all the following requirements:*~~

~~*(a) there is an additional metering equipment, being either a submeter or a dedicated measurement device (DMD, as considered in the EMDR), for the controllable units which are involved in providing the balancing, congestion management and voltage control services. The metering equipment of the controllable units measures the withdrawals and/or the injections of the controllable units involved in the provision of such services; and*~~

~~*(b) the metering equipment at the connection point can be a conventional meter or smart meter;*~~

~~*8. The aggregation models A and B defined in paragraphs 6 and 7 are the basic models. For simplification purposes, a simple version is assumed but the possibility of multiple suppliers and service providers behind the connection point providing balance or congestion management and voltage control services from different controllable units is possible. When multiple suppliers are active at the connection point, the allocation of imbalance between different BRPs of multiple suppliers is performed following national rules. The configurations and the responsibilities shall remain as they are in the simple version.*~~

~~*9. The interactions and data exchange remain the same in case of several service providers as it is in the simple version. Direct interaction and data exchange between the service providers are not envisaged.1*~~

13 Articles 20 to 24, some elements in Article 25 and article 28 (Aggregation)

As a general principle, imbalances should be attributed to the agents who caused them and they should not remain with the supplier.

This means that a supplier, unless he has access to information that can be timely incorporated into his own forecasting models, shall not be held responsible for imbalances that he could not foresee as they result from the action of a third-party (an independent aggregator). One basic principle is the Directive is that each market participant shall be financially responsible for the imbalances he causes, which implies some correction to neutralise DR activation by a third-party from the supplier’s imbalance.

When referring to financial compensation it is also relevant to distinguish between imbalance costs and other costs, such as hedging and rebound effect, that may exist even by correcting or compensating for imbalances caused by demand response activation.

This means that, it is not true that a financial compensation should apply, only when the measurements that determine the load curve of the customer is not corrected (as proposed in article 21). A correction only acts on imbalance costs, while there may still be other costs entitled for a financial compensation (e.g. hedging and rebound effect).

Article 21 refers to the payment of financial compensations by suppliers or service providers, which is not in line with the Directive or the framework guidelines. This should only be service providers. Even a supplier or an active customer should only be paying for such if acting as a service provider.

As for delegation of imbalance responsibility, this shall not be necessarily perceived as a delegation in the supplier's BRP. An independent aggregator can delegate such responsibility in any entity under a contractual agreement and the NC should not have such a great focus on the delegation into the supplier's BRP. After all, the delegation of imbalance responsibility is of relevance for the system operator so that he can know who to bill and exchange data, disregarding of being the supplier's BRP or any other entity.

Regarding the existence or not of metering, we question the models where there is DR for partial loads but no measurement behind.

If this applies for partial loads, without metering, there is no visibility on the balance responsibilities of each party, not to mention it doesn't work for more than 2 agents (between "main supplier" and other). For purposes of verification, validation, settlement, accurate billing and proper incentives for balancing there should always be any type of metering for the partial loads, or at the very least some methodologies to calculate partial loads and split responsibilities.

Also, by measuring only the controllable units at the connection point in isolation to the rest of the assets, this can only work for simpler flexibility services like load shifting, interruptibility, load reduction, etc, but not for most of ancillary services including aFRR or mFRR.

Finally, regarding baselines, these should also include as an additional variable the rebound effect expected to occur associated to any change from a requested activation.

These articles shall all be reviewed following the proposal presented above for article 19, with a complete shift of the starting point to define aggregation models.

14 Article 25 (General principles for baselining methods)

While innovation of baselining should be encouraged, system operators or the NRA should have the right to decide which baseline methods they will use.

In that regard we propose to review paragraph 2, as follow:

2 - These national requirements referred to in paragraph 1, shall enable different baselining methods where the baseline is assumed as reference for checking or validating the delivery. To enable innovation of baselining, the service providers, the DSOs, the TSOs or a third party (e.g. a SP) shall have the right to propose new approaches for determining a baseline, subject to the approval of the system operators and/or the NRA.

Baselining shall also consider the rebound effect, which means the recovery effect associated to a change in the profile due to an activation for flexibility services in one time unit and how that translates into a symmetric (or close to it) change in another time unit.

For instance, if a consumer (or service provider) reduces demand in an EV charger, in a certain hour, because the system is procuring that flexibility service (either for a frequency service, or congestion management, or something else), that EV will instead charge that same load it would need before, but in a different hour. This shift in demand that results from activation is what we refer here as the rebound effect.

Of course, this rebound effect is not necessarily symmetric (meaning a shift in the exact same level of the activation) for all forms of loads. For example: it might not even happen in lightning, in H&C might not be in the full level of activation as there is also some thermal inertia but it should occur in some extent, it should be symmetric (or close to it) in EV charging, it is very likely to be symmetric (or close to it) in some industrial processes, ... so it very much depend on the type of load/use.

Not all markets are at the same starting point and the use of distributed flexibility is still in early stages in most markets, where this may be negligible for now. But with increasing use of distributed resources this tends to be very different.

The rebound effects should be approached in 2 perspectives:

1. For the system operators' decision to activate: by activating a certain load (reducing demand) the baseline for other hours will not be the same as if no activation occurs, and this might even cause other issues to the grid in hours where no congestion (for instance) was foreseen before, because now the load reduction in a previous hour will translate in a load increase in another hour. This effect should also be taken into account by SOs when deciding activations (meaning the price to reduce the load vs. the potential new cost in other hours where a flex service might be needed due to this previous activation) and even something that can be part of the product definition (including when/how to "rebound" while minimizing the effect to the grid).

2. For the supplier's forecasting and cost/pricing: the action of third-parties like an independent aggregator, to activate load changes, result in an imbalance for the hour (or other period) of activation but also in other periods where this rebound effect occurs. Therefore, the effect of the activation doesn't end in the period for which the activation takes place but also in other periods where other baselines occur as a result from this previous activation.

This effect should be captured in baseline methodologies.

- This means that, besides the baseline as the load forecast if no activation had occurs, when considering an activation, a new forecasted curve should be assessed to capture the rebound effect in other hours (where there is no direct activation per se but the forecast needs to be corrected to reflect the change from an activation in a certain previous moment).
- It's like a "second-run" in the forecast ahead incorporating the possible activation needed in previous moments.

In that regard we propose to review paragraphs 3, 4 and 5, as follow:

3 - The national TCs referred to in paragraph 1 shall include at least the following:

(a) the roles and responsibilities of the stakeholders involved in the process of balancing, congestion management and voltage control services regarding the development and implementation of baselines;

(b) the approval process of an individual baselining method by the NRA, or by the systems operators if the ~~or~~ NRA~~s~~ so decides, which will also consider the costs and benefits of the implementation of the specific baselining method;

(c) the process of validating the baseline;

(d) the methodology to reassess the baseline considering the 'rebound effect' from a possible activation;

(e) ~~(d)~~ the process of re-evaluating proposing and approving new methods for baselining, and to set cross-border mutual recognition;

(f) ~~(e)~~ the minimum set of data necessary to deliver and validate the respective balancing, congestion management and voltage control services;

(g) ~~(f)~~ an obligation to share necessary data with all relevant stakeholders for executing processes of the respective balancing, congestion management and voltage control services;

(h) ~~(g)~~ a procedure to support new and innovative approaches to the methods; and

(i) ~~(h)~~ the obligation for the relevant entity for publishing a list of accepted baseline methods and their applicability.

(...)

4. The baselining methods shall be based on the following principles:

(...)

(d) the methods may consider the impact of a delivery of a balancing, congestion management and voltage control service, outside the time of activation but within contracted times, such as the rebound effect;

(…)

5. By 2 ~~5~~ years, and after that on a yearly basis, after the entering into force of this Regulation, ENTSO-E and the EU DSO entity shall make a common assessment which considers costs and benefits of whether further standardisation of the baselining methods brings benefits in achieving the aims of the Electricity Regulation. In this process ENTSO-E and the EU DSO entity shall consult the stakeholder and consider their feedback. Final report will be published by not more than six months ~~one year~~ after starting the assessment. Based on this report further steps shall be taken into account on national level if needed.

15 Article 26 (Baselining method: specification and validation)

The reference to the imbalance settlement period doesn't seem to make sense in the context it is proposed in this article.

One may have 15' metering data while that Member State has, for instance, a 1h ISP. Or, for instance a service with a 4 second MTU (requiring higher resolution) should not be using data with the ISP which is in some MSs still 1h ... and all converging to 15' in 2025.

Measurement and ISP don't have to be (and usually aren't) aligned.

In that regard we propose to review as follow:

1. If the data used for determining the activation of a service is based on measurement, the granularity of the data used shall be at least the metering ~~imbalance settlement~~ period. Services with shorter control cycles may require a meter able to provide a higher resolution for determining the activation of a service.

Also, in paragraph 2, suggest to be more objective in the terminology and avoid references such as "deception".

In that regard we propose to review as follow:

The system operators have the right to require all data needed to secure a proper activation of services and to set requirements designed for verification and monitoring, and assessment of accuracy ~~to avoid deception and gaming possibilities~~.

16 Article 27 (General principles for settlement of congestion and voltage services and settlement related data exchange)

This article refers, in several paragraphs, the ISP as minimum granularity. The reference to the imbalance settlement period doesn't seem to make sense in the context it is proposed in this article.

One may have 15' metering data while that Member State has, for instance, a 1h ISP, which would be less granular than the need for a service. It also has no relation to the product features. Measurement and ISP don't necessarily have to be aligned, neither do the MTU for a specific service and ISP.

In that regard we propose to review paragraphs 2 and 4, as follow:

> *2. Each relevant systems operator shall calculate the activated volume of congestion management and voltage control services energy according to the procedures pursuant to paragraph 1(a) at least for:*
>
> *(a) each market time unit as defined in the product characteristics ~~imbalance settlement period~~;*
>
> *(b) each direction, with a negative sign indicating relative energy withdrawal by the service provider, and a positive sign indicating relative energy injection by the service provider;*
>
> *(c) each SPU; and*
>
> *(d) each SPG, if relevant.*
>
> *(...)*
>
> *4 – Each relevant systems operator shall be entitled to receive the necessary measurement values, aggregated or not, by the MDA for the calculation of the activated volume of congestion management service energy, voltage control service energy and balancing service energy but at least:*
>
> *(a) for each market time unit, as defined in the product characteristics, ~~imbalance settlement period~~ of the time of activation;*
>
> *(b) in a standardised data exchange format; and*
>
> *(c) when updated data is available.*
>
> *(...)*

Additionally, paragraphs 7 and 8, refers to the right for system operators to receive individual metering data and baselines, from each controllable unit, which refers to each resource.

If the SPU includes several devices behind one metering point, that should not require one meter per technical resource. A submeter for all those technical resources should be accepted as enough. Even if there are meters per device, the SO should only need the metered data of that partial load, and be able to verify that against the main meter at the physical connection point, but not necessarily by device.

The same rational apply to baselines. The system operator should only require the baseline for each SPU or SPG, necessary to validate the activation of the service.

In that regard we propose to review paragraphs 7 and 8, as follow:

> ~~*7. Each relevant system operator shall, on request, receive the individual metering values for controllable units which are part of the concerned SPUs or SPGs necessary for the*~~
>
> ~~*validation of the activated volume of congestion management service energy, voltage control service energy and balancing service energy and to verify the respect of grid limitations, according to the procedures but at least:*~~
>
> ~~*(a) for each imbalance settlement period of the time of activation ; and*~~
>
> ~~*(b) in a standardised data exchange format.*~~
>
> ~~*8. Each relevant systems operator shall, on request, receive the individual baseline of controllable units which are part of the concerned SPUs or SPGs necessary for the validation of the activated volume of congestion management service energy, voltage control service energy and balancing service energy but at least:*~~
>
> ~~*(a) for each imbalance settlement period of the time of activation ; and*~~
>
> ~~*(b) in a standardised data exchange format.*~~

Also, if paragraphs 7 and 8 are to be kept with further clarification, the above comments regarding ISP also apply.

Paragraph 9 refers to the need for the system operator to receive information regarding grid limitation for the correct settlement.

This is very unclear and should either be eliminated or reworded for more clarity on the reach of such paragraph:

- In one hand, grid limitation is an information the system operator owns, so it's not clear from whom should it receive this information from. If this refers to the activating system operator to request info from connecting system operators (where resources are connected) that should be further specified.

- Also, there doesn't seem to be a relation between grid limitation and settlement. In the settlement phase any activation should already had occurred, thus grid limitation should not have any influence here. Again, this needs to be further clarified or deleted.

In that regard we propose to review paragraph 9, as follow:

~~9. Where applicable, each relevant systems operator shall be entitled to receive the necessary information regarding the grid limitation for the correct settlement.~~

17 Article 29 (Roadmap for the implementation of balancing bids granularity)

Paragraphs 2, 3 and 4 should refer to the provisions and timeline foreseen in paragraph 1 (instead of referring to paragraph 2), which we assume is just a typo.

Still in paragraph 3 and also in paragraph 4, there is a reference to a cost-benefit analysis of the reduction of the bid granularity, and further reassessment.

It is not clear though under which methodology tis CBA should occur and how such methodology should be set. Considering this may be the argument for some Member-States applying this bid reduction and other don't, the methodology for this CBA should be harmonised.

In paragraph 4 it is also defined a maximum period for initial derogation but, after reassessment it only foresees that the TSO may request further derogation, with no time limitation clearly defined.

In that regard we propose to:

- Review paragraphs 2, 3 and 4 as follow:

  2. The implementation deadline of the requirement set in paragraph ~~2~~ 1 shall be at least 2 years after the entry into force of this Regulation.

  3. A national regulatory authority may, at the request of a TSO or at its own initiative, grant the relevant TSOs a derogation from the provision set out in paragraph ~~2~~ 1 for all or some standard balancing products if the implementation is judged inefficient based on next condition:

(…)

4. Where the relevant national regulatory authority grants a derogation, it shall specify its duration. The derogation may be granted for a period maximum of two years, after which the TSO(s) of the concerned MS(s) shall reassess the implementation of the provision set out in paragraph ~~2~~ 1. (…)

- **Clarify the CBA methodology (foreseen in both paragraphs 3 and 4), namely how this should be defines, and the same for the reassessments to be made, under which a derogation could be granted.**

- **Review paragraph 4, regarding the derogation time limit, as follow:**

4. (…) As a result of that reassessment, TSO(s) may ask to extend the derogation period, for a period no longer than 2 years.

18 Article 30 (Qualification for service providers)

In article 30 paragraph 1, it is stated that the service provider shall successfully pass qualification requirements before being granted access to markets. In order to increase market liquidity, it should be stated that it this would only be applied if required by the market operator.

In that regard we propose to review paragraph 1, as follow:

1. The service provider, when requested by the market operator, shall successfully pass a service provider qualification with the requirements laid down in paragraphs 2, 3, 4 and 5 before being granted access to markets for balancing, congestion management or voltage control services. In case the service provider is already qualified for one or more markets for balancing, congestion management or voltage control services and applies for the participation in another market for balancing, congestion management or voltage control services, a simplified qualification process shall be foreseen further specified in the national TCMs for service providers.

19 Article 31 (Pre-conditions and applicability of the product prequalification and product verification processes)

This article sets the conditions under which system operators can request a prequalification, for either specific balancing products or local products, such as voltage control and congestion management.

However, some of the terms would benefit from a more precise and objective definition.

For instance, it refers to specific balancing products when *"the expected contribution for guaranteeing the system balance is particularly relevant"*. The same applies for local services in situations where *"the expected frequency of activation is particularly relevant"* or *"the expected contribution to resolve a congestion or voltage constraint is particularly relevant"*.

It is very subjective to define what "relevant" means in such situations and, therefore, a clarification is needed, as the default rule should be to request for an e-post verification and only in very particular circumstances to require an ex-post pre-qualification.

If these conditions aren't clearly defined, these may result in having pre-qualification as the standard if the expected impact is always considered relevant, without any definition of such circumstance.

To avoid a misuse of such conditions it is advisable that the NRA would need to approve the circumstances under which an ex-post verification would not suffice for such products, thus requiring for an ex-ante prequalification.

In that regard, in addition to a more precise and objective wording in paragraph 4, we propose to add a new paragraph as follow:

> *5. The right to require a product prequalification on SPU or SPG level, in addition to the possible product verification, as foreseen in paragraph 4, is subject to the approval of the national regulatory authority.*

20 Article 32 (Criteria for reassessment of product prequalification and product verification)

We assume that the intended default threshold, set in paragraph 1, is the 10% and the 3MW are intended to prevent the reassessment each time the 10% are reached, but with negligible volume variations.

In that regard, we propose to review paragraph 1 as follow:

> *1. The PPR shall have the right to reassess and potentially require a repetition of the product prequalification or product verification, following the steps indicated in article 31 (Pre- Conditions and Applicability of the product prequalification and product verification processes), of an SPU or an SPG, when one of the following criteria applies:*
>
> *(a) if the prequalified or verified capacity of the SPU or the SPG changes by more than the minimum between 10% and ~~or~~ 3 MW compared to the previously*

prequalified or verified SPU or the SPG due to additions or removal of controllable units. If the PPR requires a repetition of the product prequalification or product verification, the service provider shall be entitled to participate in the market with the previous qualified set-up of the SPU or SPG;

(b) if the prequalified or verified capacity of the SPU or the SPG changes by more than the minimum between 10% and ~~or~~ 3 MW compared to the previously prequalified or verified SPU or the SPG due to significant modernisation or updates of controllable units. The service provider shall provide on request by the PPR evidence of the modernizations or updates to the PPR;

Paragraph 4 seems to be redundant and even inconsistent with paragraph 5, thus we recommend to delete such paragraph. In fact, paragraph 4, without further framework seems to imply that paragraph 1 only applies to small CUs and standardized devices, while paragraph 5 also covers how to address those units, with simplified criteria.

In that regard, we propose to delete paragraph 4:

~~4. For the evaluation of the criteria pursuant to paragraph 1, standardised devices and small CUs shall be considered.~~

21 Article 33 (Switching of controllable units)

It is not clear what is meant by an *"operator of a flexibility register platform with a CU module"*, thus we recommend clarifying what is meant as having a CU module.

Additionally, where it is stated that one CU cannot be assigned to more than one service provider, it should be foreseen that such limitation should be per service to be provided, to avoid lock-in.

One element that seems to be missing regarding this switching is a register for such switching to ensure consumer protection against unintended "contracts" or undue activations from service providers without active contracts in place.

22 Article 34 (Requirements for product prequalification)

As foreseen in previous articles of this Network Code, product prequalification is applicable for standard balancing products and, under specific circumstances, it is also optional for specific balancing products, voltage control or congestion management services.

Therefore, product prequalification doesn't always apply, thus we propose to review paragraph 1 as follow:

1. *When*ever product prequalification applies, and when *multiple systems operators are potential buyers of the same product for the same SPU or SPG under prequalification, the systems operators shall agree on one PPR.*

Paragraph 7 foresees a simplified procedure whenever SPU or SPG are formed by CUs identical to other prequalified already under other SPU or SPG for the product declared by the potential service provider.

This concept of identical CUs must be further defined in a more objective way, or at least, the NC must foresee such definition is a precise and objective way within national T&Cs to be approved by the NRA.

Additionally, paragraphs 9 and 10 foresee that ENTSO-E shall report on the pre-qualification requirements and processes for standard balancing products across the EU and assess the need for further harmonization, after which (according to the results if such an assessment) a joint proposal may be submitted to ACER, to harmonize the prequalification process.

Considering this refers to standard balancing products, which should be traded in pan-European platforms, and for markets and products that should already have a high maturity level (unlike other products such as local congestion management, for instance), we see no point in having all these intermediate steps.

Standard balancing products, which are traded in pan-European platforms, must evolve for standard prequalification processes across the EU, and overcome the current barriers. It is evident the significant differences in rules required between different Member States and there is no reason to postpone this harmonization, in particular with the approach of the go-live of most TSOs in the pan-European platforms (e.g. Picasso), under common implementation frameworks.

In that regard, we propose to review paragraphs 9 and 10 as follow:

9. *ENTSO-E shall recommend a harmonized implementation framework to the prequalification process for standard balancing products, within 12 months after the entry into force of this Network Code, and submit it for approval to the Agency.*

10. This proposal shall be supported by a ~~provide a~~ description of the prequalification process for each standard balancing product in each EU member ~~in the European report on integration of balancing markets pursuant to Article 59 of Regulation (EU) 2017/2195. The report shall describe~~ including the main steps, lead times as well as information and technical requirements, and build on existing best practices. ~~The report shall identify the variants of potential improvements towards~~

~~harmonization of these prequalification processes in the light of the objectives of this Regulation.~~

~~10. If the European report on integration of balancing markets as referred in paragraph 1 recommends improvements in the harmonization of the prequalification process for standard balancing products, all TSOs shall, within 12 months of the adoption of the report, develop a common proposal for the harmonization of the prequalification process and submit it for approval to the Agency.~~

23 Article 36 (The congestion management and voltage control services product prequalification process)

The time, foreseen in this article, for confirmation by the PPR to the formal application of a potential service provider is excessive (4 weeks to assess if the application is complete or require further information + 3 months after completeness confirmation to assess if it meets the requirements).

In that regard, we propose to review as follow:

1. When the criteria of Article 31 (4) (b) (Pre-Conditions and Applicability of the product prequalification and product verification processes) are met and as a result product requires prequalification, the potential service provider shall submit a formal application to the PPR together with the required information of potential SPU or SPG. Within no more than 2 ~~4~~ weeks from receipt of the application, the PPR shall confirm whether the application is complete. Where the PPR considers that the application is incomplete, the potential service provider shall submit the additional required information within at most 2 weeks from receipt of the request for additional information. Where the potential service provider does not supply the requested information within that deadline, the application shall be deemed withdrawn.

2. Within no more than 3 weeks ~~3 months~~ from confirmation that the application is complete, the PPR shall evaluate the information provided and decide whether the potential SPU or SPG meet the criteria for a given congestion management and voltage control services. The PPR shall notify its decision to the potential service provider.

24 Article 39 (Principles for governance and interoperability)

Data portability between flexibility register platforms should be a requirement disregarding of these being or not managed by a system operator.

In that regard, we propose to review paragraph 3 as follow:

3. To avoid vendor and operator lock-ins, and to facilitate competition and innovation, data stored by flexibility register platforms ~~that are not operated by systems operators~~ shall be portable to other flexibility register platforms, particularly in cases where Member States or system operators decide to migrate towards new flexibility register platforms. (…)

25 Article 41 (Principles and requirements for operators of flexibility register platforms)

For clarification purposes, we propose the following review to paragraph 1 of this article:

1. Operators of flexibility register platforms shall make the administered data available to entitled parties, including final customers with CU providing the services, in a non-discriminatory manner through online- platforms, which shall include up-to-date as well as historical data.

26 Article 43 (CU module procedures)

Considering that, in a Member State, aggregator switching might be managed centrally by a designated entity to maintain and manage the database of aggregators, and respective switching, this article should also consider the possible link with such an entity's platform.

In that regard, we propose to review paragraph 1, d), as follow:

(d) a 'switching procedure' allowing for service providers (or final customers) to request the assignment of existing controllable units to their portfolio on behalf of and with the consent of the final customer, or ensuring interoperability with existing platforms of designated entities managing aggregators' switching;

27 Article 45 (Principles for national implementation)

For clarification purposes, we propose the following review to paragraph 4 of this article:

4. The national terms and conditions for service providers shall include:

(a) requirements and procedures for flexibility register platforms, system~~s~~ operators' coordination, market platform operators and other relevant actors to cooperate with service providers and procuring systems operators to perform end-to-end training tests;

(…)

(g) A process for assigning, switching or removing the ~~technical~~ aggregator for a controllable unit as set in Article 33 (Switching of Controllable Units) paragraph 7.

(...)

7. Regarding product verification process the national terms and conditions for service providers shall include:

(a) verification criteria for each product pursuant to Article 38 (Product Verification Process) paragraph 3;

(b) the condition to perform an ex-post ~~activation test for~~ verification test pursuant to Article 32 (Criteria for reassessment of product prequalification and product verification);

(c) the condition to impose penalties pursuant to Article 38 (Product Verification Process) paragraph 5 (b), if the verification criteria is violated, which might consider grace factors within which penalties shall not apply; and

28 Article 47 (Solutions for congestion and voltage control issues though active power)

Market-based procurement shall be the preferred option, and any redispatch (whether it is market-based or not) is subject to financial compensation, as foreseen in Regulation (EU) 2019/943 (article 13).

In that regard, we propose to review paragraph 3, as follow:

3. Non-market based redispatching may be applied within a bidding zone and/or network area, if an exception set forth in Article 13(3) of Regulation 2019/943 applies, however, market-based options should be prioritised as far as possible.

3a. Non-market based redispatch as foreseen in paragraph 3, or any redispatch related to grid prequalification where SPU or SPGs are under a firm connection agreement or license (or where the redispatch exceeds the conditions for non-firm connection agreements or license), shall be financially compensated, under the terms set by Regulation (EU) 2019/943.

Additionally, this article refers to the assessment of market-based procurement vs. other tools, and to the cost-efficiency assessment to decide on the most appropriate tool. However, it lacks clear rules on the governance regarding such an assessment.

In that regard, we propose to add the following additional paragraph:

5. For the purpose of paragraphs 2, 3 and 4 in this article:

a) By one year after entry into force of this Regulation, the system operators shall, at national level, present to the NRA a common proposal with a methodology under which they shall assess market-based procurement of local system services and compare it with other tools such as those foreseen in paragraph 2.

b) The NRA shall pursue a public consultation for at least one month, after which it shall decide to approve or the request for amendments, which must occur no longer than two months after the closure of the public consultation.

c) In case the NRA request for amendments, the system operators shall incorporate them and submit a new revised proposal for approval by at most one month after the NRA request.

d) After receiving a revised common proposal from system operators, the NRA shall either approve or amend and publish a methodology to be pursued by all system operators, that should be the base to assess between market-based procurement of local system services and other options, namely grid investments under the NDPs.

29 Article 48 (National terms and conditions for market design for congestion management and voltage control services through active power)

When preparing T&Cs as foreseen in article 6, unit or portfolio bidding is irrelevant. The relevant information is whether there is locational information or not, and in all electricity markets (as per the definition in Directive 2019/944).

In that regard, we propose to add the following additional paragraph:

6. When preparing the national terms and conditions referred to in paragraph 4, DSOs and TSOs shall consider the national context at least including:

(a) whether, in any electricity market, locational information is needed or available ~~long-term markets, day-ahead, intraday or balancing markets apply unit or portfolio bidding~~;

Additionally, we propose to delete (k) in paragraph 6 as this should be out of scope of the system operator assessment.

~~(k) the potential impact on other wholesale market prices from anticipation of pricing in subsequent, parallel or coordinated, linked or labelled local markets for congestion management and voltage control services.~~

30 Article 51 (Principles for applying non-firm connection agreements)

Any provision regarding non-firm connection agreement shall be dully adjusted to the final wording to be agreed within the trilogue negotiations regarding the electricity market design review, in particular in what concerns flexible connection agreements.

Still, it makes sense to include the concept in the network code, namely considering the coordination and links between such tools and flexibility procurement.

It is also important to foresee that flexible connection agreements shall also be subject to market-based rules, through competitive procedures, and a clear framework shall be set to ensure a fair assessment of different options, and even how they should interplay in a complementary approach.

Additionally, it must be clear that any limitations should apply differently under a flexible connection agreement, than they would under a firm connection agreements, and which compensations shall apply.

Finally, Article 51 defines that non-firm connections can have the possibility to participate in congestion and voltage markets. However, a non-firm connection was given because of the need to limit the power requested, or injected, by the non-firm client due to grid limitations, in agreement with the client. To that end the non-firm connection agreement was established which contains requirements for the system operator to limit the client non-firm power. Any set of measures to avoid grid congestion undertaken by the relevant system operator should necessarily begin with limiting the non-firm clients. Therefore, it does not make sense for non-firm clients to be participating in congestion markets, otherwise, there would be no difference between non-firm clients and firm clients.

In that regard, we propose to review as follow:

> 1. *If flexible ~~non-firm~~ connection agreements are allowed in a member state, the relevant national authorities shall define at national level the framework for non-firm connection agreements" including their applicability, scope, limitations and conditions for compensation if any.*
>
> 2. *National terms and conditions, subject to the NRA approval, or other applicable national regulation shall ensure that flexible ~~non-firm~~ connection agreements do not lead to market-distortion by providing rules following these principles:*
>
> *(a) When flexible connection agreements are allowed in a Member State, market-based and competitive procedures shall be privileged as far as possible.*

(b) ~~(a)~~ When flexible ~~non-firm~~ connection agreements are established, transmission and distribution system operators shall not unduly limit the possibility for grid users to provide services in other markets, nor shall flexible connection agreements distort flexibility procurement by system operators, including the system operator to which the resource is connected;

(c) ~~(b)~~ When non-firm connection agreements are allowed, an assessment methodology and the conditions for systems operators to choose non-firm connection agreements shall be specified;

(d) ~~(c)~~ When non-firm connection agreements and markets for ~~congestion management and~~ voltage control services co-exist, the interaction between the two options shall be specified;

(e) ~~(c)~~ When non-firm connection agreements and markets for congestion management ~~and voltage control~~ services co-exist, the interaction between the two options shall be specified, namely the priority given to limiting the flexible connection agreements, upt to the extent of the flexibility terms defined and unless the costs of doing so exceed the cost from additional procurement;

(f) ~~(d)~~ SPU or SPGs under flexible connection agreements may be limited to participate in local or balancing markets for the relevant timeframes and to the extent of the terms established in the connection agreement; ~~When non-firm connection poses a risk to the resource's ability to deliver a congestion management, voltage control or balancing service,the participation in that market may be limited for the relevant time-frame25; and~~

(g) ~~(e)~~ When the provision of services by units affected by flexible ~~non-firm~~ connection agreements is allowed at national level, the connecting and intermediate system operator shall be able to communicate restrictions, to the extent of non-firm level foreseen in such agreements, by setting limits during applicable grid prequalification process or following short term procedure defined in Title VII article 74 (Short-term procedures to account for DSO limits).

31 Article 52 (Publication of information)

For the sake of transparency, information of the expected needs and characteristics of services to be provided shall be made available without restrictions.

In that regard, we propose to review paragraph 2 as follow:

2. ~~When it is necessary for the market and does not lead to market distortion, t~~The systems operators shall publish:

(a) indicative but non-binding information on the different product needs, whether it is up- or downregulation, the foreseen utilization patterns, expected volumes or

other information, with sufficient granularity and detailed per different time horizons; and

(b) locational information for the participation of assets to provide the needed services, and where relevant other information such as the impact factor.

32 Article 53 (Principles for the coordination and interoperability between local and day-ahead, intraday and balancing markets)

We suggest to replace "long-term, day ahead and intraday as well as balancing markets" by "other electricity markets", as "electricity markets" is a concept already defined the internal electricity market Directive.

Also, because most of these markets are not confined to national markets and benefit from cross-border trading (which is the case for day-ahead, intraday and balancing), it doesn't seem reasonable to consider requirements for interoperability and portability at national level.

In that regard, we propose to review paragraph 1 as follow:

1. When defining the national terms and conditions for the market design for congestion management and voltage control services the following principles shall be respected for the coordination of and interoperability between local markets and other electricity markets as defined in the Directive (EU) 2019/944 ~~long-term, day ahead and intraday as well as balancing markets~~:

(a) interoperability and portability, in line with paragraph 2(f) between local markets and other electricity markets ~~long-term, day-ahead, intraday and balancing markets at least on national level~~

Additionally, paragraph 4 foresees the possibility to "transfer" or reuse bids between markets. We consider this chapter needs to be further developed, especially as this relates to markets that already exist and that are not fit for defining rules at national level because these are not mere national markets. There are coupling mechanisms for both day-ahead and intraday, there are pan-european platforms for balancing products, and even for those where no platforms are foreseen, they also assume cross-border trade (e.g. FCR assumes a need defined at the level of the synchronous area and then detailed at national level; non-standard balancing are also used to solve cross-border issues).

Additionally, it is necessary to consider at least 2 elements:

- Using bids between markets requires voluntary consent from the market participant for each bid, to allow for bid transfer and to agree on pricing conditions.

- Reusing bids or transferring bids need to take into account the products associated, namely if they are capacity products, energy products or if they comprise both.

We therefore suggest to further detail the rules regarding this bid transfer or reuse, or to include further assessment to be made under articles 83 and 84, and to ensure 3 basic principles regarding:

- EU harmonised rules, compatible to the current functioning of electricity markest such as DA, ID and BAL

- Voluntary participation and consent per bid and price conditions

- Incorporate interlinks of product characteristics, namely capacity products, energy products or products encompassing both capacity and energy components.

Besides this general remark to the need to further clarify we suggest the following amendments to:

- Incorporate the above mentioned principles;

- Link with compliance with REMIT and competition Law, which address topics such as capacity withholding and market abuse, and considering that this Network Code proposal includes multiple references to "gaming" which is not defined anywhere and therefore lacks objectivity in that regard. It makes more sense to link this with existing provisions in legislation that is more fit to that purpose;

- Take into account the provisions from the IEM Directive (art 15, 5, d)), that foresees "Member States shall ensure that active customers that own an energy storage facility: (...) (d) are allowed to provide several services simultaneously, if technically feasible".

4. The national terms and conditions for the market design for congestion management and voltage control services shall:

(a) Specify whether and under which conditions bids offered in day-ahead, intraday and balancing markets can be used for congestion management, and under which terms. Even if this is an option it shall be possible to organise additional local markets. This only applies regarding day-ahead, intraday and balancing markets, where further EU wide rules are specified under articles 83 and 84 of this Regulation;

(b) Describe how markets for congestion management and voltage control services shall interact with day-ahead, intraday and balancing markets, under the EU wide terms and conditions specified under articles 83 and 84;

(c) Comply with existing regulation namely regarding market integrity and transparency (Regulation (EU) 1227/2011), and general Competition Law ~~Minimize the possibilities for withholding of capacities, gaming and other market abuse~~;

(d) Ensure that the design provides efficient solutions to deal with needs for congestion management and voltage control services;

(e) Allow bids that are not procured in one market to be offered to another market, given they are qualified for that market. To achieve this the service provider may offer their services in another market themselves including by means of an intermediary or a market operator may forward the bids, given that the concerned service provider has given its consent, for each bid to be transferred and agreed with the terms and conditions (namely pricing). Aggregation of bids for forwarding to meet the requirements of other markets shall be possible; and

(f) Prevent ~~Avoid that~~ the same bid from being ~~is~~ selected twice, unless technically feasible, in particular where the same SPU/SPG is active in different markets, and the responsibilities for guaranteeing that.

(g) Take into account the specificities associated to the bids made for different products and markets, namely considering these may be capacity or energy products or products that encompass both components.

~~5. The terms and conditions referred to in article 6 [Common national terms and conditions] shall include provisions aiming at avoiding too many different market places if this leads to inefficiencies.~~

33 Article 54 (Requirements for procuring system operators)

For clarification purposes, we suggest the following amendment:

2. All procuring systems operators shall follow the next principles:

(a) The procuring systems operators shall act in a non-discriminatory manner when procuring and using congestion management or voltage control products;

(b) The procuring system operators shall not ~~No~~ exchange ~~of~~ preferential, confidential and sensitive information with affiliated companies and other service providers; and

(c) The relation between the procuring systems operators and service providers shall be transparent to all market participants.

34 Article 55 (General requirements to local market operators)

We suggest the following amendments:

1. Operators of local markets shall comply with the following requirements:

(a) it owns or has contracted adequate resources (financial resources, necessary information technology, adequate technical infrastructure, skilled workforce and operational procedures) to fulfil the local market operator nationally assigned tasks;

35 Article 56 (Local market operator(s))

Local market operators shall be designated or be authorized by NRAs, and not be self-defined or self-appointed by system operators by default, as a NRA may decide to set one single common local market operator, or define which system operator(s) or other entity(ies) shall take such a role.

In that regard we propose to review as follow:

1. National Regulatory Autorities, or another competent authority at Member State level, shall ~~Systems operators shall~~ describe in terms and conditions referred to in Article 48(4), functional requirements of local market operators and a process for nomination of local market operators, or assess and approve a proposal presented by system operators.

2. The process for nomination of local market operators shall result from national regulatory authority's assessment or take duly into account proposals of each procuring system operator (~~and~~ including the national regulatory authority's assessment) ensuring that the local market operators meet the general requirements described in Article 55 of this Regulation and in national terms and conditions referred to in Article 48(4).

3. Local market operator(s) can be:

(a) The TSO(s) or DSO(s) which procure the services, either alone or together;

(b) Another TSO or DSO, either alone or together; or

(c) A third party, designated by the NRA or representing system operator(s) either alone or together.

4. *The relevant national regulatory authority shall ensure that nomination is revoked if the local market operator fails to maintain compliance with the criteria in Article 55 (General requirements to local market operators) and in national terms and conditions referred to in Article 48(4) (National terms and conditions for market design for congestion management and voltage control services through active power).*

36 Article 57 (Tasks of local market operators)

For clarification purposes, we suggest the following amendments:

1. The operators of markets for congestion management and voltage control services shall provide, maintain and operate the IT solutions that:

(...)

(b) communicates with the service providers and the systems operators for;

(...)

iii. the information to service providers, ~~and~~ systems operators and the market transparency platform, on the market results;

(...)

2. The platforms referred to in paragraph 1 shall integrate or communicate as applicable with the flexibility register~~ry(ies)~~ platform(s).

37 Article 60 (Products from day-ahead, intraday or balancing markets)

For clarification purposes, we suggest the following amendments:

~~1.~~ If the products from other day-ahead, intraday or balancing markets are used for congestion management, as foreseen in Article 53 (Principles for the coordination and interoperability between local and day-ahead, intraday and balancing markets), then those products shall be included in the list of standardised products for congestion management as referred to in Article 58 (List of attributes).

38 Article 61 (Procedure for sharing storage ownership or operations)

The Framework Guidelines set for SO-owned storage included several elements that don't seem to be considered in the Network Code, while some of the provisions in the Network Code are redundant, regarding what is already foreseen in the IEM Directive and are confusing.

For instance, the Framework Guidelines foresee that the new NC rules shall specify criteria to be fulfilled by the tendering procedure in order to be approved by the NRA, including a series of elements. Such criteria are not being considered in the draft proposal of the Network Code.

Also, article 36 of the IEM Directive already sets the conditions under which Member States may grant a derogation for owning and operating storage facilities, by system operators, and they do not be to be repeated in the network code.

In that regard we propose to review based on the framework guidelines, as follow:

> 1. *By way of derogation Member States may allow distribution system operators to own, develop, manage or operate energy storage facilities, when the conditions set in the Directive (EU) 2019/944 are fulfilled.* *~~In Member States where it is decided that NRA can grant derogations for systems operators to develop, own, operate or maintain storages, systems operators can proceed to implement a solution that relies on systems operators development, ownership, operations, or maintenance of storage if the following conditions are met:~~*
>
> *~~(a) market-based procurement of services to solve congestion or voltage issue of the systems operators according to Articles 47-50 (Solutions for congestion and voltage issues through active power; National terms and conditions for market design for congestion management and voltage control services through active power; Principles for procurement and pricing for market-based congestion management and voltage control services; Principles for procuring by tender procedure) and 81 (Voltage control services with use of reactive power) do not result in the delivering by service provider of the needed services to solve the congestion or voltage issue at a reasonable cost and in a timely manner, including offers with not yet registered or prequalified assets as per Article 50.1.a (Principles for procuring by tender procedure) or not yet connected assets (including storages) as per Article 43.1,b if allowed by the tendering procedure;~~*
>
> *~~(b) as an additional requirement to Article 50 (Principles for procuring by tender procedure), the tender essential elements of Article 50 shall be submitted to public consultation and to NRA approval prior to starting the procurement process;~~*
>
> *~~(c) the regulatory authority during the approval procedure has carried out an assessment of the tendering procedure, including the conditions of the tendering procedure;~~*

~~(d) storage facilities are necessary for the system operators to fulfil their obligations 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~~

~~(e) the regulatory authority has assessed the need of such a derogation described in 54.1.d. and has granted its approval.~~

~~2. In Member States where systems operators are allowed to develop, own, operate or maintain storages that are fully integrated network components as approved by the NRA, systems operators can proceed to implement a solution that relies on systems operators development, ownership, operations or maintenance of storage as a fully integrated network component if market-based procurement of services to solve congestion or voltage issue of the systems operators according to Articles 47-50 (Solutions for congestion and voltage issues through active power ; National terms and conditions for overall market design for congestion management and voltage control services through active power; Principles for procurement and pricing for market-based congestion management and voltage control services; Principles for procuring by tender procedure) and 81 (Voltage control services with use of reactive power) does not result in the delivering by service provider of the needed services to solve the congestion or voltage issue at a reasonable cost and in a timely manner, including offers with not yet registered assets as per Article 50.1.a or not yet registered or prequalified assets (including storages) as per Article 50.1,b if allowed by the tendering procedure.~~

3. In addition, where it is allowed by Members States, systems operators may consider sharing ownership and operation of such storage facilities. This is without prejudice to the systems operators' rights, if such a right is given by Member State, to develop, own, operate or maintain fully integrated network elements as regulated in articles 36 and 54 of Directive (EU) 2019/944. In case systems operators consider implementing a shared storage ownership or operation, systems operators shall submit to public consultation the general terms and conditions of tenders, including the intended shared ownership agreement, it will perform, then submit the tendering process to NRA approval prior to the tendering takes place. Such tendering process may be specific to each systems operators and each assets.

~~4. Before launching a tendering procedure to share ownership and operation of systems operators storage, systems operators shall first assess the opportunity to engage such tendering procedure, considering the storage size, the storage part available to third party, cost of processing the tender and engaging in shared ownership and operations, potential savings and costs due to shared ownership and operations or other relevant criteria. If such assessment shows that such ownership and operation is not efficient, systems operators may ask NRA to discard the possibility of shared ownership, and grant the systems operators a derogation to own, develop, operate and manage the storage facilities.~~

5. The tender for shared ownership and operation shall provide relevant and useful information for the potential third party to prepare an appropriate offer. This information shall include the minimum and maximum part, in terms of capacity or energy or other relevant criteria, available to third party, the foreseen utilization *pattern and expected volumes of the systems operators part of the storage considering charge and discharge, with sufficient granularity or other relevant information.*

6. Systems operators shall publish information on economic conditions of the tender for shared ownership and operation. The transparency on the economic conditions shall be balanced against the potential impact on the pricing of the offers.

7. The tendering procedure shall ensure transparency of the selection criteria and the results of the tender.

8. Based on the applications for the tender, systems operators shall assess whether shared ownership is a better economical solution than full systems operators ownership and consistent with other relevant criteria, and submit its assessment and proposed outcome of the tender to NRA approval.

9. Based on the assessment of the systems operators according to paragraph 4 or 8 of this Article, the NRA shall:

(a) Discard the possibility of shared ownership, and grant the systems operators a derogation to own, develop, operate and manage the storage facilities; or

(b) Approve, if relevant, the final shared ownership agreement and grant the systems operators a derogation to own, develop, operate and manage the storage facilities under shared ownership and operations agreement.

10. ~~For TSO storages,~~ The NRA shall notify the decision to grant a derogation to the Commission and ACER together with relevant information about the request and the reasons for granting the derogation.

11. NRAs shall publish its decision of derogation taken according to paragraph 9 of this Article together with sufficient reasoning.

12. Paragraphs 9, 10 and 11 are without prejudice to the systems operators' rights, if such a right is given by Member State, to develop, own, operate or maintain fully integrated network elements as regulated in articles 36 and 54 of Directive (EU) 2019/944.

According to the framework guidelines, this article (or a new article) should also specify criteria to be fulfilled by the tendering procedure to be approved by the NRA. These criteria are lacking in this network code and should include:

(a) Participation conditions that shall enable participation of demand response and other relevant resources that can deliver the services needed by the SOs to fulfil their obligations, in addition to storage participation.

(b) The tender shall include the possibility of shared ownership and operation of a storage facility between the SO and a third party, as a "second best" solution to the SO procuring the total needed service from a third party.

(c) Selection criteria shall be technology-neutral and select the best techno-economic option, maximizing social welfare including when comparing to an SO owned storage facility.

(d) Transparency of the selection criteria and the results of the tender.

(e) Clear communication on the technical conditions of the tender, including as much information as possible for the potential SPs to prepare an adapted offer, such as the foreseen utilisation pattern and expected volumes, and with sufficient granularity.

(f) Clear communication on economic conditions of the tender. The transparency on the economic conditions shall be balanced against the potential impact on the pricing of the offers.

The specifications of the tender shall be submitted to public consultation and to NRA approval prior to the tendering process. Further criteria to be fulfilled by the tendering procedure shall be defined at national level. After the tender, the NRA may grant a derogation or a partial derogation (for shared ownership) if a third party cannot deliver the service at a reasonable cost and in a timely manner. In this case, the partial derogation shall be preferred if economically efficient.

This Network Code should also define the governance to set an assessment methodology under which it should define how to evaluate what is considered a reasonable price for service delivery.

39 Article 62 (Shared storage ownership and operations agreement)

As in any other resource owned and managed by a market party, third-parties with shared storage have no way to operate (or not) based on whether they may (or not) cause congestion or other issues to the grid, and the terms for operation by the system operator shall be very clear in the operations agreement from the beginning of the shared ownership. This type of requirements shall not be imposed as, an asset owned and managed by a market party needs to be in level playing field with the remaining resources/service providers in the market.

In that regard we propose to review as follow:

2. In case of shared ownership or operation of the storage facility, the third party shall own and operate its part of the storage without further constraint, as concerns shared ownership and operations~~, than neither aggravating nor creating congestion or voltage issues or other provision in line with relevant national regulation, and enabling the~~

~~systems operators to use its part of the storage facility to fulfil its obligations for the efficient, reliable and secure operation of its distribution / transmission grid~~. The third party shall be responsible for the imbalance they cause and for the purchase or the sale of the energy for its part in line with national terms and conditions. The third party shall be treated as any other participant while operating its part of the storage.

40 Article 63 (Assessing and transferring ownership of system operators owned storages)

To clarify some provisions in this article and also to review some particular topics as per the rational above presented for article 62, we propose to review as follow:

2. Parties interested in taking over the systems operators -owned storage shall submit proposals to the NRA including at least:

(...)

(b) their offer regarding the take-over of system~~s~~ operators' owned~~rship~~ storage and operations;

(...)

~~(d) their commitment to additional provisions that shall govern the storage they intend to take over, including that the storage shall neither aggravate nor create congestion or voltage issues or other provision in line with relevant national regulation, be it while providing the service needed by systems operators or at other times; and~~

Additionally, the Framework Guidelines (paragraph 41 b), also foresee the possible phase-out of the SO storage and purchase the necessary services from third parties, if a CBA shows that it is preferable rather than continuing the SO storage activity.

In fact, the market may be able to provide the required services to the system operators, in a more cost-effective way, and thus the system operators shall phase-out own storage activity even if no market parties are interested in acquire such ownership, as the technologies might already be outdated, the associated cost and historic assumed obligations might be excessive, for the existing conditions in the market at the time, the location is not favoured by the market parties in association with other resources they own, or for any other reasons.

There is no reason to impose and keep a less efficient solution and this seems to be addressed in paragraphs 5 to 9 of this article. However, it's not entirely clear as some of these paragraphs keep references to the tender regarding the transfer the property, to the transfer in itself and resulting compensation, which should not apply in those conditions (where simply the existing market services are more cost-efficient and thus no transfer of the assets need to occur but simply a phase-out of the activity and potentially a decommissioning of the assets), and there are also a few incorrections in some of the links.

In that regard, we propose the following amendments:

5. Systems operators shall provide NRA:

(a) an update of costs of owning, operating and managing the storage while providing the needed systems operators services;

(b) the costs induced by phasing out the storage activity;

(c) a Cost-Benefit Analysis of the results of the tender to procure the needed service if systems operators were to cease its existing storage activity.

6. This cost-benefit analysis shall pursue a methodology approved by the NRA and subject to prior public consultation.

7. ~~6.~~ NRA shall assess whether the overall cost benefit analysis concludes ~~indicates that~~ it is preferable to phase out of the systems operators' storage and purchase the necessary services from third parties rather than continuing the systems operators storage activity based on the information from paragraph~~s~~ ~~2, 3 and~~ 5 of this Article.

8. ~~7.~~ The NRA shall ensure that systems operators phase out storage activity within 18 months if at least one of the following ~~all~~ two ~~three~~ criteria are fulfilled:

(a) if there is at least one acceptable offer as per §3 which revels to be more cost-efficient than procuring the necessary services from third-parties;

(b) if third parties are willing to provide the services that the systems operators need~~s~~ and the CBA foreseen in paragraphs 6 and 7 concludes it is preferable to phase out of the systems operators storage and purchase the necessary services from third parties rather than continuing the systems operators storage activity ~~from the storage facility, be it by taking over the systems operators owned storage or by other means, based on the information from paragraph 4 of this Article; and~~

~~(c) if it is preferable to phase out of the systems operators storage and purchase the necessary services from third parties rather than continuing the systems operators storage activity based on the information from paragraphs 2, 3 and 5 of this Article.~~

9. ~~8.~~ If one of the two ~~all three~~ conditions for the phase-out described in §7~~6~~ are fulfilled;

(a) NRA decides on the start date of the 18 months phase out period;

(b) Where applicable, the systems operators shall decide on the best acceptable offer according to the criteria set forth in §1 and assessment in §3.

10 ~~9~~. Within 18 months from the date of the NRA set forth in §8~~7~~ of this Article:

(a) systems operators shall phase-out activity on that facility

(b) ~~and~~, where applicable, system operators transfer the storage activity to the selected ~~that~~ third party(ies), and shall receive compensation according to the proposals received;

(c) ~~(b)~~ where applicable, the systems operators contract the congestion management and voltage control services that match in a timely manner the systems operators needs in price or cost, and in volume, or discard these offers. Systems operators shall publish the outcome of the tender in line with Title IV article 52 (Publication of information).

41 Article 64 (Process and content of the Distribution Network Development Plan)

Chapter 11 of the proposed network code, and in particular article 64.º establishes a complex and thorough process regarding the Distribution Network Development Plan (DNDP). It is important to notice that the Directive (EU) 2019/944 already addresses the issue of the DNDP, particularly in article 32 of such document. Besides this, the directive establishes only some guidelines and provides the member states with the possibility to implement the DNDP in a way that is more convenient for them. Thus, it is very important that the proposed network code should not go beyond what is already in the Directive (EU) 2019/944.

Also, because some member states already have established their own process for DNDP, it is important to ensure some stability and avoid introducing new, disruptive and conflicting processes like the one being proposed in this network code. For instance, the number 3 of article 64.º states that before DSOs could submit the DNDP proposal to the regulatory authority they shall run a public consultation following the principles laid down in article 68. In the case of Portugal this does not makes sense because the process that was approved assigns the regulatory authority with the task of performing the public consultation. Therefore, to be compliant with national legislation and the proposed network code, it would require two public consultation processes.

Because of this, we consider that, although it is important to establish the need for the DSOs to do a DNDP, the processes and content should be left for the Member State to define. In fact, the distribution network is local in nature and thus is beneficial to have the flexibility to adjust different processes and contents to address local issues.

In case the decision is to keep articles 64.º through 68.º, detailing the process regarding the elaboration and approval of the DNPD, number 3 of article 64.º should make reference that only one public consultation process is required, whether it is made by the DSO, prior to submission to the NRA, or by the NRA after submission by the DSO.

In that regard, we propose the following alterative wording for paragraph 3:

> 3. *The DNPD should have a public consultation procedure following the principles laid down in the TITLE VI Article 68 (DNDP public consultation and publication), whether it is done by the DSO before submitting the DNPD to the NRA, or by the NRA after submission of the DNPD by the DSO. ~~Before submitting the DNDP, DSOs shall run a public consultation following the principles laid down in the TITLE VI Article 68 (DNDP public consultation and publication).~~*

Also, considering that the NDP should assess grid investment also taking into account other alternative solutions, **we propose to make a slight amendment in paragraph 6:**

> 6. *Systems operators within Member State shall ensure, where relevant, that their development plans are coordinated and the necessary information to prepare the network development plans is exchanged during the development process in order to identify the need of grid investments or implementation of other solutions.*

42 Article 65 (General principles on the DNDP planning methodology)

Considering that the NDP should assess grid investment also taking into account other alternative solutions, besides flexible connection agreements namely flexibility procurements which is the main focus of this network code, we propose to make a slight amendment in paragraph 2, h):

> 2. *The planning methodology shall follow the next principles:*
>
> *(...)*
>
> *(h) consider alternative solutions such as flexible ~~non-firm~~ connection agreements, flexibility procurement and other, where applicable; and*

43 Article 66 (Requirements on development scenario(s))

We propose one small amendment in paragraph 4:

4. *The scenario(s) assumptions shall be described comprehensively for stakeholders and publicly consulted.*

44 Article 74 (Short-term procedures to account for DSO temporary limits)

In case of unplanned outages in the DSO network it may be necessary to feed affected clients through alternate grid configurations. To replenish service to most clients it might be necessary to impose limits to market participants.

Similarly, congestion is forecasted assuming a generation and load profile. If any generator, or consumption client, experiences an internal outage the forecast might change and require emergency actions by the DSO to avoid outages to many clients.

Therefore, it is advisable that the DSO has the possibility to apply emergency limitation to market participants even if their bids have already been accepted. The proposal is that in case of such emergency limitation that the market participant should be rewarded by its accepted bid.

In that regard we propose the following amendment in paragraph 1:

> *(f) In emergency actions necessary to avoid an outage or damages to clients the DSO can impose immediate limits on the power injected or demanded from the network by any client. If a bid has already been activated the SPU will conform with the DSO imposed limits and will in no way be financially harmed having its bid paid in full by the market operator.*

When bids or contracted capacity are not activated or are limited, due to temporary limits in the connecting or intermediating grid, service providers that are limited in that regard shall be financially compensated in the same terms foreseen in article 13 of Regulation (EU) 2019/943.

Such limitations to bid or redispatch shall be compensated, ideally under market-based procedures or, even if using non-market based these shall foresee a financial compensation 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

(b) net revenues would have otherwise generated; 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 otherwise been received shall be deemed to be part of the net revenues.

In that regard we propose to add the following paragraph to this article:

> *5. Bids and volumes not activated due to temporary limits shall be subject to financial compensation by the system operator imposing such limits, in the terms foreseen in article 13 of Regulation EU (2019/943), namely considering the net revenues that would have otherwise been generated.*

45 Article 75 (Grid prequalification)

Similarly to article 74, when bids or contracted capacity are not activated or are limited, due to grid prequalification status that inhibits such participation, set by connecting or intermediating grid, service providers that are limited in that regard shall be financially compensated in the same terms foreseen in article 13 of Regulation (EU) 2019/943.

Such limitations to bid or redispatch shall be compensated.

In that regard we propose to add the following paragraph to this article:

> *10. Bids and volumes not activated, due to grid prequalification status set by connecting or intermediating system operators that inhibits such participation, those shall be subject to financial compensation by the system operator imposing such restrictions, in the terms foreseen in article 13 of Regulation EU (2019/943), namely considering the net revenues that would have otherwise been generated.*

46 Article 80 (Data to be provided by grid users)

This article foresees that grid users that are either SGU or participate in congestion management or voltage control issues, shall provide individual data of schedules for day-ahead (and any changes) or baselines, and real-time data.

This article should be eliminated considering that:

- Requirements for SGU are already addressed in Regulation (EU) 2017/1485
- Baselines are already covered along this network code for the purpose of providing the hereby considered services, and no additional data should be required, and even less at individual level as it should be provided in aggregated way where appropriate (which is also considered in the network code)
- Real-time data should be under the scope of action of the system operator in itself for observability and management of his own grid and no additional burden should be required to grid users in that regard.

We therefore propose to eliminate article 80.

47 Article 81 (Voltage control services with use of reactive power)

Mandatory requirements for the purpose of reactive power are only considered in the connection network codes, setting obligations regarding the type of equipment some resources must have so they're able to provide reactive power services.

The SO GL determines the voltage levels within which the system shall remain and the levels until which the resources shall remain connected (RfG e DCC), similarly to what is also set for frequency levels.

However, there is no obligation to some resources having to mandatorily provide reactive power to the system and without proper compensation.

By the contrary, the Regulation (EU) 2019/943 determines that ancillary services overall (including non-frequency ones) shall be procured under market-based rules, which implies this should be provided voluntarily and remunerated.

In that regard we propose the following amendment to paragraph 2:

> *2. When systems operators identify that the mandatory requirements for reactive power are not enough for the voltage control in its grid, the corresponding systems operators shall:*
>
> *(...)*
>
> *(b) identify the potential solutions for these additional reactive power needs identified in a), and based on the next points:*
>
> *(...)*
>
> *ii. the procurement of reactive power ~~in addition to the mandatory requirements through a congestion management and voltage control services~~; or*

48 Articles 83 (Monitoring Reports) and 84 (Harmonization)

Articles 83 and 84 refer, both, to monitoring, assessment and further harmonization, which seems to lead to some overlap.

Also, while article 83 refer clearly to monitoring reports to be produced by ACER, article 84 is not clear to that regard, namely who's responsible for: setting this European process for monitoring the implementation within the Member States and include recommendations in the defined areas, for conducting and publishing the European monitoring report, for deciding on recommendations to implement and monitoring such implementation.

Another aspect to highlight is that, article 5 refer to national terms and conditions, which are also referred in most topics foreseen in the Network Code, with detailed rules linking to terms and conditions to be defined at national level. All national "Terms and Conditions" foreseen across the NC should be included in the assessment foreseen in these articles for further harmonization, as the target should be to harmonize as much as possible the different products and processes, to foster a simpler access by DR and also more liquidity into markets, with the expected benefits from that.

Baselining methodologies should also be included. ENTSO-E and EU DSO Entity should conduct an analysis on a yearly basis, and present the results to ACER to assess whether it is feasible to converge to European baseline methodologies (even if just for some technical resources / services) or to a model of cross-border equivalence of baseline methodologies to be accepted by other SOs

In that regard we propose:

- To merge the 2 articles to avoid overlaps.
- To better define the roles and responsibilities for assessment, monitoring reports, recommend on further harmonization, and approve implementation of further harmonization.
- Include the monitoring regarding the implementation and compliance of all national terms and conditions foreseen in this Network Code.
- Yearly report on implementation status to be published by ACER.

CONSULTATION RESPONSE

EFET
European Federation of Energy Traders

DSO Entity & ENTSO-E public consultation on the Network Code for Demand Response

Brussels, 10 November 2023. The European Federation of Energy Traders (EFET) takes the opportunity of this consultation on the draft network code (NC) on demand response to insist on the necessity of a clear and robust regulatory framework to integrate demand response into the internal energy market.

Executive summary

We fully support the involvement of new market participants such as active consumers and independent aggregators in the wholesale electricity market. In our view, the EU internal energy market legislation, particularly since the approval of the Clean Energy Package, provides a comprehensive framework already. It lays down the key principles for their successful development and effective market engagement. Ensuring that the rules of the new NC fit into the internal energy market framework will be key.

The draft network code text contains several positive elements:

- We welcome that the draft NC is built on the principles of technological neutrality and non-discrimination for all market participants in all market segments.
- We applaud the overall emphasis of the draft on the development of effective price signals via well-designed market mechanisms, which is essential to build a robust business case and develop new business models and services.

However, we see also some worrying aspects in the proposed guidelines:

- We still contest the ownership and management of storage assets by SOs and have concerns with the draft NC provisions weakening the rules laid out in the Electricity Directive
- We reiterate our request to align this draft NC on existing energy market legislation. Guaranteeing non-discrimination will require many of the new market rules proposed in the draft NC to be implemented as amendments of the existing guidelines (GLs) and network codes (NCs), so as to apply to all market participants.
- The concept of market manipulation is dealt with in existing EU Regulation (REMIT, EMIR, MAR/MAD, MiFID II) and has no place in this NC.

The concept of bid transfer needs to better substantiated in order to maintain transparency, market integrity and liability/responsibility.

You will find below our proposed amendments to specific paragraphs of the draft NC.

Whereas

Whereas (d) – on the bid granularity we need to ensure consistency and refer to relevant legislation. See also our amendment to Art. 29.

Whereas (w), should read potentially limited by ''technical price limits''. There are technical price limits in electricity market EU legislation. We also suggest to add "competitive" and "transparent" before the word "mechanism". We also suggest checking whether "market-based" is defined in existing legislation.

Whereas (v), (w), (x), (z), (ee), art.12.1 ('on the internet'), art.19.8, art.30.1 ('simplified qualification process'), art.45.1, art.47.2, art.61(a) ('reasonable cost and timely manner'), art.61.1(d) ('necessary') are vaguely formulated. We suggest rephrasing.

General provisions

Art. 1.1: we suggest to substitute "storage" with "other resources" and adapt accordingly with the ACER FG that states: *the new rules shall be applicable to all resource providers mentioned or covered in the articles referred to in Article 59(1)(e) of the Electricity Regulation. The new rules shall thus be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not (hereafter referred to as "demand response and other relevant resources" or in general "resources"). No resource provider shall be excluded, and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers.*

Art. 1.2: we suggest specifying to whom the "obligations" are applicable.

Art. 2.17: instead of "an information system consisting of...", it should be "an **interoperable** information system consisting of..." . It is of utmost importance that, no matter how many platforms will eventually be used, they are interoperable at least at Member State level to ensure sufficient liquidity (e.g., no lock-in) and coordination.

Moreover, proper transparency requirements for these registers must be set at European level. Functions of interoperable components include data access, data transmission and cross-organizational collaboration regardless of its source. Interoperability helps different parties involved to achieve higher efficiency, lowering costs of processing, improve data quality, increase data security and a more holistic view of information.

Art. 9.2: instead of "may", there should be a "shall". Eventually, the vision is to have further harmonization in place.

Art. 13.1 and 14.1: the consultation shall last for a period of not less than 1 month **and a public workshop should be held in the meantime.** This would further improve stakeholder involvement, especially at national level.

General requirement for market access

As general comments to this section, we insist that any new market rule suggested in the draft NC be implemented as an amendment to the existing market NCs and GLs, so as to apply to all market participants. Guaranteeing non-discrimination in the market will require that any new market rule applies to all, and hence should not be confined in a NC applying solely to demand response.

Art. 21.8: grid limitations communicated by system operators are a matter for the zonal electricity market and congestion management mechanisms. In this context, it ruled by the EB GL and SO GL. As far as local markets are concerned, the market-based procurement of services by SOs should take account ex-ante of such grid limitations.

Art. 21.9: we have strong concerns about the fact that the supplier/BRP shall not receive specific data related to the activation. This is required for accurate imbalance settlement (as required by Art. 21.10 and 28 of the draft NC), particularly since service providers can act on BRP/suppliers' assets without consent. While confidential treatment of information should be safeguarded, not all metering data from generation/consumption/storage assets can be considered as sensitive. Withholding non-sensitive data related to activation unfairly hinders BRPs in their proper imbalance settlement.

If the Network code fails to ensure transparent real-time data exchange between service providers and BRPs/suppliers, mitigation measures are required. In the absence of activation data access, Member States should define limits on the size of assets and/or portfolios that service providers can aggregate. Beyond these limits, sharing activation data should become mandatory.

Where the supplier optimizes the customers' portfolio intraday (in the case of large industrial customers), this data transfer from the service provider to the supplier (or its BRP) has to occur in real-time. This is necessary to prevent that the BRP counteracts the activated demand response in intraday markets due to the changed offtake.

We propose: ''The BRP of the service provider shall receive the relevant data values corresponding to those periods where the controllable units under its portfolio were providing a service**. In case of intraday portfolio optimization by the supplier, the data transfer from the service provider to the supplier or the BRP must take place in real time to avoid counteraction by the supplier or the BRP.** Depending on the common national terms and conditions, the supplier or the BRP associated to the supplier shall be responsible for the reception of the relevant data values of the metering point for all timeseries with the exception of the specific data related to the activation.''

Art.22.1: Replace "may" with "shall". A financial compensation shall apply in such case. Even if the load curve has been corrected, the supplier may incur costs, e.g., the rebound effect. The text should read: ''In order to limit the impact that balancing or congestion management and voltage control services activation might generate on market parties, a financial compensation **shall** apply.~~, only when the measurements that determine the load curve of the customer is not corrected.''~~

Art. 22.4: ''and may foresee either a regulated price, a fixed price, a specific formula, or a bilateral agreement between involved market parties'' should be deleted. It is sufficient to have the method for calculating the financial compensation, which shall be subject to the approval of the national regulatory authority.

Art. 23.3: we do not see the added value of this article and we propose to delete it. The calculation is not passible/contrafactual.

If Art. 23.3 is retained, benefits shall not be netted with compensation costs for the suppliers. This leads to severe distortions. Market prices are the result of the benefits and the whole system would see the positive effect. Coherently, if a Member State wishes to externally quantify benefits, these shall be borne by the whole system.

Art. 24.4: we advocate for a balanced approach to aggregation roles and responsibilities, in line with Art. 17 of the Electricity Directive. This includes fair and open data exchange among aggregation participants. We support notifications of activations to the supplier's BRP, as outlined in the draft proposal. We suggest to further clarify that an independent party (TSO, MDA) shall notify the BRP.

Art. 25: baseline and measurement rules applying to demand response to check the delivery of the service and assess imbalance settlement for energy should apply in the same manner to imbalance settlement in other energy markets (day-ahead, intraday) and SO services as defined in paragraph 12.u of the ACER FG.

The network code does not attempt to define how the baseline in the presence of demand response is set. Instead, it simply tasks TSOs / DSOs with calculating the baseline. We see no reason why this task should be completed in a supplementary process rather than now in the network code itself. We expect the TSOs/DSOs to formulate a concrete proposal on this.

Art. 25.4 (c): remove "gaming". See our general remarks on this point.

Art. 25.5: "Based on this report further steps shall be taken into account on national level if needed. **This shall be done by including stakeholders according to Articles 10, 13 and 14**.'' We suggest adding the underlined sentence to include stakeholder feedback also at national level. Stakeholder involvement should be strengthened, also in the TCM, according to Art. 10, 13 and 14.

NEW 26.3 (c): to include all market forms, "proper activation should be rephrased "proper activation or delivery" because in intraday markets or local markets, products are not only activated but also just delivered by a counterparty, but the same baseline rules apply.

Art 29: we propose to delete it. The minimum bid granularity could be reduced to 0.1 kW/kWh according to art. 8 of Regulation (EU) 2019/943. However, this would need to apply to all market participants, and hence be tackled in the existing market guidelines (and its accompanying methodologies). Regulating this in a specific NC dealing with demand response would lead to different market participants using different product granularity. To ensure non-discrimination, article 18 of the Electricity Balancing Guideline (EB GL) and articles 40 and 53 of the Capacity Allocation and Congestion Management Guideline (CACM GL) – or the methodologies approved according to these articles – would need to be amended. This will guarantee harmonised minimum day ahead, intraday, balancing energy and balancing capacity bid size for all market participants, not just demand response operators. Along the lines of our reflections on the review of the CACM GL, such amendments should, at the very least, include the possibility to offer those bids as blocks. The possibility for NRAs to grant derogations indefinitely further reduces the harmonisation of bid granularity around Europe.

This bid granularity should therefore be tackled via the upcoming revision on the EBGL and has no place in this Network Code.

Prequalification requirement and processes

Art. 31.4.a.i: we propose to delete it. This is an unclear formulation for a legal text and the point does not come across. Responsibility for system balance cannot lie by the service provider because of a lack of system information.

Art. 32.1.a: add “more than”, ‘’if the prequalified or verified capacity of the SPU or the SPG changes by more than 10% or **more than** 3 MW compared to the previously prequalified or verified SPU or the SPG due to additions or removal of controllable units. If the PPR requires a repetition of the product prequalification or product verification, the service provider shall be entitled to participate in the market with the previous qualified set-up of the SPU or SPG.’’

Art. 33: controllable units might not be limited to those (generation or consumption) of final customers, but includes all kind of resources, including non-distributed generation. Article 33 of the draft NC does not cover this reality. Hence, the term “final customer” must be replaced by “owners of controllable units”.

We also suggest deleting or clarifying further the concept of “technical aggregator”. The legal scope of this role is not clear in the current wording. It could constrain the needs of market participants and pose a technical barrier instead. To avoid lock-ins of specific actors or technologies, there may be a case to replace the concept of “technical aggregators” by that of “technical aggregation”.

Art. 34: the prequalification rules should be better harmonised in this draft network code. We expect the TSOs/DSOs to formulate concrete proposals on this.

Art. 36.1: we suggest amending this article and lower time of confirmation to two weeks: ‘’When the criteria of Article 31 (4) (b) (Pre-Conditions and Applicability of the product prequalification and product verification processes) are met and as a result product requires prequalification, the potential service provider shall submit a formal application to the PPR together with the required information of potential SPU or SPG. Within no more than <u>**2**</u> weeks from receipt of the application, the PPR shall confirm whether the application is complete. Where the PPR considers that the application is incomplete, the potential service provider shall submit the additional required information within at most 2 weeks from receipt of the request for additional information. Where the potential service provider does not supply the requested information within that deadline, the application shall be deemed withdrawn.’’

Article 36.2: we suggest amending this article and lower time of confirmation to one month: ‘’Within no more than <u>**1**</u> month from confirmation that the application is complete, the PPR shall evaluate the information provided and decide whether the potential SPU or

SPG meet the criteria for a given congestion management and voltage control services. The PPR shall notify its decision to the potential service provider.''

With the proposed timings in the draft, the prequalification process might be longer than 4 months. We request to have the time lowered to better reflect market conditions.

Art. 37: the product verification rules should be better harmonised in this draft network code. We expect the TSOs/DSOs to formulate concrete proposals on this.

Art. 39-41: we welcome the interoperability of national sets of procedures for prequalification laid out in the new version.

NEW Art. 39.0: we suggest adding a new article: "System Operators in each Member States shall establish a flexibility register by 2 years after entry into force of this regulation. They can delegate this task to a third party.''

From the NC DR, there is no clear responsibility to actually implement it. Legal responsibility should be strengthened.

Art. 39.3: the text should be reformulated: ''to avoid vendor and operator lock-ins, and to facilitate competition and innovation, data stored by flexibility register platforms ~~that are not operated by systems operators~~ shall be portable''. Interoperability shall be ensured without exceptions.

Art. 39.4: should be deleted. Interoperability shall be ensured without exceptions.

NEW Art 41.5: we suggest adding a new article: **''Operators of the flexibility register shall publish aggregated anonymized market information like prequalified volumes**.''

The flexibility register gathers lots of information, that can help market transparency. This potential should be unleashed. The markets, but foremost SOs would profit from this.

NEW Art.46.0: we suggest adding a new article: **''6 months prior a new product, a Table of Equivalence (ToE) shall be established. The ToE shall be consulted with Market participants prior to that according to art. 13-14. ToE shall be approved by the national Regulator within 3 months prior to entry into force**.''

It is important for the usage of a flexibility register, that the information is there before introducing a new product, so the market can adapt.

Market design for congestion management and voltage control services

Art. 47.2: according to Article 13 of EU Regulation 2019/943 redispatch is to procured market-based. If a derogation from that is granted, each systems operators shall choose the most effective and economically efficient option or combination of options of the different tools at its disposal, which can include grid investments, non-firm connection agreements, grid-technical measures, including non-costly remedial actions, and market-based procurement and activation of local systems operators services or other tools to maintain active energy flows or voltage within operational limits3 . The principles to choose should be transparent and coordinated. An assessment according to Article 13(4) of EU-regulation 2019/943 has to be executed and the outcome considered accordingly.

The original text is too vaguely formulated. It should be clarified that preference is given market-based options, if occurrence is long-term to grid investments and that non-market based options such as non-firm connection agreements are exceptional and under approval by NRAs.

There should be a clear national methodology addressing this: public consultation, then decisions should be made with NRA-approval.

Art. 48.2: we suggest to add the sentence: ''By latest 6 months after the entry into force of this Regulation systems operators shall submit the common assessment referred to in §1 for approval to their respective national regulatory authority. **This assessment shall include proposals for updates according to Article 48.1. The national regulatory authority shall take into consideration market participants feedback during the consultation run by System Operators.''**

The assessment and the proposals should be linked. See also 48.34.

Art. 48.4: we suggest to amend this article: '**'Based on the outcome of the assessment according to Article 48.2 and the respective approval 48.3**, systems operators shall commonly propose national terms and conditions for the development of ~~intrazonal~~ congestion management and voltage control services through active power **within TSO and DSO observability areas**, taking into account the result of the assessment in paragraph 1 where applicable, and submit this to the national regulatory authority pursuant to Article 5 (National process to develop national terms and conditions).

The process is unclear. SOs assess and submits an assessment. Then the NRA proposes changes and SOs propose TCMs. The processes seem not aligned.

DSO observability areas are identified according to article 71 of the draft NC (and TSOs' according to SO GL). The "intrazonal" concept is confusing. The proposed rewording of article 48(4) is fully compatible with 48(6) and articles 72 and 73 of the draft NC, so no need to use the term "intrazonal" in this draft NC. Moreover, we suggest again the conversion of these proposals in amendments of the SO GL for the sake of simplicity and legal certainty, instead of giving them autonomous relevance.

Art. 48.6.a: the text ''whether long-term markets, day-ahead, intraday or balancing markets apply unit or portfolio bidding" should be replaced with "local specificities and locational information as defined in Article 2.31." It is counterproductive to refer to unit/portfolio bidding.

Art. 48.6.k: should be deleted. The text 'the potential impact on other wholesale market prices from anticipation of pricing in subsequent, parallel or coordinated, linked or labelled local markets for congestion management and voltage control services'' is legally not clear. There is no indication on how the impact is calculated and how the underlying process is designed.

Art. 49.7: should be deleted. There is no additional information, and it is too vaguely formulated.

Art. 50.1.b.iii: the text ''The connection agreement of such new assets shall ensure that they neither aggravate nor create congestion or voltage issues, during and outside of its provision of services'' should be deleted.

It is important that responsibility cannot be on the asset or provider side. The connection agreement needs to be known in advance of the tender. If the asset is not exclusively used by the tender provider, it must be clear, how the asset is allowed to be used in advance. This agreement is not the right place for this requirement.

Art. 52.2: the text should be rephrased ''~~When it is necessary for the market and does not lead to market distortion~~ the systems operators shall publish...". It is uncertain, who is in charge of evaluating the market distortion and necessity.

Art. 52.4: we suggest to add the sentence: ''In order to operate a transparent market the systems operators shall publish **on the transparency platform (ENTSO-E or a new EU-DSO-Entity platform)**,

> (a) the characteristics of products for congestion management and voltage control services; (b) bid selection criteria and pricing mechanisms for local markets; and
>
> (c) economic conditions to provide the needed services if applicable.

A publication should be centralized, to avoid confusion of publication sides.''

Art. 52.6: the text should add prices: ''Local market operator shall publish clear information on the market sessions, including the number and structure of market sessions, gate closure times and bid selection criteria, as well as information on the traded products **and prices** under the platform(s) they operate''. Price information is essential for markets functioning.

Art. 52.7: the text should read ''Systems operators or, if applicable pursuant to requirements in national terms and conditions pursuant to article 48 [National terms and conditions for market design for congestion management and voltage control services through active power], local market operator(s), shall publish, no later than ~~three months~~ **thirty minutes**, at least next market results of congestion management and voltage control services promoting transparency while respecting commercial secrecy and confidentiality of information and preventing market distortion and in compliance with national rules and applicable national regulatory authority decision(s)''

The market is helped by information closer to real time, than the proposed three months. We advocate for at least 30 minutes.

Art 53.4.c: the article should be deleted. Market manipulation and market abuse is dealt with through other, specific legislation (REMIT, MAR/MAD, EMIR, MiFID II). The article should be deleted from this NC and from the general principles for baseline methods, baseline methodology, publication of information, methodology for voltage/congestion procedures and any other article.

Art. 53.4.f: we suggest to add ‘’Avoid that the same bid is selected twice, in particular where the same SPU/SPG is active in different markets, and the responsibilities for guaranteeing that, **unless technical feasible (reference 15.5.d of Directive 944/2019)’’.**

Art. 53.5: the article should be deleted. The market will determine itself if there are too many different market places. Also, evaluation of what is too much is not clear.

NEW Art. 53.6: we suggest adding a new article with these criteria:

1. **Maintain consent on a bid-by-bid basis**

Whether a bid is submitted to a market platform automatically or manually, the consent information must be attached to that bid – it must not be valid for all bids of a market participant because those bids could serve different portfolios or customers. This requires market platforms to implement the proper infrastructure to transfer/receive those bids.

2. **Maintain transparency**

Given that a market participant has provided the locational information and its consent for a specific bid to transfer it to another parallel running market (e.g. local market) with its own merit order, it is of utmost importance that the market participant is informed about the transferred bid but to inform the whole market as well. Markets react to changes in the order book and for evaluating scarcity, so it does make a difference, whether a bid is executed, withdrawn, or transferred.
If the transfer arrangement is built in a way that bids are offered in parallel and can be executed in more than one market, the market will be duly informed of this situation.

3. **Maintain market integrity**

Market integrity and transparency is paramount to the efficient and clean operation of energy markets - and regulated in REMIT. The roles and responsibilities of each actor in that regard should be clear, but also limited to their knowledge and actions. Market participants placing a bid into a market have a responsibility. But so do the third party entities (including SOs and/or market platforms) transferring a bid. Further work is needed the clarify the chain of responsibility (and limits thereof) in the operation of bid transfers as well as to clarify with stakeholders how bid transfers can be submitted the best within the existing REMIT reporting rules and practices."

4. **Maintain control of the bid**

Control of the transferred bid (pricing/volume/possibility to withdraw) must stay in place also after the transferral in order to reflect scarcity and relations of both markets.

5. **Liability/responsibility**

The system operators and market platforms in charge of the transfer tasks, if applicable, should be accountable for any mistake made in the technical process of transfer. Mistakes can happen, when a bid is transferred to a market, where it is not prequalified for an hence maybe cannot fulfil the requirements of that market.

Art. 54 to 57: we contest the principle of “nomination” of specific actors as exclusive operators of local markets (be they SOs or individual platforms). The operation of local markets should remain in the competitive domain to guarantee innovation and adaptability, while respecting adequate interoperability requirements and use of commons standards.

To ensure that local market operators fulfil the right needs, SOs identifying specific necessities/opportunities in their control areas can launch competitive tenders. Thanks to this, we hope and expect the development of operators whose activities can span multiple local markets.

Art. 60: should be deleted. Anything regarding congestion management between bidding zones and the respective processes should be addressed in the CACM revision.

System operators-owned storage facilities

Art .61-63: we reiterate of general point that SO-owned storage is a breach of unbundling except for the very particular, specific and exceptional cases as defined in the Clean Energy Package as derogations. System Operators seem arbiters of what is deemed ‘reasonable and timely’ (Art.61.1(a) and Art.61.3), what is necessary (Art.61.1(d)), assess what is efficient (Art.61.4), and decide what are acceptable offers for divestment (Art.63.3).

Art. 61.1: this proposal does not clarify how storage facilities will buy or sell their energy if they are not allowed to so in the electricity markets as Articles 61(1) d and 62(1)b are stating.

The entire chapter is a clear indication of the danger of allowing SO owned/operated storage. It should be removed, with any exceptions dealt with directly through the Clean Energy Package derogations.

If a SO needs to procure services in a specific location of the grid and if there is no flexibility in that location, then this should not lead to a conclusion that the SO should then be allowed to own and operate storage. Instead, the procurement should then be organised over longer periods, so that market participants have a basis to invest in such assets. In this respect, we would like to refer to the advice of the ENTSO-E Advisory Committee.

Art. 61.1: instead of “In Member States where it is decided that NRA can grant derogations for systems operators to develop, own, operate or maintain storages...” use: “In Member States, where derogations according to Article36 (2) or 54 (2) of Directive (EU) 2019/944 is granted...”,

A clear reference to Articles 36 and 54 of the Directive (EU) 2019/944 avoid uncertainty about the derogation process and ensure, that processes are not ruled by different regulations.

The "market test" (i.e., the establishment of the fact that the market is not able to deliver the necessary batteries) should be transparently consulted upon. This is intended by Article39 of FG: "The specifications of the tender shall be submitted to public consultation and to NRA approval prior to the tendering process." TSOs and DSOs should draft a new section on the "market test", in line with the request from the FG.

Art. 61.1a: market-based procurement of services to solve congestion or voltage issue of the systems operators according to Articles 47-50 (Solutions for congestion and voltage issues through active power; National terms and conditions for market design for congestion management and voltage control services through active power; Principles for procurement and pricing for market-based congestion management and voltage control services; Principles for procuring by tender procedure) and 81 (Voltage control services with use of reactive power) do not result in the delivering by service provider of the needed services to solve the congestion or voltage issue at a reasonable cost and in a timely manner as assessed by the NRA, including offers with not yet registered or prequalified assets as per Article 50.1.a (Principles for procuring by tender procedure) or not yet connected assets (including storages) as per Article 43.1,b if allowed by the tendering procedure; link to 67(1) as prerequisite?

Art. 61.f: an NRA assessment following a DNDP according to Article 67 concludes the need for the service. We think that the derogation process should be assessed by NRA.

Art. 61.2: should be deleted. Fully integrated network components also fall under derogation of Art.36 and 54 CEP. To avoid legal uncertainty by ruling the same fact twice, we see no need to reiterate it.

Art. 61.3: instead “In addition, where it is allowed by Members States, systems operators may consider sharing ownership and operation of such storage facilities”, the text should be rephrased ‘’In addition, where system operators have been granted a derogation in line with paragraph 1...’’

Alignment between existing regulations and this NC is needed.

Art. 61.4: should be deleted as the possibility of shared ownership is no obligatory in paragraph 2, this is superfluous.

61.5: instead “This information shall include the minimum and maximum part..” “This information shall include the operational agreement, minimum and maximum part..”

When taking part in a tender, it is key to have the operational agreement according to Article 62 at hand to assess technical options but also from a risk/chance perspective.

Art. 61.6: the text should be rephrased ‘’Systems operators shall publish information on (economic) specifications” The sentence “ The transparency on the economic conditions shall be balanced against the potential impact on the pricing of the offers.” Should be deleted.

It is not certain, what is meant with “economic conditions”. At time of submitting this consultation answer, we assume, that specifications are meant. They need to be transparent – a balancing against potential impact is too vague.

Art. 61.8: we suggest to rephrase from “Based on the applications for the tender, **systems operators** shall assess” to “Based on the applications for the tender, **an independent third party** shall assess...”

This assessment needs to be assessed by a neutral party. In the end, the decision should be taken by the NRA.

Art. 61.9: the text should add that the NRA shall ‘’approve or discard the proposed outcome. If the NRA discards the outcome, the system operator shall restart the derogation process’’ The NRA has the right to propose amendments to the assessment.

Art. 61.10: add “**DSO**”. We believe that all derogations should be reported.

Art. 62.2: we suggest to rephrase article: “In case of shared ownership or operation of the storage facility, the third party shall own and operate its part of the storage without further constraint according to the operational agreement.” We suggest to delete: ‘’than neither aggravating nor creating congestion or voltage’’. Responsibility for creation of congestion or voltage cannot be on operators’ side.

The article seems very unbalanced as it treats the TSO/DSO preferentially, but not the other way around. These issues should be addressed in the operational agreement and should not be limited upfront.

Art. 63.1: should be rephrased: ‘’ the regulatory authorities shall perform a public consultation on the existing energy storage facilities in order to assess the potential ~~availability and~~ interest in ~~investing~~ **purchasing** such facilities. Such consultation shall take place at least every five years as prescribed in article 36.3 or 54.4 of Directive (EU) 2019/944 and shall be aligned ~~as much as possible~~ with applicable grid planning processes such as NDP. Systems operators shall define the criteria ~~needed in §7~~, to select the best offer from third party. Those criteria shall be published **before the tendering**.’’

These changes deliver a higher precision for the article and clarify timelines.

Art. 63.2.d: should be deleted. It is unclear, what the original provisions are. There should be no future provision on the usage. Responsibility for congestion creation cannot be on operators’ side.

Art. 63.3: should be rephrased: ‘’ The NRA **after consulting the System Operator** shall decide whether such offers are acceptable.’’ We believe that the tender should be run by the NRA to enhance neutrality.

Art. 63.4: should be rephrased: ‘’the public consultation referred in paragraph 1 of this article shows at least one acceptable’’.

Art. 63.8.a: should be amended: ‘’NRA decides on the start date of the **12** months phase out period;’’. Shortening the timing to reduce risk and speed up processes.

Art. 63.8.b: instead “the system operators shall...”rephrase: “The NRA after consulting the Systems Operators shall decide on the best acceptable offer according to the criteria set forth in §1 and assessment in §3." The NRA runs the tender, hence this article needs to be aligned.

Art. 63.9: should be amended: ''Within **12** months from the date of the NRA set forth in §7 of this Article:'' Shortening the timing from 18 to 12 months to reduce risk and speed up processes.

Distribution network development plans

Art. 65.2: should be amended: "consider alternative solutions such as non-firm connection agreement where applicable..." to "consider alternative solutions such as non-firm connection agreement and **flexibility procurement and others**, where applicable..."

Voltage control

Art. 81: we welcome that the activation of procured resources for voltage control shall follow the same rule as for the activation of mandatory capabilities, i.e., rules-based activation with a common merit order together with a common compensation scheme.

Derogations and monitoring

Art. 82.2: this is an empty article regarding what articles and length of derogations are allowed. We should still be consulted afterwards when concrete provisions are inserted.

Art. 82.4: it is vague and open-ended. Should have a clear end-date of when the ability to derogate ends. I.e., max one or two years.

NEW Art. 84.1.f: ''A general assessment of all national TCMs''. In this regulation, many details are implemented by Member States, hence harmonization needs to start there.

While being a step in the right direction, the Network Code often places responsibility for implementation to Member States. Granting discretion to system operators and regulators at national level is important. However, greater harmonization at regional, or preferably European level, should be to aim of the Network Code. This shall include specific market rules such as eligibility criteria, backup requirements, availability monitoring, activation control, settlement procedures, penalty frameworks, IT requirements or metering specifications. Deviation from such standardized rules should be subject to regulatory approval and require a prior assessment by system operators, demonstrating that the common EU framework is not economically efficient or would result in market distortions.

Without such harmonization, regulatory fragmentation between/within Member States will prevail. Facing different national/local requirements undermines the level playing field in pan-European markets, requires market participants to develop bespoke solutions for each market, prevents economies of scale, and imposes significant costs on grid users and taxpayers.

NEW Art. 84.1.g: ''A general assessment on Article 61 to 63 on SOs storage''.

Transitional and final provisions

Art.85.1 + Art.87.2: these are empty articles regarding what transitional provisions apply to which countries. We should still be consulted afterward when concrete provisions are inserted.

Contact

Lorenzo Biglia
l.biglia@efet.org

ANSWER TO PUBLIC CONSULTATION

Elia answer to public consultation organized by the DSO Entity & ENTSO-E on the Network Code for Demand Response

Elia Transmission Belgium

10/11/2023

Content

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Context

The DSO Entity and ENTSO-E commonly organized a public consultation, between 29 September and 10 November, on a proposal for a Network Code of Demand response. This public consultation follows the request of 9 March 2023 addressed by EU Commission to those entities and inviting them to submit a proposal to ACER for the network code Demand Response in accordance with the relevant **framework guidelines** published by ACER on 20 December 2022 pursuant to Article 59(1)(e) of Regulation (EU) 2019/943 also requested by the European Commission.

Elia is a front runner TSO in the development of Demand Response as it is convinced that the latter is a prerequisite for a successful energy transition.
Indeed, the last decade Elia has continuously being developing its market and product designs (in concertation and/or collaboration with Regulators, market parties and/or DSOs) to foster flexibility:

- By gradually opening the different products and markets to all technologies and all voltage levels. Currently all balancing products as well as voltage control products are technology neutral and open to participation of assets located in DSO grid. Additional efforts are ongoing to further reduce entry barriers and facilitate participation of assets at residential level. Congestion management products are part of a large roadmap (called Icaros project) aiming at opening the congestion management also to all technologies and all voltage levels.
- The participation of independent aggregators has been gradually developed since 2013; more concretely, today Elia proposes 3 different aggregation models for the FRR products and the DA/ID market and is currently implementing a 4th aggregation model (in the framework of the **Consumer Centric market Design**) that considers the lessons learned gathered till today. Hence Elia proposes different options for the grid user and increases competition between market parties.
- Finally, Elia also works on the development of “implicit flexibility” by allowing among others the possibility to designate different suppliers and BRPs behind the main meter.

Elia’s needs in flexibility will continue to increase in the coming years due to the characteristics of the Belgian energy landscape (high concentration of renewables in very small geographical areas such as for example the offshore production). **As a consequence, the development of Demand Response in the short term is a priority for Elia to cope with the future challenges.**

Elia therefore welcomes the above actions taken by the EU Commission, ACER and DSO Entity and ENTSO-E to provide an EU legal and regulatory framework to foster the development of flexibility. Elia followed actively the discussions within ENTSO-E that took place in the framework of this regulation and acknowledges the efforts made by DSO Entity and ENTSO-E to address EU commission’s request. Elia notes that the combination of high requirements for harmonization in the regulation, within a short period, for a very wide scope of topics (flexibility in balancing, supplying of energy, congestion management, voltage control, data exchanges and coordination between SOs …) in one and, combined with a high number of concerned SOs with heterogeneous experience and understanding in those different topics on the other hand, make the efficient development and implementation of such a regulation very challenging. **Elia is concerned that the (heavy) development and implementation of such a regulation has the opposite effect that the one expected in terms of fostering the development of flexibility.**
Therefore, based on its experience and expertise in the matter, Elia takes the opportunity of shit public consultation to express some important aspects that it believes need to be taken into account when developing the upcoming regulation.

The present document constitutes the reaction of Elia Transmission Belgium to this public consultation.

Comments

1. Harmonization of market & product-design as well as procedures should be built carefully to avoid hampering development of flexibility due to too heavy harmonization processes.

Elia would like to highlight that the unlocking and development of demand response, and in particular end-user flexibility, will be of utmost importance to support the energy transition. Whilst Elia fully understands and subscribes the value of further EU harmonization, it would also like to emphasize that the MW's of demand flexibility need to be developed on short term. Or, in other words, whilst work on further harmonization and standardization should continue, it may not hamper in any way ongoing development of demand response in the system, or the testing of new innovative approaches to unlock this flexibility. Indeed, causing additional delays in the development of this flexibility will come at a cost for society. Especially given the fast uptake of flexible devices in the system over the next few years (electric vehicles, heat pumps,…).

Elia acknowledges the need for more standardization of product requirements (flexibility that can be developed and offered by a given **asset should be able to participate to different markets** and be activated where it is the most efficient, such as for ex for congestion management by the TSO, congestion management by the DSO or balancing by the TSO). **A standardization and facilitation of some processes (such as the prequalification process) would reduce administrative burden and simplify the procedure to access different markets for new service provides. Standardized technical requirements such as metering and communication requirements would reduce time and implementations efforts**. **This being said, pursuing as goal the national or EU harmonization especially for markets and products that are sometimes not yet fully mature and/or under evolution might have as side effect that all the efforts of SOs, NRAs and market parties in the coming years are absorbed by this harmonization and that no room is left for the effective development of flexibility during this period.**
Elia believes that :

a. **Some room and time should be left for innovation and testing of new solutions** (per product possibly at local level). Therefore, less strict deadlines should be imposed for national or EU common documents and/or possibilities to develop specific products (relative to a specific local need or to test the participation of new technologies to a specific product) and/or testing new ideas at smaller scale should be allowed without necessarily engaging heavy adaptations in entire chain of compatible contracts (ex. Prequalification) or national T&Cs which imply, by nature, a long administrative process (due to the number of involved SOs, sometimes NRAs and stakeholders).
b. The concerned **EU wide documents and procedures that must be elaborated should be preceded by studies** that describe the existing models/procedures ("state of the art") and compare their advantages and disadvantages based on existing experience feedback in concentration with stakeholders (market parties and NRAs). Those studies should conclude **with recommendations evolutions and improvements while acknowledging and maintaining (or generalizing) elements that work efficiently**. This should certainly be the case before harmonizing the prequalification procedures as well as the aggregation models.

c. **Harmonization should be the goal where it makes sense**: for instance, harmonizing TSO and DSO congestion management or voltage control in areas where the same resources can solve issues in both grids is beneficial for society. At the opposite, requiring one unique national design developed in common by DSOs and TSO as well for the Medium Voltage as for the Extra High Voltage (where the needs can be different, where congestions are typically solved with units connected to TSO grid) complexifies unnecessarily the congestion management design. Same reasoning also applies for Voltage control. Therefore, Elia pleats for harmonization and drafting in common national TCMs only for assets located in one grid that can solve congestions in another grid.

d. As many of the topics that are targeted by national or EU harmonization are under evolution, **enough room should be left and/or a framework be foreseen for innovation and testing of new models and for future evolutions of harmonized TCMs**. For example, the list of aggregation models should not be exhaustive in order not to hamper SOs or market parties to develop new models. Experience in Belgium has shown that continuous improvement can be brought to aggregation models (sometimes suggested by service providers themselves), and it would be a barrier to innovation if SOs are limited to a predefined exhaustive list. Note that the same reasoning applies for baselines. To this extend Elia suggests that this list of aggregation models is to be considered as an indicative/guidance catalogue during the first years after the entry into force of this NC and certainly not as a limitative set of applicable solutions. An assessment after a few years that is foreseen to recommend eventual harmonization's could at this moment provide a stricter framework of the allowed schemes.

2. New rules should acknowledge existing design or ongoing evolutions and allow to preserve them when and where efficient.

As explained here above, designs targeted by this consultation are in constant evolution and don't have the same level of maturity in all member states and/or grids and voltage levels within a member state, which is logic as the needs are different. **Ongoing developments and evolutions that are discussed and agreed with stakeholders (market parties, involved SOs and NRAs) should not be put on hold or slowed down because of the perspective of new rules or national TCM that would imply to re-develop a new common design proposed by all SOs**. Here again although Elia is convinced of the benefits of such common TCMs, Elia believes that we should keep and preserve existing (even if newly implemented) designs if deemed efficient. Therefore, Elia supports the idea of **choosing carefully in concertation with stakeholders the design parts that need to be redrafted in common based on their added value.**

As regards to the aggregation models the exhaustive list that is described in the consulted document should in no case make that **existing aggregation models applied for years and that are the result of long term and fruitful discussions are questioned and become *illegal***. Therefore, Elia has also the following detailed comments on that matter:

- The exhaustive list of models should not forbid the possibility to have more than one supplier or more than one BRP behind the access point to the grid (or connection point). Today schemes exist where the volumes measured to a measurement point is split with a repartition key between two different BRPs. Art. 19.5 seems to limit that possibility.
- Art 20 gives the impression that the BRP associated to the SP ("BRP_{SP}" hereafter) takes full responsibility of any imbalance at the concerned access point for ISP where there is an activation; this would be an entry barrier to let the BRP_{SP}. In practice it can be that flexible assets cannot be completely isolated by

non-flexible (but still variable) assets with a submeter (ex. a small industrial site has a small cogeneration unit but no place to install a submeter in order to isolate that cogen. The BRP_{SP} should be responsible during activation periods for deviations that remain within the physical capacity of the cogen.). Elia requests to limit the balance responsibility of the BRP_{SP} to a pre-fixed contractual value that is communicated by the Grid User and which corresponds to the maximum flexibility that the Grid User offers to the Service Provider.

- In this respect it is also not correct (cf; art 21.9) to suspend the provision of metering values to the BRP of the supplier (hereafter “BRPsup”) during activation ISPs. Each BRP should receive the necessary information relative to its imbalance calculation and necessary for him to execute his contractual mission.

3. Smart meter roll-out is essential in any case. New regulation should accelerate the roll-out instead of slowing down.

The roll out of smart meters is necessary to further empower consumers at all voltage levels and to facilitate their access to the markets. It not only allows the concerned grid users to offer their flexibility with a 3rd party of their choice (independent aggregator) but it opens up the possibilities for them to opt for dynamic price contracts (when relevant). Elia is concerned by the possibility foreseen in the consulted document to develop aggregation models for schemes with analog meters. Although it is true that a sub-meter that corresponds to the technical requirement can be enough for some products (FCR for example) a metering device that can identify the consumption per ISP at the level of the access point (or connection point) combined with a submeter is necessary to apply correct adjustments[1] to the perimeter of re BRP_{SP} and the BRP_{sup} and to compensate correctly the supplier . Indeed, for areas with analog meters, SO split the volume metered per ISP for the entire area and allocate the split into the different BRPs that have customers in that area. The split is done based on a more or less complex repartition key that represents the ratio of the portfolio of each BRP in the area. Any activation of an asset of a grid user located in such area will be visible on the volume metered per ISP for the entire area. Due to the repartition key used for the allocation, not only the BRP_{sup} of the concerned grid user will be impacted, but all the BRP_{sup} of all the grid users of the area. An aggregation model should in that situation correct/neutralize the effect of the activation for all BRPs and suppliers of the area. Such a (new) scheme would imply very important design and implementation costs. Elia fears that such evolutions will have a negative CBA as they would require high implementation costs compared to a gradual installation of smart meters for the grid users that desire to monetize their flexibility and finally slow down the roll out of smart meters.
Therefore, Elia pleats for the removal of a reference to “conventional” meters from article 19.7.

[1] Adjustment aiming at neutralizing the impact of an activation by an independent aggregator for the BRP_{sup} and aiming at linking the balance responsibility of the activation to the BRP_{SP}

4. Coherence with other existing Network Codes should be ensured.

Many of the topics covered by the consulted document have a direct or indirect link with topics already regulated by existing Network Codes. Developing a specific Network Code for Demand response increases the risk of gaps and overlaps (and hence contradictions) with existing network codes (ex: art. 189 of SOGL, articles in this document and in the EBGL defining imbalance and calculation of adjustment and or imbalance settlement in the EBGL[2], require-ments for active consumers in DCC …) . Elia believes that an impact analysis should be performed to identify when existing network codes must be amended. This analysis should lead to first amend those codes before the entry into force of a new NC DR to avoid the above-mentioned gaps/overlaps and contradictions. **An absolute priority should be given to the amendment of existing guidelines and network codes wherever possible, as it will increase legal certainty and readability of the requirements. Avoiding a complex interplay of legal requirements is also a way to reduce barrier to entry for DR.**

[2] More particularly Elia is surprised to see that the way imbalance is corrected in aggregation modals is defined in national T&Cs. According to Elia this topic (certainly art. 23 od the consulted document) fully belongs to the T&C BRP (whatever the reason of the product that implies an adjustment or a correction) targeted by article 18 of the EBGL.

– **Consultation response** –

DSO Entity & ENTSO-E public consultation on the new Network Code for Demand Response

Brussels, 10 November 2023 | Europex welcomes the opportunity to provide feedback to the EU DSO & ENTSO-E public consultation on the new Network Code for Demand Response (NC DR). We strongly support a swift increase of the flexibility of the electricity system, in line with the 2030 objective of "doubling flexibility" as stipulated in the [EEA/ACER Report on Flexibility solutions to support a decarbonised and secure EU electricity system] of September 2023.

To this end, the new Network Code should enable equal, non-discriminatory and transparent access to flexibility assets in wholesale electricity markets which provide the most reliable price signals for the activation, integration and remuneration of flexibility resources. Yet, as the new Network Code introduces an additional layer of regulatory, organisational and technical complexity, the impact of these new rules on the well-functioning, the liquidity and the integration of wholesale electricity markets should be properly assessed.

In our response to the consultation, we emphasise that the new Network Code should be more ambitious in fostering market-based flexibility procurement in comparison to the status quo and existing regulation. However, as the current draft fails to do so, it is questionable if and how the new Network Code will improve the framework provided by the Clean Energy for all Europeans package (CEP) which is not yet fully implemented across the EU, four years after its entry into force in 2019.

In addition, we believe that the present draft fails to properly recognise the role of Power Exchanges, Delegated Operators and NEMOs in organising trading across all timeframes, and within and between bidding zones, therefore allowing the procurement of flexibility resources through, e.g., local flexibility markets, including in a cross-border manner. When developing local flexibility markets, third parties remain the most efficient option to assure neutrality and transparency in Member States with multiple system operators (i.e., TSOs and DSOs).

Furthermore, we have identified several discrepancies between the ACER Framework Guidelines (FGs) and the EU DSO Entity & ENTSO-E draft of the new Network Code. For example, the market-based definition of flexibility procurement and the safeguarding of security of supply, two key concepts explicitly mentioned in the FGs, have not been taken up in the current draft text. Furthermore, the consulted text fails to ensure a pan-European approach to the development of flexibility while avoiding market fragmentation.

Finally, it remains unclear to us how exactly the new Network Code will take into account possible new flexibility rules that are currently discussed in the Electricity Market Design (EMD) review. In particular, a proper impact assessment should be conducted on the possible introduction of peak shaving products, an unnecessary and counterproductive instrument for the development of additional flexibility. We firmly believe that peak shaving products, if implemented, are detrimental to the well-functioning of electricity markets as they would directly impede the participation of flexibility resources in the wholesale market when needed most (i.e., during peak hours). Any such assessment should naturally involve relevant stakeholders.

Please find our responses to selected questions below:

Article	Comment	Text proposal
Whereas (w)	Europex believes that regulatory price caps should be removed as they distort the market and its efficient, reliable and transparent price signals. However, this is not to be confused with technical price caps (i.e., technical bidding limits) which manage the exposure of market participants' to unnecessary costs and risks and therefore ensure the well-functioning of the optimisation algorithm.	(w): Market-based procurement is understood as a mechanism whereby a service is procured by soliciting market participants to place an offer for the service. The market participants choose the amount they are offering and the prices (potentially limited ~~by price caps~~ by technical maximum and minimum clearing price bidding limits). The remuneration may be determined by a market-mechanism (supply vs demand) pay as bid or pay as cleared. Examples, which may be labelled "market-based" based on assessment of national regulatory authority in Member State: Marketplace/ Exchange / an organised market for service (includes service specific market or taking offers from another market such as Energy-only-markets, balancing).
(4)	The ACER Framework Guidelines (FGs) clearly specify that the new Network Code should foster "market-based" procurement of services for system operator. Therefore, the objective of fostering "market-based" needs to be added in this article. In addition, as the FGs emphasise the preservation of the grid security, this additional objective should also be included in this Article.	3. Contributing to market integration, non-discrimination, effective competition and the efficient functioning of the market while not jeopardising grid security. 4 (a): removing all undue barriers for the participation of these resources in all wholesale electricity markets (including those for procuring systems operators services), and establishing European principles for the assessment of the need for, the market-based procurement of and the use of local systems operators services.
(5)	The development of a national process for the definition and implementation of	1. By three months following the entry into force of this Regulation, all systems

	terms and conditions, involving the NRA and multiple TSOs & DSOs, should be kept easy to manage and not be too lengthy in order to avoid that, in the meantime, the development of local pilot flexibility projects is impeded.	operators shall jointly submit to the competent national regulatory authority a proposal for a national process to develop national terms and conditions referred to in Article 6 (Common national terms and conditions). This is without prejudice to the right of: (a) The Member State or NRAs to define the national process on how systems operators jointly develop national terms and conditions pursuant to this Regulation; b) SOs to launch in the meantime local pilot projects.
(6)	The deadline for submitting the proposals for the national terms and conditions should be clearly stipulated in this article. In case more granular deadlines are needed, they should be jointly determined by the NRAs.	1. All systems operators shall develop common proposals for the national terms and conditions required by this Regulation and jointly submit them for approval to the competent national regulatory authority within ~~the respective deadlines set out in this Regulation~~ [name the deadline here]. If additional more granular deadlines are deemed necessary, they should be jointly set by the NRAs.
(17)	If a task is delegated, the same cost recovery principle shall apply to the delegated entity.	1. The costs borne by the relevant transmission system operators, ~~and~~ distribution system operators, delegated parties and closed distribution system operators where relevant, 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.
(47)	The solutions to voltage control issues should not be restricted to "active power" only. Both active and reactive power should be utilised for voltage control. In paragraphs 3 and 4, the new Network Code should insert an additional	Solutions for congestion and voltage issues ~~through active power~~ 3a. In case of non-market based redispatching according to the target model defined in Art. 13 (3) of Regulation (EU) 2019/943, system operators shall establish a public annual report which

	assessment or stricter criteria for not applying market-based redispatch according to Art. 32 in order to foster the application of the European target model of market-based flexibility procurement. Such assessment should be stricter and/or stricter criteria should apply in order to limit non-market-based solutions to a strict minimum. Otherwise, it is questionable how the new Network Code will improve the regulatory status quo of the Clean Energy for all Europeans package (CEP) with the latter not yet fully implemented across the EU, four years after its entry into force in 2019.	outlines the additional costs/welfare losses resulting from non-market-based procurement compared to the target model solution of market-based procurement. 4. The relevant national regulatory authority may adopt non-market-based solutions pursuant to Article 32(1) and Article 40(5) of Directive (EU) 2019/944 when its proper assessment according to strict, objective and explicit criteria has concluded that the procurement of market-based services is not economically efficient or where such procurement would lead to severe market distortions or to higher congestion. The assessment shall take into account that conclusions may differ for different parts of the grid within a Member State, for different products (especially distinguishing short-term and long-term products).
(48)	The solutions to voltage control issues should not be restricted to "active power" only. Both active and reactive power should be utilised for voltage control. Paragraph 5 is a repetition of the articles it quotes and is therefore redundant. In paragraph 6, as the list is not applicable in practice, it needs to be clarified how the elements should be "considered" in the national terms and conditions for market-based procurement of flexibility. For example, to "consider" whether wholesale and balancing markets apply unit or portfolio bidding (Art. 48 (6) (a)) reads quite vague. When preparing the national terms and conditions, DSOs and TSOs should also assess and make public the following: cost-savings that market-based procurement will bring compared to non-market-based procurement (such as reduced redispatch costs, reduced or	National terms and conditions for market design for congestion management and voltage control services ~~through active power~~ 4. Additionally, systems operators shall commonly propose national terms and conditions for the development of intrazonal congestion management and voltage control services ~~through active power~~, taking into account the result of the assessment in paragraph 1 where applicable, and submit this to the national regulatory authority pursuant to article 5 (National process to develop national terms and conditions). ~~5. The national terms and conditions referred to in paragraph 1 shall comply with the following principles and requirements: (a) principles for procurement and pricing of congestion management and voltage control services, in line with Article 49 (Principles for procurement and pricing for market-based congestion management and voltage control services); (b)~~

	deferred grid investment costs, reduced grid operation costs, etc.). This will help foster market-based solutions instead of non-market-based solutions. In paragraph 9, it is unclear what “or other market processes” means. In paragraph 10, it is necessary to further clarify what it means in practice to combine and forward bids to other markets. In paragraph 12, an incentive should be provided to system operators to engage in market-based flexibility procurement processes, complementary to an appropriate grid expansion. Therefore, the costs for market-based procurement of congestion management and voltage control need to be recognised. This needs to be clearly state in the Network Code, otherwise it will not bring improvement compared to the status quo. In paragraphs 13 and 14, system operators should not only be entitled, but also incentivised and encouraged to present a common proposal for market-based congestion management mechanisms.	~~requirements for publication of information in line with Article 52 (Publication of information); (c) principles for the coordination of and interoperability between local and day-ahead, intraday and balancing markets, in line with Article 53 (Principles for the coordination and interoperability between local and day-ahead, intraday and balancing markets); (d) requirements to procuring system operators, in line with Article 54 (Requirements for procuring system operators); and (e) requirements applicable to operators of local markets, in line with Articles 55 (General requirements to local market operators) to 57 (Tasks local market operators).~~ 6 (l): assess and publish the cost-savings that market-based procurement will bring compared to non-market-based procurement. 12. The costs for market-based procurement of ~~procuring~~ congestion management and voltage control services shall be allocated and recovered. ~~in line with the applicable national legislation.~~ 13. Systems operators should be ~~are~~ entitled, incentivised and encouraged to present a common proposal for market-based congestion management mechanisms to the national regulatory authority that complements the existing non-market-based mechanisms in line with paragraph 4. This proposal shall describe interactions with existing non-market-based mechanisms. 14. Systems operators should be ~~are~~ entitled, incentivised and encouraged to bring proposals to relevant national regulatory authority for handling grid issues in certain parts of the grid with non-market-based solutions in accordance with conditions specified in Directive (EU) 2019/944, when this is advised when the procurement of market-based services is not economically efficient or where such

		procurement would lead to severe market distortions or to higher congestion, or when the market options have proven not to solve the need.
(56)	Concerning paragraph 3, we believe that a third party – in the form of, e.g., a market operator, power exchange or delegated operator – is the most efficient option for assuring neutrality in Member States with multiple SOs.	/
(57)	In paragraph 4, it needs to be clarified what the interoperability between the local market operator and TSOs/DSOs entails. In addition, it is unclear what it means in practice "to coordinate" local flexibility markets with others.	/
(58)	The Framework Guidelines stipulate that the new rules "shall define a common European list of attributes for products used for congestion management" (paragraph 82). The list of a minimum level of standardised attributes and standardised products across the EU should be directly included in the new Network Code instead of referring to a future process taking additional six months to develop it by the same entities (i.e., EU DSO & ENTSO-E) which are now co-drafting the Network Code.	~~When systems operators define nationally standardized congestion management products, they shall use attributes from the common list of attributes. The common list of attributes shall be commonly developed and published by ENTSO-E and EU DSO Entity within 6 months after entry into force of this Regulation following the process to develop EU TCMs in line with Article 9 (Union-wide terms and conditions or methodologies).~~ [The minimum level of standardised attributes and, as applicable, of standardised products across the EU should be listed and defined here].

About

Europex is a not-for-profit association of European energy exchanges with 34 members. It represents the interests of exchange-based wholesale electricity, gas and environmental markets, focuses on developments of the European regulatory framework for wholesale energy trading and provides a discussion platform at European level.

Contact

Europex – Association of European Energy Exchanges
Rue Archimède 44
1000 Brussels, Belgium

Phone: +32 2 512 34 10
Website: www.europex.org
Email: secretariat@europex.org
X: @Europex_energy

EU Transparency Register: 50679663522-75

Piclo Response to DSO Entity & ENTSO-E Public Consultation on Network Code for Demand Response

We welcome the opportunity to respond to the DSO Entity and ENTSO-E public consultation on the Draft Proposal for a Network Code for Demand Response.

Piclo is the leading independent marketplace for flexibility services with an established presence in Europe including Italy, Portugal, Ireland and Lithuania, in addition to the UK and North America. Piclo Flex facilitates the end-to-end flexibility journey from Flex Service Provider (FSP) registration, company and asset qualification, flexibility competition advertisement and bidding, availability, dispatch, settlement and payment for System Operators (SOs) at both TSO and DSO level. We work alongside SOs such as E-Distribuzione, E-Redes, ESO (UK) and UK Power Networks on both long-term markets as well as day-ahead and intra-day services. To date, over €60 of flexibility contracts have been awarded, from +16GW of flexible capacity.

The proposed Network Code is an ambitious and critical step forward for the development of scalable, coordinated and interoperable energy and flexibility markets across Europe. We offer the following response in addition to specific comments on the articles written:

- **Market Design:** The development of flexibility markets depends on market-based solutions being used ahead of non-market-based options
- **Platforms, market operators and flexibility registers**
    - The network code must deliver interoperability and global standards
    - SOs platform nomination and selection process must ensure fair competition
    - The network code must ensure fair competition between third-party and in-house platforms
- **Market Operator roles and functionality**
    - Ensure Network Code is consistent on platform or multiple platform possibilities
    - Clarify what is meant by local market operators needing separate accounts for tasks and activities
    - Ensure Market Operator role descriptions are non-exhaustive and consistent
    - Market operators should also be able to provide flexibility register services
    - Review the scope of local market operator information provision
- **Flexibility Register role and functionality**
    - Ensure Network Code is consistent on platform or multiple platform possibilities
    - The network code must ensure fair competition between third-party and in-house platforms
- **The Network Code process must not halt or slow flexibility market progress**
- **Other articles with suggested rewording**

Market Design

The development of flexibility markets depends on market-based solutions being used ahead of non-market-based options

Flexibility services are critical to delivering an optimised, cost-effective net zero transition. However, the implementation and scaling of true market-based solutions such as local, DSO flexibility markets is dependent on the approach SOs take and the order in which they use the different tools (market-based or non-market-based) they have at their disposal. For competitive, liquid and scalable markets to develop, it is critical that SOs operating their networks and markets use market-based mechanisms to resolve network issues first, ahead of non-market-based mechanisms such as non-firm connections, active network management or grid reinforcement. This is not sufficiently captured within the proposed network code drafting, putting at risk the development of DSO flexibility markets:

> Title IV Market Design for Congestion Management and Voltage Control Services, Article 47: 2. *Each system operator shall choose the most effective and economically efficient option or combination of options of the different tools at its disposal, which can include grid investments, non-firm connection agreements, grid-technical measures, including non-costly remedial actions, and market-based procurement and activation of local systems operators services or other tools to maintain active energy flows or voltage within operational limits3. The principles to choose should be transparent and coordinated*

Market-based mechanisms such as flexibility services procured through SO flexibility markets must be assessed and used first. Only if flexibility is not possible to procure through such a true market-based route should non-market-based mechanisms be turned to. These non-market mechanisms include non-firm access agreements, non-market-based dispatch and grid investments.

DSO flexibility markets take time to establish so SOs must repeat assessments and retender for market-based flexibility: participation and competition in DSO flexibility markets take time, potentially years, to build up. This is because FSPs must have confidence in the market longevity, DSO commitment and value before committing time, resources and money to participating or investing in new systems or integrations. Consequently, DSOs must continuously signal what flexibility they are seeking as well as the market outcomes to build confidence. It must not be the case that if a DSO receives no or too expensive offers for flexibility in one area, that this is ruled out permanently and non-market-based options are used on an enduring basis. DSOs in the UK have built confidence by tendering and re-tendering flexibility repeatedly, with growing success.

Equally, for many DNOs and SOs, using flexibility is a significant step away from business-as-usual operation and there is a risk of concern, hesitation and pushback to implement these markets. Without a clear, explicit framework to determine that market-based procurement should be the default with other options used as a last resort and back-up, many SOs will have the room to not establish or implement in any real sense flexibility markets we need to transition to net zero most cost-effectively. The network code must be amended to explicitly prioritise market-based procurement first, without which the development of DSO flexibility markets will be put at risk due to it being highly likely that non-market-based routes such as unpaid non-firm connections are the most cost-effective option for SOs.

> **Recommended wording:** Title IV Market Design for Congestion Management and Voltage Control Services, Article 47: 2. *Each systems operators shall assess and seek to use market-based procurement and activation of local services to maintain active energy flows or voltage within operational limits first. If this is option is not economically efficiency or effective, non-market measures including non-firm connection agreements, grid-technical measures and grid investments or a combination of options should be explored. The principles to choose should be transparent and coordinated, prioritising market-based mechanisms first. System operators should repeatedly signal and assess the use of market-based flexibility procurement in areas where initially deemed uneconomic.*

Platforms, market operators and flexibility registers

The network code must deliver interoperability and global standards
For scalable, coordinated markets, the Network Code must drive towards interoperability across all market roles including System Operators, platforms, registers, market operators, Flexibility Service Providers (FSPs) and beyond. EU-wide interoperability and standards are key to unlocking the true scale and value of energy and flexibility markets. Such standards will deliver the data infrastructure and exchange, processes, and coordination

across SOs to optimise procurement and dispatch, whilst also providing the visibility and processes to mitigate conflicts or gaming risks. Equally, Flexibility Service Providers need to be able to participate and stack value across multiple revenue streams and interoperability and coordination across markets with global standards are key to enabling this. We welcome the inclusion of the network code's emphasis on interoperability and market coordination and the efforts for EU harmonisation must review and progress standards, interoperability and data-sharing harmonisation as a priority.

SOs must select and nominate platforms they want to use - remove regulatory assessment
The Network Code Article 16: 1 Delegation and assignments of tasks proposes that *"Transmission system operators and distribution system operators may delegate all or part of any tasks with which it is entrusted under this Regulation to one or more third parties or system operators in case they can carry out the respective function at least as effectively as the delegating DSO and/or TSO".*

The selection of platforms to use is important for any energy market, however, it is particularly important for DSOs. DSO flexibility markets are (or will be) extensions of a DNO's DERMs systems, so they must have a direct say over the systems they integrate with. We disagree with a regulator assessment being part of either the nomination/selection process for market operators.

SOs already have to undergo very strict procurement/tendering processes determined by the EU legislation. This formal process ensures there's fair competition and that the platforms they procure for market operation have e.g. adequate financial resources, and technical infrastructure (such as what's in Article 55 that the NC is proposing the regulators assess platforms on). The provisions of the network code would be baked into those procurement processes. As such, there doesn't need to be this additional regulator assessment step, which would be difficult to implement without impacting competition for platforms.

Nor should it be the regulator's role to be involved in signing off on what platforms are used by SOs (the regulator should be setting the principles for flexibility markets and holding the SOs to account for their activities through their price controls). As such, recommend taking out the references for NRA assessments to be part of this nomination

As such, the network code must ensure a fair, competitive process for SOs to select what market platforms, registers and platforms they use. The nomination and assessment process must be clarified to ensure this for local market operators and flexibility registers:

> Article 56 Local market operator(s): *1. Systems operators shall describe in terms and conditions referred to in Article 48(4), functional requirements of local market operators* ***and a process for nomination of local market operators.***
> ***2. The process for nomination of local market operators shall take duly into account proposals of each procuring system operator and include national regulatory authority's assessment ensuring that the local market operators meet the general requirements described in Article 55*** *of this Regulation and in national terms and conditions referred to in Article 48(4).*
> *3. Local market operator(s) can be a. the TSO(s) or DSO(s) which procure the services, either alone or together; b. another TSO or DSO, either alone or together; c. a third party.*
> *4.* ***The relevant national regulatory authority shall ensure that nomination is revoked*** *if the local market operator fails to maintain compliance with the criteria in Article 55*

Recommended wording: Article 56 Local market operator(s): *1. Systems operators shall describe in terms and conditions referred to in Article 48(4), functional requirements of local market operators* ***and a process for nomination of local market operators.***
2. The process for nomination of local market operators shall take duly into account proposals of each procuring system operator and include ~~national regulatory authority's~~ SO assessment ensuring that the local market operators meet the general requirements described in Article 55 *of this Regulation and in national terms and conditions referred to in Article 48(4).*
3. Local market operator(s) can be a. the TSO(s) or DSO(s) which procure the services, either alone or together; b. another TSO or DSO, either alone or together; c. a third party.
4. ***The ~~relevant national regulatory authority~~ SO shall ensure that nomination is revoked*** *if the local market operator fails to maintain compliance with the criteria in Article 55*

The network code must ensure fair competition between third-party and in-house platforms

The network code enables SOs to delegate or select services from the TSO(s) or DSO(s) which procure the services, either alone or together; b. another TSO or DSO, either alone or together; c. third party(ies). However, there must be fair competition between third-party platform providers and in-house SOs platforms to avoid vendor lock-in and mitigate in-house advantages. This is not adequately captured in the network code and must be amended. For instance:

Article 39 Principles for Governance and Interoperability
To avoid vendor and operator lock-ins, and to facilitate competition and innovation, ***data stored by flexibility register platforms that are not operated by systems operators shall be portable to other flexibility register platforms, particularly in cases where Member States or system operators decide to migrate towards new flexibility register platforms.***
Therefore, operators of such flexibility register platforms shall periodically demonstrate to the national regulatory authorities:
(a) that all data stored in the CU module and the SP module can be exported to a common European or national standard in a structured, machine-readable and well-documented format; and
(b) the existence of a well-defined procedure to export that data and suspend operation at a pre-defined point in time to facilitate potential migrations to other platforms.
4. For flexibility register platforms operated by systems operators, NRAs may decide to apply the provisions of paragraph 3 after a positive cost-benefit analysis.

The conditions for in-house or third-party flexibility registers, market operators or other platforms must ensure and deliver fair competition and have the same principles applied to each. As such, we recommend the following wording:

Article 39 Principles for Governance and Interoperability
To avoid vendor and operator lock-ins, and to facilitate competition and innovation, ***data stored by flexibility register platforms ~~that are not operated by systems operators~~ shall be portable to other flexibility register platforms, particularly in cases where Member States or system operators decide to migrate towards new flexibility register platforms.***
Therefore, operators of such flexibility register platforms shall periodically demonstrate to the national regulatory authorities:
(a) that all data stored in the CU module and the SP module can be exported to a common European or national standard in a structured, machine-readable and well-documented format; and
(b) the existence of a well-defined procedure to export that data and suspend operation at a pre-defined point in time to facilitate potential migrations to other platforms.

~~4. For flexibility register platforms operated by systems operators, NRAs may decide to apply the provisions of paragraph 3 after a positive cost-benefit analysis.~~

Market Operator roles and functionality

Ensure Network Code is consistent on platform or multiple platform possibilities: throughout the Network Code, there are references to it being possible for multiple platforms to provide any of the services specified throughout. For instance

> Article 16: 1 Delegation and assignments of tasks: *"Transmission system operators and distribution system operators may delegate all or part of any tasks with which it is entrusted under this Regulation to one or more third parties or system operators in case they can carry out the respective function at least as effectively as the delegating DSO and/or TSO".*

The network code should drive different local market operators to have the same standards, interoperability and data sharing in place to enable multiple market platforms to coexist and scale DSO flexibility markets efficiently, competitively and innovatively. It should be clarified that for the SOs proposing the T&Cs, each DSO can select the market operator(s) or platform(s) best suited for its operations, either alone or collectively with other DSOs. As such, Article 56 Local Market Operator(s): 3 should be clarified as followed:

- As written: *Local market operator(s) can be a. the TSO(s) or DSO(s) which procure the services, either alone or together; b. another TSO or DSO, either alone or together; c. a third party*
- **Recommended**: *Local market operator(s) can be a. the TSO(s) or DSO(s) which procure the services, either alone or together; b. another TSO or DSO, either alone or together; c. third party(ies)*

Clarify what is meant by local market operators needing separate accounts for tasks and activities:

> Article 55 General Requirements to Local Market Operators: *1(b) it shall have an adequate level of business separation from market participants, including service providers, and keep separate accounts for local market operator tasks and other market activities*

This provision requires further clarification. We agree that market operators should require business separation from market participants, including service providers. This is important to ensure neutrality, and competition and mitigate risks of perceived bias in market operations. However, it is unclear what is meant by keeping separate accounts for local market operator tasks and other market activities or what the desired outcome is and how it will benefit SOs, FSPs or the wider energy market ecosystem. It is not clear whether these accounts are referred to at a business level, financial or regarding platform functionality.

Piclo provides end-to-end functionality for facilitating SOs markets including FSP and asset registration and qualification, competition visibility and bidding, market clearing, asset availability, dispatch signals, settlement, baselining, payment and invoicing and contract exchange services. Within a market area, this functionality all coexists within one platform environment to ensure a seamless journey for FSPs participating across the DSOs and TSO markets that are hosted on our platform and easy usability for the SOs facilitating their markets on Piclo Flex. Each SO has an individual account and what they can access depends on what services they contract with Piclo for, however, there is no separate platform functionality and separating the accounts of local market operator tasks and activities such as registration and qualification from competition and bidding from dispatch and settlement is unclear in its intention of what benefit this would provide to participants and has the possibility of acting as a barrier to a seamless FSP experience. We recommend removing this section of the provision due to the unclear nature of the request (business, financial, technological) and the unclear outcomes or benefits it is seeking to secure.

Article 55 General Requirements to Local Market Operators: *1(b) it shall have an adequate level of business separation from market participants, including service providers ~~and keep separate accounts for local market operator tasks and other market activities~~*

Ensure Market Operator role descriptions are non-exhaustive and consistent
The network code Article 57 Tasks of Local Market Operators describes the following roles for market operators:

> *1. The operators of markets for congestion management and voltage control services shall provide, maintain and operate the IT solutions that:*
> *(a) processes bids, provides a merit order list of bids as applicable, facilitates the matching of the markets for congestion management and voltage control services in line with the procurement and pricing rules as described in national terms and conditions pursuant to Article 48 (National terms and conditions for market design for congestion management and voltage control services through active power); and*
> *(b) communicates with the service providers and the systems operators for; i. the offers from service providers and if applicable the demands from systems operators;*
> *ii. as applicable, the information necessary for systems operators to perform their tasks in line with Title VII [TSO-DSO COORDINATION and DSO-DSO COORDINATION], including reception and processing of temporary limits affecting service providers offers in line with Article 74 (Short-term procedures to account for DSO limits);*
> *iii. the information to service providers and systems operators, on the market results; iv. communicate as applicable relevant information to other affected market roles; and v. gathers and exchanges the information for the settlement of the markets of congestion management and voltage control services as described in national terms and conditions pursuant to article 48 (National terms and conditions for market design for congestion management and voltage control services through active power).*
>
> *3. The following non-exhaustive list of tasks may also be delegated by systems operators, when applicable, to a local market operator*
> *(a) inform potential service providers about the local market;*
> *(b) selection of bids;*
> *(c) validation of delivered services;*
> *(d) communication of relevant information from DSOs and TSOs; and*
> *(e) settlement tasks in line with national terms and conditions pursuant to Article 48 (National terms and conditions for market design for congestion management and voltage control services through active power).*
>
> *Explanatory note: Local market operators should operate and maintain the platform for communicating with service providers and transmission and distribution system operators, providing the clearing of bids, and if applicable the settlement of bids. The validation of the service may not be done by local market operators, but eventually by the procuring system operator. The selection of bids may be done as a result of a matching process, run by the local market operator, considering only the bids of the units identified as purposeful for solving the grid issue by the procuring system operator. The activation of the units may be done by procuring system operator, local market operator or the service provider*

These 3 paragraphs have different and in some places contradictory (e.g. 3b vs explanatory note for validation of delivered service) outlines the role of market operators and what services they can provide. This approach risks limiting the extent of services provided or confusing, unnecessary fragmentation and a suboptimal user experience for SOs and FSPs.

As mentioned above regarding the roles Piclo already provides to SOs across Europe, the role of market operator extends much beyond the capabilities outlined. For instance, Piclo provides end-to-end functionality for facilitating SOs markets including FSP and asset registration and qualification, competition visibility and bidding, market clearing, asset availability, dispatch signals, settlement, baselining, payment and invoicing and contract exchange services. We also are building out TSO-DSO coordination functionality to streamline the TSO and DSO markets hosted on Piclo Flex and are developing services to enable better participation across markets for FSPs. The network code mustn't set the trajectory for market operators to be limited in the services, scope or development of additional innovative solutions beyond what they already provide. Nor should it prevent the role of a market operator from developing as greater experience and understanding of energy and flexibility market scalability and coordination are captured and advanced. The Network Code must provide the framework for local markets whilst still driving innovative and competitive solutions to be continuously put forward. As such, we recommend that the following statement be prioritised

> Article 16: 1 Delegation and assignments of tasks: *"Transmission system operators and distribution system operators may delegate all or part of any tasks with which it is entrusted under this Regulation to one or more third parties or system operators in case they can carry out the respective function at least as effectively as the delegating DSO and/or TSO".*

Additionally, every reference to the role of market operators within the network code should include the following:

- That the list is non-exhaustive
- References limiting the roles a market operator can do are removed
- Flexibility Service Provider registration and qualification can also be carried out by a market operator
- FSP availability
- Dispatch signals
- Baselining and settlement
- Invoicing and payment
- TSO-DSO coordination
- The validation of the service may be carried out by the market operator following SOs market rules, design, criteria and processes or decisioned by the SO on the market operator platform

Market operators should also be able to provide flexibility register services

> Article 57: Tasks of local market operators: *The platforms referred to in paragraph 1 shall integrate or communicate as applicable with the flexibility registry(ies).*

We agree that local market operators should integrate with flexibility registry(ies) however, it should also be possible for a flexibility register to act as a local market operator. DSO flexibility markets across Europe and the UK have been established on this basis, with the same platform providing both registration and qualification services as well as market procurement, bidding, dispatch and settlement services. This is the service we have provided to E-Distribuzione, ESBN, E-Redes, ESO (Lithuania) as well as UK Power Networks, SP Energy Networks, ESO (UK) and Electricity North West. This use case of Europe's leading SOs must be enabled within the network code (as well as ensuring integrations across platforms) to prevent unnecessary market fragmentation and enable platforms to deliver the services and functionalities they have built up experience and expertise.

Review the scope of local market operator information provision

> Article 57: Tasks of local market operators 5: *Local market operators shall publish market results, avoiding market distortion and respecting commercially sensitive information in line with Article 52 (Publication of information)*
> Article 52 Publication of information 6: *Local market operator shall publish clear information on the market sessions, including the number and structure of market sessions, gate closure times and bid selection criteria, as well as information on the products traded under the platform(s) they operate.*
> Article 52 Publication of information 7: *Systems operators or, if applicable pursuant to requirements in national terms and conditions pursuant to article 48 [National terms and conditions for market design for congestion management and voltage control services through active power], local market operator(s), shall publish, no later than three months, at least next market results of congestion management and voltage control services, promoting transparency while respecting commercial secrecy and confidentiality of information and preventing market distortion and in compliance with national rules and applicable national regulatory authority decision(s):*
> *(a) Aggregated and anonymized information on results of market-based procured capacity for congestion management and voltage control services, at least for: i. Procured capacity (MW and time period); ii. Resulting price (currency/MW/time period).*

In the UK, at the request of transparency from SOs, Piclo Data Hub publishes all market information in a non-aggregated or anonymised manner including availability and utilisation pricing from FSPs participating in DSO and TSO flexibility markets on Piclo Flex as well as reasons that SOs rejected bids (e.g. uneconomical). The data fields captured include:

DSO flexibility markets	ESO Local Constraint Market (short term)
• Flex Provider (name) • Bid Result • Rejection Reason Type • Competition Name • Competition Ref • Competition Ref & Competition Close (Combined) • Bid Type • DSO Name • Competition Open • Competition Close • Period Name • Window Name • Competition Type • Power Type • Product Category Type • Need Type • Asset Max Runtime D HH:MM:SS • Offered Capacity (MW) • Service Fee (£/MW) • Availability Price (£/MW/h) • Utilisation Price (£/MWh)	• Service Name • Competition Reference • Ballot ID • Bid ID • Service Window ID • Service Window Start • Service Window End • Flex Service Provider • Asset Types • Tendered (MW) • Instructed (MW) • Contracted (MW) • Tendered Utilisation Price (£/MWh) • Contract Status

This transparency helps provide a steer for FSPs participating in future. You can see the data sheets available here. As written, this data could be in contradiction with the network codes "Article 57: Tasks of local market operators 5: *Local market operators shall publish market results, avoiding market distortion and respecting* *commercially sensitive information in line with Article 52 (Publication of information)" and (a) Aggregated and anonymized information on results of market-based procured capacity for congestion management and voltage control services.* Further clarification of what consists of commercial sensitive information and review is needed to enable market transparency and visibility across markets.

Flexibility Register role and functionality

Ensure Network Code is consistent on platform or multiple platform possibilities
The Network Code makes it clear that flexibility registers and market operators can be one or multiple platforms throughout. However, there are some provisions that as written could be perceived as in conflict or better clarified. For instance:

> Title III: *(g) The establishment of a 'common front door' as referred to in Article 34 (Principles and requirements for SP register modules) should not pre-empt the data management approach used to realise the uniform set of procedures. Depending on existing national practices for energy data management, it might be better to establish single or multiple SP register modules and single or multiple CU register modules acting in a coordinated and standardised manner.*
>
> Article 2 Definitions: *(20) 'common front-door' means an online application as the single access point per Member State for service providers for the registration and prequalification.*
>
> Article 40: Principles and requirements for data exchange in the prequalification phase.
> *1. (The) operator(s) of flexibility register platform(s) shall establish a 'common front-door' at a Member State level to make it easy for SPs to register and administer their information about SPGs and SPUs, and CUs assigned to them.*
> *2. If a flexibility register in a Member State consists of multiple flexibility register platforms, operators of flexibility register platform(s) shall closely cooperate to facilitate the proper interoperation of all flexibility register platform(s) in a Member State.*

The definition in Article 2 including "single access point" implies the common front door should be a single platform, as opposed to the possibility of including multiple interoperable flexibility register platforms, operators of flexibility register platforms closely cooperating.

> **Recommended:** *Article 2 Definitions: (20) 'common front-door' means an online application as the single access point per Member State for service providers for the registration and prequalification, either by establishing a single or multiple SP register modules and single or multiple CU register modules acting in a co-ordinated and standardised manner.*

The network code must ensure fair competition between third-party and in-house platforms: the same point as above in the market operator section.

The Network Code process must not halt or slow flexibility market progress
Flexibility markets and DSO flexibility markets already exist and there is momentum from leading SOs in wanting to continue to set up, implement, scale, develop and coordinate these markets across the EU. The Network Code mustn't stifle or halt any progress in this area, causing a potentially multi-year delay in DSO flexibility markets being established whilst the T&Cs process is established, written, signed off and time is given for implementation. In many cases, it will be difficult or damaging for SOs to halt the procurement of flexibility services when they have existing markets and have signalled their commitment to FSPs. Market progress and

network code development must be concurrent activities that push each other forward. We urge that this clearly signalled within the document and externally too.

> Article 48: National terms and conditions for market design for congestion management and voltage control services through active power
> *11. The main elements of the procurement process shall be submitted to national regulatory authority as part of the national terms and conditions according to this article prior to starting the procurement process.*
>
> **Recommended wording:** *11. The main elements of the procurement process shall be submitted to national regulatory authority as part of the national terms and conditions according to this article ~~prior to starting the procurement process.~~*

Other articles to reword

Article	Comment	Rewording
Article 41: Principles and requirements for operators of flexibility register platforms *2b. grant SPs access to the data of the SPU or SPG assigned to them, at any point in time easily, online and without undue delay on their request. Future and historical states of that data shall be made available*	Unclear how future states of data will be made available	*2b. grant SPs access to the data of the SPU or SPG assigned to them, at any point in time easily, online and without undue delay on their request. Data sets (historic and current) shall be made available*
Article 50: Principles for procuring by tender procedure *(b) The tender process may enable participation of assets not yet connected provided that 1) they will be connected, registered or prequalified in a timely manner consistent with the procurement process and service providers document connection, registration and prequalification in a timely manner*	Much of the network code has been written only with existing assets in mind. The registration for planned assets should require significantly fewer data fields such as what is required by DSOs in the UK on Piclo Flex. See here for planned and existing asset data fields	Data field upload requirements for planned assets should be simplified compared to operational
Article 34 Requirements for Product Prequalification *3. The PPR shall evaluate whether the potential SPU or SPG is ready to provide the service, comparing the technical characteristics of the potential SPU or potential SPG with the technical requirements of the declared product. In the case of a negative result of this evaluation, the potential service provider shall decide how to improve the potential SPU or potential SPG to fulfil the requirements.*	The qualification process has been established only in mind for operational assets. How planned assets can register and "qualify" for long-term markets will need further assessment.	
Article 52 Publication of information	Unclear what or where this platform has come from. All other	**Article 52 Publication of information**

8. The relevant regulatory national authority may require system operators publish the information referred to in this Article on a single platform on national level.	platforms within the network code have been established based on interoperability so that it can be one or multiple providing this service.	*8. The relevant regulatory national authority may require system operators publish the information referred to in this Article on a single platform on national level or data access must be available across multiple platforms with shared standards and interoperability*
Article 31: Qualification for Service Providers *1. The service provider shall successfully pass a service provider qualification with the requirements laid down in paragraphs 2, 3, 4 and 5 before being granted access to markets for balancing, congestion management or voltage control services. In case the service provider is already qualified for one or more markets for balancing, congestion management or voltage control services and applies for the participation in another market for balancing, congestion management or voltage control services, a simplified qualification process shall be foreseen further specified in the national TCMs for service providers.*	On Piclo Flex, FSPs register for a Piclo Flex account and upload their assets to have visibility of and receive notifications about DSO or ESO market opportunities relevant to their assets. If they want to participate and bid in these markets they undergo a company (SP) qualification and asset qualification. But they are enabled access to the market for visibility-only purposes without qualification	*The service provider shall successfully pass a service provider qualification with the requirements laid down in paragraphs 2, 3, 4 and 5 before being granted access to participate or bid in markets*
Article 45: Principles for national implementation *4(b) further specifications of the systems operators right to suspend or revoke the 'qualification status' of a service provider for reasons of incompliance or repeated inadequate service provision set out in Article 30 (Qualification for Service Providers), paragraph 8.*	If revocation is possible there must be a clear process to get back into qualification status. Ensure this is captured within the network code.	

Article	Comment	Proposal
1 - Definitions	*(1) This Regulation establishes a network code which lays down the requirements in relation to demand response, including rules on aggregation, energy storage, and demand curtailment rules, to contribute to market integration, non-discrimination, effective competition and the efficient functioning of the market pursuant to Article 59(1) of Regulation (EU) 2019/943.* In article 3 the scope of application refers to “demand response including load, storage and distributed generation”. In article 4 “rules regarding demand response, including rules on aggregation, energy storage and demand curtailment.” Why this ambiguity? Is generation included or not? If not so, when not? And what is the definition on distributed generation? *(22) – ‘Controllable unit’ or ‘CU’, means a single technical resource or an ensemble of technical resources behind the same single connection point, if these technical resources are commonly controlled.* – the term connection point is not correct in this case – the term should rather be “accounting point”	*(1) This Regulation establishes a network code which lays down the requirements in relation to demand response, including rules on aggregation, energy storage, demand curtailment rules **and distributed generation**, to contribute to market integration, non-discrimination, effective competition and the efficient functioning of the market pursuant to Article 59(1) of Regulation (EU) 2019/943.* **The definition of distributed generation is missing.** *(22) – ‘Controllable unit’ or ‘CU’, means a single technical resource or an ensemble of technical resources behind the same single **accounting** point, if these technical resources are commonly controlled*

	(28) – 'Service providing unit' or 'SPU', means a single controllable unit or an ensemble of controllable units connected to the same single connection point. SPU is defined by the service provider to provide balancing, congestion management and voltage control services. – the term should rather be "accounting point" *(29) – 'Service providing group' or 'SPG', means an aggregation of controllable units connected to more than one connection point. SPG is defined by the service provider to provide balancing, congestion management and voltage control services. –* the term should rather be "accounting point"	*(28) – 'Service providing unit' or 'SPU', means a single controllable unit or an ensemble of controllable units connected to the same single **accounting** point. SPU is defined by the service provider to provide balancing, congestion management and voltage control services* *(29) – 'Service providing group' or 'SPG', means an aggregation of controllable units connected to more than one **accounting** point. SPG is defined by the service provider to provide balancing, congestion management and voltage control services.*
19 – Aggregation models	*(1) – The aggregation models that are described below aim at defining how the participation of service providers is allowed, based on the configuration of the meter equipment and by the relationships established between the BRPs and market entities present at and behind any connection point. –* the term should rather be "accounting point" *(6) - The aggregation model A prescribes all the following requirements:* *(d) the performance of the controllable units involved in providing the balancing, congestion management and voltage control services is*	*(1) – The aggregation models that are described below aim at defining how the participation of service providers is allowed, based on the configuration of the meter equipment and by the relationships established between the BRPs and market entities present at and behind any **accounting** point.* *(6) - The aggregation model A prescribes all the following requirements:* *(d) the performance of the controllable units involved in providing the balancing, congestion management and voltage control services is*

	assessed only through the metering equipment at the connection point; – the term should rather be "accounting point" *(e) the only metering equipment is the smart meter at the connection point, which is the only meter to perform measurements of the energy injected or withdrawn used by both the supplier(s) and by the service provider(s); and* – the term should rather be "accounting point" *(7) - The aggregation model B prescribes all the following requirements:* *(b) the metering equipment at the connection point can be a conventional meter or smart meter;* – the term should rather be "accounting point" *(8) - The aggregation models A and B defined in paragraphs 6 and 7 are the basic models. For simplification purposes, a simple version is assumed but the possibility of multiple suppliers and service providers behind the connection point providing balance or congestion management and voltage control services from different controllable units is possible. When multiple suppliers are active at the connection point, the allocation of imbalance between different BRPs of multiple suppliers is performed following national rules. The configurations and the responsibilities shall remain as they are in the simple version.*	*assessed only through the metering equipment at the* ***accounting*** *point;* *(e) the only metering equipment is the smart meter at the* ***accounting*** *point, which is the only meter to perform measurements of the energy injected or withdrawn used by both the supplier(s) and by the service provider(s); and* *(7) - The aggregation model B prescribes all the following requirements:* *(b) the metering equipment at the* ***accounting*** *point can be a conventional meter or smart meter;*

20 - Energy allocation, balance responsibility in each aggregation model category and imbalance adjustments	*(1) - When model A applies, the delivery of the service provider may be validated by comparing the baseline for the controllable units involved in the connection point and the measurements provided by the metering equipment installed at the connection point, after having applied one of the approaches described in Article 28(4) [Imbalance Settlement] for the consideration of the requested activation.* – the term should rather be "accounting point" *(2) - When model B applies:* *(b) when service provider takes his balance responsibility or contractually delegates his balance responsibility to a third party that is not the BRP of the supplier, the allocated volume to the supplier's BRP is based on the measurements of the meter at the connection point. One of the approaches described in Article 28(4) [Imbalance Settlement] shall be applied to the BRP of the supplier for calculating the actual delivery and subsequent imbalance; and* – the term should rather be "accounting point" *(4) - For both models A and B, when service provider takes his balance responsibility or contractually delegates his balance responsibility to a third party that is not the BRP of the supplier, the supplier's BRP holds full responsibility of the connection point when the*	*(1) - When model A applies, the delivery of the service provider may be validated by comparing the baseline for the controllable units involved in the* ***accounting*** *point and the measurements provided by the metering equipment installed at the* ***accounting*** *point, after having applied one of the approaches described in Article 28(4) [Imbalance Settlement] for the consideration of the requested activation.* *(2) - When model B applies:* *(b) when service provider takes his balance responsibility or contractually delegates his balance responsibility to a third party that is not the BRP of the supplier, the allocated volume to the supplier's BRP is based on the measurements of the meter at the* ***accounting*** *point. One of the approaches described in Article 28(4) [Imbalance Settlement] shall be applied to the BRP of the supplier for calculating the actual delivery and subsequent imbalance; and* *(4) - For both models A and B, when service provider takes his balance responsibility or contractually delegates his balance responsibility to a third party that is not the BRP of the supplier, the supplier's BRP holds full responsibility of the* ***accounting*** *point when the*

	controllable unit is not activated for balancing, congestion management and voltage control services. By contrast, when an activation from the service provider takes place, service is activated, the responsibility of any deviation from the meter data compared to the baseline at the metering point remains within the service provider's BRP. – the term should rather be "accounting point"	*controllable unit is not activated for balancing, congestion management and voltage control services. By contrast, when an activation from the service provider takes place, service is activated, the responsibility of any deviation from the meter data compared to the baseline at the metering point remains within the service provider's BRP.*
21 - Roles and responsibilities of market parties and systems operators related to Aggregation Models	*(6) The Metered Data Administrator (MDA) is responsible for all the tasks regulated in article 5 of Commission Implementing Regulation (EU) 2023/1162 concerning the data of the metering equipment as defined in the articles 19.6 [Aggregation models] and 19.7 [Aggregation models].* – MDA should not be responsible for submeter data	
25 - General principles for baselining methods	*(4) The baselining methods shall be based on the following principles:* *c) the methods shall avoid gaming (e.g. manipulating the baseline instead of activation or deactivation of power);* "avoid gaming" or "avoid market abuse" is highly unrealistic. Here, the code needs to switch over to patterns proven-in-use by REMIT and Market Abuse Regulation (MAR). This means abuse/gaming must be analysed ex-post. Start with an initial set of scenarios that describe unwanted behaviour and provide for an extension	Will require a dedicated article and the inclusion of e.g. EFET and ACER at least to get to a good result. So no Article proposal here.

	of this list over time and include analyses of market behaviour data. Fine ex-post and probably assign responsibility for data collection to ACER, fines to NRA.	
26 - Baselining method: specification and validation	Baseline for every single asset prevents DSOs of having more liquidity into the market (2) „avoid gaming“ – more details Article 25 – 4c)	 Will require a dedicated article and the inclusion of e.g. EFET and ACER at least to get to a good result. So no Article proposal here.
27 - General principles for settlement of congestion and voltage services and settlement related data exchange	Baseline for every single asset prevents DSOs of having more liquidity from service providers wanting to use portfolio-based baseline. This is especially important for small assets like EV chargers. *(12) - Each service provider shall ensure that the delivery of the congestion management and voltage control services is registered at the connection point(s).* – the term should rather be “accounting point”	The use of portfolio-based baseline containing asset information for verification must be allowed in national terms and conditions. *(12) - Each service provider shall ensure that the delivery of the congestion management and voltage control services is registered at the* ***accounting*** *point(s).*
34 - Requirements for product prequalification	It should be specified, who could be the PPR.	*Add a paragraph:* *PPR(s) can be:* *a. the TSO(s) or DSO(s) requesting prequalification, either alone or together;* *b. another TSO or DSO, either alone or together; c. a third party.*
37 - Product Verification Requirements	*(3) - The national terms and conditions for service providers shall clarify which systems operators will act as the PPR to conduct the product verification process pursuant*	European harmonized rules are preferred; procuring SO for a given market could define the pre-qualification responsible party

	to Article 38 (Product Verification Process). - This could be an issue in some countries.	
39 - Principles for Governance and Interoperability	(1) - *Systems operators in each Member State shall describe in terms and conditions referred to in Article 45(8) (Principles for national implementation), functional requirements for CU and SP modules and a process(es) for nomination of the operator(s) for flexibility register platform(s).* (2) - *The process(es) for nomination of operator(s) of flexibility register platform(s) shall take duly into account proposals of each connecting systems operator and include an NRA assessment ensuring that operator(s) of flexibility register platform(s) meet the requirements of this Regulation.*	It should be explicitly stated in the Code, that at least Controllable Units (CUs) is the responsibility of the connecting SO establishing flexibility master data management, as this responsibility is linked to meter point management and measurement data management and should not be separated. (2) - *The process(es) for nomination of operator(s) of flexibility register platform(s) shall take duly into account proposals of each connecting systems operator ~~an NRA assessment ensuring that operator(s) of flexibility register platform(s) meet the requirements of this Regulation.~~*
48 - National terms and conditions for market design for congestion management and voltage control services through active power	*(6) - When preparing the national terms and conditions referred to in paragraph 4, DSOs and TSOs shall consider the national context at least including:* *(f) the number and structure of DSOs; -* Number and structure of DSOs is irrelevant. *(j) the existing ancillary service and congestion management market structure or organisation; and* A future-proof regulation/structure is required. Requesting to follow	Delete (f) and (j)

	structures of the past will just ice ineffective structures. *(7) In the national terms and conditions pursuant to this article at least the following roles and processes related to this Regulation and in line with this Regulation should be described:* *(d) The affected system operators;* *(f) The coordination with operators of long-term, day-ahead, intraday and balancing markets;* These roles should not be described in national terms and conditions, but by the systems operator.	 Delete (d) and (f)
53 - Principles for the coordination and interoperability between local and day-ahead, intraday and balancing markets	It is not specified how bids offered in local markets can be used for DA, ID and BAL markets (4) c) „avoid gaming" – more details Article 25 – 4c)	We propose including a paragraph saying that national terms and conditions for market design shall specify whether and under which conditions bids offered in local markets can be used for DA, ID and BAL markets provided they are qualified for that market. Will require a dedicated article and the inclusion of e.g. EFET and ACER at least to get to a good result. So no Article proposal here.
56 - Local market operator(s)	*(1) - Systems operators shall describe in terms and conditions referred to in Article 48(4), functional requirements of local market operators and a process for nomination of local market operators.* (2) - *The process for nomination of local market*	It should be the responsibility of each procuring SO for its network operation area to decide whether to establish its own marketplace, use the service of a provider, or use a national platform. (2) - *The process for nomination of local market*

	operators shall take duly into account proposals of each procuring system operator and include national regulatory authority's assessment ensuring that the local market operators meet the general requirements described in Article 55 of this Regulation and in national terms and conditions referred to in Article 48(4).	*operators shall take duly into account proposals of each procuring system operator ~~and include national regulatory authority's assessment ensuring that the local market operators meet the general requirements described in Article 55 of this Regulation and in national terms and conditions referred to in Article 48(4).~~*
74 - Short-term procedures to account for DSO temporary limit	(e) - *"… This process shall not be used to cancel previously activated bids. In case of unforeseen events that result in a measure violating operational limits in DSO grid, the TSO shall coordinate to find a solution in line with Article 42(4) of Regulation (EU) 2019/943"* It´s difficult to understand and accept for DSOs that they should not be allowed to intervene in cases where operational limits are at risk and this task is "delegated" to TSOs.	It should be clarified how the process in such situations allows DSOs to keep the "steering wheel" in hand and guarantee secure grid operation.
80 - Data to be provided by grid users	*(2) With the NRA approval, the systems operators can extend the applicability of the structural, schedule and real-time data provision referred in Article 71 to other grid users in their (DSO) observability area that are not SPUs/SPGs, if it is needed for forecasting or to maintain operational security* It should be clarified that the purpose of this article is to allow DSOs in their observability area to ask for additional data if required and	*(2) With the NRA approval, **DSOs** can extend the applicability of the structural, schedule and real-time data provision referred in Article 71 to other grid users in their ~~(DSO)~~ observability area that are not SPUs/SPGs, if it is needed for forecasting or to maintain operational security* *With the NRA approval, connecting systems operators can extend the applicability of the structural, schedule and real-time data provision*

	approved by NRA. TSOs data needs in DSO grids are already well covered via SOGL, etc. and is extended via NC DR to data from SPU/G. We strongly mandate to change to avoid excessive and unnecessary data exchange requirements. In fact, connecting SOs should have the right to require more data from *specific significant grid users*. Then they can pass on aggregated information to higher-level SOs.	*referred to in Article 71 to specific and significant grid users in their (DSO) observability area that are not SPUs/SPGs, if it is needed for forecasting or to maintain operational security. Higher-level systems operators above the connecting SO may – with NRA approval – request aggregated data.*
84 - Harmonisation	*(1) d)* - „avoid gaming" – more details Article 25 – 4c)	Will require a dedicated article and the inclusion of e.g. EFET and ACER at least to get to a good result. So no Article proposal here.
TITLE VI DISTRIBUTION NETWORK DEVELOPMENT PLANS - CHAPTER 11 Distribution Network Development Plan	In a fundamental level we want to raise the question whether there is a mandate to set rules for Distribution Network Development Plans (DNDP) in this NC. The guidelines of network codes are set in Electricity Regulation 2019/943 CHAPTER VII NETWORK CODES AND GUIDELINES. As we see the regulation doesn't give a mandate to regulate DNDPs in the network code. In case there however is a mandate to regulate DNDPs in this NC we want to highlight that the draft network code shall be revised and compared with existing EU legislation. Electricity directive Article 32 point 3 already includes many of the provisions proposed in the draft Network Code.	Delete CHAPTER 11 Distribution Network Development Plan from NC or (if existing mandate is proven) assess and remove all overlaps with existing regulation (namely Electricity directive Article 32 point 3).

	Requirements for NDPs are at now least partially overlapping with existing EU legislation. Overlaps shall be avoided. In more detail, as we see following points are overlapping with existing Electricity Regulation as: Draft NCDR Art 64 (1), (2), (3), (4) Draft NCDR Art 65 (1), (2 at least to large extent) Draft NCDR Art 66 (3) Draft NCDR Art 68 (1), (6), (7), (8), (9)	

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EPEX SPOT's key recommendations for improving the Network Code on Demand Response proposal

10.11.2023
Paris

DSO Entity and ENTSO-E have been tasked by the European Commission in its letter of 9 March 2023 to develop a new European Network Code on Demand Response (NC DR). According to the Framework Guideline on Demand Response of 20 December 2022 issued by ACER, the new Network Code shall aim at "removing all undue barriers for the participation of these resources in all wholesale electricity markets (including those for procuring SO services), and establishing European principles for the assessment of the need for, the procurement of and the use of local SO services."

A proposal for the new Network Code on Demand Response was publicly consulted until 10 November 2023. As European Power Exchange and developer of local flexibility market solutions, EPEX SPOT is sharing its assessment on critical aspects of the proposed text. Four key topics arise where the Network Code proposal needs to be considerably improved during the further drafting process.

1. **Promote more strongly and clearly the market-based flexibility procurement of congestion management and voltage control services by system operators. Be more ambitious by making clear improvements for market-based flexibility procurement compared to the status quo and existing regulation.**

Market-based solutions, such as local flexibility markets, are not an end in itself, but provide a pricing mechanism that is superior to any regulated pricing, especially for complex usage profiles as demand response. A market represents the economically most efficient way to bring together supply and demand. Local flexibility markets create the right economic space for the development of existing and new flexibility. Market-based flexibility procurement for congestion management by TSOs and DSOs is the European target model according to the Clean Energy Provisions (Art. 13 Electricity Regulation and Art. 32 Electricity Directive).

The NC DR is supposed to clearly foster the market-based flexibility procurement, but the present NC DR proposal fails to a large extent to do so. More ambitious provisions are needed. Otherwise, it is questionable how Network Code will bring progress compared to the already existing Clean Energy Package provisions which are still not implemented everywhere in the EU even four years after its entry into force in 2019.

In our consultation response, we make concrete improvement proposals, e.g., in our amendment proposals for Art. 47 and 48 NC DR. For example, the NC DR shall insert an additional assessment or stricter criteria for NOT applying market-based redispatch. Furthermore, when preparing the national terms and conditions, DSOs and TSOs shall also assess and make public cost-savings that market-based procurement will bring compared to non-market based procurement, such as reduced redispatch costs, reduced or deferred grid investment costs, reduced grid operation costs. This will help foster market-based solutions instead of non-market-based solutions. In addition, system operators need to have incentives to engage in market-based flexibility procurement processes, complementary to an appropriate grid expansion. Therefore, the costs for market-based procurement of congestion management and voltage control need to be recognized and should be recoverable. This needs to be clearly stated in the Network Code, otherwise it will not bring improvement compared to the status quo.

2. **Facilitate value stacking for market participants through product compatibility, process improvements and technology. Avoid combined markets with forwarding of bids between spot markets and local flexibility markets.**

The option of combined markets, as described amongst others in Art. 48, 53, 57 and 60 NC DR, is not the right way forward to develop market-based flexibility procurement for technical and practical reasons, but also for market design reasons.

Combining the European-wide coupled wholesale markets (SDAC, SIDC) with local flexibility markets, e.g., through locational tagged bids, is unrealistic and highly complex. SIDC is not compatible with it: you have different products, different ways of trading, etc. It raises many questions with regard to the European-wide harmonized Single Intraday Coupling (SIDC) algorithm. Such additional constraints would probably not be implementable in the matching engine. For SDAC, such a change of SDAC products would have a major impact on Euphemia calculation time, will delay other market coupling projects. In addition, intraday and local flexibility are different markets for different uses, with different products, different risks, hence different prices. They should not be mixed up or it would create price signal distortions and undermine overall market transparency.

In particular, mixing local flexibility with the intraday market makes little sense from a flexibility service provider's (FSP) risk perspective and from a price signal perspective, and would dramatically reduce transparency and readability of the intraday market. More straight-forward alternatives to combined markets exist, such as the options of parallel or sequential markets. There is no need to opt for the combined option. What should be aimed for is product compatibility and process improvement to ensure value stacking for FSPs across all wholesale and balancing and flexibility electricity markets. Certainly, it should be facilitated for FSPs to offer their flexibility and arbitrate between these different value pools, but this could be facilitated through technology, and does not require markets to be mixed.

3. Avoid lengthy implementation processes

The implementation processes need to be significantly accelerated at various points. The new rules should be implemented without unnecessary delays in order to utilise and further develop the urgently needed load-side flexibility as quickly as possible in the interests of a successful energy transition. For example, it is unclear why the step of development of a national process to develop national terms and conditions by SOs is really needed. It will take at least 4 months. Instead, SOs shall directly start developing the common proposal for the national terms and conditions according to Art. 6 NC DR.

Furthermore, instead of creating new rules that could be redundant or contradictory as Art. 53 (4) (c) suggests, existing rules on capacity withholding and market abuse shall be also applicable for local flexibility markets. In addition, the list of attributes shall be directly included in the Network Code instead of only referring to a future process taking additional 6 months to develop the list of attributes (Art. 58). This will again save time.

4. Do not create overcomplex nomination processes for local markets operators. Instead, define clear functional requirements which will ensure that these markets are operated compliant to the NC DR.

The idea is that System operators shall procure market-based flexibility services. They can do it using the services of local market operators or through tenders. In both cases the regulation should be the same. System operators have the duty to procure the flexibility market-based and they shall be left free to operationally do so without recuring to additional nomination from the regulators.

Existing rules from public procurement, and fair treatment of grid users should apply. Setting up additional rules for nomination of local market operators would create unnecessary administrative layer. Moreover, the Framework Guideline does not stipulate a nomination process for local market operators.

* * *

About EPEX SPOT

The European Power Exchange EPEX SPOT SE and its affiliates operate physical short-term electricity markets in Central Western Europe, the United Kingdom, Switzerland, the Nordics and in Poland. Furthermore, EPEX SPOT newly offers local flexibility markets solution and Guarantees of Origin auctions, to foster the integration of renewable energy sources and to enhance the engagement of consumers and producers in the power market. As part of EEX Group, a group of companies serving international commodity markets, EPEX SPOT is committed to the creation of a pan-European power market. Over 300 members trade electricity on EPEX SPOT. 49% of its equity is held by HGRT, a holding of transmission system operators. For more information, please visit www.epexspot.com.

Contact

Kora Töpfer
Head of German Public & Regulatory Affairs
EPEX SPOT
k.toepfer@epexspot.com

Adrien Atayi
Senior Product Development Officer
EPEX SPOT
a.atayi@epexspot.com

Energistyrelsen

To
ENTSO-E/EU-DSO entity

Office/Department
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Date
10-11-2023

J nr. 2023-14174

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Hearing on the Draft Network Code Demand Response

Denmark welcomes the work of ENTSO-E and the EU DSO entity on the draft network code demand response (NC).

Denmark generally supports the draft NC as an important element for the establishment of a framework for market access for demand response[1] across the EU, and for the development of markets for flexibility services.

However, Denmark would like to highlight a number of aspects that should be addressed in subsequent drafts.

- As a general point, we urge for **more clarity** in terms of the overall envisaged architecture of the legal framework established. It is our understanding that completing the NC´s framework with national implementing rules by SOs will require, as a first step, the development and adoption of a *process to develop national terms and conditions* (TCs) for, in a second step to develop and adopt such *national TCs in three areas*: (1) overall market design; (2) service providers, (3) TSO-DSO/DSO-DSO coordination. We believe this architecture should be better reflected throughout the document. Added clarity thereon will increase the effectiveness of the subsequent implementation at Member State level.
- In addition, we would welcome more clarity regarding **deadlines** for delivery, ideally as an Annex to the NC. While some deadlines are spelled out in the draft NC, others will be subject to what will be decided at national level. Our understanding is, for example, that it is not a requirement to set up local markets for congestion management/voltage control by active effect by a certain date. The timing in that respect will depend on the process for the development of national TCs on market design, to be approved by the NRA, which will also influence the timing of implementation of national TCs on service providers to such markets. These interactions in terms of timing should be made more clear.
- In terms of subsequent **harmonisation**, the draft NC sets up a process giving the task for development of TCs at EU level to ENTSO-E/the DSO unity and ACER. We are very concerned that this bypasses the procedures established in the electricity market regulation on the amendment of network codes, and thereby Member State involvement.
- Regarding articles on **aggregation**, it should be noted that the NC should be coherent with requirements and purpose of the electricity market regulation and directive (also forthcoming adjustments regarding dedicated metering devices), cf. art. 19. It seems as if the draft NC's provisions regarding aggregation and

[1] including load, storage and distributed generation

Danish Energy Agency

Carsten Niebuhrs Gade 43
DK-1577 Copenhagen V

Niels Bohrs Vej 8
DK-6700 Esbjerg

P: +45 3392 6700
E: ens@ens.dk

www.ens.dk

balance responsibility are not coherent with the electricity market regulation article 5 (on balance responsibility). Furthermore, there is a risk of introducing unnecessary requirements towards the sector if they are asked to deliver data for each controllable unit (even though this is data used by aggregator), cf. art. 79.

- We note that the general application of **voltage control management through active power** is a deviation from the norm. Reactive power is normally used due to its technical capabilities, which does not result in, for example, an imbalance in the system. We would urge to revisit this notion.
- The **flexibility register** proposed, while in principle positive, could result in an undue administrative hurdle for the promotion of flexibility in the system. If the regulation becomes too rigid it could provide administrative and technical barriers for the future flexibility market, notably taking account of the current deadlines for establishing the flexibility register, which in any case seem unrealistic.
- On the development of local markets for **congestion management services** we note that different tools, both market-based and non-market based (including rules-based) exist and that SOs shall use the most effective and economically efficient tools in line with transparent and coordinated principles. We would like to see some formalization in this respect by requiring SOs to lay down an explicit methodology in choosing between the different options.
- In addition, we would like to see added focus in the rules on the **interaction between different instruments for congestion management**, including notably non-firm connection agreements, and local markets for congestion management, where the former may risk preventing the emergence of the latter.
- On the provisions regarding **energy storage**, we find it problematic that they go beyond the requirements of the electricity market directive, which notably does not require prior approval by the NRA on the use of integrated network components.
- Furthermore, also regarding the energy storage provisions, we do not agree that subsequent opening of markets to third parties in situations where SOs initially have been allowed to own, manage, develop or operate energy storage facilities, should require the third party to take over the SOs storage facility, rather than providing the service with own facilities. This would risk locking such third parties into potentially outdated technology.
- On the provisions of **network development plans**, we are concerned that the current draft that requires these plans to be provided by a specific deadline, risks interfering with the periodicity for the submission of the plans that is already established in the Member States. The focus should rather be on from which planning year the plans shall comply with the new rules.
- In addition, there are a number of requirements relating to network development plans, including the hearing process, which we find overly restrictive and administratively burdensome.

Public Consultation on
the draft Network Code for Demand Response

10 November 2023

Executive summary

Centrica thanks the EU DSO Entity and ENTSO-E for the opportunity to provide comments to the consultation on the draft Network Code for Demand Response.

Centrica is a major energy trading company involved in various European countries, including balancing responsible party and aggregator activities. We endorse European efforts to establish a transparent and fair regulatory framework that grants equal access to all market participants, including prosumers and independent aggregators, across wholesale, balancing, congestion management, and voltage control markets.

We welcome that the Network Code upholds technology neutrality and non-discrimination principles while promoting market-based practices, including non-balancing ancillary service procurement.

Centrica would like to offer the following feedback to support the EU DSO Entity and ENTSO-E in achieving these goals:

- We strongly back transparent data sharing among market parties, including activation data.
- We endorse a diverse range of metering solutions, advocate for increased standardization, and underscore the importance of checks and balances.
- We request clarification regarding the ex-post determination of baselines.
- We urge authorities to enhance the harmonization of the regulatory framework for flexibility.
- We oppose the idea of unconditionally adhering to grid limitations set by system operators and advocate for a more nuanced approach that respects asset boundaries.
- We strongly object to system operators owning storage facilities.

All relevant text proposals are included in Annex I, at the end of this document.

Centrica strongly backs transparent data sharing among market parties, including activation data.

(i) Enable sharing of activation data for accurate imbalance settlement

We advocate a balanced approach to aggregation roles and responsibilities in compliance with Article 17 of the Directive 2019/944 (Electricity Directive). This means fostering fair and open data exchange among aggregation participants. As such, we support notifications of activations to the supplier's BRP as outlined in **Article 24(4)** of the proposal. We suggest further clarifying in the Network Code that an independent party, such as the system operator or MDA, notifies the BRP.

We have however strong concerns about **Article 21 (9)**, which states that "*the supplier or the BRP associated to the supplier shall be responsible for the reception of the relevant data values of the metering point for all timeseries with exception of the specific data related to the activation*".

We stress the importance of supplying real-time metering data – including data related to activations – to BRP/suppliers for accurate imbalance settlement, particularly since service providers can act on BRP/supplier's asset without consent[1]. This data should be provided at an aggregated level, not on an individual asset basis, to support the financial sustainability of residential aggregation.

(ii) Safeguard data privacy while upholding market parties' regulatory obligations

We advocate a cautious approach to data exchange, aligning with Article 17 (3)(c) of the Electricity Directive, to ensure confidential treatment of sensitive information. This includes the fact that information should not be shared without customer consent, and that the BRP/supplier should receive information on a need-to-know basis.

Simultaneously, we recognize the BRP/supplier's responsibility for portfolio imbalances under **Article 21 (10)** and **Article 28** of the draft Network Code. It's therefore essential to clearly define what qualifies as sensitive information based on concrete evidence. For example, while data on *certain* specific metering points, like large industrial sites or individual grid users, can be commercially sensitive, this doesn't generally apply to renewable or thermal generation assets, energy storage, or smaller controllable units. Withholding non-sensitive activation data from such assets unfairly hinders BRPs in their proper imbalance settlement, which goes against the principles of the Regulation.

We therefore recommend adjusting the draft Network Code to both safeguard data confidentiality while ensuring that withholding non-sensitive activation data does not place unnecessary burden on BRPs.

[1] Directive 2019/944, Article 17 (3)(a): "*Member States shall ensure […] the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants*".

(iii) Avoid convoluted and ineffective financial compensation mechanisms

Article 22 of the Network Code suggests financial compensation is subject to each Member State's discretion[2]. This is meant to address imbalances caused by the absence of data and to cover costs related to guarantees of origin, green certificates, specific network charge exemptions, tariffs, etc.

However, based on our experience in countries like Belgium, Germany, and the UK, these mechanisms often prove unwieldy, struggle to determine fair compensation, lead to time-consuming negotiations, and create operational inefficiencies for both BRPs/suppliers and service providers.

We strongly advocate for fostering a transparent exchange of real-time data between service providers and BRP/suppliers. This is crucial for streamlining financial compensation processes, especially in a system where a large number of activations need automated settlement, as manual handling will be impracticable.

(iv) Mitigation measures if transparent data exchange cannot be ensured by the Network Code

As stated above, we strongly urge the Network Code to ensure transparent real-time data exchange between service providers and BRPs/suppliers, encompassing activation data. Failing this, we propose following mitigating measures:

- **Mandatory compensation**: We recommend making financial compensation mandatory for market participants directly affected by activations related to balancing, congestion management, and voltage control services.

- **Aggregation thresholds**: The Network Code should introduce aggregation thresholds for service providers, above which activation data needs to be provided. The current draft doesn't differentiate between small and large-scale assets, such as electric vehicles and offshore wind parks. Our experience shows that managing larger assets is more complex and can significantly impact grid stability. When independent service providers interact with these assets without sharing real-time meter-level data, it hampers the ability of BRP/suppliers to forecast and mitigate activations. Therefore, in the absence of activation data access, Member States should define limits on the size of assets and/or portfolios that service providers can aggregate. Beyond these limits, sharing activation data becomes mandatory. This approach strikes a balance between the socio-economic benefits of aggregation and regulatory obligations of balancing responsible parties.

[2] Network Code Demand response, Article 22 (2): "*Member States may require suppliers or service providers or active customers to pay financial compensation*".

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Centrica endorses a diverse range of metering solutions, advocates for increased standardization, and underscores the importance of checks and balances.

In **Article 19(7)**, the aggregation model “B” suggests utilizing various metering equipment, such as submeters and dedicated measurement devices (DMD), including conventional meters at the connection point. We endorse these ideas, since the development of flexibility should not rely solely on the deployment of smart meters, especially at the low-voltage level. We also emphasize the importance of incorporating asset meters to measure and monitor the performance of specific assets, including residential appliances.

We encourage further exploration of standardizing existing (sub-)metering specifications. This includes evaluating the appropriateness of current accuracy levels for balancing, congestion management, and voltage control services. Additionally, harmonizing requirements between transmission and distribution systems is essential.

Lastly, we welcome the role of the Metered Data Administrator (MDA) as outlined in **Articles 21(6) and 24(5)** of the draft Network Code. It is our understanding that the MDA is fully responsible for metering data, both for aggregation models “A” and “B”. This introduces essential checks and balances concerning metering data, enhancing the reliability and accuracy of the system.

Centrica requests clarification regarding the ex-post determination of baselines.

Article 24(2)(a) suggests that baselines may, in some cases, be determined retrospectively for settlement purposes. In our perspective, baselines act as a reference point to confirm service delivery by indicating how much electricity would have been consumed (or generated) without any activation. As such, the baseline should generally be determined before service delivery. We respectfully seek clarity on the scope and application of post-activation baseline determination.

Centrica urges authorities to enhance the harmonization of the regulatory framework for flexibility.

A recent joint report[3] by ACER and the European Environment Agency emphasizes the necessity of doubling Europe's power system flexibility by 2030 to accommodate variable renewable sources. This requires reducing bureaucratic burdens and enacting harmonized flexibility-boosting measures.

While the draft Network Code is a step in the right direction, it often places the responsibility for implementation to Member States, who must create detailed provisions in their national Terms and Conditions (T&Cs), as outlined in **Articles 5 to 14** and **Article 84**. This covers various aspects such as prequalification, baselining, establishing flexibility registers, certifying measurement devices, enabling data exchange, and more.

3 https://www.acer.europa.eu.mcas.ms/Publications/EEA-ACER_Flexibility_solutions_support_decarbonised_secure_EU_electricity_system.pdf?McasCtx=4&McasTsid=26055

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While we acknowledge the importance of granting discretion to system operators and regulators at the national level, we firmly believe that the Network Code should strive for greater harmonization at the regional or, preferably, European level. It is challenging for market participants to compete on a level playing field in pan-European organized markets when faced with differing national or local requirements. Requiring market participants to develop customized solutions for each national or even local market hampers innovation and prevents the realization of economies of scale.

We strongly urge authorities to harmonize specific market design elements related to balancing, congestion management and voltage control markets within the Network Code. These elements include eligibility criteria, backup requirements, availability monitoring, activation control, settlement procedures, penalty frameworks, IT requirements, and metering specifications. Such harmonization is essential to prevent the current regulatory fragmentation between (and within) Member States, which imposes significant costs on grid users and taxpayers, while impeding the scalability of flexibility solutions.

In cases where system operators wish to deviate from the standardized rules mentioned above, they should be required to provide an assessment demonstrating that the common EU framework is not economically efficient or would result in sever market distortions. Such exemptions should be subject to regulatory approval.

Centrica opposes the idea of unconditionally adhering to grid limitations set by system operators and advocates for a more nuanced approach that respects asset boundaries.

We are strongly concerned about **Article 21(8)(a)**, which emphasizes the importance of service providers complying with grid limitations communicated by system operators. The current wording introduces ambiguity, enabling system operators to impose constraints without compensating market participants for missed opportunities, and even subjecting them to penalties[4]. We believe this grants system operators too far reaching rights to restrict the market.

This stands in sharp contrast to the principles laid out in **Articles 47(1) and 49**, which advocate for procuring congestion management and voltage control services through market-based methods, unless specific exemptions apply. It also contradicts **Article 51**, which stipulates that even assets having entered non-firm connection agreements should still have the opportunity to participate in the market, provided contractual requirements are met.

We therefore suggest either the removal of **Article 21(8)(a)** entirely or, at the very least, mandating system operators to precisely define and restrict the limitations they intend to impose.

Finally, we advocate for the incorporation of a provision requiring service providers to adhere to the specified boundary conditions set by the supplier/BRP's regarding the flexible volume that can be bid or activated for generation assets, such as wind turbines. This ensures a comprehensive and balanced approach to asset management.

[4] Draft Network Code Demand Response, **Article 20 (6)**: "*Systems operators shall not reward to the concerned service provider any energy [...] violating grid limitations expressed by the connecting systems operators at the connection point. Common terms and conditions at national level may define penalties to service providers violating those grid limitations.*"

Centrica strongly objects to system operators owning storage facilities.

The draft Network Code's **Articles 61 to 63** permit system operators ownership or operation of storage. This directly contradicts the Electricity Directive's Articles 36 and 54, which clearly state that system operators shall not own, develop, manage, or operate storage facilities.

Any derogations to this rule must remain exceptional, require regulatory approval, and apply exclusively to fully integrated network components that do not participate in the market under any circumstances. The Network Code Demand Response must uphold the unbundling principle and ensure a level playing field and fair competition in the industry.

Annex I

Article	Text proposal
19(7)(a)	There is an additional metering equipment, being either a submeter, ***an asset meter*** or a dedicated measurement device (DMD, as considered in the EMDR), for the controllable units which are involved in providing the balancing, congestion management and voltage control services. The metering equipment of the controllable units measures the withdrawals and/or the injections of the controllable units involved in the provision of such services;
21(8)(a)	Respect ~~**all**~~ **contractually defined** grid limitations ~~**and temporary limits communicated by the connecting systems operators and intermediate systems operators**~~ **as well as specific boundary conditions set by the BRP of the supplier, where relevant**;
21(9)	The BRP of the service provider shall receive the relevant data values corresponding to those periods where the controllable units under its portfolio were providing a service. Depending on the common national terms and conditions, the supplier or the BRP associated to the supplier shall be responsible for the reception of the relevant data values of the metering point for all timeseries ~~**with exception of the specific data related to the activation**~~.
NEW 21(12)	*[if the above text proposal for Article 21(9) is not retained]* **Member States shall delineate specific thresholds pertaining to the scale of assets and/or portfolios that service providers are permitted to aggregate. In instances surpassing these predetermined limits, obligatory disclosure of specific data related to the activation data to the supplier or the BRP associated to the supplier is mandated.**
22(1)	*[if the above text proposal for Article 21(9) is not retained]* In order to limit the impact that balancing or congestion management and voltage control services activation might generate on market parties, a financial compensation ~~**may**~~ **shall** apply~~**, only when the measurements that determine the load curve of the customer is not corrected**~~.
22(2)	*[if the above text proposal for Article 21(9) is not retained]* Member States ~~**may**~~ **shall** require suppliers or services providers or active customers to pay financial compensation, if those market participants are directly affected by the balancing or congestion management and voltage control services activation.
24(4)	If applicable the BRPs involved in the activation shall obtain the notification about the activation from an independent party**, such as the relevant system operator or MDA**.
61	**To be removed**
62	**To be removed**
63	**To be removed**
84(5)	EU harmonisation shall be ~~**envisaged, if**~~ **pursued where** it increases overall effectiveness and efficiency of the system**, for example by making balancing, congestion management and voltage control markets more accessible to market participants.** ~~**and considers costs and may distinguish between self-dispatching models and central dispatching models**~~ **The options for further harmonisation shall be considered by a stakeholder group** after ~~**several EU monitoring publications**~~ **each publication of the EU monitoring report.** The items to be examined for possible further harmonisation ~~**might**~~ **shall** include**, amongst others**: (a) timeline, deadlines for data delivery; ~~**and**~~ **(b) eligibility criteria;** **(c) backup requirements;** **(d) availability monitoring;** **(e) activation control;** **(f) settlement procedures;** **(g) penalty frameworks;** **(h) IT requirements;** **(i) metering specifications;** (~~**b**~~**h**) interaction with regional methodologies pursuant to Article 76(1) of Regulation (EU) 2017/1485, such as utilisation of potentials, solving of internal congestion, solving of DSO congestion.

DSO Entity & ENTSO-E Public consultation on Network Code for Demand Response

ESMIG reply

ESMIG, the European association of smart energy solution providers, appreciates the introduction of Network Code Demand Response to enable a flexibility market and, thus, the utilisation of flexible assets in a more cost efficient and effective grid operation.
ESMIG welcomes the opportunity to participate in the public consultation launched by ENTSO-E and the EU DSO Entity. Our main concerns are summarised below.

1. **Ensure a common process and principles for prequalification across Europe.**

We believe that only with common rules on a Pan-European level we can achieve an effective market mechanism, equal consumers and prosumers rights and a competitive landscape that will allow the development of flexibility markets. We suggest minimum possible national variations to ensure harmonisation across European Member states and avoid unnecessary and expensive requirements concerning:

- Prequalification process
- Telemetry
- Data sharing

2. **Flexibility product definition should ensure maximum market inclusion.**

In Title II (d) the minimum bid size of standard balancing products is defined as 1.0 MW. We suggest defining the minimum bid size 0.1-0.3 MW to facilitate market access to more flexibility assets and a non-discriminatory mechanism. More specifically, we also suggest including asymmetrical bids and a minimum duration of 1 h for flexibility products.
Additionally, easy registration of assets shall avoid heavy administration burdens for distributed assets like EV or residential loads.

3. **Aggregation models**

We believe that smart meters play a crucial role in Demand Response, but we also recognise the risk of supporting specific real-time actions required by DSR programs with already installed smart or conventional meters. Aggregation models should be defined considering limitation of capabilities of existing telematics. Therefore, we support the option of two models A and B, but we also suggest that the DSR related requirements are included in the smart meter requirements in the long term to ensure capabilities in the field and feasibility of common requirements for meter data collection and processing across Europe. As the responsibility of collection and processing of meter data.

10 November 2023

View of Energie-Nederland on draft Proposal for a Network Code on Demand Response

Energie-Nederland welcomes the possibility to provide a view on the draft proposal for an EU Network Code on Demand response.

Our main concerns are as follows:

1. **Major concerns on purpose and overlap**
   The title of the Code does not reflect its contents. It is not just about demand response, it is about services provided to SOs, namely balancing, congestion and voltage support services and about coordination between the different SOs. It is therefore also not restricted to distributed assets. Generation, connected to transmission grids for example, is also directly affected by this Code. Therefore the scope of this Code should be more clearly defined and the title should reflect that scope.
   The overall purpose of this Code is still extremely unclear and the added value is highly questionable. There is large overlap with several existing Codes and the actual rules from this new Code will be, to a large extent, be developed at national level. Therefore there is a huge risk that this Code will not contribute to a single, harmonized EU power market and that it will bring more damage than good, for example because of contradictions between codes.
   There is no explanatory document. It is impossible for us to properly assess this proposal and to suggest amendments. It is strongly emphasized to go back to the basics and first clearly define and limit the scope of this code to ensure that new rules will be proportional. We therefore recommend:
   - First do a best practice analysis of the different solutions that are being applied or developed (e.g. regarding demand response and aggregation), and only then assess which rules need to be laid down in a new EU Code
   - Draft the new Code together with a review of the System Operation Code, the Balancing Code and the Demand Connection Code. Only in this way coherence between these Codes can be ensured and overlap and contradictions can be avoided.
2. **The BRP role is key**
   The role of BRP should be clearly allocated to the grid user / connection point. The role of BRP cannot be split or shared by more entities (like supplier and aggregator) for the same grid user / connection. If different roles (like BRP or BSP or any other new SP) for the same grid user / connection point are being provided by different companies, then such construction can only be allowed if all involved entities are able to agree on the commercial terms (like for compensation of the BRP) in free negotiations. Ultimately, grid users can switch supplier or SP and competition between market participants is the basis to ensure that grid users are properly serviced to enter the market.

3. **Balancing services are fundamentally different from congestion and voltage support services.**
   Provision of balancing services is an integral part of the wholesale market and plays a role in matching demand and supply. Congestion and voltage support services are services to the TSO/DSO that allow the TSO/DSO to ensure a secure grid, whereas the grid is facilitating the market. In other words: balancing services are integral part of the market; congestion and voltage support services allow to facilitate the market. It is necessary that the Code does acknowledge this fundamental difference.
4. **Freedom of dispatch remains the principle and any service to a SO must be compensated.**
   Freedom of dispatch also means that a grid user is allowed to change its dispatch in real-time. Such real time decisions may be part of the role of the BRP to balance its own portfolio or the support the system balance. In other words, grid users (generation, demand response and storage) may be active in balancing the system without providing explicit balancing services to a TSO. But if a grid user decides to provide a balancing service to a TSO, and if this grid user cannot provide these balancing services to its TSO because its local SO has congestion or voltage problems, then this grid user may not be able to provide balancing services, however such limitation is a service to the local SO and must thus be compensated by that local SO.
5. **Storage is a market asset**
   Current EU regulations clarify that storage is in the market domain and SOs should not invest in or operate storage assets. However, these regulations also allow for derogation. In assessing the need for derogation, the key question should not be whether the market wants to develop storage or not. Because SOs do not need storage, they need certain services. And if these services are properly defined and tendered, then it should always be possible for SOs to procure such services from market participants. If new storage assets are needed to deliver these services, these assets remain fully with the market participant that provides the services.
6. **Baseline per allocation point**
   According to the proposal, each allocation point will have to nominate a baseline, which will result in several million individual nominations per ISP/day. Apart from increasing the tasks of the relevant market role (probably the BRP), the question is whether this is also realistic in terms of quality. The added value of these individual nominations does not outweigh the possible earnings in various market segments, let alone the network calculations that are recalculated at a total grid level (not on individual level). The question remains whether the potential flexibility related to this baseline and nomination is used efficiently.
7. **Certification per unit**
   With the proposal, each controllable unit must be registered and certified in advance, this means registration of, for example, heat pumps, EV charging points, production installations before they can supply flexibility. How is it monitored whether a controllable unit has actually been verified before flexibility is offered to the market from this unit? And what if flexibility is offered and requested that later turns out not to be "certified"?

Solar industry key messages on Demand Response:

1. **Principles for storage ownership**: Storage must by default be developed by market parties and such ownership be restricted to cases where markets have demonstrated to fail. In such cases storage assets should be tendered by TSO and DSOs in a way that offers a maximum degree of freedom for third parties to (over)size and optimize the battery in times where the system operator does not need it.

2. **Principles for flexibility value stacking in flexibility products**: The possibility to perform several different flexibility services at the same time, and to stack existing and future flexibility products across pan-European and local markets should be carefully reviewed and analysed to maximise revenue redistribution to consumers. New flexibility products should by default be stackable with pan-European wholesale and balancing mechanisms unless dully justified at national levels (and validated by NRAs).

3. **Use of Baseline based on near real-time data:** Baselines for the calculation of the flexibility services should be as precise as possible, based on local distributed energy generation (DER) near-real-time data instead of statistical methods.

4. **Pan-Europe certification of Dedicated Measurement Devices (DMDs)**: DMDs are the source of key operational data required to manage DER transactions with markets. Necessary pan-European rules and processes should be established for their certification and type test approval as well as subsequent interoperable and standardised data exchange processes (as defined through the parallel implementing act).

5. **Standardisation of pan-European balancing pre-qualification and provision for DERs:** The pre-qualification process and attributes for service provision for all common pan-European balancing products should be standardised at the European level. The network code should foresee the development of a harmonized DER certification and type test approval process for mass produced DERs (aligned with their associated DMDs as defined in point 2).

6. **Principles for Service provider switching:** Many PV installations coupled with battery storage have been deployed through European markets due to high retail prices and positive revenue returns to consumers. A large share of these distributed assets are presently connected digitally and remotely maintained and operated through dedicated DER operators/technical aggregators (often represented by DER/inverter OEMs) on behalf of consumers. The flexibility code should define processes, rights, and obligations under which the enrolment of such distributed assets into flexibility service provider portfolios with consumer consent occurs. The process should standardise sufficiently the data exchange to ensure harmonised and seamless accessibility to data and controls. This would allow a flexible service provider switching and avoid consumer lock-in. Similar approaches are expected to emerge with solar PV coupled to EV Smart and bi-directional charging which will soon become significant shares of DER flexibility moving forward.

7. **Standardisation of grid flexibility activation and monitoring signals**: Standardised pan-European APIs should be defined to manage DSO/TSO data exchanges with DER operator/technical aggregator communication on grid power signals.

DMD certification – The optimal option

Feature	MID-based Certification	Type Test-based Certification
Compliance environment	Dedicated production line certification, systematic DMD testing on production line, no possible over the air upgrade	Type testing in independent labs & OEM self-calibration process and device over the air upgrade as per OEM quality insurance
Energy Metering Accuracy	[Measurements Instruments](), Module D, reference to same accuracy class	e.g. Use of IEC EC62052-11 for energy metering accuracy (class to be agreed)
Metering definition	Meter is associated to "physical box", in-device meters require to certify the entire dedicated device as a meter	Focus measurement methodologies, possible use of embedded measurements in standardised devices serving different Control functions
Cost of certification	High, requires to carve out dedicated production lines	Marginal, included in standardised device type testing and manufacturing quality insurance
Retroactive applicability	✕ (requires new physical installations)	☑ (no physical intervention once type tested)
Display via external software (Apps)	✕ (physical displays required, difficult to access)	☑ (near real-time remote connection)
Uniform requirement for all Member States	✕ (very fragmented metering market across Europe)	☑ (harmonised mass-produced DER market)
Possibility to certify all energy services	✕ (certification only applicable to active energy)	☑ (possibility to adapt certification to each flexibility product requirements - active energy, reactive power, frequency, voltage...
Certifiable granularity	Moving from hourly and 30min towards ~ 15 min	From 15minutes to minutes and seconds
Verification/re-certification	Certification lasts for a set period of years (e.g. 8 years)	Notified bodies/competent authorities can conduct randomized field-tests for limited amounts of devices if necessary. See e.g. UK P375 and California R18-12-006

Other relevant documents:

- [A Guide to EU Electricity Market Design Negotiations - SolarPower Europe]()
- SolarPower Europe's response to ACER's RfG NC draft amendment submitted on 25 September 2023 [here]()

Respondent: Iberdrola

NETWORK CODE FOR DEMAND RESPONSE COMMENTS

Article 1(1):

Refer to the whole range of resources in article 1(1) and align the whole draft network code with this wording.

Justification:

No resource provider shall be excluded. The main aim of the new rules shall be to ensure access to all electricity markets for all resource providers, as the ACER FG states. Paragraph 4 of ACER FG reads that the new rules shall be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not, hence referred to in the FG as "demand response and other relevant resources" or in general "resources".

Article 2:

Some definitions in article 2 must take the form of amendments of the corresponding ones of SO GL or be introduced directly in the SO GL, always with the DSO perspective for the sake of completeness. Same comment for articles 5-18, 78-80, 83 and 84.

Justification:

In line with ACER FG, the NC must not overlap existing regulations and focus on minimum necessary amendments and complements aimed to build a simple, coherent and fit for purpose regulatory framework, because legal certainty and simplicity are key for market participants.

The amendments and the draft NC must not be aimed to further develop TSOs' needs. We acknowledge that DSO vision is currently scarce and unbalanced in the SO GL with respect of TSO's. Therefore, the objective of the draft NC (and related amendments) is achieving a level playing field within SOs and boost market-based provision of flexibility in DSOs markets.

Accordingly, this draft NC needs further refinement to avoid overlaps with existing regulations, inaccurate terms and an excess of requirements to relevant grid users, while complying with the mandate of scope done.

Article 2(9):

Definition of 'DSO observability area' can be used to define local arrangements. However, article 2(9) must be technically amendment to clarify the reference to grid users in the definition. Grid users are not part of the observability area. This should be reworded in coherence with SO GL (and relevant amendments of the SO GL, if necessary).

Justification:

Observability is guaranteed in the connection point of the 'significant grid users' (not necessarily all grid users and never in the same manner/with the same requirements).

Article 2(12):

Delete reference to balancing issues.

Justification:

Balancing is neither an issue as defined in article 2(12) nor a local product. It is well defined in Regulation (EU) 2019/943 and managed in the EB GL.

Article 2(23):

Exclusion of type D power generation modules in the definition of technical resource is discriminatory and lead to legal uncertainty. Generation, demand and storge at distribution level currently participate in congestion, voltage control and balancing markets.

The definition of technical resource also comprises "any other consumption device". This term is complemented with the definition 2(39) of "standardized device", but generation and storage at any voltage level can fit perfectly with this definition (they are also mass-produced in scalable technologies e.g. batteries and even combined cycle generation turbines).

Justification:

No resource provider shall be excluded, and the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers, as the ACER FG states. Paragraph 4 of ACER FG reads that the new rules shall be applicable to load, storage (in particular when combined with load), and distributed generation, aggregated or not, hence referred to in the FG as "demand response and other relevant resources" or in general "resources". The whole draft network code must be aligned with this.

Article 2(37):

Definition must be amended to reflect that dispatch limitation must be a product itself and can be procured prior or after closure of the day-ahead market.

Justification:

Otherwise, the use of temporary limitations as defined in the draft NC can drain the interest of creating robust and valuable congestion products.

Article 2(50):

Delete 'CU Operator' definition and reference across the draft NC. It overlaps with technical aggregator's and service provider's and poses concerns because the term "operator" can be confusing. This can be perfectly substituted by "CU owner or delegated third party in charge of controlling the CU" in Article 33(6) and Table 2.1 of Annex 2.

Justification:

Regulation (EU) 2019/943 and Directive (EU) 2019/944 do not include this role.

Moreover, the interface for structural, scheduled and real-time data exchange with TSOs and DSOs of any kind of resources (not only demand response) and the necessary market arrangements must be established at national level without double reporting requirements and by avoiding overlap of roles or unnecessary creation of new regulated ones. Only general principles about interfaces for data exchanges aligned with current KORRR framework and general requirements of any kind of solutions of market platforms should be set up in the draft NC.

Article 2(51):

Delete 'Technical aggregator' definition and reference across the draft NC. It overlaps with aggregators' role.

See our related comments on article 33.

Justification:

Management of resources by SOs must be set up on robust but simple governance. The legal scope is not clear in the current wording, could not respond to the needs of the variety of market participants and could pose a technical barrier instead of avoiding technological lock-ins from the manufactures' side.

Regulation (EU) 2019/943 and Directive (EU) 2019/944 do not include this role.

Moreover, the interface for structural, scheduled and real-time data exchange with TSOs and DSOs of any kind of resources (not only demand response) and the necessary market arrangements must be established at national level without double reporting requirements and by avoiding overlap of roles or unnecessary creation of new regulated ones. Only general principles about interfaces for data exchanges aligned with current KORRR framework and general requirements of any kind of solutions of market platforms should be set up in the draft NC.

Article 19:

The general aggregation models must be developed in this draft NC. The metering architecture described in the draft NC must accompany the general aggregation models to avoid free riding, unlevel playing field, double payment, and even absence of real delivery of a contracted product.

Justification:

This will pave the way for efficient and harmonized development. The metering architecture and related definitions shall not be the way of lowering the requirements that are mandatory for other participants to provide the same service.

Article 23:

Benefits shall not be netted with compensation costs for the suppliers. This leads to severe distortions.

Justification:

Market prices are the result of the benefits and the whole system would see the positive effect. Coherently, if a Member State wish to externally quantify benefits, these shall be borne by the whole system.

Article 25:

We do not support the principle “buy your baseline” despite paragraph (31) of the ACER FG is open to include it (“the baselining approach for validating the activation is not mandatory and SO can implement alternatives, such as taking the final position of the SP’s BRP as the baseline, to be used as reference of the delivery of service”). This leads to never ending discussion about gaming (see article 25(4)(c) and 26(2)) or even fraud, instead of focusing on rigorous baseline methodologies.

We advocate for a more ambitious approach regarding harmonization of baselining methodologies. Governance of article 25(5) must be reinforced and led by ACER.

Justification:

Rigorous baseline methodologies and harmonization of baselining methodologies should be key features of this draft NC.

Article 26:

The data used for determining the activation of a service must be always based on measurement, although different methodologies can be devised based on these data. Article 26(1) shall be amended accordingly.

Baseline methodologies shall be approved only by the NRA. Amend accordingly article 26(6): SOs cannot approve their own methodologies.

Justification:

Rigorous baseline methodologies and harmonization of baselining methodologies should be key features of this draft NC.

Article 29:

Provisions related to bid granularity must take the form of amendment of EB GL. Same for prequalification matters on specific balancing products.

Review of balancing bids granularity in article 29 lacks development of principles to perform the CBA of paragraph 3(a). Paragraph 3(b) should be included in paragraph 3(a), not dealt separately. Paragraph 4 lacks correct development: approval of derogations, maximum time of derogations, etc.

Justification:

In line with the ACER FG, the NC must not overlap existing regulations and focus on minimum necessary amendments and complements aimed to build a simple, coherent and fit for purpose regulatory framework, because legal certainty and simplicity are key for market participants.

Article 31:

We do not agree with the simplification of the prequalification for specific balancing products in general, although article 31(4) provides exceptions.

Justification:

These specific products compete with standard ones and hence must follow the same rules to the maximum extent for the sake of harmonization across EU.

Article 33:

Controllable units could not be the final costumers but all kind of resources, included generation. Article 33 of the draft NC does not cover this reality. Hence, the term "final customer" must be replaced by "owners of controllable units". Same for articles 41, 43 and 45 and Table 2.1 of Annex 2.

Moreover, as commented in Article 2(51), the role of "technical aggregator" must be deleted. Instead of 'technical aggregators", flexibility can be marketed by using in-house technological developments implementing innovative solutions of any kind and while complying with relevant national regulation in force for detailed data exchange and controllability.

For example, the role of technical aggregator in Spain cannot be separated of the rest of data exchanges and controllability duties of relevant grid users for system operation. The so-called generation and demand control centers (CCGD) interact with TSOs and DSOs control centers in an efficient manner and already integrates distributed generation, demand response and storage. Resources participating in flexibility markets (not only those linked to/owned by final costumers) must be integrated in these CCGD, as the rest of relevant grid users which are participating in current electricity markets. The service provider (SP) as defined in the draft NC can be a market participant acting independently of the CCGD but delegating the data exchange and control duties in the CCGD. Alternatively, the SP must comply with those requirements directly by setting up their own CCGD. Out of the scope of this NC, contractual arrangements must be set up by the service provider with the resource(s) to remunerate contractual flexibility while ensuring the fulfillment of technical requirements defined in the draft NC.

Therefore, article 33(7) must focus on impeding technological lock-ins in mass-produced devices by using controllability standards (e.g., IEC-62747) and publicly available technical documentation about how the controllable unit operation can be switched from a service provider to another easily, without giving relevance to the so-called “switching of technical aggregator”. Accordingly, article 45(4)(g) must be deleted (no need to develop switching of technical aggregators) and 2(19) definition must omit reference to technical aggregators.

Justification:

Management of resources by SOs must be set up on robust but simple governance. The legal scope is not clear in the current wording, could not respond to the needs of the variety of market participants and could pose a technical barrier instead of avoiding technological lock-ins from the manufactures’ side.

Regulation (EU) 2019/943 and Directive (EU) 2019/944 do not include this role.

Article 51:

A clarification if needed from ACER/EC on how to deal with non-firm connection agreements.

Justification:

They can be seen as a way to minimize congestion relief needs or, alternatively, be defined as a product. We caution about the approach of considering them while defining the pre-conditions to participate in services, because this can lead to complexity in the definition of products and ways of procuring them.

Article 56:

We do not agree with reflecting a “nomination” of any local market operator in article 56. The delegation right is already present in the SO GL and replicated in article 16 of the draft NC, and Regulation (EU) 2019/943 and Directive (EU) 2019/944 do not include these roles. Article 55 and 56 must be reworded and merged to reflect general requirements to be fulfilled by delegated parties duly monitored by NRAs, if this delegation exists (same for 24(3), 48(5)(e), 52(6), 52(7), 74(1)(c)). This delegated parties other than SOs can be called “market platforms” in a generic mode in the relevant text of the draft NC. Article 57 is again a collection of tasks that could be delegated or not, not a differential role from SOs’ one.

Justification:

Market platforms are technological solutions used by the SOs, not a nominated role enshrined in the NC. Therefore, SOs are the ultimate responsible for key tasks regarding procurement, validation, and settlement of their products.

Moreover, there is a risk of draining competition and hindering innovative solutions in emerging markets while respecting adequate interoperability requirements and use of commons standards to avoid technological lock-ins. One could think instead that a big number of market platforms is not efficient, as suggested in article 53(5), but we remind that innovative and efficient solutions come up from competition and that efficiency in dealing with a market platform must be ensured directly by SOs with appropriate regulatory incentives within their regulated retribution, if applicable at national level.

Article 57:

Without prejudice of our comment on article 56 against the role of local market operator, we do not support to confer the task of neither validation of delivered services to third parties as established in article 57(3)(c) nor activation as explained in footnote 8.

Justification:
Validation is a core task of SOs and then not possible to delegate. As regards activation of bids, it must rely on the service provider in general, although it can be possible arrangements with direct activation of the connecting SO, but never dealt by a market platform. Otherwise, we could face double reporting, multiple business interfaces and the deployment of additional procedures to implement those activities.

Article 58:

Avoidance of fragmentation of products at national level must be reflected as a principle and governance must endeavor to promote common practices and align attributes within Member States to the maximum extent. Moreover, process described in article 58 must include public consultation.

Justification:

Otherwise, we risk having a circular task at EU level without any added value because it is aimed to update a catalogue of national practices.

Article 59:

Local products used by DSOs (i.e. in a particular bus bar) must be differentiated from national products managed by TSOs (i.e. same rules and procedures for congestion issues at bidding zone level although the congestion arises at local/zonal level).

Justification:

The task of standardization referred to in article 59(1) is too vague and can lead to a blockage of valuable DSO initiatives.

The way congestion product is activated is a key attribute: redispatching or schedule adjustment in the energy markets. If redispatching is used, the way to rebalance the redispatch is an important complementary attribute but cannot be defined as balancing.

Article 61:

Articles 61-63 must be focused on exceptional situations of property sharing, and not cover indistinctly “develop, own, operate or maintain storages”, as referred in a recurrent manner across the wording.

Moreover, the principle of “first-market” in the draft NC must be further developed, especially in the case of TSO ownership of storage. This principle is reflected in paragraph (38) of the ACER FG and Electricity Directive.

There are several mandates of ACER FG not sufficiently fulfilled by the wording. Instead, the wording in unduly focused on principles and ways of conducting derogations according to the Electricity Directive, or preconditions to launch the tender, or any decision after the tender or in parallel. Those aspects are exclusively managed by NRAs (subject to open consultation), hence out of the scope of the draft NC.
Examples of vague development:

- “criteria to be fulfilled by the tendering procedure in order to be approved by the NRA” (paragraph 39 of the ACER FG).
- “ownership and contractual relations (for use of the facilities, distribution of costs, etc.) between the SO and the third party” (paragraph 40 of the ACER FG)
- Guidance for the scope of the CBA as mentioned in paragraph 41 of ACER FG.

Provision showing clear vested interests must be eliminated/reworded:

- Article 61(1)(d): generic reference to efficient, reliable, and secure operation, which is a reiteration of art. 36.2.b of Directive (EU) 2019/944.
- Article 61(3): the right of SOs to opt for co-owned storage is not “without prejudice” of keeping full ownership of it as stated in the draft NC but is defined as second-best as referred in paragraph 39(b) of the FG GL, being the first, no ownership at all.
- Article 61(8): according to FG (40) it is not the decision by SOs to discard co-owned storage during the tender procedure, but the NRA “if deemed economically inefficient”.
- Notification of NRA to ACER according to article 61(10) shall be compulsory irrespective of the SO (TSO or DSO).
- Article 62(1)(b) does not impose a real firewall to implicitly breach the prohibition of participation in electricity markets. The NRA shall monitor and report every 3 months (and subject to public consultation), whether the practical implementation of the framework to charge and discharge the storage have any effect on market dynamics.
- Any real right is conferred to the third party in article 62. Moreover, there is no reference to cross-subsidy in both senses, only from SO to the third party.
- Article 62 does not elaborate interactions between third-party and SO when managing jointly a co-owned storage.
- Article 62(5) must elaborate conditions to transfer ownership to the third party. This must be referred to in article 63(2) as part of the proposal of transfer. Conversely, condition under article 63(2)(d) must be deleted: it is an unfair balance commitment.

- The condition of “technically possible” in article 63(1) must be defined accurately. Otherwise, it must be deleted. It is not enough to link the decision to open consultation “at least every five years”.
- Article 63(4)(a) the third party should be appointed following a transparent process based on objective conditions.

These aspects must be carefully checked by ACER and EC during the approval process of the draft NC.

Justification:

Articles 61-63 of the draft NC do not satisfactorily comply with section 2.5 of ACER FG and Directive (EU) 2019/944.

Article 81:

When procuring voltage control services, mandatory capabilities must be remunerated for the sake of market coherence. These must be defined as a minimum requirement set uniform for all service providers. Article 81(2) must be reworded in that sense: SOs cannot assume that capabilities required to new facilities set up in connection codes (for generating, demand and storage) are delivered to SOs for free.

Voltage services must be jointly developed in the draft NC, for the sake of clarity. They can be procured through congestion management (via redispatching of active power) or with use of reactive power (i.e. contracted as capacity+energy). These services are the real novelty of this draft NC. It is important to set clear and ordered rules in the draft NC.

Justification:

The investment signal must be preserved for delivering additional capabilities by implementing new technological solutions and for disclosing new capabilities within existing or new facilities.
The editorial comment seeks for completeness and simplicity of the proposal.

Respondent: BDEW e.V.

Article	Your comment on the article	Your text proposal
Any supporting material from your side:	General remark: The German TSOs for Electricity (being part of ENTSO-E) as well as DSOs (being part of the EU DSO Entity) have been involved in the development of the draft Network Code on Demand Response. Therefore, the relevant groups organised within BDEW abstain from voting on the present BDEW comments. We are of the view that the Network Codes should define detailed and harmonised market rules. However, the present Network Code proposal falls short in doing this as it mentions points which to a large extent are to be implemented on a national level. The preferred option would be that the Network Code on demand response provides uniform European rules without the need for national implementation.	
Whereas (f)	No discussion has taken place on how mobile resources could participate.	
Whereas (u)	This recital refers to Art. 13 of the Electricity Regulation (EU) 2019/943 which provides rules for redispatching. It has to be clarified that the new NC on demand response is not overruled by Article 13 of the Electricity Regulation (EU) 2019/943. Instead, demand response is one option applicable in the context of Redispatching (Art. 13 of Electricity Regulation) but is not limited to this field of application.	
Whereas (w)	There shall be no regulatory price caps. Regulatory price caps shall be removed because they distort the market and the market price signal. However, this is not to be confused with technical price caps which are set a a level that does not limit the market, manage market participants' exposure to unnecessary costs and risks, and are necessary for the functioning of the optimization algorithm.	(w): Market-based procurement is understood as a mechanism whereby a service is procured by soliciting market participants to place an offer for the service. The market participants choose the amount they are offering and the prices ~~(potentially limited by price caps)~~. The remuneration may be determined by a market-mechanism (supply vs demand) pay as bid or pay as cleared. Examples, which may be labelled “market-based” based on assessment of national regulatory authority in Member State: Marketplace/Exchange/ an organized market for service (includes service specific market or taking offers from another market such as Energy-only-markets, balancing).
Whereas (z)	It has to be reassured that this recital does not contribute to watering down the priority of market-based flexibility procurement, in contradiction to article 47(1) of the NC and article 32 of the Electricity Directive (EU) 2019/944.	
Whereas (aa)	It has to be reassured that this recital does not contribute to watering down the priority of market-based flexibility procurement, in contradiction to article 47(1) of the NC and article 32 of the Electricity Directive (EU) 2019/944.	
Whereas (bb)	It has to be reassured that this recital does not contribute to watering down the priority of market-based flexibility procurement, in contradiction to article 47(1) of the NC and article 32 of the Electricity Directive (EU) 2019/944.	

Whereas (cc)	It has to be reassured that this recital does not contribute to watering down the priority of market-based flexibility procurement, in contradiction to article 47(1) of the NC and article 32 of the Electricity Directive (EU) 2019/944.	
Whereas (dd)	It has to be reassured that this recital does not contribute to watering down the priority of market-based flexibility procurement, in contradiction to article 47(1) of the NC and article 32 of the Electricity Directive (EU) 2019/944.	
Whereas (ff)	The recital seems to exclude balancing markets and congestion management markets from wholesale markets, contrarily to their definition. Also the DR FG refers to local flexibility markets as wholesale markets. Moreover, large parts of the NC should apply when accessing all wholesale markets, such as provisions on aggregators etc.	delete the words "which are also known as 'wholesale markets'" in the first sentence.
Whereas (ii)	This recital makes reference to Article 76(1) of the Guideline on System Operation (Regulation (EU) 2017/1485) which prescribes how TSOs of a capacity calculation region are assigned to set up common provisions for regional operational security coordination. BDEW does not understand why this reference is included in the present NC prososal and what is meant by it?	delete this recital
Article 2 (16)	The definition should be more precise to focus new contracts and avoid including contracts which are meant to overcome unusual temporary grid constraints (e.g. § 14a EnWG in Germany).	"…where a new grid user or a grid user requesting increased connection capacity has not been granted with a firm access…"
Article 2 (29)	A "free" definition of the service providing group (SPG) may be an obstacle to the efficient and effective implementation of local system operator services. Restrictions could be provided via the grid prequalification process.	"'Service providing group' or 'SPG', means an aggregation of controllable units connected to more than one connection point. SPG is defined by the service provider to provide balancing, congestion management and voltage control services. System operators can set the conditions for the definition of SPG, e.g. taking into account the sensitivity to network constraints, in order to ensure the efficiency and effectiveness of flexibility services."
Article 2 new	It is not defined what belongs to a "systems operator(s) service(s)", which is mentioned several times in the NC, for example in Art. 28 (2). The term should be additionally defined in Article 2.	"A systems operator service includes either the provision of balancing, congestion management and voltage regulation services. The latter two represent local systems operators services."
Article 4 (4) (a)	The Framework Guideline clearly specifies that the new rules are about "market-based" procurement of system operators services. Therefore, "market-based" needs to be added in this article about the objectives of the regulation.	4. ensuring ...: (a): removing all undue barriers for the participation of these resources in all wholesale electricity markets (including those for procuring systems operators services), and establishing European principles for the assessment of the need for, the market-based procurement of and the use of local systems operators services;
Article 5	Unclear why this step of development of a national process to develop national terms and conditions by SOs is really needed. It will take at least 4 months. Instead, SOs shall directly start developping the common proposal for the national terms and conditions according to Art. 6.	delete Article 5

Article 6 (1)	What are the deadlines set out in this Regulation? Shall be added here for a good readability and understanding of the text.	All systems operators shall develop common proposals for the national terms and conditions required by this Regulation and jointly submit them for approval to the competent national regulatory authority within ~~the respective deadlines set out in this Regulation~~ [name the deadline here].
Article 10 (2)	Provisions should be included for the following situations: (1) ENTSO-E and EU DSO Entity do not agree on the need for harmonisation (2) The report concludes on a need for harmonisation but ENTSO-E and EU DSO Entity disagree: ACER should be able to ask ENTSO-E and EU DSO Entity for applying the recommendations in the report through updated methodologies.	
Article 13 (3)	There is a logical mistake: The justification on the inclusion or not-inclusion of stakeholders' views resulting from the consultation can't be published at the same time as the proposal for terms and conditions (which is the starting point of the consultation). It has to be published after the consultation at the moment when the revised proposal is sent for regulatory approval.	Change the last sentence: "... together with the submission of the proposal, and both the justification and the proposal submitted for regulatory approval shall be published before or at the same time as it is sent for regulatory approval".
Article 14 (3)	There is a logical mistake: The justification on the inclusion or not-inclusion of stakeholders' views resulting from the consultation can't be published at the same time as the proposal for terms and conditions (which is the starting point of the consultation). It has to be published after the consultation at the moment when the revised proposal is sent for regulatory approval.	Change the last sentence: "... together with the submission of the proposal, and both the justification and the proposal submitted for regulatory approval shall be published before or at the same time as it is sent for regulatory approval".
Art. 19(2)	Text wrongly references Art. 13 instead of Art. 19 (twice).	2. Member States shall allow the aggregation models defined in the Articles 19(6) and 19(7) for each balancing or congestion management and voltage control services in the scope of this regulation, either one or the other or the combination of both.
Article 19(3)	What's important is whether sub-meters are used for these purposes. Not whether there's any measurement equipment present. There's often lots of irrelevant measurement equipment. The MID is not relevant for DMDs. The test is not that there is "no additional metering equipment", as there could well be additional metering that's either not suitable or just not being used for market purposes.	"The aggregation model will depend on whether the controllable unit disposes of a measurement equipment which ist suitable for the purpose needed in the context of demand response."
Article 19 (7) (a)	It should be clarified that not every controllable unit necessarily requires additional metering equipment. If different controllable units are assigned to one customer these units can be measured by one metering equipment.	"... The metering equipment of the controllable units measures the withdrawals and/or the injections of the controllable units involved in the provision of such services; the minimum requirement for aggregation model B is one additional metering equipment for all controllable units behind the grid connection point; and"
Article 21 (4)	It should be avoided that we end up with different local market operators for each DSO. To avoid fragmentation (for example in Germany where we have hundreds of DSOs), the network code should give TSOs, DSOs, NRAs and local market operators a mandate to cooperate and to at least create a common interface for market participants.	Add: (f) creation of one common interface for service providers within a single bidding zone, where multiple local market operator exist.

Article 21 (8)	We have concerns about the requirement for service providers to respect all grid limitations communicated by system operators. Such a broad provision grants SOs with unchecked power which can result in market restrictions, leaving market participants uncompensated for missed opportunities, or possibly even subject to penalties as foreseen in Art. 20 (6). This contrasts with the principles laid down in Art. 47 (1) and 49 of the Network Code (market-based procurement of congestion management/voltage control services). It also contradicts Art. 51, since even for non-firm connection agreements, system operators should not unreasonably restrict grid users from offering services in relevant markets beyond the explicit restrictions of said agreements. In case of grid limitations, service providers have to be compensated for their financial losses resulting from these grid limitations, and penalties have to be excluded.	The service provider shall be responsible for the following: (a) Respect ~~all~~ pre-defined grid limitations and exceptional temporary limitsations communicated by the connecting systems operators and intermediate systems operators;
Article 21 (9)	Where the supplier optimizes the customers' portfolio intraday (in the case of large industrial customers), this data transfer from the service provider to the supplier (or its BRP) has to occur in real-time. This is necessary to prevent that the BRP counteracts the activated demand response in intraday markets due to the changed offtake. Besides, the supplier/BRP also has to receive the full timeseries, including data related to activations, in order to enable accurate imbalance settlement. We therefore suggest to delete the part of the text which excludes such access.	The BRP of the service provider shall receive the relevant data values corresponding to those periods where the controllable units under its portfolio were providing a service. In case of intraday portfolio optimization by the supplier, the data transfer from the service provider to the supplier or the BRP must take place in real time to avoid counteraction by the supplier or the BRP. Depending on the common national terms and conditions, the supplier or the BRP associated to the supplier shall be responsible for the reception of the relevant data values of the metering point for all timeseries ~~with exception of the specific data related to the activation~~.
Article 22 (1)	Even if the load curve has been corrected, the supplier may incur costs, e.g. the rebound effect.	In order to limit the impact that balancing or congestion management and voltage control services activation might generate on market parties, a financial compensation may apply~~, only when the measurements that determine the load curve of the customer is not corrected~~.
Article 25	The network code does not attempt to define how the baseline in the presence of demand response is set. Instead, it simply tasks TSOs / DSOs with calculating the baseline. We see no reason why this task should be completed in a supplementary process rather than now in the network code itself.	We expect the TSOs/DSOs to formulate a concrete proposal on this.

Article 29a new	All TSOs shall have the same prequalification and service provision process and infrastructure for FCR, aFRR, mFRR, RR. This means harmonizing - communication infrastructure and data-sets through a pan-European application programming interface (API) - type-prequalifications of mass-produced devices - data provisions on adequate granularity, latency, statistical interpolation, and data storage limitations - automatic lower-level system operator approval for a higher level system operator service - metering certification for inverter-based meter readings	Provisions for the activation and settlement for standard balancing products and jointly procured FCR on a synchronous area level 1. By 6 months after entry into force of this regulation, all TSOs shall adapt the European provisions on data exchange and communication structures for providing standard balancing products and jointly procured FCR on a synchronous area level to the requirements set out in this regulation and shall make publicly available the details of the data exchange process for each standard balancing product. 2. Flexibility Service Providers shall bid and settle service provisions for standard balancing products and FCR through a Europe-wide (for FCR through a synchronous area wide) harmonized API. 3. The harmonized API shall allow purely internet-based cloud-to-cloud data exchange, and no additional communication channels shall be necessary. 4. Dataset exchange shall be proportionate and standardized through ETSI-CEN-CENELEC standards. Real-time operational data shall not be requested unless it serves a real-time optimization process by the system operator. Operational data for purely observational means shall not be collected. If real time data is necessary, only aggregated data to the grid node where flexibility is purchased shall be required. Settlement data shall be provided ex-post only for the duration of the flexibility event. 5. Data resolutions, accuracy, latency and settlement deadlines should be clearly identified for each product in the European T&C. Storing data on the level of the technical resource for verification purposes shall not exceed 12 months.
Article 31	Access should be allowed to all markets once this procedure is done.	The service provider shall successfully pass a service provider qualification with the requirements laid down in paragraphs 2, 3, 4 and 5 before being granted access to participate or bid in markets
Article 31 (1)	In order to prevent too many network restrictions being imposed on the Service Provider (complexity reduction), it should be possible to define such aggregation restrictions. The configuration of SPGs ensures that the products can achieve the desired network effect.	(1) Before a service provider applies to provide a service, all the involved SPUs and SPGs shall be successfully registered in the respective SP module. The SP shall consider configuration restrictions of SPG pursuant to Article 69 (National implementation and condition for coordination).
Article 34	The prequalification rules are not harmonised in this draft network code, which means that prequalification rules will continue to differ. Therefore, some products will continue to be traded across borders in Common Merit Orders, even though they are of different quality depending on where they were prequalified (e.g. balancing products).	We expect the TSOs/DSOs to formulate concrete proposals on this.
Article 37	The network code fails to harmonise product verification rules. Like for prequalification, this means that no level playing field is achieved.	We expect the TSOs/DSOs to formulate concrete proposals on this.

Article 37 (9) (new)	Standardised pan-European APIs should be defined to manage DSO/TSO data exchanges with DER operator/technical aggregator communication on grid power signals.	Add new paragraph: "SOs must offer EU-wide uniform open and standardized APIs for data exchange with service providers and CU operators aggregating standardised devices, based on ETSI-CEN-CENELEC defined sets of standards. Associated electronic exchanges should be cloud based an real-time leveraging when applicable CU operator platform for registration, baseline nomination and activation. When applicable CU operators should be able with consumer consent to cover the responsibilities of DMD data administration, registration as well as activation. All associated data exchanges should be based on open and standardized interface to minimise integration cost barriers of small standardised devices. Associated data exchange standards should be clearly defined through each Table of Equivalence and defined through this European Network Code T&Cs. Service providers should keep the option to maintain existing legacy market interfaces or to opt for such interfaces eventually delegating associated data exchange to CU operators."
Article 39	In order to facilitate the processes for service providers to offer flexibility services in different regions we should strive for having only one flexibility register platform per Member State including TSO and DSO data, not multiple ones, operated by different operators. Art. 39 (1) and (2) risk fragmentation through difficulties of access and different standards. If there are multiple register platforms in one Member State they should at least be shaped in a way which allows uniform access procedures via one Application Programming Interface (API).	1. Systems operators in each Member State shall describe in terms and conditions referred to in Article 45(8) (Principles for national implementation), functional requirements for CU and SP modules and a process~~(es)~~ for nomination of the operator(s) for a flexibility register platform(s). The access process shall be identical in all register platforms in each Member State allowing access via a uniform interface; in the best case there is only one flexibility register platform per Member State. 2. The process~~(es)~~ for nomination of (the) operator(s) of flexibility register platform(s) shall take duly into account proposals of each connecting systems operator and include an NRA assessment ensuring that the operator(s) of (the) flexibility register platform(s) meet(s) the requirements of this Regulation.
Article 39(3)	This forwardlooking paragraph 39(3) is welcomed but should apply regardless of the identity of the operator of the flexibility register.	delete "that are not operated by system operators"
Article 39(4)	The provision in Art. 39(3) should apply regardless of the identity of the operator of the flexibility register. Therefore, there is no need to introduce an NRA decision in the case of flexibility registers operated by system operators.	delete article 39(4)
Article 39 (6)	Slow implementaton of flexibility registers must not be allowed to be a barrier to participation.	replace the wording by: "Where suitable systems for a flexibility register have not yet been implemented or are not functioning correctly, this must not be allowed to be a barrier to participation. In these circumstances, all relevant parties must cooperate to facilitate participation in a timely manner despite the lack of those systems, for example through alternative, more manual data exchange processes."

Article 40	It is important that - not only for SPs, but also for other users of the flexibility register(s) - the register appears as one at least at MS level, even if it actually consists of several registers or platforms. Therefore, there should not only be standardised access but one single access points for API and other manual access, regardless of where the information is registered/stored. This should apply for access by SPs, but also SOs (not only the connecting but also procuring - that in principle may be any other SO), BRPs, market platforms/operators etc. Moreover, as specified in our comment to the definition, the concept' of master data should be introduced in the requirements or the definition.	
Article 40 (1)	Regardless of the organisation of the flexibility register, it should appear as one for the users: Service Providers, Market operators (including all wholesale markets), System operators, BRPs, through a unique interface.	
Article 41 (2)(b)	Unclear how future states of data will be made available.	2b. grant SPs access to the data of the SPU or SPG assigned to them, at any point in time easily, online and without undue delay on their request. Data sets (historic and current) shall be made available;
Article 45 (4) (b)	If revocation is possible there must be a clear process to get back into qualification status. Ensure this is captured within the network code.	
Article 47 - title	No restriction to "active power" only. Both active and reactive power can be utilised for voltage control.	Article 47 Solutions for congestion and voltage issues ~~through active power~~
Art. 47 (2)	Replace „should" by „shall". „Should" implies too much uncertainty. Besides, it should be reconsidered whether all the tools are to be considered as equally eligible.	2. Each systems operators shall choose the most effective and economically efficient option or combination of options of the different tools at its disposal, which can include grid investments, non-firm connection agreements, grid-technical measures, including non-costly remedial actions, and market-based procurement and activation of local systems operators services or other tools to maintain active energy flows or voltage within operational limits[3]. The principles to choose ~~should~~ shall be transparent and coordinated.
Article 47 (4)	The Network Code shall insert an additional assessment or stricter criteria for NOT applying market-based redispatch according to Art. 32 in order to foster the application of the European target model of market-based flexibity procurement. Assessment shall be stricter or stricter criteria to apply in order to limit non-market based solutions to a strict minimum. Otherwise, it is questionable how Network Code will bring progress compared to the already existing Clean Energy Package which is still not imlemented everywhere in the EU even 4 years after its entry into force in 2019.	add an additional assessment or stricter criteria for NOT applying market-based solutions pursuing to Art. 32(1) and Art. 40(5) of the Directive (EU) 2019/944
Article 48 - title	No restriction to "active power" only. Both active and reactive power can be utilised for voltage control.	Article 48: National terms and conditions for market design for congestion management and voltage control services ~~through active power~~
Article 48 (1-3)	The process should include a public consultation before conclusions are handed over to the NRA. The SOs shall comment on each input and explain how it is taken into account or why it is not.	

Article 48 (4)	No restriction to "active power" only. Both active and reactive power can be utilised for voltage control.	Additionally, systems operators shall commonly propose national terms and conditions for the development of intrazonal congestion management and voltage control services ~~through active power~~, […]
Article 48 (5)	Art. 48 (5) is redundant and a repetition of the articles that it quotes.	delete 48 (5)
Article 48 (6)	This list is not applicable in practice. It needs to be clarified how the elements of the list shall be "considered" in the national terms and conditions for market-based procurement of flexibility. To give an example, what does it mean to "consider" whether wholesale and balancing markets apply unit or portfolio bidding (Art. 48 (6) (a))? This means nothing.	delete 48 (6) or clarify how the elements of the list shall be "considered": Does "consider" only mean describe? But then, what follows from the description?
Article 48 (6)	(e) the potential depth and liquidity of the market cannot be evaluated as long as the market does not exist. Its size definition will be key to create the adequate level of liquidity.	delete 48 (6) (e)
Article 48 (6)	When preparing the national terms and conditions, DSOs and TSOs shall also assess and make public the following: cost-savings that market-based procurement will bring compared to non-market based procurement (such as reduced redispatch costs, reduced or deferred grid investment costs, reduced grid operation costs, etc.). This will help foster market-based solutions instead of non-market-based solutions.	6 (l): assess and publish the cost-savings that market-based procurement will bring compared to non-market based procurement
Article 48 (9)	unclear what "or other market processes" means. To be deleted.	9. National terms and conditions shall describe whether sequential~~,~~ or simultaneous ~~or other~~ market processes is used for congestion management and voltage control services procurement and between local markets and day-ahead, intraday and balancing markets on Member State level while ensuring time for coordination of power system balance and congestion management and voltage issue management.
Article 48 (10)	The option of combined markets is not the right way forward to develop market-based flexibility procurement for technical and practical reasons, but also for market design reasons. Combining the European-wide coupled wholesale markets (SDAC, SIDC) with local flexibility markets, e.g. through locational tagged bids, is unrealistic and highly complex. SIDC is not compatible with it: you have different products, different ways of trading, etc. It raises many questions with regard to the European-wide harmonized Single Intraday Coupling (SIDC) algorithm. Such additional constraints would probably not be implementable in the matching engine. For SDAC, such a change of SDAC products would have a major impact on Euphemia calculation time, will delay other market coupling projects. In addition, intraday and local flexibility are different markets for different uses, with different products, different risks, hence different prices. They should not be mixed up or it would create price signal distortions and undermine overall market transparency. In particular, mixing local flexibility with the intraday market makes little sense from a FSP risk perspective and from a price signal perspective, and would dramatically reduce transparency and readability of the intraday market. More straight forward alternative to combined markets exist, such as the options of parallel or sequential markets. There is no need to opt for the combined option. What should be aimed for is product compatibility and process improvement to ensure value stacking for FSPs across all wholesale and balancing and flexibility electricity markets. Certainly, it should be facilitated for FSPs to offer their flexibility and arbitrate between these different value pools, but this could be facilitated through technology, and does not require markets to be mixed.	delete Article 48 (10)

Article 48 (12)	System operators need to have incentives to engage in market-based flexibility procurement processes, complementary to an appropriate grid expansion. Therefore, the costs for market-based procurement of congestion management and voltage control need to be recognised. This needs to be clearly state in the Network Code, otherwise it will not bring improvement compared to the status quo.	The costs for market-based procurement of ~~procuring~~ congestion management and voltage control services shall be allocated and recovered. ~~in line with the applicable national legislation~~
Article 48 (13) and (14)	System operators shall not only be entitled, but incentivised and encouraged to present a common proposal for market-based congestion management mechanisms.	
Article 49 (2)	Unclear what is meant by this article. If a product is activated on the same asset and relieves a congestion and at the same time solves a voltage control issue, and that those services have different values, what does it mean to remunerate it once?	delete Art. 49 (2)
Article 49 (5)	Organized markets should be defined as the preference. Here tender procedures and market-based solutions are set on equal footing, which is not consistent with expectations.	Procurement of products can be contracted in advance in organised markets (preferred procurement mechanism) or tender procedures (only where organised markets are not possible). Tender procedures shall follow principles in Article 50 (Principles for procuring by tender procedure).
Article 49 (7)	No, congestion management shall not be procured IN day-ahead or intraday markets, but can be procured DURING day-ahead and intraday timeframes. Replace "markets" by "timeframes".	When congestion management and voltage control services are procured in long-term, day-ahead, intraday or balancing markets, the pricing mechanism may be different from the general pricing mechanism in the day-ahead, intraday or balancing ~~markets~~ timeframes whilst still being in accordance with the rationales and criteria in this Article.
Article 52	The publication of data needs to be limited in terms of history because the data pertain to the market platform or system operator, depending on their contracting nature.	
Article 52 (7)	Can you please clarify what is meant by "next markets results" to be published at least 3 months later?	
Article 53	In general, the Network Code shall not add too much complexity from the beginning, but let these new local flexibility markets develop. It is sufficient to state that local flexibility markets shall not impede the well functioning of the other markets (day-ahead, intraday, balancing) and that value stacking for market participants shall be facilitated. But "principles for the coordination and interoperability" as described in Art. 53 are not needed and create too much complexity.	Article 53 ~~Principles for the coordination and interoperability between local and~~ Non-distortion of day-ahead, intraday and balancing markets
Article 53 (1) (c)	It needs to be clarified what "coherence in the interaction" means and how to assess if the interaction is coherent or not.	~~coherence in the interaction across different markets and different time frames including the scheduling and imbalance settlement process; and~~
Article 53 (2)	This does not add any information.	delete Art. 53 (2)
Article 53 (3)	The article should not be about "coordination", but about the markets themselves.	~~Coordination between c~~Congestion management and voltage control services shall not distort day-ahead, intraday or balancing markets and shall respect the rules of their functioning established on the basis of applicable legislation.

Article 53 (4) (a)	Remove this paragraph because combined markets are highly complex and more straight forward alternatives exist to develop market-based flexibility procurement. The option of combined markets is not the right way forward to develop market-based flexibility procurement for technical and practical reasons, but also for market design reasons. Combining the European-wide coupled wholesale markets (SDAC, SIDC) with local flexibility markets, e.g. through locational tagged bids, is unrealistic and highly complex. SIDC is not compatible with it: you have different products, different ways of trading, etc. It raises many questions with regard to the European-wide harmonized Single Intraday Coupling (SIDC) algorithm. Such additional constraints would probably not be implementable in the matching engine. For SDAC, such a change of SDAC products would have a major impact on Euphemia calculation time, will delay other market coupling projects. In addition, intraday and local flexibility are different markets for different uses, with different products, different risks, hence different prices. They should not be mixed up or it would create price signal distortions and undermine overall market transparency. In particular, mixing local flexibility with the intraday market makes little sense from a FSP risk perspective and from a price signal perspective, and would dramatically reduce transparency and readability of the intraday market. More straight forward alternative to combined markets exist, such as the options of parallel or sequential markets. There is no need to opt for the combined option. What should be aimed for is product compatibility and process improvement to ensure value stacking for FSPs across all wholesale and balancing and flexibility electricity markets. Certainly, it should be facilitated for FSPs to offer their flexibility and arbitrate between these different value pools, but this could be facilitated through technology, and does not require markets to be mixed.	~~(a) Specify whether and under which conditions bids offered in day-ahead, intraday and balancing markets can be used for congestion management. Even if this is an option it shall be possible to organise additional local markets;~~
Article 53 (4) (e)	This should not be about bids, but give service providers the ability to participate in the different markets and commercialise their flexibility in the best ways. Value stacking for FSPs across all wholesale, balancing, and flexibility markets shall be facilitated, e.g. through product compatibility and process improvement.	~~Allow bids that are not procured in one market to be offered to another market, given they are qualified for that market. To achieve this the service provider may offer their services in another market themselves including by means of an intermediary or a market operator may forward the bids, given that the concerned service provider has given its consent. Aggregation of bids for forwarding to meet the requirements of other markets shall be possible; and~~ Service providers shall have the ability to participate in the different markets and commercialise their flexibility in the best ways; and
Article 53 (4) (f)	This shouldn't be in the national terms and conditions. It is a responsibility of the service provider and BRP, which roles are already clearly defined. There should not be added something specific to demand response to stay technology and market participant neutral, because same rules exist already for market participants in other markets.	~~Avoid that the same bid is selected twice, in particular where the same SPU/SPG is active in different markets, and the responsibilities for guaranteeing that.~~

Article 53 (6)	**Maintain consent on a bid-by-bid basis**: Whether a bid is submitted to a NEMO automatically or manually, the consent information must be attached to that bid – it must not be valid for all bids of a market participant as it is serving different portfolios or customers. This requires market operators to implement this infrastructure when bids from other markets (and market operators) are taken. **Maintain transparency**: Given that a market participant has provided its locational information and its consent for a specific bid to be transported to another parallel running market (e.g. local market) with its own merit order, it is of utmost importance that the market participant is informed about the transferred bid but also the whole market as well. Markets react to changes in the order book and for evaluating scarcity, so it does make a difference, whether a bid is executed, withdrawn, or transferred. If the structure is built in a way, that bids are offered in parallel and executed in one market, the above said also counts. **Maintain market integrity**: Another dimension to the transferral of bids comes to market integrity. The market participant that places a bid into a market is responsible. Yet, if bids are added by a third party (the one transferred a bid) and the market participant also acts in the market, where the bid is transferred, the market participant has no force to not make it seem like a manipulative bid. **Maintain control of the bid**: Control of the transferred bid (pricing/volume/possibility to pull back) must stay in place also after the transferral in order to reflect scarcity and relations of both markets. **Liability/responsibility**: The market operator should take the responsibility that the transferred bid is physically dispatchable in the market it is transferred to. If everything goes right, this is not an issue. However, unlikely mistakes must be taken into consideration, e.g. the product is redirected to a market, where it is not prequalified to – other dimension: liability is to the connecting grid operator if transferred between grids.	
Article 54 (6) (new)	Add a paragraph: Procuring system operators shall apply these dispositions whether they procure directly or through a third party.	new Art. 54 (6): All procuring system operators shall apply the requirements of this Article 54 whether they procure directly or through a third party.
Article 55 (1) (b)	It is not necessary for local market operators to keep separate accounts. Unclear what value it brings.	it shall have an adequate level of business separation from market participants, including service providers, ~~and keep separate accounts for local market operator tasks and other market activities;~~
Article 56 (2)	There is no reason why NRAs should be involved at this stage. The described nomination process is not needed. As long as system operators are compliant with this Network Code, there is no need for further NRA involvement in the selection process. Instead of the described nomination process, functional requirements of local flexibility markets will ensure that these markets are operated in a way which is compliant with the Network Code provisions. Moreover, the Framework Guideline does not stipulate a nomination process for local market operators.	~~The process for nomination of local market operators shall take duly into account proposals of each procuring system operator and include national regulatory authority's assessment ensuring that the local market operators meet the general requirements described in Article 55 of this Regulation and in national terms and conditions referred to in Article 48(4).~~
Article 56 (4)	There is no reason why NRAs should be involved at this stage. The described nomination process is not needed. As long as system operators are compliant with this Network Code, there is no need for further NRA involvement in the selection process. Instead of the described nomination process, functional requirements of local flexibility markets will ensure that these markets are operated in a way which is compliant with the Network Code provisions. Moreover, the Framework Guideline does not stipulate a nomination process for local marekt operators.	~~The relevant national regulatory authority shall ensure that nomination is revoked if the local market operator fails to maintain compliance with the criteria in Article 55 (General requirements to local market operators) and in national terms and conditions referred to in Article 48(4) (National terms and conditions for market design for congestion management and voltage control services through active power).~~

Article 57	It should be avoided that we end up with different local market operators for each DSO. To avoid fragmentation (for example in Germany where we have hundreds of DSOs), the network code should give TSOs, DSOs, NRAs and local market operators a mandate to cooperate and to at least create a common interface for market participants.	Add: The operators of markets for congestion management and voltage control services shall cooperate in the creation of a common interface for market participants in each biding zone.
Article 57 (1) (a)	Unclear what it means "provides a merit order list of bids as applicable". To be deleted. In addition, add to the list "adequate representation of network and asset constraints if applicable"	(a) processes bids, ~~provides a merit order list of bids as applicable~~, facilitates the matching of the markets for congestion management and voltage control services in line with the procurement and pricing rules as described in national terms and conditions pursuant to Article 48 (National terms and conditions for market design for congestion management and voltage control services through active power), adequate representation of network and asset constraints if applicable; and
Article 57 (2)	Remove this paragraph because the role of the registry is not clear.	~~The platforms referred to in paragraph 1 shall integrate or communicate as applicable with the flexibility registry(ies).~~
Article 57 (4)	The option of combined markets is not the right way forward to develop market-based flexibility procurement for technical and practical reasons, but also for market design reasons. See comment on Art. 48 (10) for more detailed explanations. What should be aimed for is product compatibility and process improvement to ensure value stacking for FSPs across all wholesale and balancing and flexibility electricity markets. It should be facilitated for FSPs to offer their flexibility and arbitrate between these different value pools, but this could be facilitated through technology, and does not require markets to be mixed. In addition, it is unclear what it means in practice "to coordinate" a local flexibility market with other markets. This provision should therefore be deleted as well. It is sufficient to state that local flexibility markets shall not impede the well functioning of the other markets (day-ahead, intraday, balancing) and that value stacking for market participants shall be facilitated.	~~4. Operators of local markets shall coordinate with other markets in line with national terms and conditions pursuant to Article 48 (National terms and conditions for market design for congestion management and voltage control services through active power). In the case a local market operator is allowed to combine bids to suit the needs of DSOs or TSOs, or to forward bids to other markets combined or not, the local market operator shall perform this task while ensuring the necessary transparency and following the pricing mechanism and settlement principles defined in the national terms and conditions referred to in Article 48(National terms and conditions for market design for congestion management and voltage control services through active power), and subject to the service providers consent.~~ The local market operator is prohibited from performing any arbitrage in the bid selection or acting as market participant in the market in which they act as the local market operator.
Article 58 (1)	The Framework Guideline stipulates that the new rules "shall define a common European list of attributes for products used for congestion management" (number 82). The list of attributes shall be directly included in the Network Code instead of only referring to a future process taking additional 6 months to develop the list of attributes. This will save time.	~~When systems operators define nationally standardized congestion management products, they shall use attributes from the common list of attributes. The common list of attributes shall be commonly developed and published by ENTSO-E and EU DSO Entity within 6 months after entry into force of this Regulation following the process to develop EU TCMs in line with Article 9 (Union-wide terms and conditions or methodologies).~~ Attributes to be listed here.

Article 60 (1)	The option of combined markets is not the right way forward to develop market-based flexibility procurement for technical and practical reasons, but also for market design reasons. See comment on Art. 48 (10) for more detailed explanations. What should be aimed for is product compatibility and process improvement to ensure value stacking for FSPs across all wholesale and balancing and flexibility electricity markets. It should be facilitated for FSPs to offer their flexibility and arbitrate between these different value pools, but this could be facilitated through technology, and does not require markets to be mixed.	~~1. If the products from other day-ahead, intraday or balancing markets are used for congestion management, then those products shall be included in the list of standardised products for congestion management as referred to in Article 58 (List of attributes).~~
Article 61	With regard to SO-owned storage, Articles 61-63 of the draft NC do not satisfactorily fulfil section 2.5 of the ACER FG, as it needs to be clearly stated that other sources of flexibility are preferable to the construction of storage by TSOs.	We expect TSOs/DSOs to bring the network code in line with the FG
Article 61	The "market test" (i.e. the establishment of the fact that the market is not able to deliver the necessary batteries) should be transparently consulted upon. Quote from paragraph 39 of FG: "The specifications of the tender shall be submitted to public consultation and to NRA approval prior to the tendering process. "	TSOs and DSOs should draft a new section on the "market test", in line with the request from the FG.
Article 64 (6)	This provision should include a reference to SO Coordination for which data to exchange. As a minimum, requirements for coordination of plans should be set at national level.	
Article 65 (2) (h)	Don't limit these alternative solutions to non-firm connection agreements, but consider all different types of market-based flexibility procurement	consider alternative solutions such as ~~non-firm connection agreement~~ market-based flexibility procurement, where applicable; and
Article 66 (3)	Also existing and future available flexibility (market based) shall be included in the scenarios	include "existing and future flexibility" in the list.
Article 67 (2)	The geographical/topological granularity should be as fine as possible in order to enable potential flexibility providers to use the information for making flexiblity accessible to SOs.	
Article 67 (3) (b) (ii)	Flexible connection agreements bear costs for the consumers. These costs should explicitly include the lost social welfare due to flexible connection agreements and non-connected customers (discarded due to lacking grid capacity).	Costs of losses, non-injected energy, and the value of lost load, included those related to flexible connection agreements and refused connections;"
Article 67 (6) (b)	There's not such a clear distinction between projects addressing congestion management and those addressing reliability or recovery time.	"… such incident, except to the extent that congestion management or voltage control services could help achieve the same objectives; and"
Article 68 (1)	The consultation should be open to all relevant stakeholders, including markets operators, potential new system users, aggregators…, not only system users	replace "system users" by "stakeholders"

Article 68 (7), Article 68 (8)	The publication in point 7 should take place before or simultaneously with the submission to the NRA in point 8. The publication in point 7 should include the DNDP to be submitted to the NRA.	
Article 69 (2)	There should be a maximum time limit for implementation e.g. 3 years after entry into force of the NC	
Article 73 (3)	Both methods should be available in all member states, with also a description of when they are to be applied. If not, the prequalification will be too conservative and restrictive and deprive potential SPs of market access and the SOs of accessing the relevant resources.	
Article 73 (5)	Paragraph 5 is not in line with paragraph 4 since paragraph 5 restricts the explanations from paragraph 4. The specifications contained under this paragraph should be subject to national implementation.	delete Art. 73 (5) or find new proposal below.
Article 73 (5)	In order to reduce complexity and SO coordination efforts as well as enable to leverage efficiencies in eliminating simultaneous congestions in different systems operators' networks, this option should be included.	Replace the existing wording by: The requesting systems operators shall be entitled, after consultation, to delegate the selection of bids to other systems operators.
Article 74 (1) (e)	This task cannot be fulfilled by a TSO. The coordination should rather be in the hands of the requesting systems operator.	National processes shall ensure that the temporary limits are communicated as soon as they are known and at the latest before the times the bids are processed as a remedial action to be used in the international process in accordance with Article 76(1)(b) of Regulation (EU) 2017/1485, where applicable, and national procedures. This process shall not be used to cancel previously activated bids10. In case of unforeseen events that result in a measure violating operational limits in DSO grid, the ~~TSO~~ requesting systems operator shall coordinate to find a solution in line with Article 42(4) of Regulation (EU) 2019/943
Article 74 (1) (f) (new)	New clause.	(f) Where a bid is not activated due to a temporary limit, the SO that imposed the limit will compensate the affected SP for their forgone revenue.
Article 74 (2)	This should be mandatory and included in national TCs, in order to ensure regulatory oversight, and potentially increased transparency.	Replace "may" by "shall"
Article 75 (1)	The grid prequalification procedure shall happen ex-ante; DSOs must transparently communicate in advance through the Network Development plans which areas are prone to grid constraints; the SP should be able to start the product prequalification based on this knowledge.	A procedure for grid prequalification shall be developed as part of the national terms and conditions or methodologies pursuant to Article 66(3)(a) and in accordance with Article 182 of Regulation (EU) 2017/1485. For standard balancing products and, where applicable FCR provision, the procedure shall be developed as part of the European terms and conditions.

Article 75 (2)	According to the annotation to Art. 2 (29)	"Such a procedure shall ensure that the delivery of the balancing or congestion management and voltage control services by SPU/SPG does not compromise the safe operation of the connecting grid and, when applicable, of the intermediate grids. In addition, conditions can be imposed by system operators on the definition of SPG to ensure the efficiency and effectiveness of flexibility services, e.g. conditions that take into account sensitivity to network constraints."
Article 75 (3)	See explanation for Article 31.	Replace the existing wording by: In order to ensure an efficient use of balancing, congestion management or voltage control services, the requesting, connecting and intermediate systems operators jointly set the conditions for the configuration of SPG, considering sensitivity/ topology aspects and potential issues in the grid. The configuration may differ for different kind of service products. (As a general guideline, the configuration of SPG shall enable groups as large as possible). Explicit mechanism shall be defined as part of the national terms and conditions pursuant to Article 69 (National implementation and condition for coordination)
Article 75 (5) a	According to the annotation to Art. 2 (29)	"approved if the SPU/SPG can deliver the full capacity of the prequalified congestion management or voltage control service in an efficient and effective manner; or"
Article 76 (3)	Sensitivity reportings are not yet covered by Network Code. However, they are essential for an efficient measure dimensioning.	Proposal for additional point (d): relevant information about the sensitivities of SPU or SPG to the upstream or neighboring systems operators shall be delivered by the connecting and intermediate systems operators. In case of SPG, scheduling, forecast and real-time data can be solely delivered on the respective SPG level.
Article 82 (1)	Such derogation should be reasoned and time limited, publicly available etc as described for derogations from national TCs in 82(4). The NC should give a maximum time limit for derogations (e.g. 2 years).	
Article 82 (2) (b)	It remains unclear why there should be the option for a derogation from requirements concerning monitoring or registry of derogation. The provision in itself is not clear.	
Article 82 (3)	It would be good to clarify that such tests can only be applied to market-based procurement, not anything rules-based.	
Article 83	The ACER monitoring report should include monitoring of derogations from the NC or from national TCs, and more generally of implementation of the NC.	
Article 84 (1) (c)		Remove "options for".

Article 84 (5)	Waiting for "several EU monitoring publication" is too slow, there's no mention of stakeholder input, and the aim isn't clear.	EU harmonisation shall be ~~envisaged, if~~ pursued where it increases overall effectiveness and efficiency of the system, for example by making markets more accessible to SPs and so increasing participation. The options for further harmonisation will be considered by a stakeholder group after each publication of the EU monitoring report described in paragraph (2). ~~and considers~~ Their consideration should consider costs and may distinguish between self-dispatching and central dispatch models. The items to be examined for possible further harmonisation might include:
Article 84 (7)	A time-limit should be set, e.g. 12 months after entry into force of the NC	7. A proposal for the methodology to further harmonising the areas listed in paragraphs 4 and 5 shall be developed jointly by ENTSO-E and EU DSO Entity and submitted, by 12 months after entry into force of this Regulation, to ACER for review and approval, and considering the stakeholder engagement in a public consultation.
Article 85 (1)	It is unclear why the NC should not apply in all MS at the same time	
Article 85 (2)	Welcomed, should apply to all countries	
Article 85	A transitional provision should be foreseen to enable SOs to procure market-based congestion management products through the local market platform of their choice even before national TCs are approved.	
Article 87	It should be clearly stated which Articles will have to be applied immediately from the entry into force of the Regulation and which Articles will have to be applied at a later stage.	

november **2023**

UFE's reply to ENTSOE and DSO ENTITY consultation on the draft proposal for network code on demand response

1. WHEREAS

UFE welcomes the significant work done so far and is pleased to see that a consultation is taking place at this stage in the drafting of the network code on demand response. Flexibility will be a key element of tomorrow's electricity system, and its development is required to achieve a successful low-carbon energy transition. Thus, this network code must aim to accelerate its development and offer the possibility to Service Provider to participate in all markets.

However, before going into the details of the network code, UFE would like to make a few general comments :

1) **Scope and consistency with existing legislation and network codes :**

In line with the Electricity Directive, the network code shall consider all types of flexibilities to improve the cost-effectiveness of network design and operation :

- **UFE thus recalls that the network code on demand response must respect the principle of technology neutrality**. In order to select the least-cost flexibility for the system and for the collectivity, it is necessary to not distort competition between technologies included in the NC and technologies not included in the NC. Likewise, the development of flexibility must not take place to the detriment of other market actors by transferring undue risks and costs onto them. **Therefore, the NC should not jeopardize the financial compensation in the countries that require it.**

- **In the same way, the network code must not exclude any resource provider** as the main aim of the new rules shall be to ensure access to all electricity markets for all resource providers (FG paragraph 1.1(2) and (4)). The current draft code must include load, storage, and distributed generation (aggregated or not).However, generation in particular is missing from the definitions and key articles throughout the code.

The scope of the network code as well as its articulation with other network codes, directive and regulation should be clarified :

- **The scope of the network code needs to be clarified: indeed, the current version of the network code proposal seems to be a mix of rules** regarding (i) flexibility provision as a service to SOs (in that case, the scope may be restricted to the balancing timeframe, but all technologies should be covered) and (ii) independent demand-side response aggregation, which require to define roles and responsibilities of different market players acting on a same consumption unit (in that case, the scope may be restricted to DSR, but all market timeframes should be covered).

  Besides, UFE considers that all references to multi-energy suppliers per site should be removed.

- **The Network Code on Demand Response must not encroach on existing legislation, other network codes and guidelines. Regulatory certain and simplicity are key for market participants** : on certain issues, the network code seems at best redundant (and therefore useless and risky if the provisions are not updated simultaneously in the various texts in the future) and at worst in contradiction with existing texts (for example, on BSP/BRP relations or payment issues). **Therefore, UFE recommends to review the document in order to :**
  - **Remove articles whose content is already covered in other network codes or in the directive.** For example, references to "gaming, market distortion and deception" are already present in other legislation aimed at combating market abuse, and should therefore be removed.
  - **Simplify the wording** (and therefore interpretation) as much as possible **to avoid disputes during implementation.**

2) **Timelines :**

UFE recommends adopting a step-by-step approach instead of aiming at a too fast implementation of the target model. **The initial set of rules must be reduced to the strict essentials**, leaving room for evolution based on national specificities and different voltage levels afterwards.

3) **Harmonisation at European level :**

The development of flexibility tools, in particular demand response, is not at the same level of maturity across Europe. Demand side participation in different markets is already mature in some countries, while in others it is poorly developed. Therefore, **it is essential that this network code removes the identified barriers to entry in the latter and encourages actors to provide more flexibility.**

However, the retail market is mainly designed at national level and each retail market is characterised by national specificities. **It is thus essential to ensure that the scope of choices allows for the retention of existing national provisions that work and to take advantage of new opportunities, with an overall cost-benefit rationality that needs to be ensured.**

UFE therefore considers that :

- **The network code should remain flexible to ensure local specificities can be taken into account at national level,** whether in terms of different maturity of the SOs in terms of demand response, voltage level of the constraints or specific regulatory contexts.

- **If the choice was finally made to harmonize further at European level with no proper consideration of the necessary level of subsidiarity, UFE considers that the network code should necessarily fits with the rules of the most advanced countries in particular on aggregation models and financial compensation** not to jeopardize the rules implemented in the most advanced countries at the risk of slowing down the expected development of flexibility**.** For example, in France, the rules implemented are the result of discussions that have lasted for more than ten years, in particular concerning the aggregation models and baselining. These rules are now robust and made it possible for flexibility to develop.

4) **Market-based procurement :**

UFE welcomes article 47.1 according to which "the procurement of services for congestion management and voltage control within a bidding zone shall be in accordance with transparent, non-discriminatory and market-based procedure". UFE underlines that Market-based procurement must be prioritized as far as possible when this enhances overall economic efficiency. However, we recognise that there are situations which may arise where a system operator may need to rely on rules-based procurement when market-based procurement is not economically efficient pursuant to Article 32(1) and Article 40(5) of Directive (EU) 2019/944.

5) **Use of dedicated measurement devices (DMD)**

UFE underlines that the use of Dedicated Measurement Devices (DMD), if any come forward through the market design proposals, must be regulated in order to avoid undesired effects (arbitrage, compensation effects etc…). Those measurement devices shall comply with norms in place such as the Measuring Instrument Directive to provide the same measurement quality and accuracy than boundary meters. Besides, **interoperability of those measurement devices shall be ensured to avoid any lock-in effect of end customers** (it should be easy to change aggregator).

2. DRAFT PROPOSAL

Article 5 to 8

The topic of 'Common national terms and conditions' (Articles 5 to 8) deserves clarification: it is not explicitly stated whether the defined model should be uniform or whether it can offer various options for the System Operator to choose from based on its own characteristics, including its size and its maturity on the subject. Indeed, it is important to allow different modalities adapted to the varying maturities, capabilities and needs of different System Operators. In particular, depending on these characteristics, System Operators must have appropriate lead times, while maintaining the same objectives, particularly in terms of using flexibilities for congestion management. That is why the term « *all* » should be deleted from Articles 5 to 8, and add « *, System Operators must have appropriate lead times in consistence with their characteristics (including its size), while maintaining the same objectives, particularly in terms of using flexibilities for congestion management.* ».

Title II (article 19 to 27)

UFE points out that in France the BRP is assigned to a physical site and not to a market party, and asks that the network code on demand response maintain this design possibility. For BTC, BRP is the supplier' BRP but for BTB, the final customer (site) must designate its BRP.

Article 19

A particular point of attention concerns the two aggregation models as described in Article 19:

- Model A is the 'basic' model: the contribution to the flexibility service is measured by the meter (C) located at the point of connection.
- Model B is different in that the controllable unit (in this case, the electric vehicle) is equipped with a dedicated metering device (or sub-metering) (CD/SC) that allows for the measurement of the contribution to the flexibility service.

In this Model B, it appears that there may be a risk of the user being compensated for a service they have not provided. If the installation is equipped with an energy management system that optimizes the subscribed power at the point of connection (whether it is a domestic or industrial customer), a decrease in demand on the controllable unit will free up capacity for other uses, which can then negate the effect of flexibility. **In order to make sure that the energy reduction (or injection) eligible to a compensation and calculated by the dedicated meter device has an negative (or positive) effect on the distribution system, it seems therefore necessary to make the use of DMD conditional on verification of the consistency between the sub-measurement and the general meter reading.** Detailed provisions on this verification process should be developed to clarify what needs to happen if an inconsistency is identified during those checks.

In addition, the proposed "aggregation models" are misnamed, in that they describe only the way in which service activation is controlled (with or without sub-measures), and not the relationships and flows between the various players – notably the independent aggregator of demand response – who may be active on the same consumption site.)

In this context :

- **UFE proposes to delete the detailed provisions on aggregation models in the network code on demand response to maintain consistency with existing regulations.**
- **UFE underlines that the network code should state that the activation of flexibility must be financially neutral for the balance responsible party (BPR) and the supplier of the withdrawal site, in a consistent way between the different mechanisms (balancing, congestion management)**

Nevertheless, if aggregation models were to be detailed in the network code as provided for in the framework guidelines, UFE stresses that :

- **all aggregation models should be included**
- **the network code should not be too rigid, and should remain open to other aggregation models to reflect national specificities or future developments**

UFE would therefore suggest that the article be rewritten as follows:

Aggregation models for explicit demand response

1. The aggregation models that are described below aim at defining how the participation of service providers are allowed by limiting the impact on other parties, based on different ways to do imbalance settlement and on contractual relationships, while ensuring each market participant is responsible for the imbalances it cause.

2. Member States shall allow the aggregation models defined in the articles 19.4 for each flexibility services in the scope of this regulation, either one or the other or the combination of both.

3. Every aggregation model presumes the following base assumptions:

a. Aggregators (including independent) do not require consent from other market parties to participate in electricity markets;

b. Aggregators (including independent) are financially responsible for the imbalances they cause (which they may delegate under contractual agreement), apart from possible derogations foreseen in article 5 of the Regulation (EU) 2019/943;

c. Compensations to suppliers may apply if a Member State decides so according to article 17(4) of Directive (EU) 2019/944, regarding costs proven to be incurred as a result of demand response activation;

4. Besides the situation where the aggregator and the supplier are the same market participant, which can be considered as an integrated model and is also called Implicit Demand Response, there can be three base models:

a. Model A – Corrected model
b. Model B – Central settlement model
c. Model C – Contractual model

5. Model A – Corrected model – assumes the following:

a. The load curve paid by the consumer is corrected from the activation realized, thus it neutralise the imbalance volumes as well as the supplier;
b. Additional costs may apply referring to rebound effects

6. Model B – Central settlement model – assumes the following:

a. There is no correction of load curve paid by the consumer but a correction of the imbalances to neutralize the imbalance effect caused by the activation, under a methodology to be approved by the NRA;
b. The financial compensation is compliant with article 22 paragraphs 4 and 5

7. Model C – Contractual model – assumes the following:

a. There is no correction of load curve paid by the consumer but a correction of the imbalances;
b. the financial compensation is established contractually between the two parties;

8. All these different models can exist or co-exist in each Member State or as a combined version. However, model C can only be proposed as an alternative and voluntary option to another model.

9. The aggregation models described in articles 4 to 7 may be supplemented by other aggregation models to reflect national specificities or future developments.

Article 22

Article 22 on financial compensation appears to be redundant with the 2019 directive (article 17.4) and may even risk being in contradiction with it. In this context :

- **UFE proposes to delete the detailed provisions on financial compensation in the network code on demand response to maintain consistency with existing regulations.**
- UFE recalls that the activation of flexibility must be financially neutral for the balance responsible parties (BRPs) and the supplier of the withdrawal site, **in a consistent way between the different mechanisms (balancing, congestion management)**

Nevertheless, if financial compensation was to be detailed in the network code, UFE recommends to :

- Remove paragraphs 1, 2, 3, and 5.
- Clarify paragraph 4 as follow : « If a Member State decides to apply financial compensation according to article 17(4) of Directive (EU) 2019/944, it may foresee either a regulated price, a fixed price or a specific formula. Involved market parties may also be allowed to negotiate a bilateral agreement to settle the compensation. The national rules that foresee the financial compensation shall be subject to approval of the national NRA."

Article 23

Article 23 on financial compensation appears to be redundant with the 2019 directive (article 17.4) and may even risk being in contradiction with it. In this context :

- UFE proposes to delete the detailed provisions on financial compensation in the network code on demand response to maintain consistency with existing regulations.

Nevertheless, if financial compensation was to be detailed in the network code, UFE considers that Article 23 on the costs and benefits deserves some adjustments:

- In paragraph 2, replace "compensation" with «supply costs including both energy and when applicable capacity costs » since it is the corresponding cost item;
- The reference to liquidity in paragraph 3 does not seem relevant to us: it is already taken into account in the assumptions of a) and b) of the same paragraph, and it would also have an impact on costs.

Neither the Electric Directive, nor the Framework Guidelines requires that the financial compensation includes the net benefits. UFE considers that financial compensation must not take into account the potential net benefits brought by the flexibility Service Provider. The suppliers whose consumers have activated DR do not have to bear the costs. The financial compensation must be paid to suppliers affected by balancing actions as the compensation a) neutralizes the financial impact of a third-party intervention at the supply point and b) is a key aspect of demand response acceptability to all market participants. The question should be "who pays?" if the net benefits are demonstrated. A minima, Member States should have the possibility to mutualize the potential net benefits.

Article 33, 41 and 45

Regarding the flexibility register, UFE stresses the need to :

- Keep “a maximum of 3 weeks” (instead of 1 business day mentioned in article 33.4) for the ' the technical switch of Controllable Units' deadline, as per Directive 944 (in France, the target will be the weekly time step).
- Remove the direct interaction of the end customer with the flexibility register operator which would be costly, complex, and would not ensure data quality : the relationship should remain between System Operators and Service Providers

Article 51

UFE welcomes the fact that Article 51, allows existing French provisions on non-firm connection agreements (Reflex, optimal sizing) to be included in a European framework.

Regarding non-firm connection agreements, UFE nevertheless recalls that it is crucial to specify that activation of flexibility pursuant to non-firm connection agreements should only be an alternative to market-based mechanisms when the latter are less efficient. As stated in article 47-2 of the network code proposal, each systems operators shall choose the most effective and economically efficient option or combination of options to maintain active energy flows or voltage within operational limits.

Individual connection agreements are not in the scope of the code. **UFE recalls as a warning that this alternative connection proposal must remain on a voluntary basis for end users who may be willing to support full cost of a firm connection agreement and/or accept a longer connection time unless for areas where the regulatory authority, or other competent authority where Member States has so provided, deems network development not to be the most efficient solution, and enables where relevant flexible connection agreements as a permanent solution**.

Article 84

The harmonization process described in Article 84 should remain proportionate to the expected benefits of harmonization and not hinder innovation.

Dear Madam or Sir,

Agora Energiewende appreciates the consultation on the draft demand response network code.

We suggest clarifying the scope of the network code and to focus on elements with cross-border relevance and relevant for the well-functioning of European electricity markets. The comments submitted on individual articles are based on the proposed draft network code and may become irrelevant for this network code if the respective content is removed.

Regarding the topics proposed in the draft network code, Agora underlines that distribution networks should be planned in line with climate and renewable targets and that dynamic time of use tariffs should be included as an option for congestion management on local level. Furthermore, an explanatory paper would be helpful to explain the main concepts and terms in a concise manner.

Concretely we propose to:

- Plan Distribution Networks in line with climate targets:
    - The planning methodology shall ensure that distribution networks are developed to achieve the climate targets. This should be done in a cost-efficient manner (Art. 65).
    - The planning methodology for the distribution network plans (DNDP) should include a reference to integrated net-zero infrastructure planning across the electricity, fossil gas and H2 sectors (Art. 65).
    - The DNDPs should be aligned with local heat plans to ensure electricity distribution grids are sufficiently reinforced to accommodate heat pumps while avoiding over investments, e.g. in areas where district heating will be rolled out (Art. 65).
    - The DNDPs should be aligned with transport infrastructure planning to ensure sufficient capacity for electricity charging infrastructure will be available (Art. 65).
    - All scenarios for the Distribution Network Development Plan need to be in line with European and national climate and renewable targets (Art. 66).
    - The chapter on Distribution Network Plans should be complemented with a requirement to develop Distribution Network Target Plans facilitating a largely decarbonized electricity system by 2035. The DNDPs should therefore show the stepwise evolution to the target plan.
- Incentivize grid-supportive behavior:
    - Dynamic time of use tariffs can play a key role for incentivizing consumers to shift consumption to limit or avoid congestions in distribution grids and respectively to reduce investment needs. Title IV should be complemented with an article on time of use tariffs, similar to non-firm connection agreements as in Art. 51. Time of use tariffs should also be added to Art. 47.2 respectively.
- Align the draft network code with the draft update of the Electricity Regulation:
    - A reference to the indicative national objective for demand side response and storage and data provision (Art. 19c and 19d, draft Electricity Regulation) should be included in the recitals. DSOs should be tasked to monitor and report available demand side response and storage volumes (e.g. Art. 67) and reference to Art. 19c and 19d, draft Electricity Regulation should be made.
    - A reference to the requirement to publish information on the capacity available for new connections (Art. 57, draft Electricity Regulation) should be included in Chapter 11 on Distribution Network Development Plan Art. 64.
- Simplify and streamline the network code and its implementation:

- Focus on elements of relevance for cross border issues and EU electricity market functioning and explain in recitals which elements are in scope and which are out of scope of the network code.
- Simplify the structure of the draft network code among others, by adding a summary of tasks for TSOs, DSOs and Service providers and a summary of elements for national terms and conditions with references to the detailed articles (Art. 21)
- Simplify processes by directly including deadlines for deliverables instead of developing processes for a deliverable first, e.g.
    - All system operators should submit a proposal for Terms and Conditions by one year after entry into force (Art. 5).
    - T&Cs should include the baselining methodology (-ies) and not a separate process for it (Art. 25).
    - Add a deadline for a proposal for national terms and conditions for the development of intrazonal congestion management and voltage control services (Art. 48.4).
- avoid adding rules to existing regulations. If changes in existing regulation are needed, they should be done directly in the respective regulation. (Art. 29).
- interoperability requirements between local and EU markets should be explained in this network code, not in national T&Cs (Art. 53).
- clarify who is in charge of monitoring the implementation directly in the network code (Art. 84). ACER shall provide an opinion on ENTSO-E's and the EU DSO entities' assessment on benefits for further harmonisation of baselining methods to the EC (Art. 25).

We hope you find these comments useful and remain available for questions and feedback.

Best regards,