Supporting Document for the Network Code on Demand Response

8 May 2024

The positions expressed in the Explanatory Document reflect - ***unless otherwise indicated*** – the common and shared ENTSO-E / EU DSO Entity position.

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1. PURPOSE AND OBJECTIVES OF THIS DOCUMENT

In a letter sent on the 9th of March 2023 to the General Secretaries of ENTSO-E and EU DSO Entity, the European Commission invited the EU DSO entity in cooperation with ENTSO-E to submit a proposal for a Network Code in Demand Response (NC DR) consistent with the Framework Guidance submitted by ACER to the European Commission on 20th December 2022. This Framework Guidance sets clear and objective principles for the development of a network code based on Article 59(4) of the Electricity Market Regulation.[1]

Building on the Memorandum of Understanding signed by ENTSO-E and EU DSO Entity on the 11 October 2022, the two organisations created a joint team to develop the proposal for Network Code on Demand Response (NC DR). This team organised itself into four sub-groups charged with developing proposals for specific areas. In the development of these proposals, these team complemented the input including in the Framework Guidance with that from the different stakeholders (organised in the Drafting Committee) and the internal experience of the systems operators.

The proposals from these sub-groups were then evaluated and refined by a Development Team composed of two chairs and 2 representatives of each one of the sub-groups. To ensure the robustness of these proposals, the Development Team consulted widely with stakeholders to facilitate that the final version of the document considers the different sensitivities of the different agents that will be affected by the NC DR.

Given the complexity and novelty of the issues being considered as well as the large number of stakeholders, each sub-group needed to select one among multiple options for the delivery of the requirements in the Framework Guidance. Accounting for the complexity of choosing between these options, the European Commission in the letter mentioned above, also invited the EU DSO Entity, in cooperation with ENTSO-E, to submit a supporting document together with the proposal of the NC DR explaining the reasons for choosing the respective provisions that are included in the proposal.

Therefore, this document aims at shedding light on the rationale that support the decision of the team to put forward the current options included in the proposal of the NC DR being submitted to the European Commission.

For consistency with the NC DR, this document explains the rationale for the choices in each one of the articles. In a limited of cases when articles were too interlinked to be explained separately, this document presents the common rationale that underpin the decisions of the team.

1.1. Scope, Structure and Approach to drafting the NC DR

As indicated by ACER in its Framework Guidance, this proposal for the NC DR “is developed in order to set out clear and objective principles for the development of harmonised rules regarding demand response, including rules on aggregation, energy storage and demand curtailment (hereafter referred to as the “new rules”), pursuant to Article 59(1)(e) of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (hereafter referred to as the “Electricity Regulation”), and to contribute to market integration, non-discrimination, effective

[1] ACER (2022) “Framework Guideline on Demand Response”, available in https://acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/FG_DemandResponse.pdf

competition and the efficient functioning of the market pursuant to Article 59(4) of the Electricity Regulation. "

Both ENTSO-E and EU DSO Entity consider a great privilege to be granted the opportunity to develop this NC DR as it will be an important piece of the delivery of the European energetical transition. This NC DR will be the basis to ensure the develop of new services that put consumers at the centre of the electricity system.

2. GUIDING PRINCIPLES OF THE NC DR

To ensure that this NC DR achieves that important objective, the team has applied the principles identified by ACER in the Framework Guidelines. These principles include:

- Technological neutrality: The NC DR has been developed with the objective that all requirements apply to all resources including load, storage, and distributed generation, aggregated or not.
- Non-discrimination: No resource providers 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 proposed NC DR aims to ensure that all resources can have access to all market-based processes related to electricity, including both retail and wholesale markets as well as the market-based procurement of balancing, voltage control and congestion management.
- Applicable to all systems operators: All rules apply to all systems operators unless a different scope is explicitly mentioned.
- Coordination between systems operators: The new rules shall apply to DSO-DSO coordination and DSO-TSO coordination and exclude TSO-TSO coordination, as this is already covered sufficiently in the current legislation.
- Balancing between harmonising and Member States' rights to establish national network codes which do not affect cross-zonal trade: Recognising the right of the Member States of developing network codes for those areas where there is no cross-zonal trade, this NC DR aims to provide a common framework for the national terms and conditions aimed at facilitating a robust European electricity system.

These objectives required some careful balancing while drafting of the NC DR. First, the team faces a significant challenge as it needed to strike a balance between a more prescriptive network code that harmonises the operations of the European electricity system to facilitate that service providers provide services in different Member States and the Member States' right to develop Network Codes for those areas where there is no cross-zonal trade. To address this challenge, the NC DR identified a number of fields where national terms and conditions should be developed while, at the same time, identified the components that should be included into those terms and conditions. The team considers that this approach provides the right balanced framework that will facilitate innovation by allowing that service providers aiming to operate in multiple Member States identify a common framework. At the same time, this NC DR also allows the flexibility for Member States to develop terms and conditions that adapted to the realities of each Member State.

Second, the team also needed to deliver a temporal balancing. The NC DR cannot discriminate between present and future technologies and agents. This is an area where significant amounts of innovation are happening and are expected to keep happening in the following years. Therefore, it was important that the NC DR ensured that new technologies could be developed and implemented to facilitate the delivery of the European objectives related with the energy transition.

2.1.Working with Stakeholders

From the beginning of the work, the team aimed to engage with the relevant stakeholders for which a Drafting Committee formed by the organisation listed in the figure below:

Figure 1: Members of the Drafting Committee

Significant effort has been made by both the stakeholders and the development team to develop this NC DR. Recognising that no proposal can satisfy all stakeholders given the difference in objectives and requirements, the team is confident that this represents a balanced proposal for the NC DR that should deliver a good outcome for energy consumers.

To facilitate that the team could obtain the right input at each stage of the development of the NC DR, different engagement techniques were used. These techniques included among others:

- meetings where stakeholders presented their initial thinking about topics to be included into the NC DR;
- consultation where drafts of the NC DR were circulated to collect the comments from the different stakeholders;
- meetings updating stakeholders on the current thinking of the team on different topics;
- presentations by stakeholders to the team on specific topics as the thinking got more mature;
- analysis of document developed by stakeholders in areas concerning the NC DR; and
- ad hoc meetings to discuss specific concerns from one set or group of stakeholders.

To ensure the best deliverable for consumers, the team has cooperated closely with ACER as their representative. This cooperation has materialised in ACER being a member of the Drafting Committee discussed above. Furthermore, bilateral meetings were organised every two weeks to obtain direct feedback on topics arising as part of the on ongoing work of the team.

3. NETWORK CODE ON DEMAND RESPONSE

3.1. TITLE I - GENERAL PROVISIONS

3.1.1. General provisions

The general provisions part of the Network Code deals with all general aspects of the Network Code which refers to all Titles of the NC and are valid throughout all the provisions in general. The structure and content of the general provisions reflects on the one hand the common European standards for drafting legislative texts rules (see Joint Practical Guide of the European Parliament, the Council and the Commission for persons involved in the drafting of European Union legislation) and on the other hand the structure of other Network Codes and Guidelines within the scope and on the basis of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

The general provision's part has to deal with Subject Matter, Definitions, Scope of Applications, Objectives and Regulatory Aspects covering all the general procedural aspects in relation towards the competent authorities, including Public Consultations and Stakeholder Involvements. Moreover, the text contains other general provisions like Delegation and assignment of tasks, Recovery of costs or confidentiality obligations.

The general provision's part is followed by the so-called enacting part grouped in Titles according to the major topics, which formulates the concrete obligations, rights, and responsibilities of different addressees.

The Network Code refers to Regulation (EU) No 943/2019 (Electricity Regulation) as a legal basis on which it will be adopted. In the concrete legal text of the general provision’s part and the enacting part, there is no concrete reference to the Framework Guideline on Demand Response (20 December 2022), because this is not binding and cannot be a legal basis for the adoption. Nevertheless, the text of Framework Guideline is being respected. However, in case of any discrepancy between Framework Guideline and the Electricity Regulation the latter prevails, and the text of Network Code may deviate from the details of the Framework Guideline where it is a reason for that because are non-binding from legal perspective.

The Network Code is a Commission Implementing Act according to the paragraph (1) of Article 59 of the Electricity Regulation:

“The Commission is empowered to adopt implementing acts in order to ensure uniform conditions for the implementation of this Regulation by establishing network codes in the following areas:

(e) rules implementing Article 57 of this Regulation and Articles 17, 31, 32, 36, 40 and 54 of Directive (EU) 2019/944 in relation to demand response, including rules on aggregation, energy storage, and demand curtailment rules."

Subject Matter, Definitions, Scope of application, Regulatory aspects

The FG content had been respected: we copy paste some content of paragraphs (1), and (2) in the articles (1) and (4) and check that they are aligned with article 59(1)(e) of ER.

The scope of this NCDR is: “in relation to demand response, energy storage, distributed generation and demand curtailment rules, including rules on aggregation”.

3.1.2. Article 1 Subject matter

The subject matter of the Network Code specifies what the legal act deals with, practically lists all the major topics the Network Code in relation to what it prescribes rights and obligations, and it is defined in line with the legal basis of this Network Codes in accordance with point e) of paragraph (1) of Article 59 of the Electricity Regulation. In practical terms the subject matter reiterates the text of the Electricity Regulation and Framework Guideline because this clearly defines the subject the Network Code has to deal with on the one hand and cannot go beyond on the other hand.

“This Regulation establishes a network code which lays down the requirements in relation to demand response, energy storage, distributed generation and demand curtailment rules, including rules on aggregation”.

Furthermore, the subject matter defines among others the main actors of this Network Code to whom obligation and rights are laid down: the resources and service providers on the one hand and the systems operators on the other hand.

3.1.3. Article 2 Definitions

The Network Codes and Guidelines on the legal basis of the Electricity Regulation and the Electricity Directive build a coherent structure therefore the definitions provided there are also applicable in this Network Code. In the beginning of Article 2 are listed all the pieces of legislation of which the definitions may be used in the same meaning in this Network Code. If a regulation or other legislation is not in the list of Article 2 (e.g., some Network Codes and Guidelines and REMIT regulation) than those definitions are not applicable automatically.

“For the purposes of this Regulation, the definitions in Article 2 of Directive (EU) 2019/944 of the European Parliament and of the Council, Article 2 of Regulation (EU) 2019/943, Article 2 of Commission Regulation (EU) 2015/1222 ....”"

This means if this Network Code uses certain terms with different meaning in other legislations and finds necessary to define then a new term (maybe only slightly different from the existing ones) is introduced in order to avoid confusion.

(7) and (8) Definitions of congestion issue and of voltage issue

The proposed Regulation defines the concept of ‘congestion issue’ as complementary to the definition of ‘congestion’ in the Regulation 2019/943 and of ‘physical congestion’ in the Regulation 2015/1222.

‘Congestion issue’ means a situation when the electric current flow exceeds operational limits applied by systems operators in line with their national framework.

The proposed definition accounts for possible nationally acknowledged practices and operational limits that cannot be stated as a violation of thermal limits or as the result of trades between network areas. The definition of congestion issue and voltage issue also intends to clarify a situation that may happen at any voltage level, transmission, and distribution.

Operational limits are applied are the result of the network characteristics as well as the operational framework acknowledged at national level. It is important to clarify that the connection and access applicable framework is important pre-requisite to fulfil requirements for security operation that are allocated to transmission and distribution system operator.

Transmission system operators are bound by the implementation of operational security limits, in line with Regulation 2017/1485 and in line with methodology implementing article 75 of such Regulation 2017/1485 (CSAm), where n-1 criterion is stated, and that will be complemented by a methodology on common probabilistic risk assessment by 2027 (article 44(4) of CSAm).

Distribution system operators define their operational thresholds in line with the thermal and voltage limits of the distribution assets, but also considering other aspects, like for instance asset management criteria (typical example is the rate of use of transformers in line with their rate of reposition and maintenance) or limits associated to the connection agreements with other overlaying grids, that are the result of the distribution in planning, connection and access timeframe of available capacities in overlaying grid elements among the users and underlaying grids. There may be other operational criteria related with network security regulations, acknowledged as valid at national level, that distribution and transmission grid operators apply as operational threshold.

This new definition intends to acknowledge situations already happening in the different Member States that may trigger the need for an action (market-based procurement or as applicable) to solve congestion issues.

Further to that, it may be on interest to link this new definition with existing definitions in Regulation 2019/943 (Electricity Regulation) and Regulation 2015/1222 (CACM Regulation), namely:

- ‘Market congestion’, in article 2(17) of CACM Regulation, means a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints;
- ‘Physical congestion’, in article 2(18) of CACM Regulation, means any network situation, where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system;
- ‘congestion’, in article 2(4) of Electricity Regulation, means a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows;
- ‘Structural congestion’, in article 2(6) of Electricity Regulation, means congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions;

Definition of ‘market congestion’ is mainly associated to the process of cross-border capacity allocation and congestion management, while definition of ‘physical congestion’ acknowledges for congestions that are realised later to the capacity allocation processes and that need to be solved, normally in a coordinated TSO-TSO manner through remedial actions, as for instance coordinated redispatching and countertrading implemented pursuant to article 35 of CACM Regulation.

The definition of ‘congestion’ in Electricity Regulation is more general and covers both concepts in CACM Regulation (market and physical congestions). Those ‘congestions’ that are unambiguously defined, frequent, predictable, and geographically stable over time, are defined as ‘structural congestions’ and are of interest with regards to the definition of bidding zones.

A ‘congestion issue’ as defined in the Network Code Demand Response is a kind of ‘physical congestion’ but also allows for additional consideration at local level of operational situations that may not be considered as ‘physical congestion’ in the implementation of CACM Regulation. At the end, a ‘congestion issue’ is a necessary condition to start many of the processes defined in this NC.

3.1.4. Article 3 Scope of application

The Scope of application defines all the addressees who are bound by the rules laid down in this Network Code.

In the first group there are the systems operators: “transmission system operators (‘TSOs’), distribution system operators (‘DSOs’) including closed distribution system operators to the extent they are responsible for the tasks set out in this Regulation pursuant to Article 38 of Directive (EU) 2019/944. Closed distribution systems shall be considered to be distribution systems for the purposes of this Regulation.

As regards the closed distribution system operators they are only responsible for tasks assigned to DSOs as far they are not exempted under the national legislation.

Paragraph (2) of Article 38 of the Electricity Directive says: “Closed distribution systems shall be considered to be distribution systems for the purposes of this Directive. Member States may provide for regulatory authorities to exempt the operator of a closed distribution system from:

- the requirement under Article 31(5) and (7) to procure the energy it uses to cover energy losses and the non-frequency ancillary services in its system in accordance with transparent, non-discriminatory and market-based procedures;
- the requirement under Article 6(1) that tariffs, or the methodologies underlying their calculation, are approved in accordance with Article 59(1) prior to their entry into force;
- the requirements under Article 32(1) to procure flexibility services and under Article 32(3) to develop the operator's system on the basis of network development plans;
- the requirement under Article 33(2) not to own, develop, manage, or operate recharging points for electric vehicles; and
- the requirement under Article 36(1) not to own, develop, manage or operate energy storage facilities."

This means e.g., if a CDSO is exempted in the respective Member State based on the national law implementing the Electricity Directive from the requirements related to network development plans or storage facilities than the requirements in this Network Code in connection with those topics are not applicable.

The exemptions for CDSOs are not listed in each and every Title/Article (topic) where CDSOs might be affected and may be exempted but instead there is a general clause in the general provision’s part, which cover all the fields. Therefor if at a specific title the exemption of CDSOs in not mentioned it has to be evaluated together with the general part and the national legislation if in a specific case the exemption is exist or not. This Network Code does not go beyond the scope of the Directive and does not take over the responsibility of the Member State to define the exemptions for CDSOs it adapts itself to the national legislation only.

Another example where there is no exemption at national level for the performance of certain tasks, in this case also the related obligations are applicable and the respective rights. E.g., closed DSOs are included in the recovery of costs article because they are considered as DSOs for the purpose of this Network Code and if they are not exempted from the tasks all related provisions are applicable.

It has to be mentioned that transmission system operators (“TSOs’) and distribution system operators) are commonly referred to as systems operators, however the term is not defined under Article 2.

In the second group there are the: Regulatory authorities or, any other entity designated by the Members State (‘competent regulatory authority’). The designated entity shall be the regulatory authority pursuant to Article 57 of Directive (EU) 2019/944 unless otherwise provided by the Member State.

The formulation has its reason because paragraph (1) of Article 57 of the Electricity Directive lays down that: “Each Member State shall designate a single regulatory authority at national level.” Hence regulatory authority is used in the meaning that is designated for the tasks under the Electricity Directive.

But not in all Members states those regulatory authorities are responsible for the supervision of activities listed in this Network Code (in some MSs those are ministries or other authorities) therefore it adapts to the national legal framework accepting the regulatory structure of the Member State. In order to minimize the national legal implementation work, the base case is defined as the regulatory authority designated according to the Directive. In Member States where it is the case no additional implementation is needed at national level and those Member States where the regulatory structure is different may adopt the relevant rules at national level naming the responsible authority.

The text reflects the similar provisions in the connection codes (RfG, DCC, HVDC), where the same problematic was discovered.

The third group contains the Agency, ENTSO-E and EU DSO Entity.

Those parties are named in the fourth group, to whom responsibilities have been delegated or assigned. They fulfil in the major part systems operator's tasks. The difference between delegation and assignment is explained at the respective Article 16.

The fifth group refers to all type of market participants (including customers, participating customers and service providers for demand response including load, storage, and distributed generation whether aggregated or not) to whom a task and obligation is assigned in the respective titles.

The Network Code contains provisions to the cooperation and coordination between transmission system operators and distribution system operators and between distribution system operators this Regulation, so this cooperation is also within the scope of the Network Code.

3.1.5. Article 4 Objectives and regulatory aspects

Terms and conditions or methodologies (European, national), Amendments to terms and conditions or methodologies

2 levels for the TCM development: European with the Union-wide TCMs, and at national level with the national TCs.

3.1.6. Article 5 National process to develop national terms and conditions

Article 5 describes the national process and its content to be approved at least 5 months after entry into force of the NC DR.

Option 1: DSO Entity

The article sets out a national level process how systems operators jointly develop proposals for common national terms and conditions. The option itself aims to safeguard that all relevant systems operators can participate in setting up the procedures to draft the common national terms and conditions. For that reason, DSO Entity’s option emphasizes that “all” systems operators are tasked to “jointly develop” the process when defining common proposals for national terms and conditions. This approach seeks to ensure that no DSO is left out of this process, which is especially important because of the relevant impact of the NC DR provisions on the DSO roles and responsibilities. This addition also follows a similar approach taken in other network codes and guidelines. For example, same wording

(“All TSO”) is repeated more than 200 times in the System Operation Guideline (SOGL, Commission Regulation (EU) 2017/1485) to clarify that no TSO is left out of the prosses. DSO Entity finds it important to guarantee involvement of all DSOs in the processes and sees that not including “all” will leave out some DSOs.

Further to the previous explanation, DSO Entity understands that for an efficient work environment in developing the proposals for common terms and conditions, in these Member States where there are many DSOs or several TSOs, these parties have to organize themselves in a manner to facilitate a swift decision-making process in the drafting phase. For that reason, DSO Entity has foreseen in the article paragraphs to guarantee such cooperation. DSO Entity proposal seeks to ensure that all the systems operators define how they organize themselves. As a good practical example, DSO already have experience in defining national implementation of network codes and guidelines. The existing RfG, DCC, SO GL already mandate DSO to define their national implementation with TSO. Additionally, in many countries different working arrangements for many DSOs are already in place and used, for example DSO associations already represent many DSO, which clearly facilitates and speeds up the decision-making process of DSOs. That means that there are organization schemes and cooperation processes that many DSOs already follow in many existing national working groups. DSO Entity believes that these naturally developed and organized cooperation examples and models should be supported by the NC DR and emphasized as the ‘way of working’ on national level by expressing them clearly in the article, as seen in the proposal paragraphs 4 and 5(a), (b). In addition, the national process can also specify the division or roles, procedures (including voting procedures) to reach common positions and ways to deal with blocking points. DSO Entity believes that developing these ‘working conditions’ among system operators is a necessary task to be done among themselves (the systems operators) and therefore the option presented here is guided by the thinking that national level procedures should be set up by the same organisations who need to follow them in the later developments of proposals for common national terms and conditions.

DSO Entity acknowledges that in some Member States national processes for developing terms and conditions might be in place but emphasizes that the clear involvement of all DSOs in the development phases as one of the main parties of drafting proposals for terms and conditions in these existing processes is not always clear. A codified role of DSOs is needed to guarantee fair representation of DSOs. The article aims to clarify the roles and responsibilities by involving all systems operators in the phase of developing national processes.

Competent regulatory authority is tasked to approve this process proposed by all systems operators, which seeks to ensure the regulatory principles: efficiency, transparency or non-discriminatory, as well as guarantee the participation of stakeholders.

The national process to develop common national terms and conditions also involves creating a permanent stakeholder forum where all system operators developing proposals for common national terms and conditions can cooperate with relevant stakeholders. DSO Entity is of the opinion that creating a permanent forum for stakeholders ensures ongoing communication and engagement between stakeholders and the system operators. It also promotes transparency throughout the developments of proposals for common terms and conditions as well as allows system operators to hear and discuss stakeholder’s issues and share perspectives in a more efficient and quicker way which in the end results in a better-informed decision making and more comprehensive views when developing proposals for Common national terms and conditions.

Option 2: ENTSO-E

The ENTSO-E proposal aims at addressing recital (23) of the Framework Guideline regarding the development of common system operators' proposals at Member State level in a way that:

- on the one hand strikes the balance between efficiency (i.e., realistic timelines of developing and adopting proposals) and inclusivity, i.e., ensuring that different kinds of systems operators are given the opportunity to participate in the development;
- on the other hand, ensures legal certainty by taking into account each national context, explained in detail below.

Each Member State context is different. There are varying numbers of DSOs in different Member States - from one to as many as nine hundred. Moreover, the DSOs differ greatly in terms of scale, their tasks and how they will be impacted by the common proposals - from DSOs covering large territories and serving millions of end users to local DSOs serving a limited number of e.g., business customers in an industrial area.

Even more importantly, Member States have different administrative procedures. In those MS where the terms, conditions and methodologies are adopted by NRAs' decisions it may be procedurally very complex to involve several hundred parties to a single administrative proceeding, thus several hundred addressees of a single decision, and for example several tens of mutually contradicting administrative appeals.

Thus, ENTSO-E proposal focuses on clearly providing for three options of establishing the national systems operatorsprocess:

1) through MS legislation - especially addressing the need to represent each DSO and TSO, but at the same time to ensure expedience and stability of administrative proceedings;
2) NRA decision addressing the same issue, in which case the Member State would have to empower the competent NRA;
3) as a backup solution, after an all systems operators proposal approved by the competent national regulatory authority in absence of the other two choices, where the systems operators would come up with their own governance concept.

In each case, paragraphs 7 specify the requirements which must be met by the national process, regardless of the option chosen. They aim at ensuring that even in the large Member States each DSO is provided an opportunity to contribute to the process, while ensuring that the development and approval can be concluded in appropriate timelines. In any case, the process for developing national TCs will have to include both DSOs and TSOs.

3.1.7. Article 5A: Differentiated process for the reviewing existing markets and for developing additional local markets.

Article 5A sets out requirements for reviewing existing markets that promote efficient regulation.

As the status of existing markets is currently very diverse among the member states, with, in some countries, developed redispatching markets used to solve congestions, the starting point is a common transmission and distribution system operators assessment to investigate whether existing national regulation and national terms and conditions are compliant to the requirements in the Draft Network Code on Demand Response, as well as to assess if they are effective and efficient to solve congestions and voltage issues. This assessment will also contain preparing a list of potential improvements on the existing national processes, as well as on the existing congestion management mechanisms, and a proposal on the development and updates needed in the existing national terms and conditions.

The national regulatory authority shall decide on the way the review of the existing markets, if and as applicable, shall take place: either by mandating systems operators to follow the process pursuant to articles 6-8 or by indicating that the applicable national process for the development and update of the existing markets shall be followed. The national process to review existing markets may be quicker and more efficient, when allowing for differentiated treatment e.g., concrete detailed proposals for complementary markets developed as part of differentiated procedures.

This process will promote swift development of local markets and will ensure legal certainty and efficient regulation and a joint cooperation of systems operators in the assessment. It is understood as in line with the principle of proportionality and no unduly creation of administrative burden. It will allow to commonly assess the need for adjustment or addition of rules and processes where needed, in compliance with new Network Code.

3.1.8. Article 6 Common national terms and conditions

Option 1: DSO Entity

In accordance with the national process developed pursuant to article 5, systems operators shall develop proposals for common national terms and conditions. DSO Entity deems it important to emphasise also in this article that 'all systems operators' will have the right to develop the proposals to guarantee fair representation of all parties.

As NC DR with its regulation is a bridge builder between different network codes, the wording of the article and special mention of 'common' national terms and conditions refer to the task of the systems operators to use the process of developing proposals for the terms and conditions as a tool to bridge the gap between different processes, markets, and activities. Therefore, the 'common' represents the joint exercise of finding best solutions to the processes regulated in NC DR in a common manner. Regarding the way of submitting the proposals paragraph 4 clarifies that systems operators can submit all common national terms and conditions in one proposals or can submit the proposals also by the topic mentioned in points a-g.

Option 2: ENTSO-E

Once the process is in place, systems operators shall develop the common proposals for the national terms and conditions listed in Article 7(3), following the process established pursuant to Art. 5.

The Article 6 further clarifies the national flexibility in the way the implementation of TCs can be done: per service, per subject, as several separate proposals.

3.1.9. Article 7 Approval of common national terms and conditions

Option 1: DSO Entity

Previously presented article 7 is merged with the current article 6.

Option 2: ENTSO-E

Article 7 establishes that the competent national regulatory authority shall be responsible for approving in 6 months the common proposals for national terms and conditions and consult systems operators in case if revision of the proposal. The article includes the list of the common proposal for terms and conditions that shall be subject to approval by the competent national regulatory authority.

The list of terms and conditions makes specific reference to "TCs for local service providers" but not to "TCs for balancing service providers" in order to not interfere with EBGL Art. 4-5-6. This distinction is in line with the ACER Framework Guideline paragraph 22, which states that "TCs for SPs related to local services (TCs for local SPs) may be separate from those related to balancing (TCs for BSPs)". The new provisions for BSPs stemming from this Network Code are included in the EBGL amendments proposed by ENTSO-E.

3.1.8. Article 7b Stakeholder involvement

Option 2: ENTSO-E

Art. 7b ensures stakeholder involvement in line with Market Codes.

3.1.10. Article 8 Amendments to common national terms and conditions

Articles 6, 7 and 8 deal with the national TCs, their submission by the systems operators (at the latest 18 months after approval of the national process), their approval by the competent NRA (at the latest 6 months after their submission), and their amendment (the submission of the amendment by systems operators must be done at the latest 4 months after the NRA request). The list of national TCs is provided in article 7 on the approval of TCs.

Option 1: DSO Entity

The article creating a framework for amending the common national terms and conditions follows the purpose and reasoning of including 'all' systems operators. Mainly on the same reasoning as provided above but also on the reason that there might be circumstances where an already developed national level terms and conditions document is being amended again in a circumstance where some practical realities have changed. Therefore, with this procedure it is being considered that all systems operators are involved in a proper manner to assure that relevant representation on DSO level, especially by impacted DSOs is guaranteed in a sufficient manner. As described in previous articles above, the need to limit systems operators to not mentioning 'all' would hinder the participation of DSOs. The systems operators representation in Member States with many DSOs or several TSOs should follow similar approach as in art 5, as the national process would foresee and support such cooperation to facilitate swift decision-making process.

Option 1: ENTSO-E Entity

ENTSO-E proposes to draft a version without mentioning "all systems operators" to develop the national TCs: In practice, as explained in the comment to Article 5, it will be impossible to ensure the participation of hundreds of systems operators and will lead to unnecessary delays. It is also risky to impose that all systems operators participate because it means that the process is invalid if some do not participate. Moreover, it is of outmost important that it is up to the Member State to consider the right conditions for system operators to develop the common national terms and conditions and not mandating that all system operators must actively participate. What matters is that the process is transparent and that the provisions at Union level are drafted in such a way that accommodates different administrative procedural regimes across the Member States, ensuring legal certainty.

3.1.11. Article 9 Union-wide terms and conditions or methodologies

Art. 9 lists the ENTSO-E and EU DSO Entity or All TSOs proposals on Union-wide terms and conditions or methodologies.

Two of them have to be submitted within 12 months after entry into force of this Regulation (the proposal for the list of attributes of local products in accordance with Article 58 paragraph 1 and for specifying technical requirements for DMDs in accordance with Article 33A paragraph 5).

Other two Union-wide terms and conditions or methodologies concern harmonisation and are subject to the identification of harmonisation content by the relevant monitoring report drafted pursuant to Articles 83 (Monitoring reports) and 84 (Harmonisation).

Finally, it is up to All TSOs to develop a proposal for Union-wide terms and conditions or methodologies for the harmonisation of processes for the prequalification of standard balancing products pursuant to Article 35 (Provisions for prequalification for standard and specific balancing products) .

ACER shall be responsible for approving the Union-wide terms and conditions or methodologies in 6 months, including revising the proposals where necessary, after consulting ENTSO-E and EU DSO Entity, or all TSOs.

3.1.12. Article 11 Amendments to Union-wide terms and conditions or methodologies

Article 11 refers to the amendment to the 1.1.1. Union-wide terms and conditions or methodologies that can be requested by ACER, EU DSO Entity and ENTSO-E

3.1.13. Article 12 Publication of Union-wide terms and conditions or methodologies on the internet

Article 12 provide the obligation for ENTSO-E and EU-DSO Entity on the publication of the Union-wide TCMs on the internet.

3.1.14. Article 13 Public consultation for common national terms and conditions

Articles 13 mention the public consultation for the national TCs. This consultation will last for a period of not less than one month.

The public consultation rules for national terms and conditions are similar to the ones in other Network Codes and Guidelines. It prescribes the obligation for the public consultation sets the minimum timeframe for that (1 month) and provide some rules for the treatment of the responses received during the public consultation.

Option 1: DSO Entity

This article follows the purpose and reasoning of including ‘all’ systems operators. Mainly on the same reasoning as provided above. Therefore, with this procedure it is being considered that all systems operators are involved in a proper manner to assure that relevant representation on DSO level, especially by impacted DSOs is guaranteed in a sufficient manner. DSO Entity also sees it important to continue the style and approach as in existing network codes, where for example in SOGL the reference to ‘all TSOs’ is made. As described in previous articles above, the need to limit systems operators to not mentioning ‘all’ would hinder the participation of DSOs. The systems operators’ representation in Member States with many DSOs or several TSOs should follow similar approach as in art 5, as the national process would foresee and support such cooperation to facilitate swift decision-making process.

Option 2: ENTSO-E

ENTSO-E proposes to draft a version without mentioning “all systems operators” to develop the national TCs: In practice, as explained in the comment to Article 5, in opinion of ENTSO-E it will be impossible to ensure the participation of hundreds of systems operators and will lead to unnecessary delays. It is also risky to impose that all systems operators participate because it means that the process is invalid if some do not participate. Moreover, it is of outmost important that it is up to the Member State to consider the right conditions for system operators to develop the common national terms and conditions and not mandating that all system operators must actively participate. What matters is that the process is transparent, and that the provisions at Union level are drafted in such a way that accommodates different administrative procedural regimes across the Member States, ensuring legal certainty.

3.1.15. Article 14 Public consultation for Union-wide terms and conditions or methodologies

Articles 14 mention the public consultation for the Union-wide TCMs, respectively. This consultation will last for a period of not less than one month.

The public consultation rules for Union-wide terms and conditions and methodologies are similar to the ones in other Network Codes and Guidelines. It prescribes the obligation for the public consultation sets the minimum timeframe for that (1 month) and provide some rules for the treatment of the responses received during the public consultation.

3.1.16. Article 15 Stakeholder involvement

The Agency, in close cooperation with EU DSO Entity and ENTSO-E, shall organise stakeholder involvement regarding secure system operation and other aspects of the amendments and implementation of this Regulation. Such involvement shall include regular meetings with stakeholders to identity problems and areas for improvements notably related to the areas covered in this Regulation.

This provision keeps open the way how the Agency wants to organise the stakeholder involvement. This flexibility and the control by the Agency give sufficient legal basis for the appropriate organisational set up. Similar general rules and in other Network Codes and Guidelines without specifying more details on it.

The difference between the public consultations Articles (13 and 14) and the Stakeholder involvement is that the public consultation is happening during a concrete legal procedure for the preparation or amendment of national terms and conditions or Union-wide terms and conditions and methodologies where the procedure is performed in line with the national rules and this Network Code. While the stakeholder involvement is not connected to a certain procedure of terms and conditions but provides a platform for the stakeholder to discuss the achievements, future developments, etc. This is a less formal procedure.

3.1.17. Article 16 Delegation and assignments of tasks

Article 16 describes the cases of the delegation (the delegating system operator keeps the responsibility of the task) and the assignment of tasks (a Member State, or a relevant regulatory authority, may assign tasks or obligations entrusted to systems operators).

These are two different cases. In the case of the delegation, the system operator is responsible for the tasks according to European and national law. As a general private law principal obligations and tasks may be delegated but the delegating party remains responsible for the performance of the tasks ultimately. This is a well working practice in the business world and in the system operators' practices. This is main essence of the provision that this possibility is ensured for the systems operators and the Article describes some other details which are in line with the general civil law principles related to delegation. An additional element is that the delegation system operator shall inform the competent authority, but no approval is required.

A different case is the assignment. In this case tasks – mainly certain tasks that can be in general tasks of the system operators – are by law or eventually by decisions of an authority assigned to a third party not to a system operator. In this case it is the difference that there is no responsibility of a system operator behind, but the third party is responsible on the basis of its own rights. This is mainly a possibility for the Member States to distribute certain tasks and responsibilities in a different manner.

In the event that tasks and obligations are assigned to a third party or a transmission or distribution system operator by a Member State, or a regulatory authority, references to systems operators in this Regulation shall be understood as referring to the assigned party. This provision reflects the genuine rights and obligation of the assigned party who steps into the place of the assignee. The relevant regulatory authority shall ensure regulatory oversight of the assigned party in respect of the assigned tasks and obligation. This ensures the same oversight as this would be a system operator task.

Whenever in the Network Code assignment or delegation is used it is used in this sense.

3.1.18. Article 17 Recovery of Costs

The Recovery on costs is also general element of other Network Codes and Guidelines. The provisions respect the general rule in other European and national legislation practically it refers to that – reinforcing the fact that by the systems operators' costs will be born in connection of the implementation of the Network Code – and that should be taken into account according to the present legislative framework. The text emphasises that the costs assessed as reasonable, efficient, and proportionate shall be recovered through the network tariffs of the respective systems operators or other appropriate mechanisms.

3.1.19. Article 18 Confidentiality Obligations

Provisions related to confidentiality obligations exist in other Network Codes or Guidelines (e.g., in Electricity Balancing Guidelines. The text uses the already adopted formulations and lays down that in general the obligation of professional secrecy shall apply.

3.2.TITLE II - GENERAL REQUIREMENTS FOR MARKET ACCESS

3.2.1. Article 19.0 Aggregation models

This article aims at describing potential interactions that would take place between market parties when an aggregator providing local or balancing services is established at a connection agreement point.

The aggregation models shall promote to limit the impact an aggregator may create on other market parties active at the connection agreement point.

- With the aim to limit such an impact, aggregation models must deal with the following terms. The imbalance calculation. Unless one of the following actions are taken, the BRP associated to the service provider would face an imbalance due to the activation of the service, even when such activation matches the requested service perfectly, while at the same time, the BRP of the connection agreement point, called in the NCDR the BRP of the accounting point, would perceive an unexpected impact (i.e. deviation from schedules, or baseline) due to service provider activation. In such a case, both BRPs would face such imbalances they are not directly responsible for. For dealing with these aspects, three potential actions are foreseen to be applied to either the BRP of the accounting point and the BRP of the service provider.
    - Correction of position. The concerned BRPs are responsible for correcting their position, within the available markets, to consider the activation of the service provider.
    - Correction of the allocated volume. The relevant measurement values for the concerned BRPs would be corrected considering the activation of the service.

    - Imbalance adjustment, if the 2 first actions could not be done before. The TSO would be responsible for applying an adjustment to the concerned BRPs, within the imbalance calculation process, to consider the requested or provided service.
- The financial transfer/compensation. Besides imbalance calculation aspect, the participation of a service provider may impact economically the active supplier at the connection agreement point. A financial transfer/compensation may be foreseen in each Member State to limit such economic impacts. The details for establishing such financial transfer/compensation are included in Articles 22a, 22b and 23.

Apart from the choices made for the terms before (how imbalance is calculated, whether a financial transfer/compensation is foreseen), the determination of the provided service, as well as the determination of the responsibility for the imbalance may be affected by the infrastructure of metering equipment available at the connection agreement point.

The same rationale for each of the options should be applicable to the situations where the BRP of the service provider is the same or different from the BRP of the connection agreement point.

The possibility of delegating the balance responsibility between parties is not subject to this NCDR, since such process is already envisaged on the EBGL.

The national terms and conditions on aggregation models will determine the allowed aggregation models at the national level and these models can depend on the type of the service, and also the type of the product especially according to other factors such as time of activation for the same service (activation ahead gate closure time or after GCT).

3.2.2. Article 19 Quantification of services

Before determining the imbalance incurred by each of the parties that may affect the system balance, it is essential to determine how the delivered service can be calculated and how the balance responsibility of the service provider is established, aiming at assigning as precise as possible the potential imbalance to each responsible party.

This article reflects the main difference on potential physical arrangement of metering equipment that can be found at and behind a connection point. The aim is to distinguish those configurations where the service provided by a controllable unit is directly measured by a metering equipment or, conversely, the delivered service by the controllable unit can only be calculated by the measures available at the connection agreement point, that aggregate the delivery of more than one service provided by more than one entity.

Two configurations have been defined based on the above and depicted in the following figures:

a) The CUs behind the accounting point, being part of SPU or SPG providing services do not have a metering infrastructure or other methods to quantify the service or the metering infrastructure is not used for the settlement of the delivery of the service, and for the correction of the imbalance:

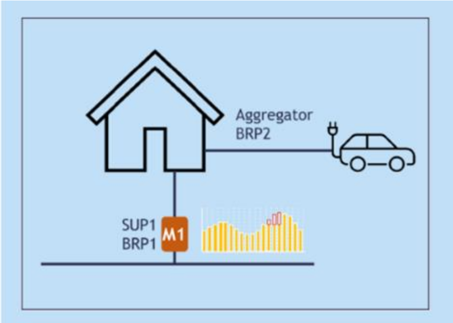

Figure 2: Configuration 1 in Article 19

b) The CUs behind the accounting point, being part of SPU or SPG providing services have their own method of quantification which is used for the settlement of the delivery and for the correction of the imbalance:

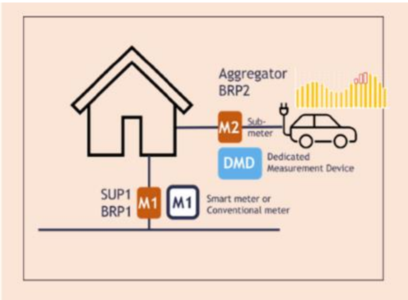

Figure 3 Configuration 2 in Article 19

The numerical example described below takes into account both Models. The main difference in the calculations is how we quantify the allocated volume. The Table below shows this difference and the allocated volume and position both for the BRP of the Service Provider and the BRP of the accounting point.

Table 1 Model A

MODEL A	Allocated volume	Position
BRP_{SP}	M1-baseline M1	0 (No position)
BRP_{AP}	Measured in main meter = M1	Schedule

Table 2 Model B

MODEL B	Allocated volume	Position
BRP_{SP}	M2-baseline M2	0 (No position)
BRP_{AP}	Measured in main meter =M1	Schedule

The following assumptions are made:

- The baseline of the house (baselineM1) is -100 (consumption).
- The schedule of the BRP of the accounting point (the supplier/house) is also -100.
- The service requested by the systems operatorsto the SP (whose CU is the EV) is to reduce by 10 its consumption. But the EV, when activated, just reduces by 8. (it's a deviation from the request and will be highlighted in the imbalance of the BRP of the SP)
- We suppose that the measurement at M1 when there's the service activation is -92. (the house behaves as it is expected, with no unexpected action)
- In case with a second meter (model B), we have a measurement at M2 and we have also a baseline for the EV (baselineM2). When activated, under the above assumption, we know that M2-baselineM2 is 8.

Below the three potential actions to calculate the imbalance are shown:

a) Imbalance adjustment: the TSO applies an imbalance adjustment to the BRP of the SP and to the BRP of the accounting point. (for Model A and Model B respectively):

Table 3 Model A imbalance adjustment

MODEL A	Allocated volume	Position	Imbalance adjustment	Imbalance
BRP_{SP}	M1-baseline M1= 8	0	Applied with the requested value 10	8-10= -2 The non-respect of the requested service is reflected here
BRP_{AP}	Measured in main meter = M1 -92	Schedule -100	Applied with the delivered service value 8	-92-(-100)-8=0 (no imbalance)

Table 4 Model B imbalance adjustment

MODEL B	Allocated volume	Position	Imbalance adjustment	Imbalance
BRP_{SP}	M1-baseline M1= 8	0	Applied with the requested value 10	8-10= -2 The non-respect of the requested service is reflected here
BRP_{AP}	Measured in main meter = M1 -92	Schedule -100	Applied with the delivered service value 8	-92-(-100)-8=0 (no imbalance)

b) The position is changed by commercial schedules. In the case of the correction of positions we have two options based on the timeframe that the BRP of the accounting point is informed and change its commercial schedules. The first case is that the BPR of the accounting point is informed ex-ante about a service activation. In this case the BRP of the accounting point can be informed with the requested service and not the delivered since the timeframe is before the activation of the service. Numerically speaking, this equals with the 10 that the Service Provider has agreed with the systems operatorsto offer as a service. Looking at the Table (row3 of both tables below) the BRP of the accounting point will then end with an imbalance of –2. Thus, the BRP of the accounting point is attributed an imbalance which did not cause. That is why in this case we anticipate that there is a correction/neutralisation so that the BPR of the accounting point will not face any imbalance. In the second case (row 4 of both tables below) the BRP of the accounting point is being informed ex-post and thus with the correct value of the activated service (numerically with 8) so the imbalance calculated results in zero.

Table 5 Model A position correction

MODEL A	Allocated volume	Position	Final position	Imbalance adjustment	Imbalance	Correction / Neutralisation
BRP_{SP}	M1-baseline M1 -92-(-100) = 8	0	Requested value of service 10	Nothing is done	(M1-baselineM1)-Requested value of service 8-10=-2 The non-respect of the requested service is reflected	NO
BRP_{AP} (ex-ante) if informed and correct before the activation	Measured in main meter = M1 -92	Schedule (=baselineM1) -100	Schedule + Requested value of service -100+10= -90	Nothing is done	M1-(baselineM1+requested value of service) -92-(-90)=-2	= - imbalance of BRP_{SP} An extra correction ex-post may be needed
BRPAP (ex-post) if informed and correct ex-post	Measured in main meter = M1 -92	Schedule (=baselineM1) -100	Schedule + delivered value of service -100+8= -92	Nothing is done	M1- (baselineM1 +delivered value of service) 0 (no imbalance)	NO

Table 6 Model B position correction

MODEL B	Allocated volume	Position	Final position	Imbalance adjustment	Imbalance	Correction / Neutralisation
BRP_{SP}	M2-baselineM2	0	Requested value of service	Nothing is done	(M2-baselineM2)-Requested value of service 8-10=-2	NO

	8		10		The non-respect of the requested service is reflected	
BRP_{AP} (ex-ante)	Measured in main meter =M1 -92	Schedule (=baselineM1) -100	Schedule + Requested value of service -90	Nothing is done	M1-(baselineM1-requested value of service) -92-(-90)=-2	= - imbalance of BRP_{SP} An extra correction ex-post may be needed
BRP_{AP} (ex-post)	Measured in main meter =M1 -92	Schedule (=baselineM1) -100	Schedule + delivered value of service -100+8= -92	Nothing is done	0 (no imbalance)	NO

c) The allocated volumes had been corrected (for Model A and B respectively)

Table 7 Model A allocated volume corrected

MODEL A	Allocated volume	Allocated volume correction (requested service)	Final allocated volume	Final position	Imbalance adjustment	Imbalance	Correction/ Neutralisation
BRP_{SP}	M1-baseline M1 -92-(-100)=8	Requested value 10	(M1-baselineM1)-Requested value of service 8-10=-2	0	Nothing is done	(M1-baselineM1)-Requested value of service -2-0=-2 The non-respect of the requested service is reflected	NO
BRPAP (ex-post)	Measured in main meter = M1	Correction with the measured		Schedule -100	Nothing is done	0 (no imbalance)	NO

	-92	value of the delivery 8	-92-8=-100				

Table 8 Model B allocated volume corrected

MODEL B	Allocated volume	Allocated volume correction (requested service)	Final allocated volume	Final position	Imbalance adjustment	Imbalance	Correction/ Neutralisation
BRP$_{SP}$	M2-baseline M2 8	10	(M2-baselineM2)-Requested value of service 8-10=-2	0	Nothing is done	(M2-baselineM2)-Requested value of service -2-0=-2 The non-respect of the requested service is reflected	NO
BRPAP (ex-post)	Measured in main meter =M1 -92	Correction with the measured value of the delivery 8	-92-8=-100	Schedule -100	Nothing is done	0 (no imbalance)	NO

In the 2nd configuration with “model B”, we introduce the possibility to have a conventional meter at the connection agreement.

Nevertheless, we consider the roll-out of smart meter is crucial to ensure a full and complete approach for correcting the perimeter of the BRP.

It is essential and 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).

Some TSOs are concerned by the possibility foreseen in the consulted document to develop aggregation models for schemes with analogue 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 to the perimeter of re BRPSP and the BRPsup and to correctly compensate the supplier. Indeed, for areas with analogue meters, systems operators 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 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 BRPsup of the concerned grid user will be impacted, but all the BRPsup 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. Some TSOs fear 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, the usage of an analogue meter combined with the sub-meter should be considered case by case, depending on the products that are targeted and the aggregation models that are developed.

3.2.3. Article 20 Energy allocation, balance responsibility in each aggregation model category and imbalance adjustments

Energy allocation, balance responsibility in each aggregation model category and imbalance adjustments

Before determining the imbalance incurred by each of the parties that may affect the system balance, it is essential to determine how the delivered service can be calculated and how the balance responsibility of the service provider is established, aiming at assigning as precise as possible the potential imbalance to each responsible party. For the first point, the determination of delivery of the service will depend on the disposal of metering equipment and the determination of the baseline of all the elements associated to the resulting metering. Regarding the balance responsibility, the service provider may take its own responsibility or delegates it to a third party that is not related to the BRP of the supplier, or, alternatively, the service provider may delegate its balance responsibility to the BRP of the supplier. If the latter is the case, the total imbalance is assigned to the single BRP, so the distinction between the imbalance incurred by the supplier or by the service provider is not relevant from a system operation point of view. For establishing the correct calculation and allocation of imbalances to each of the involved BRPs an explicit reference to the provisions set out in article 28(3) is introduced.

Provision of transfer of energy services

As stated in the Framework Guideline paragraphs 4 and 18 the main aim of this network code is to ensure access for demand response and other relevant sources to all electricity wholesale markets. This includes balancing and local services but also in particular day-ahead market and the intra-day market. The definition of wholesale markets in REMIT extends beyond the energy markets, including derivatives and capacity products, that are understood to be out of scope. Therefore, the draft Network Code has inserted the concept of 'transfer of energy services' and 'transfer of energy service providers' (TSP), to precise the requirements associated to this article.

Normally BRPs can participate in the wholesale market by buying or selling energy and actively steer power generating modules or actively steer demand units. The perimeter of a BRP consists of the trades and measured production and consumption of the accounting points a BRP holds responsibility for. However, a BRP of a service provider who controls a certain number of controllable units can't participate with these controllable units in the wholesale market if the reduced or increased amount of energy is not transferred to his perimeter. This needs to be organised to enable all market actors, including those aggregating units, participate in all wholesale markets.

Therefore, when a service provider wants to sell an amount of upward or downward energy in the wholesale market by using "his" controllable units, the energy needs to be transferred from the perimeter of the BRP of the accounting point to the perimeter of its BRP.

In cases where the controllable units behind the accounting point have their own method of quantification and when these values are chosen to be used, the metered or calculated values of the controllable unit shall be compared with the baseline of the controllable unit. In cases where the controllable units behind the accounting point do not have a method to quantify the service or when the metering infrastructure is not used for the settlement of the delivery of the service, and for the correction of the imbalance, the metered values of the accounting point will be compared with the baseline of the accounting point. This way the quantification of the amount of energy is calculated.

To facilitate the transfer of energy the relevant service provider needs to notify the relevant party. This is not needed in the case of a balancing services or local services because in this case, a system operator is the one who buys the service. Therefore, a notification for balancing or local services is not needed. However, since the systems operator is not aware of the fact that a transfer of energy is required, he needs to be notified of this.

Possible processing of a transfer of energy service

The following diagram describes in high level the possible processing of a transfer of energy service: depending on national framework, some flows can be differently implemented, especially between specific market participants (roles and responsibilities of MDAs, of the accounting point, and also of its BRP...)

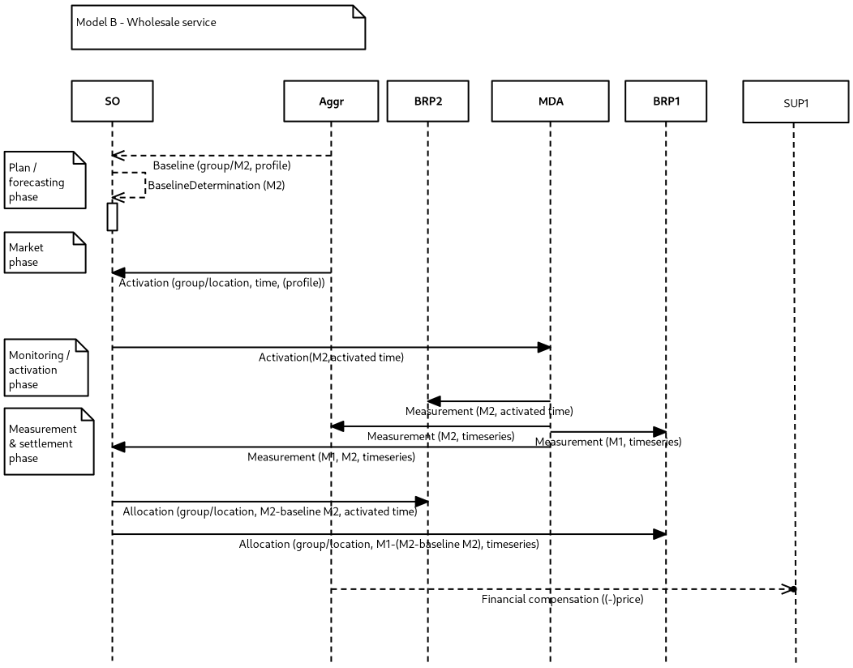

Figure 4 Possible example of wholesale markets interaction with other markets

In cases where the controllable units behind the accounting point do have their own method of quantification whose values are chosen to be used at national level, normally the systems operator receives a baseline from the aggregator/service provider/supplier, or he calculates the baseline of this controllable unit. When the service provider sells a certain amount of energy to another market party through his BRP, he must make sure the amount of energy is transferred from BRP1 (the BRP of the accounting point) to BRP2 (the BRP of the service provider). The systems operator will inform the MDA because the relevant market actor and its associated BRP should have access to the meter readings during the activation of the activation time of the wholesale product delivery. The activated energy should be allocated to the BRP of the service provider who activated such energy and should not be allocated to the BRP of the accounting point.

Article 20b integrates in its paragraph 6 the reference to the articles in the draft network code that are initially foreseen for TSPs. The principles in the Articles do not apply entirely. Therefore, the reference to ‘relevant principles’ from those articles are introduced here.

3.2.4. Article 21 Roles and responsibilities of market parties and systems operators related to Aggregation Models and quantification methods

This article summarises the responsibilities of the different roles related to the aggregation models and the quantification methods. The responsibilities can differ for the different services. For instance, balancing services can be organised significantly differently from congestion management services. Especially if it is related to congestion management at the distribution level.

The roles that are relevant for the aggregation models and quantification methods are: the systems operators, the Meter Data Administrator, the customer and the service provider, the BRP of the accounting point and the BRP of the service provider, and in case of a financial transfer between the supplier and the service provider also the supplier.

The customer is addressed here in paragraph 6 because the grid limitations apply to the connection agreement points. One connection agreement point can have different accounting points with multiple Controllable Units which are operated by different service providers. More than one service provider may be active at the same time behind one accounting point or connection agreement point. If this is the case it is not possible to hold the service provider responsible for respecting the grid limitation. Also since it is the customer who signs the contract agreement with the systems operator ultimately it is the customer who is responsible that the grid limitation is respected. The grid limitation is specified in the contract agreement. When the grid limitation is a dynamic grid limitation the customer should be informed in a clear and timely manner. A customer can outsource this to a service provider.

3.2.5. Article 22 Financial transfer and financial compensation

This section of the network code demand response reflects TSOs' and DSOs' approach to the financial transfer due to non-consumed or over-consumed energy (and possible extension to not injected or over-injected energy) while financial compensation relates to the additional costs of the supplier due to the activation of the flexibility services balancing, local service or of another wholesale energy product on market parties. The financial transfer mechanism is applicable to a non-consumed energy incurred by the supplier of the participating customer in case that supplier previously purchased that energy and to over-consumed energy due to service activation (with possible extension to injection). Financial transfer mechanism is subject of the approval by the national regulatory authority. Financial transfer mechanism is applicable in both directions of activation, downward activation as well as upward activation of services. Financial flows are possible in both directions, from the service provider to a supplier and also from the supplier to a service provider.

For instance:

- CASE A - systems operators send a request for an upward activation to a service provider who provides the service by decreasing the consumption of its contracted asset. This activation causes the forgone loss for a supplier under the assumption that supplier previously purchased that energy. In this case service provider will compensate the supplier.
- CASE B – systems operators send a request for a downward activation to a service provider who provides the service by increasing the consumption of its contracted asset. In this case of increased consumption, supplier will bill to its customer more energy and supplier will have to transfer the part of its revenues to the concerned service provider.

All other variations are not excluded meaning increase of consumption or decrease of injection in case of downward activation and decrease of the consumption and increase of injection in case of upward activations.

For a calculation of financial transfer must be established clear calculating method considering all possible financial flow variations and directions of activation. This calculation method consists of specific formula or it may be financial amount approved in both cases by the competent national regulatory authority. Bilateral agreements between the supplier and the service provider could be possible and optional meaning that no side could be forced into the negotiations but in case when these negotiation fails, for instance when deadline for the making the agreement is broken, there always must be calculating method to substitute the failed bilateral negotiation.

Financial transfer is applicable only when the measurements that determine the load curve of the customer in not corrected for the billing purposes, given the fact that correction of the load curve would empower supplier to bill the consumer for the amount of consumed energy as there was no activation of flexibility service. In fact the principle of financial transfer is already integrated in the situation where the billing is done by the supplier on the basis of the baseline, when there was no activation of the flexibility service: in the corrected model, the financial flows include already this financial transfer.

Method for the calculation of the financial transfer/compensation should be subject to the approval of the national regulatory. Method of calculation of the financial transfer may be represented by specific formula including several variables (for instance average DA price, Average ID price, Forward price, weigh of gross margins, prices of fuels etc.), and it may also be determined in a form of financial amount per unit of energy. Member Stat may allow bilateral negotiations between the supplier and flexibility service provider, giving them deadline to reach agreements but in case when two sides cannot reach a bilateral agreement, calculation based on the method approved by national regulator shall prevail.

Example:

- Member State allows bilateral negotiations about the financial compensation
- Agreement should be reached latest 30days after the activation of the service
- Supplier has got a loss of non-consumed energy –10MWh.

Case 1

- Supplier and FSP reach agreement on 25th day after the activation
- Following day financial settlement intermediary is informed about the agreement.

Case 2

- Supplier and FSP do not reach agreement or central financial settlement intermediary was not informed that agreement has been reached during the 30 days after the activation
- Central financial settlement intermediary calculates the financial compensation and informs the affected parties on 31st day after the activation

Case 3

- Member State does not allow bilateral negotiations over the financial compensation
- Financial compensation is calculated based on an approved method within the given deadline

In the process of financial transfer/compensation systems operators may have intermediary role. This role means that Systems operator may calculate the financial transfer/compensation according to the method previously approved by National regulator and invoice the service provider or other relevant parties for the financial transfer/compensation. Systems operator will not be subjects of penalisation and will not charge any additional fees for its intermediary role.

The implementation of the financial compensation mechanism of the additional costs due to demand response activation has to be in line with the Article 17(4) of Directive (EU) 2019/944. According to Article 17(4) of Directive (EU) 2019/944, Member State may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation. Therefore, TSOs and DSOs consider the financial compensation of the supplier not to be mandatory and is implemented only upon Member State's decision to implement such a mechanism.

3.2.6. Article 23 Benefits brought by service provider to other market participants due to activation of the balancing or local services, or transfer of energy service

Activation of the balancing services, local services or the transfer of energy service through the aggregation brings certain benefits to a system as a whole and may bring certain benefit to a single market party. Financial transfer and compensation mechanism described in articles 22a and 22b can take into consideration benefits brought by a service provider. If Member State decides to consider benefits, these benefits are to be determined nationally by the relevant national authority. However, benefits that may be considered are listed in Article 23(3) of network code. When considering these benefits for the calculation of financial transfer or other acknowledged additional costs, it must be evidently proven that benefits have positive impacts on the related product and the benefits should be quantifiable.

Financial transfer from the service provider to a supplier may be reduced by the verified benefits that the service provider brings to a supplier but only up to the extent that do not exceed the direct costs incurred.

Example under the assumption that financial transfer is being reduced by verifiable benefits.

- Case 1 -Supplier has a forgone revenue of 100€ that should be paid by a service provider to a supplier.
  Service provider brings direct benefit to a supplier of in the amount of 120€. In this case service provider pays to a supplier 0€.
- Case 2 –Supplier has a forgone revenue of 100€ that should be paid by a service provider to a supplier.
  Service provider brings direct benefit to a supplier of in the amount of 80€. In this case service provider pays to a supplier 20€.

Example under the assumption that calculation method for financial transfer does not include consideration of benefits. Supplier has forgone revenue of 100€ that should be paid by a service provider to a supplier. As benefits are not considered, service provider will pay 100€ to a supplier for its forgone revenues. Article 24 Data exchange process for aggregation models

The following diagram describes in high level the possible data exchange process: depending on national rules, some flows can be differently implemented, especially between specific market participants (roles and responsibilities of MDAs, of the accounting point, and also of its BRP...)

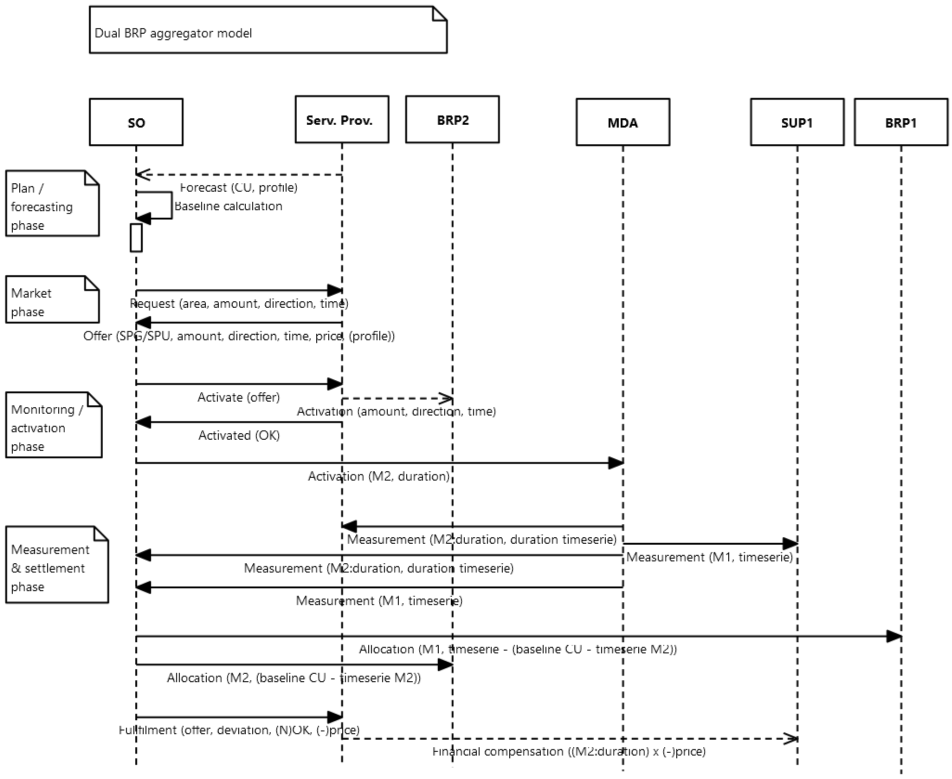

Figure 5 Possible exchange process for aggregation models.

One of the possibilities is for the Service Provider (SP) to provide the baseline for the Controllable Unit. Another option would be that the systems operators calculate the baseline for the CU. Typically for congestion management, the systems operators inform the Market that a certain amount of energy reduction (or increase) is requested in a certain congestion area and also when this amount of energy is needed and the duration of the service.

A SP can make an offer. This can be based on a bid ladder or the activation of a long-term contract bid. When the systems operators accept then he will inform the SP. The MDA may be informed by the systems operators. This enables the MDA to also send the measurement values to the SP for the duration of the activation of the service. The allocated volume for the BRP2 of the SP will be the baseline of the CU minus the measurements of the CU. This is the delivered energy by the SP. The allocated volume of the BRP1 of the supplier will be the measurement values of the meter at the accounting point minus the delivered amount of energy of the SP.

The SP will be rewarded for his service if everything is delivered according to the offer. It is possible that the SP is required to compensate the supplier.

In any case, the process of data exchange must respect the requirements of GRPD and rules on commercially sensible data.

Based on this scenario the article is drawn.

3.2.7. Article 25 General principles for baselining methods

These requirements shall not provide one single baseline methodology, but rather enable different baseline methodologies (such one based on schedules, measurements, derived values, near real time values and others) where the baseline is assumed as reference for checking the delivery or validating the delivery. As a basis there is a standardized predefined process for nominating and proofing new baseline methodologies. This process guarantees, that innovation takes place and continuous development is possible.

To establish baselines, different methods can be applied:

- The historical or statistical method
- The sample method (or mirrored peer method)
- The use of the measured values by a metering device or calculated values

The 2 first ones will provide profiles as baselines, especially useful in the case where we have at the connection agreement point a conventional meter.

For baselining methods such as methods using peer or mirror nonflexible sites, recalculability and transparency are guaranteed by the entity in charge of processing the baselining method, as this entity may be the sole entity allowed to collect and use the necessary data for baseline estimation (such as data from mirror or peer sites).

- Recalculability is ensured in the sense that for a given set of data used for baselining, consistent baseline results are produced by the method.
- Transparency is guaranteed through detailed description of the baselining method, as well as the definition and calculation of indicators; it excludes, however, any intermediate result that would disclose commercially sensitive information or data protected by the GDPR.

Rebound effects:

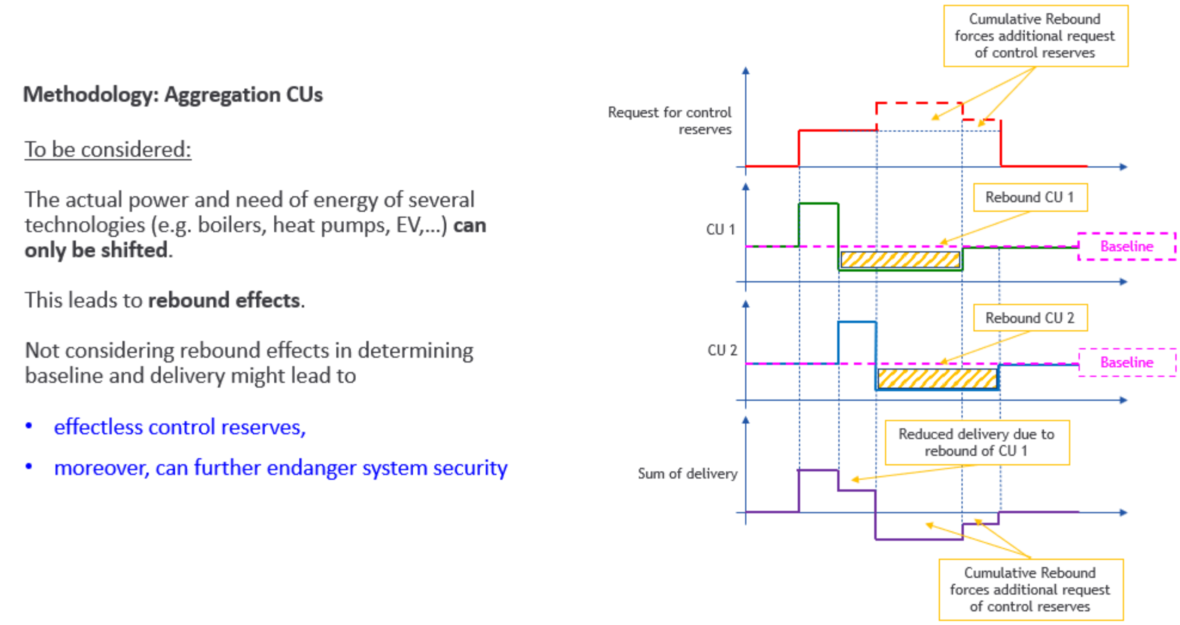

Figure 6 Rebound effect

In the baselining method register, the description of the baseline method will contain a minimum set of inputs including:

- The name of the baseline method
- A light description of its principles
- The type of assets and of products it can be applied to
- Any additional specific requirements (it can be provided regarding some national provisions)

Here is a French example:

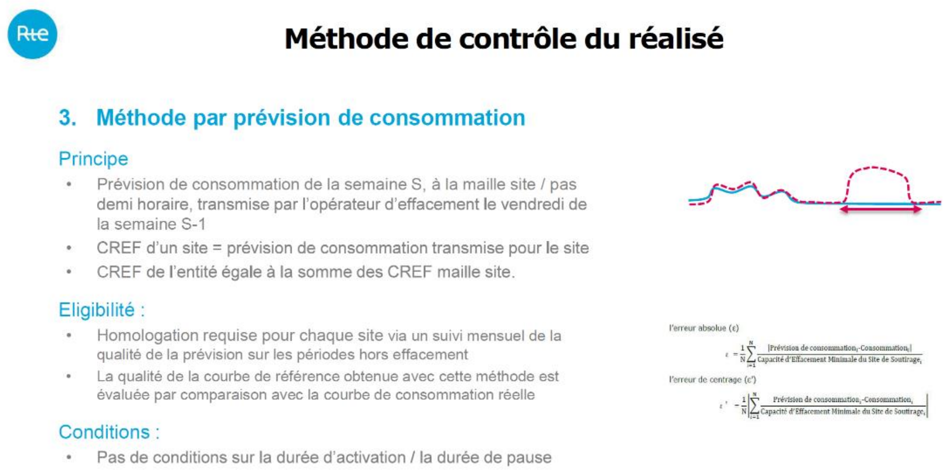

Figure 7: Method of control of realisation

3.2.8. Article 26 Baselining method: specification and validation

3.2.9. Article 27.a General principles for settlement of local services

This section aims to ensure that at national level the settlement of local services is enabled.

By making sure the relevant systems operator is defined in the national terms and conditions as either procuring system operator, the connecting system operator or requesting system operator.

By ensuring the above-mentioned national terms and conditions include a procedure for the settlement of local services. This could be achieved by either validating that existing national terms and conditions fulfil the requirements and amend according if necessary or developing new terms and conditions.

The procedure shall include the different ways to arrive at the service delivery and its recalculation, if those are considered as part of the product:

- Requested energy
- Metered energy
- Calculated energy.
- Activation period
- Provided capacity

When grid limitations or temporary limits are set, those apply for services delivery and compliance is to be validated.

Besides the above-mentioned ways, which shall be at least part of the procedure, national Terms and conditions may include other things. This is particularly highlighted for the rebound effect associated with an activation.

Furthermore, this section sets the minimum requirements for the calculation of the service delivery. Highlighting the resolution must be in sync with the market time unit for the product. The calculation must be per service providing “entity” being either SPU or SPG and giving guidance on how to represent withdrawal and injection or capacity reduction and capacity increase.

Concluding by stating the nationally defined relevant systems operator is responsible to perform the procedure for the calculation and settlement with the concerned service providers.

3.2.10. Article 27.b Settlement related data exchange

This section aims to specify who is entitled to receive which data to enable:

- The calculation of a service delivery,
- The validation of the service delivery,
- The consideration of temporary limits or grid limitation when the national settlement procedure envisions it
- The calculation of the imbalance adjustment by the TSO when applied as part of the aggregation model; and
- to make sure the data exchange itself is facilitated in a good way.

For the calculation of a service delivery two parts are required.

- One being the baseline to represent the behaviour without an activation, the other being a way to represent the deviation from the baseline due to a service activation.

- The way to represent the deviation from the baseline can be achieved by using the necessary measurement or the necessary activation information in case the expected behaviours during an activation is known.

To enable the relevant systems operator, as define in the previous section, to be able to calculate a service delivery, the relevant systems operator shall be entitled to receive the necessary measurements, necessary activations information and necessary baselines.

In those cases, “necessary” can be aggregated or individual but to ensure the settlement can be achieved.

For the validation of a service delivery three parts are envisioned.

- The necessary metering or measurement values for CUs which are part of the concerned SPUs or SPGs
- The necessary baselines of CUs which are part of the concerned SPUs or SPGs
- The mapping between the individual CUs and their part in providing a service.

With this information the relevant systems operator is enabled to “reconstruct” the service delivery based on measurements.

Those measurements could be from meter(s) of the connection agreement point, the DMD, or smart meter(s) of the accounting point.

For the consideration of temporary limits or grid limitation when the national settlement procedure envisions it the procuring systems operator shall be entitled to receive the required information by the connecting system operator.

For the calculation of the imbalance adjustment by the TSO, when applied as part of the aggregation model, the TSO has to get the required information by other market participants to be enabled to calculate and apply the correct imbalance adjustment to the concerned BRPs.

Finally, all participants in the data exchanges of this section have to make sure they are able to process the received data from a technical and content aspect. If they are unable to process the sender has to be informed without undue delay in a meaningful way. This should enable a clearing process and both involved parties are aware of the problem with the data exchange.

3.2.11. Article 28 Imbalance settlement

This section aims to describes the options for the correct imbalance settlement for aggregation models and what to consider when correcting the concerned BRPs.

(1) According to article 54 of the EB Regulation each TSO shall calculate the final position, the allocated volume, the imbalance adjustment and the imbalance. The final position of a BRP is equal to the sum of its external and internal commercial trades from consumption as well as generation. Imbalance to be settled = allocated volume – final position +- imbalance adjustment.

imbalance =
allocated volume - final position +/- imbalance adjustment

Figure 8 Imbalance Calculation

Three options are possible to correct the imbalance in case of a service provision, by changing one of the three variables of the imbalance equation.

- Option a) Since the market parties concerned correct their positions themselves through commercial transactions, no imbalance adjustment is necessary to the BRPs according to article 49 of EB Regulation.
- Option b) The allocated volume means an energy volume physically injected or withdrawn from the system and attributed to a BRP, for the calculation of the imbalance of that BRP. The allocated volume can only be corrected by the relevant system operator. According to article 4(2) of the methodology for the harmonisation of imbalance settlement the corrections shall be delivered to the connecting TSO by the relevant DSO in accordance with Article 15(2) of the EB Regulation, or by other parties, if specified in the Member State's terms and conditions for BRPs pursuant to Article 18(6)(d) of the EB Regulation. As in option a) also for option b) no imbalance adjustment is necessary.
- Option c) The final position and the allocated volume are not corrected, but the relevant TSO applies imbalance adjustment for the activated local or balancing services.

(2) The BRP of the accounting point shall be corrected based on the provision of the service. The specific amount could be different in cases an upfront information is provided and the BRP of the accounting point is supposed to act on this information.

The BRP of the SP shall be corrected based on the requested service, the provision of the service or a calculation.

This does neither limit the national option to delegate the balance responsibility nor does it exclude the option of aggregations models as nationally defined from making the balance responsible party themselves responsible for sourcing the correction.

3.2.12. Article 29 Granularity of standard balancing products

ENTSO-E Disclaimer: The rules set out in this Article have been drafted in consideration of the ACER framework guideline and in a first step in the NC DR. The workstream of allocating provisions correctly to existing Regulations has not yet been concluded by the finalisation of this document. Therefore, it should be emphasized that ENTSO-E supports to move the content of this Article to the Commission Regulation 2017/2195 (EB GL).

ENTSO-E considers the integration of smaller resources in balancing processes is more efficient and effective through aggregation. There is an understanding that lowering minimum bid below 1 MW only for the very first bid, has very low added value in terms of improving market access requirements and may create an unnecessary burdensome process, while at the same time making it more difficult the monitoring of service performance. On the other hand, TSOs understand that allowing higher granularity would make a difference for aggregators and facilitate the update of their portfolios with new participating resources joining them.

This draft option has been valued as of highest value by European association of aggregators.

The proposal of reducing the bid granularity will facilitate that small resources can be more swiftly aggregated in portfolios, therefore fulfilling the target to integrate smaller demand resources.

3.3.TITLE III - PREQUALIFICATION REQUIREMENTS AND PROCESSES

ENTSO-E Disclaimer: The Prequalification rules set out in this Title have been drafted in consideration of the ACER framework guideline and in a first step in a general sense covering local services but also balancing services. The workstream of allocating provisions correctly to existing Regulations has not yet been concluded by the finalisation of this document. Therefore, it should be emphasized that ENTSO-E supports to move the solely balancing related prequalification requirements of this Title to the Commission Regulation 2017/2195 (EB GL) and to the Commission Regulation 2017/1485 (SO GL).

DSO Entity disclaimer: All provisions regarding prequalification should be in the NC DR to assure clarity and consistency, streamline processes, reduce redundancy, enhance oversight and control, as well as harmonise and align. First of all, having all prequalification processes and requirements in one legal act provides clear guidelines and criteria for prequalification, ensuring consistency in the overall process. This clarity reduces ambiguity and potential misinterpretation, enhancing overall efficiency of the procedures for all parties involved. Furthermore, consolidating prequalification into NC DR simplifies the process for both: service providers and systems operators. Rather than navigating through various legal documents, all relevant prequalification procedures are contained within one comprehensive framework. Having the requirements in a single legal act also facilitates better oversight for NRAs, where necessary, and allows everyone interested in being a service provider to assess the framework in advance. In addition, consolidating prequalification into NC DR promotes harmonization and alignment among Members States and contributes to market integration, non-discrimination, effective competition and the efficient functioning of the market pursuant to Article 59(4) of the Electricity Regulation. For the previous reasons, DSO Entity notes that for situations of any misalignments the NC DR prequalification procedures framework should take precedence over prequalification requirements and processes coming from other network codes and guidelines.

3.3.1. Article 30x Market Access Processes

The process for service providers to get access to markets for balancing, congestion management or voltage control services consists of 3 parts in general:

- SP qualification, which qualifies the service provider itself.
- product prequalification or product verification (depending on the product), which qualifies the assets (SPUs and SPGs) with respect to the compliance with the product requirements.
- grid prequalification, which shall ensure that the service delivered by the assets (SPUs and SPGs) does not violate grid security limits.

By default, the service provider is only entitled to bid in the respective markets, if all of the abovementioned procedures have been completed. National specifications might foresee that certain steps for market access will not be implemented and thus are not necessary to fulfil.

3.3.2. Article 30 Qualification for Service Providers

The Article 30 focuses on the “SP qualification” that serves the purpose of checking the capability of the service provider itself, and its reliability to deliver a balancing, congestion management or voltage control service, meaning the required communication channels with the systems operators and/or the market platform are set up, which also may be subject to a test during the qualification process, financial prerequisites and the overall technical concept and the IT-system of the service provider are compatible with the product, the SP intends to provide.

Paragraph 1a is clarifying that financial pre-requisites for a service provider need to be fulfilled according to the national TCs. The rationale for these financial requirements is derived from the need of ensuring creditability of service providers.

Since the requirements for the service provider can vary greatly between services, the service provider qualification is product and market specific. A service provider which is already qualified to deliver a product can therefore not skip the qualification process for other products. Also, if the service provider wants to expand and wants to offer the same product to another market (platform), the qualification process needs to be re-performed e.g. to ensure a proper onboarding on the new market platform.

On the other hand, the qualification process should be as simple as possible. Hence, as described in paragraph 2, the national TCs shall foresee rules avoiding duplications in the qualification process for service providers that already have a valid qualification, but decide to deliver other products, the same product to another market or both.

The counterparty in the SP qualification process assessing the compliance of the service provider with the respective requirements is the “SP qualifying party”. In most cases this role is taken over by the TSO or by the DSO, that need the service in one of their markets but can also be delegated to a third party. When a service provider applies for SP qualification, it should only be one “SP qualifying party” per product and per market (platform), even if multiple systems operators intend to procure that product on that market. The status of the qualification of the service provider, as well as the associated portfolio of SPUs and SPGs intended to provide a certain service or product, should be registered in the SP module of the flexibility register. The intention of this is that other SP qualifying parties can see the qualification status, the SP has for different markets and products, which then may be used for simplification of future qualifications. To maintain the required level in quality in service delivery, the qualification status of service providers can also be revoked by the SP qualifying party, if any of the requirements for SP qualification are no longer fulfilled, or if later the SP repeatedly fails to deliver a service.

The SP qualification is meant to examine the basic qualification of a service provider in terms of the financial pre-requisites, the appropriate ICT system and the correct conceptual understanding of delivering the respective product. To ensure the appropriateness of the ICT system and the conceptual understanding, the SP qualifying party can optionally request a communication test with the service provider and also request the documents listed in paragraph 1 d). With regards to the conceptual understanding, dispelling general misunderstandings already at an early stage of the entire market access process has been proven to be an efficient procedure by the experiences made in existing ancillary service.

The list of descriptions to be provided upon request also entails the management of compensation effects and rebound effects (if applicable). It is of importance for the system operators to know if and to what extent rebound effects will occur especially for the management of congestion- and voltage issues.

In case of changes to the ICT system the SP qualifying party is entitled to re-perform at least the communication test. Those re-testing efforts shall be limited as much as possible and shall only be conducted where the reliability of the service provision due to a significant ICT system change might be compromised.

3.3.3. Article 30A Requirements for CU operators, service providers and operators of platforms

This Article primarily aims to propagate a risk-aware view on developments. On the one hand Technical Aggregators (CU operators acting on behalf of final customers and controlling potentially millions of assets owned by European citizens) are clearly foreseen, whilst on the other hand Commercial

Aggregators (Service Providers) are also – if hopefully they grow and flourish – may place and accumulated risk. Therefore, these actors need to be carefully regulated, especially if they are providing services from regions or trusts that the European Union as a whole or in parts may run into conflict with. Dangerous dependencies must be kept detectable and correctable, and data belonging to European data subjects must be processed under European terms. Under this light, the Article mainly categorises these actors as shown in the diagram below:

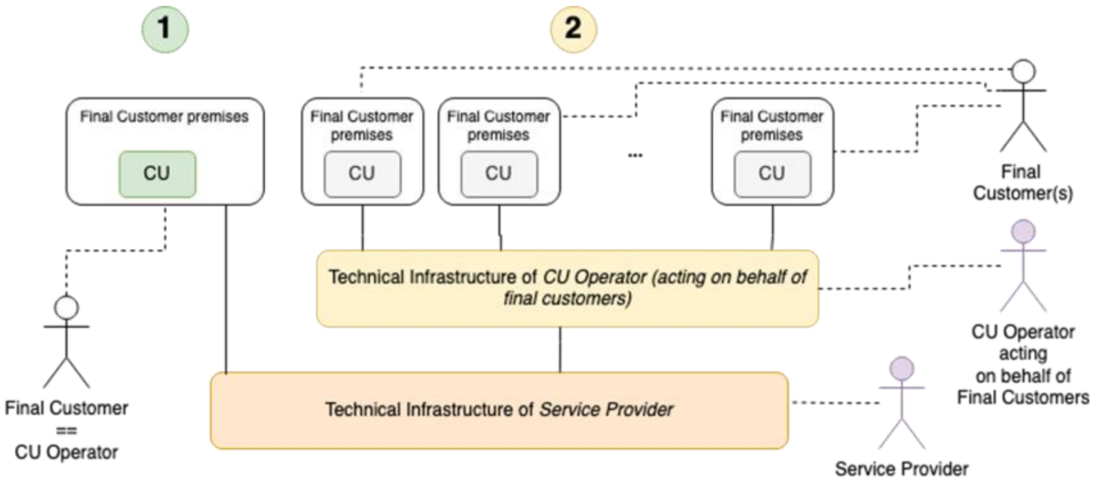

Figure 9: Overview on infrastructure and actors as the main subject of Article 30A

The yellow and orange boxes are the technical and organisational assets that may show an accumulation of risks. Therefore, their operators – CU Operators acting on behalf of Final Customers and Service Providers – must be taken under closer consideration to avoid cybersecurity risks and dangerous dependencies. Assessments were undertaken to see whether the scenarios that would place a danger in the context of Demand Response would probably already been tackled by other pieces of regulation (e.g., NC Cybersecurity or the Data Act), but no satisfying provisions were found. Therefore, the NC mirrors the provisions taken for 5G infrastructure and risky suppliers.

During negotiations with stakeholders it was raised by non-EEA actors that the geographical scope for platform operators should be extended from EEA to EFTA. This was rejected intentionally, as some EFTA MSs do not guarantee the financial transparency that would allow to investigate appropriately interests and control structures behind certain players.

3.3.4. Article 31 Pre-Conditions and Applicability of the product prequalification and product verification processes

Article 31 provides the basic allocation for which product the (ex-ante) product prequalification process or the (ex-post) product verification process applies and provides conditions that need to be fulfilled before those processes can start. The pre-conditions are distinguished into a previous successful SP qualification and the data registration of the potential SPUs or SPGs the service provider intends to deliver services with. For the SPU or the SPG, the service provider shall register the data itself, while for the controllable units the service provider shall only ensure the completeness of the data, not necessarily registering the controllable unit data itself. The NC DR provides flexibility in this regard allowing for implementations of solely B2B focussed interactions with the flexibility register, meaning that the service provider also registers the controllable unit data on behalf of the flexible customer, or allowing for the flexible customer to directly register and update data of its controllable units itself.

Due to some grid-related data necessary for controllable units, the registration of controllable unit data can be assigned partially to the relevant systems operators by the national TCs.

Paragraph 3 describes the initiation of the grid prequalification (if applicable) at the time of submission of the product prequalification or product verification. For SPGs or SPUs requiring a product prequalification, the grid prequalification shall be conducted in parallel to the product prequalification process. For SPGs or SPUs only requiring a product verification, the grid prequalification shall still be assessed before market participation is granted for these SPGs or SPUs.

Paragraphs 4 and 5 rule the basic allocation. For SPUs and SPGs, for which the service provider intends to provide standard balancing products, the (ex-ante) product prequalification process applies. For specific balancing products as well as congestion management and voltage control products the (ex-post) verification process applies by default, whereas paragraph 6 also foresees exemptions for those products in particular circumstances. These exemptions shall be explained in the following individually:

- For service providers that apply to deliver a product for the first time, the PPR shall have the right to request a product prequalification instead of product verification. If this prequalification process is successfully completed, the subsequent applications for that product shall be dealt with by the product verification processes (provided the other criteria in paragraph 4 do not apply). This criterion applies for all products.
- A deviation from the default product prequalification also applies if a SP has failed to pass the product verifications for the same products with the same or with other SPUs or SPGs. The reasoning behind this criterion lies in that a SP that is responsible to handle the bidding process and delivery of the services on account of the resources, and if this has been a problem before it is more likely an unsuccessfully delivery can happen again, making the SP less reliable. This criterion applies for all products.
- A deviation from default product verification also applies in the case when central dispatching model is used.
  - The central dispatching model and the integrated scheduling process co-optimisation relies on having tested and proven capability for system security in real-time operation. Given the co-optimised nature of the integrated scheduling process, each individual service provider and resource is relied upon to provide the capability expected. If a service provider does not provide the service as required, this does not just have a negative impact on that particular service but across the entire co-optimised schedule of generation and demand as a whole. Because this schedule is relied upon to ensure that operational security limits are maintained, this means that any individual service provider not providing the service as required has a direct knock-on impact to operational security. Operating without knowing in advance if a service provider can actually provide the service required would result in operating in an insecure state, where the failure of the service provider to meet the requirements does not just fail in the provision of a single service but would have a knock-on impact on the ability of the rest of the scheduled generation and demand to meet all operational security limits. In order to prevent operating in an insecure state, there is a requirement to prequalify providers to ensure in advance that they can provide the service as expected, rather than assuming that they can provide the service until proven otherwise.
  - When using the central dispatching model, much greater certainty of providing the balancing service is required, in particular it is necessary to confirm the ability to provide the balancing service after passing the prequalification process with activation test rather than relying on product verification.
- For specific balancing products, the PPR shall also have the right to request a product prequalification in case the SPU or SPG exceeds a prequalified capacity of more than 500 kW (unless otherwise defined in the national TCs) due to the significant impact on the overall balancing quality. Furthermore, some specific balancing products are designed to be activated as a last resort measure in a particular tense system state (as referred here to “alert state” or “emergency state” defined in SO GL). The TSO relies on the proper functionality of those SPGs and SPUs that must be checked before market participation.

- For congestion management- and voltage control products, the PPR shall also have the right to request a product prequalification in case the SPU or SPG exceeds a threshold defined on national level in the national TCs. The threshold shall be based on the effect the undelivered product may have on the grid and thereby prevent risking its operational security. The effect the undelivered product may have as well depends on which voltage level the product is delivered on and can be measured in possible change in load-flows, voltage or triggered congestion. Therefore, an analysis of the national specifics of the grid and products should be made to set this threshold, as this varies between member states.

3.3.5. Article 32 Criteria for reassessment of product prequalification and product verification

With the implementation of the clean energy package and with that the role of the independent aggregator, it is expected that controllable units are more commonly removed, added or switch between service providers, and thereby making changes to the SPU/SPG qualified to provide a certain service and product. This Article is seeking to find a good balance for when the PPP can re-assess the qualification status of formerly already qualified SPUs or SPGs (either by product prequalification or by product verification) that have been subject to modifications, e.g. due to re-configurations of included controllable units. In principle the PPP should have the right to request a new product prequalification or a new product verification in cases where the ability to deliver a product can be questioned after a significant change has been made. A change to the SPU or SPG also includes, beside adding, removing or switch CUs between SPUs or SPGs, a significant modernisation or update to the CUs or a fundamental change to the communication system or technology.

- The first two criteria 2a) and 2b) aim towards the situation a SPU or SPG is modified by additions or removals of controllable units. With the criterion 2a), the PPP is entitled to reassess the qualification, when more than 10% of the nominal capacity of the originally qualified SPU or SPG is modified, while additions and removals shall both be counted positively. Example: SPG with 100 identical controllable units each having a nominal capacity of 10 kW (leading to a nominal capacity of the SPG of 1 MW). If 5 controllable units of the same type are added and other 6 controllable units are removed from this SPG, 110 kW of nominal capacity is changed compared to the SPG under previous product prequalification or product verification, giving the PPP the right for a reassessment and a potential repetition of a product prequalification process or product verification process (dependent on the product). Since the relative value of 10% can result in a significant absolute value for particularly large SPUs or SPGs, the addition absolute value of 3 MW shall serve as a second option for the PPP to initiate a new qualification process.
- Criterion 2b) aims in contrast to criterion 2a) on the “prequalified or verified capacity” instead of the nominal capacity. The prequalified or verified capacity is the capacity with which the service provider is entitled to participate in the market with this SPU or SPG. The PPP may request a new product prequalification or product, when the service provider adapts the prequalified or verified capacity on the bases of added or removed controllable units up by more than 10% or 3 MW.
- For the avoidance of doubt, it shall not be allowed to change the SPUs or SPGs stepwise by up to 10% or 3 MW to circumvent the criteria 2a) and b). The reference to calculate the modification is always the SPU or SPG as it was previously assessed in the last product prequalification or product verification.
- Criterion 2c) considers the scenario, when a significant share (again 10% or 3 MW) of the SPU or SPG is subject to a modernization or update.
- Criterion 2d) clarifies the re-assessment by the PPP, when the service provider or, may it be the case pursuant to the implementation of Key Organisational Requirements, Roles and Responsibilities (KORRR) relating to Data Exchange in accordance with Article 40(6) of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a Guideline on

Electricity Transmission System Operation, third parties mentioned in article 3(7), 5(6), 9(1) that have been delegated with data exchange function, has adopted changes to its communication system, when it might impact the reliable delivery of services.

- Criterion 2e) and 2f) are considered not to require further explanations.
- By the criterion 2g), the PPP can request a new product prequalification or product verification, when the service provider introduces a new type of technical resource to its SPU or SPG.

To keep the impact of a new prequalification as low as possible on the SPs participation in the respective market, the national terms and conditions shall define rules for how to enable a continued market participation in case a re-prequalification is being conducted. Those rules may foresee a market participation with a reduced capacity of the affected SPU or SPG, where reasonable, but shall avoid compromising the reliability of the service provision as far as possible.

As a response to the feedback received by ACER when publishing the first version of the FG DR for public review, the reuse of prequalification results from unchanged CUs and the right to combine these with new results from the modifies CUs is included in the network code, as long as the product prequalification or product verification is not older than 3 years. To be in line with the SOGL, article 155, 159 and 162, the product prequalifying responsible shall reassess the prequalified SPU/SPG every 5 years.

The assigned CU operator of the CU must be able to offer data exchange with the SP based on a European standard to make this process possible, alternatively register a full and accessible documentation in the CU module in the flexibility register for how these controllable units can be controlled and monitored by any other service provider after switching have taken place. This will enable that the switch can be issued fast and that the final customer don´t get lock-ins to any SP based on the communication protocol the CU operator have chosen. To also avoid lock-ins of final customers to CU operators, which may be a third party, European standards for controllability of CUs is of importance and is suggested in the code to be mandatory for CU operators of mass-produces devices. To not surpass the time limit mentioned in article 12 of the directive, (EU) 219/944, of three weeks, third party CU operators is suggested to provide technical documentation of how the controllability of the CU may be switched to another party, third party or the final customer itself, within maximum 3 weeks. This should be done at registration of the CU in the CU module of the flexibility register.

The NRA is the logical party to monitor that the mentioned standards and documentation is complete and registered according to this article. To not slow down the market development and create barriers for already existing CUs, CUs in operation at the entry into force of the code is suggested to be given a derogation of maximum 3 years for the changes implied by the standards and documentation implemented by this article.

3.3.6. Article 33 Switching of Controllable Units

A smooth and fast switch between service providers is key for the final customers sovereignty and its freedom of choice. Therefore, a switching process is included in the network code with the objective of being aligned with the switch of supplier, regulated in article 12(1) of Directive (EU) 2019/944. This article states that the final customers shall be allowed to technically switch supplier as they wish within a maximum 1 day after 2026, calculated from the date of the request:

To not risk double activation when participating in the service markets of several services, each CU shall only be allowed to be assigned to one SP at any single point in time. The operator of the CU module of the flexibility register is the most reasonable actor to make sure this is fulfilled, as this party has the overall picture of the CU assignments.

The new SP is the most logical party to make the final customer aware of the terms and conditions for the switch as it´s between these two parties the contract is signed.

After the new service provider has concluded the contract with the flexible customer, the new service provider can apply for the switch in the flexibility register. Although the switch shall be technically conducted and registered in the flexibility register within 1 business day, the NC DR foresees a lead time of at least one month until the controllable unit can be deployed by the new service provider. This lead time shall

- allow the old service provider to take the necessary steps to disconnect the concerned unit from its communication system; and
- for the PPPs and affected system operators to assess the impact on the qualification status of the affected SPUs or SPGs in accordance with the reassessment criteria of Article 32 in order to ensure a smooth and seamless transition to the new service provider. If deemed feasible and sensible this lead time can be reduced on national level. For the avoidance of doubts, the given deadline of 10 days for the PPP and for the affected system operators is to assess whether a new qualification process is needed. If the PPP or the affected system operators see the need for re-performing one of the qualification processes in line with the re-assessment criteria of Article 32, the affected SPUs or SPGs can only to used in market participation under the conditions defined in Article 32 paragraph 3..

3.3.7. Article 33A: Framework for the validation and quality of DMD data

Article 7 b) 2) of amended Regulation 2019/943 provides that Member States shall establish requirements for a dedicated measurement device data validation process to check and ensure the quality and consistency of the respective data, and interoperability, in accordance with Articles 23 and 24 of Directive (EU) 2019/944 and relevant Union legislation. The provisions in Article 33A of this regulation aim towards streamlining these checks for consistency.

Article 33A 1) a) also aims to avoid excessive and unnecessary data exchange and respects that not all data captured or being available from DMDs is needed for validating the delivery of services. In most cases it will only be necessary to acquire data for times in which the CU has been activated and not down to very small-time intervals that e.g. SPs use to monitor during operation.

DMDs may be used to isolate the controllable unit from other assets at the side of a flexible customer with regards to the provision of balancing and local services. DMDs may serve purposes to quantify the performance of the flexible customer towards aggregators, service providers, systems operators and BRPs, serving in the verification of fulfilment of the products requirements, to quantify the activated flexibility as a basis for the transfer of energy, and to allow different aggregators and/or service providers to operate different controllable units at the same flexible customer at the same time. They may be used to detect whether a specific CU has delivered the service, whereas smart meters at the connection agreement point may detect whether the service has actually arrived in the grid.

Article 33A 4) a) states that parties responsible for validation may consider the utilisation of the standardised interface or remote access described in Directive (EU) 2019/944 and by Commission Implementing Regulation 2023/1162. When Member States develop an architecture to make that data source available to diverse players, it is important that this data source is not exclusively occupied by single actors, as also market roles not involved in Demand Response (e.g. Energy Communities, Suppliers, etc.) need access to the same near-real time data in a non-discriminatory way.

DMD data should be usable for all flexibility-related secondary corrections (e.g. accounting of state-aid relevant electricity volumes). In order to exactly validate the delivery of sold flexibility to the grid and the reliable detection of compensation effects, taking into account measurements from the boundary meter at the connection agreement point is inevitable.

In addition to the concepts stated above, Article 33A 1) and a), b) and c) are aiming to clarify the responsibilities for measurement responsible parties and metering data management for DMDs.

Principles and requirements for consistency of DMD measurements with smart meters metering, and requirements for the consistency of DMD measures with respect to the effective electrical values at the connection socket of the CU. This could include synchronisation, DMD measurement class, and what is exactly measured (internal DC by the inverter or state of charge of the battery so that we miss a great amount, or AC from the connection socket of the CU), generation of replacement values, etc.

Validation strategies for local and balancing services provisioned by Article 20 and Article 33 provisions that national terms and conditions should foresee tolerances for deviations for activated services not being reflected at the connection agreement point. They should allow for occasional deviations, but ensure that there is a penalisation for systematic compensation effects. These systematic malfunctions may stem from typical energy management or power control systems, integrations with energy communities, energy sharing or other sources and may be of intentional or unintentional nature. Most of these systems will cause compensation effects in their default configuration, so action – mostly by the flexible customer – needs to be taken to actively re-configure them in order not to interfere with the provision of local and balancing services. The provisions in this Regulation accept that there will be unforeseeable deviation especially in the residential domain, and tolerances should allow for these to happen. Also, different services may have different tolerances for deviations at single connection agreement points or a collection of connection agreement points.

3.3.8. Article 33B: Standardised data exchange and application programming interfaces

This article aims to establish data exchange standards for balancing, congestion management and voltage control processes that shall simplify the market participation in different Member States and different services.

The existing balancing-related data exchange standards shall be updated and listed by ENTSO-E by 12 months after entry into force of this Regulation for various processes. It is important to note, that the mentioned “activation of bids” does refer to the acceptance of a bid in the market and not to the real-time activation signal to the service provider. The real-time operational data exchanges are excluded from the standardisation efforts, since those are assessed not to be cost-efficient imposing immense investments on both sides systems operators and established balancing service providers.

In parallel ENTSO-E and EU DSO Entity shall publish a list of acceptable standards for other listed interactions (excl. TSO-BSP interface) within the same deadline of 12 months after entry into force of this Regulation. Therefore paragraph 3 identifies all necessary lines of communication and foresee – in addition to optional proprietary interfaces – interfaces following a European standard. This list of European standards is proposed to be adopted and maintained by ENTSO-E and EU DSO. The purpose of this provision is to establish a common and consistent set of standards to be applied across the Union.

It is important that the standards itself will be developed by European Standards Defining Organisations under the requirement of broad and proper stakeholder integration. The list(s) of acceptable standards will be subject to updates, and so will be the standards.

The commonly developed list of preferred European standards referred to in paragraph 3 may be developed in the joint working group between ENTSO-E and EU DSO Entity referred to in Article 11(1) of Commission Implementing Regulation 2023/1162.

During the drafting period of this code, a number of relevant standards have been analysed for their applicability to serve as a basis for the works on standardisation. As an example, Solar Power Europe has provided the Figure 1010 below, to show the lines of communication and available candidates for the lists of acceptable standards.

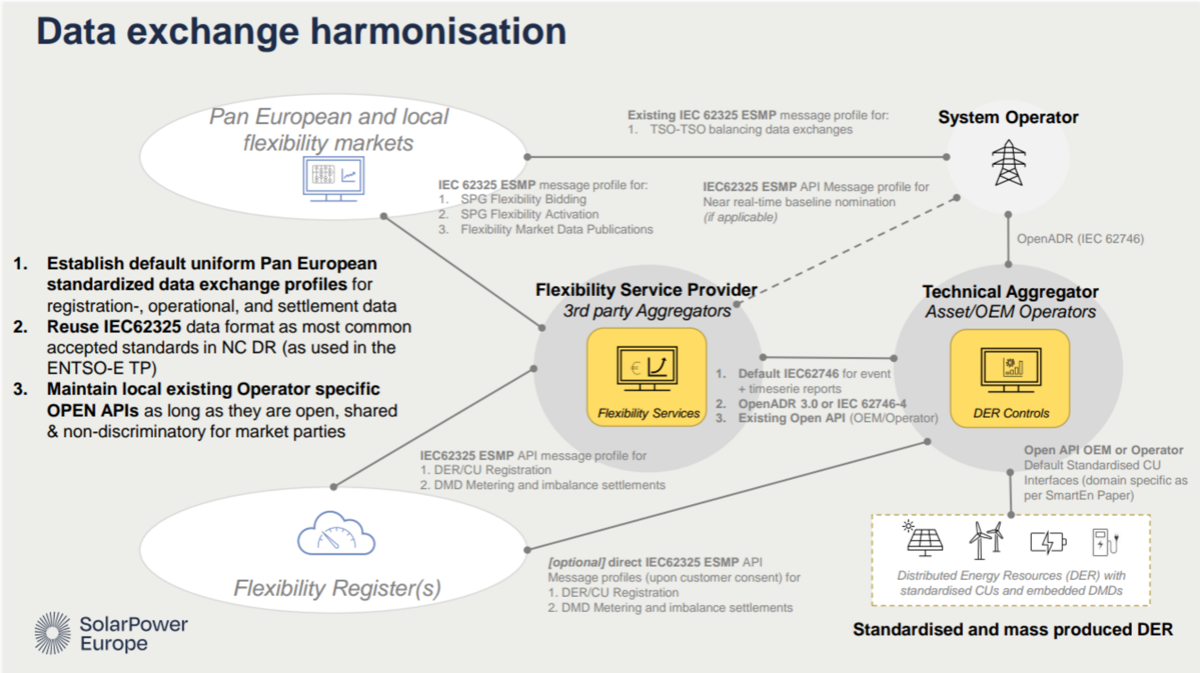

Figure 10: Stakeholder contribution from SolarPower Europe: Available international information exchange standards as a basis for the follow-up works on standardisation

3.3.9. Article 34 Requirements for product prequalification

The provisions of Article 34 apply to all cases of product prequalification, regardless of whether they concern products intended for this mode, i.e., standard balancing products or services for which product prequalification is applied under the exceptions described in Article 31 paragraph 6.

The condition for proceeding to the product prequalification is the prior qualification of the service provider, referred to in Article 30.

The product prequalification is carried out by the PPP (product prequalifying party), which is the procuring systems operator by default. Hence, for balancing- products the TSO is the PPP and while for local products multiple systems operators may potentially buy the same products from the SPU or SPG under prequalification. In this case the national terms and conditions shall define the criterion to determine the procuring system operator that takes over the rules as PPP: This solution aims to avoid excessive burdens on the service provider and undergoing several prequalification processes by several procuring system operators.

The purpose of the product prequalification is to confirm that the service provider is able to deliver the product of its choice through the SPU or SPG under assessment. For this purpose, the PPP may request various information from the service provider to confirm the ability of the SPU or SPG to deliver the required product. In particular, these may be:

- technical documentation, including communication, regarding technical devices included in the SPU or SPG,
- information about measurement devices and measurement data necessary to establish the baseline and subsequent settlement of the service provided.

The product prequalification process consist of an evaluation phase that involves comparing the characteristics of the SPU or SPG with the requirements of the product the service provider intends to provide.

The next phase may be the activation test to confirm the service provider's ability to deliver the required product using its SPU or SPG, but the conditions when this activation test can be performed are determined by the national terms and conditions for service providers.

If the central dispatching model is used, the prequalification process takes into account the specificity of this model, in particular in terms of conducting activation tests. This is due to the following conditions:

- The central dispatching model and the integrated scheduling process co-optimisation relies on having tested and proven capability for system security in real-time operation. Given the co-optimised nature of the integrated scheduling process, each individual service provider and resource is relied upon to provide the capability expected. If a service provider does not provide the service as required, this does not just have a negative impact on that particular service but across the entire co-optimised schedule of generation and demand as a whole. Because this schedule is relied upon to ensure that operational security limits are maintained, this means that any individual service provider not providing the service as required has a direct knock-on impact to operational security.
- Operating without knowing in advance if a service provider can actually provide the service required would result in operating in an insecure state, where the failure of the service provider to meet the requirements does not just fail in the provision of a single service but would have a knock-on impact on the ability of the rest of the scheduled generation and demand to meet all operational security limits. In order to prevent operating in an insecure state, there is a requirement to prequalify providers to ensure in advance that they can provide the service as expected, rather than assuming that they can provide the service until proven otherwise.
- When using the central dispatching model, much greater certainty of providing the balancing service is required, in particular it is necessary to confirm the ability to provide the balancing service after passing the prequalification process with activation test. This is due to the following circumstances:
    - The integrated scheduling process bids are used for unit commitment and dispatch of dispatchable facilities (generating and consumption and storage units) to cover the power system demand not the residual balancing demand;
    - The integrated scheduling process bids are also used to solve internal congestions in transmission network (Art. 24 (7) (b) of EBGL), and to establish generation and consumption schedules which maintain operational security limits for other non-energy system requirements.
    - If a balancing service, in the case of central dispatching model understood as balancing of a significant part of the power system or congestion-solving service, is not provided, power system security or network security will be endangered.
    - Since the schedule is done in a co-optimised way, the schedule of one unit will impact the schedule of all other units meeting all other system requirements – so this security is not just endangered for the one unit and service which was failed to be delivered, but potentially some or all other units and system needs. Therefore, operating without knowledge that a service provider will provide the service in the expected way (such as through a prequalification with activation test) would result in operating in an insecure state.
    - It should be borne in mind that in accordance with Art. 27 EBGL, TSO is obliged to convert integrated scheduling process bids in a central dispatching model into standard balancing energy products, required by platforms TERRE, MARI and PICASSO. Because this process takes place in near real time, it is very difficult to reselect subsequent bid if the selected bid is not delivered.

- In the event of failure to provide the balancing energy in accordance with the submitted integrated scheduling process bid, the TSO must take immediate action to select another bid, which may be significantly more expensive and which must be available and feasible (taking into account near real-time operation). Since the pricing stack has been previously established, the price difference between old and new bids will be an additional CDM TSO cost.

The Article 34 foresees further simplification for small CUs and for CUs that are identical to already prequalified CUs in other SPUs or SPGs of the same service provider. The simplification for small CUs in paragraph 6 shall ensure that in large aggregations/SPG of many small CUs the capability of the service provider to deliver the concerned products is already acknowledges, if the service provider can prove with a subset of this SPG reliable service provision by the activation test.

The final phase is the registration of the product prequalification status in the flexibility register platform with SP module. The positive status can be registered upon successful completion of the SPU or SPG evaluation and their activation test, if required.

When performing the activation test, a coordination with all affected parties is required, which means that grid prequalification must be taken into account (paragraph 9) and the possible coverage of the costs of activation tests will be decided by the terms and conditions for service providers (paragraph 10).

3.3.10. Article 35 Provisions for prequalification for standard and specific balancing products

3.3.11. Article 36 The congestion management and voltage control services product prequalification process

Provisions of this Article apply to the product prequalification process, where one of the exceptions set out in the Article 31 [Pre-Conditions and Applicability of the product prequalification and product verification processes] applies to congestion management or voltage control products.

The paragraphs describe the individual stages of the process.

The process begins with submitting an application to the PPP, which is obliged to verify the application within 2 weeks. Then, if the application is complete, the PPP must conduct an assessment within 3 weeks to confirm that the potential SPU or SPG meets the criteria for a congestion management or voltage control product and, if required, may also perform an activation test according to the requirements described in Article 34.

3.3.12. Article 37 Product Verification Requirements

For voltage control, congestion management and specific balancing services, FG foresees a light weight alternative besides the regular PQ process for obtaining the PQ status by applying an ex-post verification. The idea behind this proposal is that the most normal “ex-ante” product prequalification can be replaced by an “ex-post” verification trying to add simplification in the process to help the participation of SPs. One of the requirements for this process, and since specific balancing products and local services usually are not prequalified before they can participate in the markets, is to foresee a temporary qualification status to be reviewed after their preliminary participation on the respective market. If the outcome of the verification process is positive, a regular qualification is granted to that product (as explained in the next Article).

3.3.13. Article 38 Product Verification Process

Criteria for the verification process will be detailed in national terms and conditions for service providers based on some guiding principles set in this Article.

The market participation(s) for a newly added SPU or SPG automatically serves as the input data to assess the SPUs or SPGs capability to deliver the requested product. If the result of this ex-post verification is positive, the respective SPU/SPG shall be granted the status of regular qualification.

3.3.14. Article 39 Principles for Governance and Interoperability

The provisions for the organisation and governance of the flexibility register have been written in a way to be in line with the framework guidelines that allow for single as well as multiple platform configurations for *flexibility registers*. This not only an appreciated clarification because of the fact that according to Article 23 of Directive (EU) 2019/944 data management is a subject to MS decisions, but also due to the fact that the flexibility register needs to integrate properly in diversely organised MS environments The decision to implement a centralised or de-centralised flexibility register will depend on the particular circumstances per Member State, such as already existing platforms to facilitate the qualification of service providers and the organisation of connection point registers among others. In distributed flexibility registers, a logical distinction between the different platforms is the domain of SP/SPU/SPG data and the domain of CU data, which is the reason why this Regulation is introducing a SP module and a CU module. The SP module shall facilitate the administration of data about the service providers and its respective SPUs and SPGs, whereas the CU module administers data about controllable units. The proposed code does not pre-empt which modules should be operated by which and by how many national actors, and also leaves the freedom for national actors to operate more than one of these modules. In any case and independently of the platform configuration of the flexibility register the single and common front-door as a single access point for service providers and other entitled actors shall be established and provided.

As the basis for the conceptualisation of the *Flexibility Register*, two main configurations have been taken under consideration that shall by no means limit the freedom for the actual implementation on Member State level:

Configuration 1: A single SP Register Platform; distributed CU data management

This configuration foresees one flexibility register platform that encompasses the SP module as well as the single and common front-door features, whereas the CU module functionalities are complemented in (existing) connection point registers. The flexibility register platforms with the CU modules interact with the flexibility register platform with the SP module and the *Common Front-Door* to achieve a seamless B2B integration. Changes due to existing/other energy-related processes are propagated through existing CP data registers. The relevant standing data is used in line with other market processes (like e.g. Energy Communities, supply, etc.) and management of standing data for the utilisation of balancing and local services by CUs is added. Newly needed functionality to organise these markets is then organised through a centralised platform dedicated to the utilisation of flexibility.

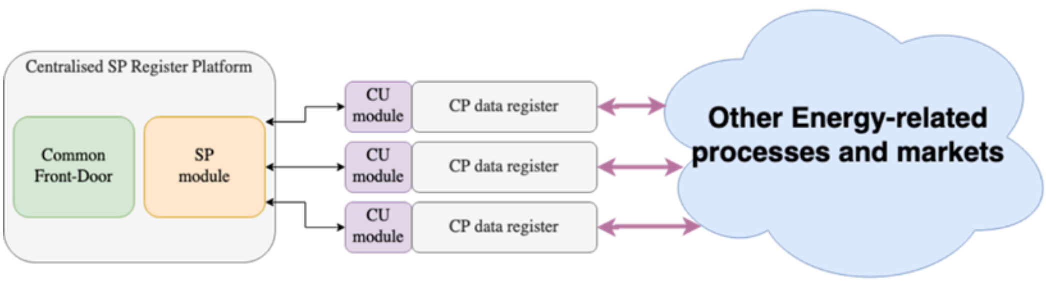

Figure 11 Configuration 1: Centralised SP Register Platform; de-centralised CU data management

Configuration 2: Centralised Flexibility Register Platform

This configuration foresees a realisation of all modules of the flexibility register within the same flexibility register platform, which is operated by a single operator or an entity owned by multiple shareholders. Here the interaction and synchronisation with other energy-related market processes and standing data management might be done through the single platform.

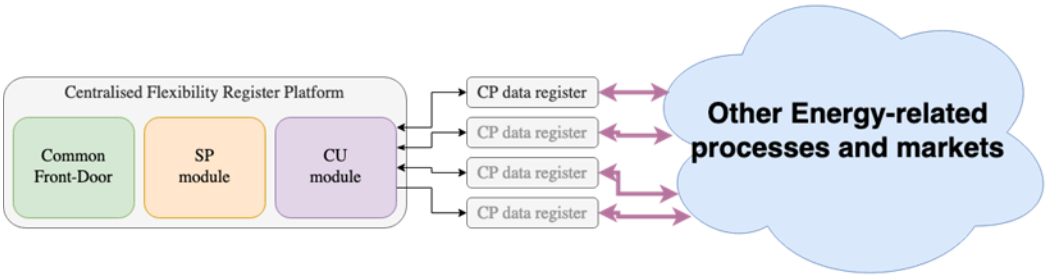

Figure 12 Configuration 2: Centralised Flexibility Register Platform

Configuration 3: Single Common Front-Door; multiple SP module platforms and multiple CU module platforms

This is to a degree representing MSs which have already built up and running solutions, with e.g. local markets operational in different areas. The aim here might be to leverage already rolled-out infrastructure and connect it through a *Common Front-Door.* For such MSs, also this setup might be tempting as an intermediary solution. However, the development team merely saw advantages in this approach, but also didn't see a reason for why to exclude that option, as current configurations look like this.

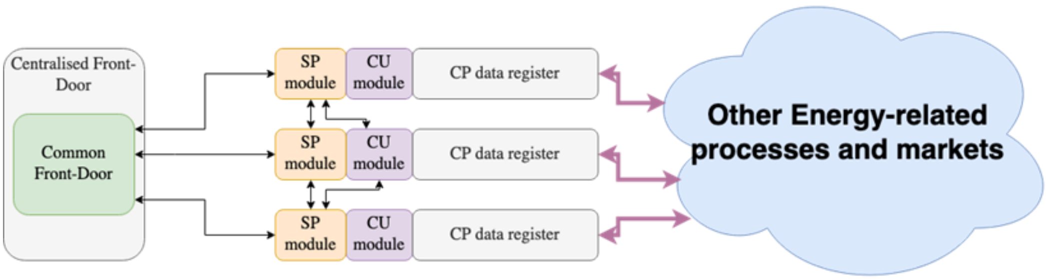

Figure 13 Configuration 3: A single Common Front-Door; multiple SP module platforms and multiple CU module platforms

3.3.15. Article 40 Principles and requirements for data exchange in the prequalification phase

3.3.16. Article 41 Principles and requirements for operators of flexibility register platforms

3.3.17. Article 42 SP module procedures

As of Article 45, national terms and conditions shall foresee the functional and data exchange related requirements for flexibility register SP modules. As a basis for the work, the development team used the following information objects and attributes to be stored and managed by an SP module. As a starting point, please see the list below:

Table 9 Service provider (SP) data managed by flexibility registers

No.	ATTRIBUTE	DESCRIPTION
0	SP register module	Identification of SP register module at EU level.
1	Identification	A unique identifier of the SP at EU level.
2	License issued by the NRA	If applicable.
3	Name	Name of the service provider in a human readable and clearly identifiable form.
4	Contact information	Comprising at least, but not exclusively, phone number, email and postal address.
5	Settlement information	Comprising at least the VAT number if applicable, bank account information and other related data.

Table 10 Service providing group (SPG) data managed by SP register modules

No.	ATTRIBUTE	DESCRIPTION
0	SP register module	Identification of SP register module at EU level.
1	Identification	A unique identifier of the SPG at EU level.
2	Service provider	Nationally unique identification of the service provider as referred to in Table 1 No. 1.
3	Qualification status	Qualification for products in Table of Equivalences for the SPG as a whole.
4	Limits on operation	Limits on operation due to grid constraints as provisioned in Article 34 – Grid prequalification, paragraph 2.

Table 11 Service providing unit (SPU) data managed by SP register modules

No.	ATTRIBUTE	DESCRIPTION
0	SP register module	Identification of SP register module at EU level.

1	Identification	A unique identifier of the SPU at EU level.
2	Accounting point identifier	Identifier of the accounting point / connection point the SPU is connected to.
3	Service provider	Nationally unique identification of the service provider as referred to in Table 1 No. 1.
4	Qualification status	Qualification for products in Table of Equivalences for the SPU.
5	Operational constraints Limits on operation	Limits on operation due to grid constraints as provisioned in Article 34 – Grid prequalification, paragraph 2.

Table 12 Third-party CU Operator data managed by SP register modules

No.	ATTRIBUTE	DESCRIPTION
1	Identification	A unique identifier of the technical at EU level.
2	License issued by the NRA	If applicable.
3	Name	Name of the CU Operator in a human readable and clearly identifiable form.
4	Contact information	Comprising at least, but not exclusively, phone number, email and postal address.
5	Settlement information	Comprising at least the VAT number if applicable, bank account information and other related data.
6	Switching documentation	Information on how controllable units operated by the CU Operator can be migrated to another CU Operator or to self-control by the final customer.

INITIAL TABLE OF EQUIVALENCES DATA

This list should be taken into account by ENTSO-E and EU DSO Entity when preparing the Table of Equivalences (ToE) Data in accordance with Article 9 of Network code on demand response.

Table 13 Product requirement characteristics of SPUs and SPGs in the SP register module, if the 'product requirements' -based ToEq approach is employed.

No.	ATTRIBUTE	DESCRIPTION
1	SPU or SPG identifier	Unique identifier of SPU or SPG at EU Level as described in Table 2.3 No. 1 and Table 2.4 No. 1.
2	Product requirement characteristics	Characteristics of the SPU or SPG in terms of the 'product requirements', as verifiable by the PPR that writes them.

3.3.18. Article 43 CU module procedures

INITIAL DATA ON SERVICE PROVIDERS, CONTROLLABLE UNITS OPERATOR, CONTROLLABLE UNITS, SERVICE PROVIDING UNITS, SERVICE PROVIDING GROUPS

This list should be taken into account by ENTSO-E and EU DSO Entity when preparing the Data on service providers, controllable units operator, controllable units, service providing units and service providing groups in accordance with Article 9 of Network code on demand response.

Table 14 Controllable unit (CU) data managed by CU modules.

No.	ATTRIBUTE	DESCRIPTION
0	CU module	Identification of CU module at EU level.
1	Identification	A unique identifier of the controllable unit at EU level.
2	Accounting point identifier	Identifier of the accounting point / connection point the controllable unit is connected to.
3	Service provider	Nationally unique identification of the service provider as referred to in Table 2.2.
4	CU Operator	Either the final customer or the unique identifier of the 'third-party CU Operator'.
4	Connecting systems operators	Connecting systems operators of the connection/accounting point the controllable unit is connected to.
5	Locational information	Geographical or topological information about the location of the accounting point/connection point in the grid.
6	List of SPGs and SPUs the controllable unit is a part of	If applicable, the identification of the SPG or the SPU belongs to as referred to in Table 2.3 and Table 2.4.
7	Grid prequalifying party	Entitled party that has confirmed the grid prequalification details of the controllable unit. In most cases, this will be the connecting systems operators.
8	Grid prequalification status	Status of the grid prequalification of the controllable unit.
9	Start date	Meaning the date from when the controllable unit is grid qualified, if applicable
10	End data	Meaning the date until when the controllable unit is considered grid qualified, if applicable
11	Regulation direction	Meaning the regulation direction, the controllable unit is qualified for; Up, down or both.
12	Minimum duration	Meaning the minimum time for which the unit can be activated.
13	Maximum duration	Meaning the maximum time for which the unit can be activated.
14	Standard implemented	If applicable and if the controllable unit is a standardised CU, the reference to the certified standard implementing by the controllable unit.
15	Type certificate information	If applicable, information on the certificate the standardised CU has obtained.
17	Supplier	The supplier assigned to all technical resources within a controllable unit. Note that all technical resources coordinated by a controllable unit must be assigned to the same supplier.

3.3.19. Article 45 Principles for national implementation

The obligation for systems operators to develop National terms and conditions for service providers is given in Article 5 of the Regulation. Article 45 gives overall provisions for the development of the TCs on National level and also summarizes the relevant provision from other Articles to help the implementation. Nevertheless, the context of these provisions is described in the respective Articles where Article 45 refers to, and the National implementation shall take this into account.

3.3.20. Article 46 Table of Equivalences

In order to understand better the (Pre-)Qualification and Verification Process, it is important to understand how the ToE, List of comparable product attributes, products and their requirements would work together to enable simplified qualification efforts for SPGs offering multiple products – nationally and at a European level. Figure 14 below gives an overview on the respective actors, elements and processes. Below the figure, the reader finds a chronological view of certain steps to be run through in product qualification lifecycles.

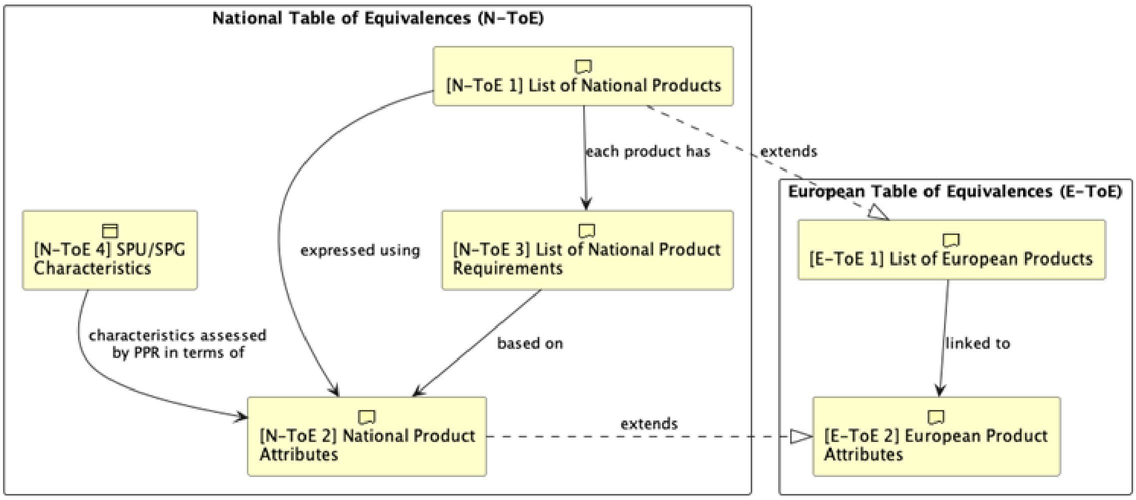

Figure 14 **Relationship of National ToE and European ToE**

- [E-ToE 1] ENTSO-E and EU DSO entity define and publish a common *List of European Products*, refine and streamline a list of attributes that most of these products have in common. Periodically, this list shall be reviewed and adapted according to the *Lists of National Products* defined at MS level in [N-ToE 1].
- [E-ToE 2] ENTSO-E and EU DSO entity elaborate that list of common *product attribute specifications*. Products in step [E-ToE 1] must all be expressed using these attributes. Processes are foreseen to periodically and as necessary update the *List of European Products* and the *product attribute specifications* done in [N-ToE 1] and [N-ToE 2].
- [N-ToE 1] MSs extend and publish at national level the *List of National Products* and add their own products. As far as possible, these national products are defined using the *European Product Attributed* defined in [E-ToE 2].
- [N-ToE 2] MSs define and publish necessary *National Product Attributes*. Hence, products defined in the *List of National Products* will express their requirements using European and national attributes.
- [N-ToE 3] *National product requirements* are expressed using the attributes defined in [E-ToE 2] and [N-ToE 2]. It is important that requirements can be expressed in a flexible manner (e.g. Boolean is_available/is_not_available, minValue/maxValue, etc.). However, the structure should always remain the same for all products.
- [N-ToE 4] When – later - *[Q3]* Evaluations is done for SPUs/SPGs, the results of the SPG assessments are written in a *Register of SPG Characteristics* inside *SP modules* of Flexibility Registers to make these characteristics available to entitled parties.

Table 15 Exemplary list of product attributes

No.	ATTRIBUTE	DESCRIPTION/ DEFINITION
1	Product identifier	Unique identifier of the product at EU level.

2	Name	Name of the product at national level.
3	Product category	May be one of: Standard balancing Specific balancing Congestion management Voltage control based on active power Voltage control based on reactive power Other
4	Capacity / energy	This attribute determines whether the product accounts for the possible acquisition of capacity (in MW or MVAr) or energy (in MWh or MVArh)
5	Validity period	The period when the bid offered by the service provider can be activated, where all the characteristics of the product are respected. The validity period is defined by a start and end time.
6	Duration of the contract	The duration of a given contract between the system operators and the service provider. The duration may vary from hours to years.
7	Locational information	Information where (electrical localisation defined on national level) the product is available.
8	Direction of activation	Direction means in which direction (up or/and down) the volume can be activated.
9	Symmetric/asymmetric product	This attribute determines whether only symmetric products or also asymmetric products are allowed. For a symmetric product upward regulation volume and downward regulation volume has to be equal.
10	Certificate of origin	This attribute determines whether the service provider would be required to deliver a certificate of origin of the energy they sell.
11	Maximum number of activations per time period	Maximum number of times the procuring system operator can activate a service provider during a period of time.
12	Availability Window	Availability window (e.g. per 15 minutes, per hour, per day, per week, per year) is the time period required by the procuring system operator when the resource shall be available to provide a service.
13	Recovery period	Minimum duration between the end of deactivation period and the following activation.
14	Preparation period	The period between the activation request by the procuring system operator and the start of the ramping period.
15	Ramping period	The period during which the input and/or output of power will be increased or decreased until the requested amount of power is reached.
16	Full Activation Time (FAT)	The period between the activation request by the procuring system operator and the corresponding full delivery of the concerned product.
17	Minimum and maximum duration of delivery period	The minimum/maximum length of the period of delivery during which the service provider delivers the full requested product.
18	Maximum positive and negative rebound avoidance time	The maximum time to which a demand reduction or increase can be shifted before or after the delivery of the service (if applicable).
19	Maximum rebound power	Maximum additional power that can be used between rebound avoidance time
20	Deactivation period	The period for ramping from full delivery to a set point.
21	Mode of activation	The mode of activation of products, manual or automatic, depending on whether product is triggered manually by an operator or automatically in a closed-loop manner.

22	Minimum and maximum quantity	Minimum and maximum quantity of a bid traded on the market and it may be capacity or energy based depending on the nature of the product
23	Divisibility	The possibility for the procuring system operator to use only part of the bids offered by the service provider, either in terms of power activation or time duration.
24	Granularity	The smallest increment in volume of a bid.
25	Maximum / minimum price	Maximum and minimum price the procuring system operator accepts.
26	Aggregation allowed	Determines whether a grouped offering of power by covering several units via an aggregator is allowed.
27	Baseline methodology	Methodology used to estimate the volume of energy delivered by an SP compared to the case if the product would not have been activated.
28	Redundancy of Data Link	This attribute determines (YES or NO) whether a dual data connection is required or not. Dual data connection means second independent communication channel.
29	Data Granularity	The required data resolution in seconds or minutes
30	Data Type	This attribute determines whether the data is based on real time metering values or calculated average values
31	Archiving	This attribute determines the minimum duration the data needs to be archived (e.g. 0, 1 month, 3 months, 6 months)
32	Measurement Accuracy	This attribute determines the max. tolerated measurement error (e.g. 0,5% or 1%)
35	Data Protocol	The communication protocol(s) (e.g. IEC 60870–5–101) the systems operators accept
33	Data Interface	The data platform(s) over which the service provider is allowed to connect
34	Metering Type	The type of meter used (smart meter, traditional meter, dedicated measurement device)
35	Quality of service	This attribute determines max. tolerated failure ratio in executing an activation, to be guaranteed by the service provider (e.g. 1% or 5%)

3.4. TITLE IV - MARKET DESIGN FOR LOCAL SERVICES

3.4.1. Article 47 Solutions for congestion and voltage issues through active power

The main purpose of this Draft Network Code on Demand Response is to establish a European legal framework that facilitates the creation and development of local markets to solve congestion and voltage issues by enabling demand response and distributed energy resources while ensuring interoperability with the existing markets. Market-based options are the preferred and default option for solving congestion issues and voltage issues.

To maintain stable grid operation, both in the short- and long-term, market-based local services or other measures will be applied as appropriate. It is of utmost importance that the system operators have a well-established national framework to guide their long-term and short-term decisions. The relevant national authorities are key to establish that national framework, which should strive for optimising socio-economical welfare. Systems operators shall take decisions to choose between available options following effectiveness and efficiency criteria, as well as in transparency and coordinated manner, in line with such national framework. Article 48 para 5 e and *f* sets out that procurement of market-based solutions requires liquidity. Article 49 para 4 a-c sets out that procurement of market-based solutions has to be economic efficient. The national framework needs to guide systems operators in their decision.

To solve congestion issues and voltage issues, transmission and distribution system operators may apply redispatch mechanisms pursuant to Article 13 of Electricity Market Regulation 2019/943 as well as other mechanisms, such as products contracted in long term capacity markets that may be activated before day-ahead markets (e.g., by 'dispatch limitation' products activated before day-ahead) on the basis of system operators forecast of congestion or voltage issues. Market-based redispatching mechanism within a bidding zone, described in article 13 of Regulation 2019/943, is understood as a local market.

Nevertheless, this Draft Network Code on Demand Response acknowledges that, in line with Articles 32(1) and 40(5) of Electricity Market Directive 2019/944, the local character of congestion issues and voltage issues may lead to market failure. Competition in an area may be limited due to service providers' market power or a lack of sufficient offers, and strategic bidding and gaming between markets may occur. Therefore, there is a need for the regulatory authorities to enable other solutions when market-based procurement is not suited to cost-effectively solve congestion and voltage issues or may even aggravate congestion or voltage issues. National authorities may then establish or allow non-market-based solutions to solve congestion and voltage issues.

A rules-based mechanism is understood as a specific mechanism available to systems operators pursuant to their applicable framework -therefore following a competent national authority decision-, which allows a deviation from market-based procurement.

In the absence of a competent national authority decision for applying a rules-based mechanism at the moment of entry into force of the Network Code on Demand Response, systems operators will follow requirements in Article 48 and present, at the latest 18 months after the entry into force, common proposals for terms and conditions pursuant to the Network Code on Demand Response. Even in the case of a rules-based mechanism at the entry into force of the Network Code on Demand Response, systems operators are entitled to present common proposal for national terms and conditions to procure market-based local services on a complementary manner to the existing rules-based mechanismsFor example, it is already the case that rules-based are applicable to generation over a threshold, therefore those resources may be affected by a rules-based mechanism (therefore the reference to 'partially applied' in the draft) while other demand-side resources may engage in market-based mechanism on a complementary manner.

It may happen that, even in the absence of a national authority decision for a national rules-based mechanism, at the time of proposing terms and conditions for a market-based procurement of local services, transmission and distribution system operators find the need to clarify to the national authorities why market-based is not a suitable approach and the possible alternative approaches to deal with congestion and voltage issues, for national authorities' approval. A system operator may only apply non-market-based congestion management and voltage control mechanism pursuant to an assessment by the national regulatory authority, in line with requirements in Electricity Regulation and Directive. As a result, an assessment conducted by national regulatory authority may conclude, in line with provisions in Articles 32 and 40 of Directive and in Article 13 of Regulation, that a market-based approach is not suitable and may allow transmission and distribution system operators to adopt non-market-based solutions. The conclusion might be different for different parts of the grid or voltage levels depending on the nature of the grid, maturity of marked-based solutions or liquidity in a marketplace.

There may be changes in the underlying conditions that led to the initial conclusion for the national regulatory authority to motivate a rules-based approach: for example, if the number of flexible resources connected to a grid level or in a grid area increases sufficiently to ensure competition, a market may then become feasible in parts or the whole of the grid. Another example can be the existence of a sufficient amount of controllable demand units and corresponding SPs while the competition for generation units may not be sufficient, which allows only for partial implementation, treating all demand units on an equal level. Conditions that were evaluated by national competent authorities when making the decision allowing systems operators to deviate from market-based procurement may vary and therefore authorities should check at least every two years if this is the case, in order to re-evaluate the decision. In the latter case, if the authority concludes that market-based procurement shall be applied, systems operators shall then propose a roadmap to implement market-based procurement of services. The timing for implementation may be very different, depending on the existence or not of a mature local market that can be subscribed by the systems operators and the extent to which the existent market covers the needs.

3.4.2. Article 48 National terms and conditions for market design for local services through active power

The article presents a non-exhaustive list of what the systems operators could consider when making the common proposal for national terms and conditions for local market design. All this, to be able to account for existing electricity markets and their possible impact or how they might be influenced, the nature of the existing grid with its connected grid users and systems operators as well as describing the roles, responsibilities and processes.

Allocation of local market costs

Draft Network Code on Demand Response states that the allocation and recovery of costs to solve congestion and voltage issues shall be determined at national level.

This drafting option is consistent with the existence of different regulatory regimes that today coexist in Europe regarding the treatment of congestion management costs.

It may be of interest to clarify that the cost of redispatching or other local services is not in all member states allocated to DSOs or TSOs. In some cases, costs are dealt as power system costs and follow a specific treatment under national regulatory authorities´ supervision. This does not mean that there are no incentives to network operators to reduce the amount of congestions/market restrictions – e.g., indicators and corresponding incentive/penalty may be set at national level. Additionally, there may be diversity in the way the cost is allocated to customers (e.g., only to demand customers, also to generation, etc.).

The drafting option is consistent with the main principle of subsidiarity, since national regulatory authorities are those responsible to make the decision on how these costs of intra-zonal markets are allocated and recovered from customers and on the role of transmission and distribution system operators in translating locational price signals to end customers.

3.4.3. Article 49 and 50 Principles for procurement and pricing for market-based local services and principles for tender

Article 49 describes the main principles for procurement and pricing for market-based congestion management and voltage control services. The principles shall:

- Enable participation of all resources, not only demand response,
- be non-discriminatory,
- be technology neutral, and
- respect confidentiality.

The principles also ensure that market processes allow for matching needs and offer, in timely manner and therefore enable an effective solution to grid issues. 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.

In case of low market liquidity or high risk of market abuse, it may be necessary to implement mechanisms to ensure an effective functioning of the markets limiting the risk of gaming and high prices. Such mechanisms could include: only procuring in case of availability of sufficient offers of different service providers, price caps, or linking the pricing of a market to the mean prices of another more liquid market.

When technically feasible, products can be defined in such a way that they can be activated for different purposes or for the same purpose in different grids.

It is important to note that service providers shall only be remunerated once for the delivered product - still making value stacking possible through enabling participation in different electricity markets.

The pricing mechanisms shall be efficient and fair, allowing variations depending on product, voltage level and the horizon of the product contracted. The pricing mechanisms shall also, when assessed efficient, allow differences between energy prices and availability prices in capacity markets or in tenders.

Submission of bids from non-precontracted providers shall be allowed in capacity markets.

Activation of bids without a procured capacity shall be able to compete on equal terms with activation bids resulting from a procured capacity. This combination of a capacity and activation market may promote more liquidity and competition thus resulting in more cost-effective use of available local services.

Article 50 describes conditions for tender procedures to enable not yet installed, contracted or registered assets to participate. In the case of non-connected assets, it is of additional importance that systems operators ensure that the service providers engaged in the tender process do not have access to preferential information over other service providers. This relates to the possible further discussions when setting up the connection agreements which can increase the risk to disclose preferential information with respect to the information available to the other service providers and market participants when discussing the details of the conditions of the connection.

3.4.4. Article 51 Principles for applying flexible connection agreements in the context of solving congestions and voltage issues

Article 51 states principles for the interaction of congestion management products on the one hand, and flexible connection agreements on the other, ensuring that markets are not unduly distorted.

In line with whereas 15 of New Market Design -recast Directive- “in areas where electricity grids have limited or no network capacity, network users requesting grid connection should be able to benefit from establishing a flexible, non-firm, connection agreement”.

Non-firm access rights are normally implemented in the form of ‘flexible connection agreements’ as in definition 24(b) of recast Directive:

‘flexible connection agreement’ means a set of agreed conditions for connecting electrical capacity to the grid, that includes conditions to limit and control the electricity injection to and withdrawal from the transmission or distribution network.

It must be noted that the network access and connection conditions are differently regulated, in content and in form, all over Europe. In some Member States a quite prescriptive top-down approach is followed, where national framework describes the system users’ rights - including non-firm conditions- that may be extensive to all units of a certain technology (e.g. all generators over a certain national threshold), while in other Member States the access and connection conditions are less regulated and therefore more bottom-up approach is followed, where the systems operators can propose ad-hoc network access conditions in line with a streamlined national approach.

3.4.5. Article 52 Publication of information

Article 52 deals with requirements of the procuring systems operators and the operators of local market for publication of information regarding utilization of market based local services.

Published information can be divided into the following categories:

- General information on market rules (paragraph 1 -3)
- Information prior to the procurement – ex-ante publication.(paragraphs 4-7)
- Information after the procurement – ex-post publication or publication of market results (paragraph 8).

The systems operators shall make available approved national terms and conditions and other market relevant information on their website or similar. The information must be open and accessible, so it is easy for service providers and other market participants to acquire it. Specific rules for a market must be published by the systems operators or the operators of local markets in the same manner as national terms and conditions. Included in this are requirements for the products in a local market, the way bids are selected and the pricing mechanisms.

Paragraphs 1-3 are mandates to procuring system operators and to operators of local markets, as applicable, to publish the main features of local markets, as part of national terms and conditions or as applicable to ensure full transparency of the services to market participants and service providers, namely: the local product characteristics, the pricing mechanism and the economic conditions to service providers, number and structure of market sessions, gate closure times, etc.. The local market operator should publish relevant ex-ante information on the functioning of the market and the platform,information on market sessions, gate closure times and type of products that can be provided on the platform.

Paragraph 4 is a mandate for transmission and distribution system operators to publish non-binding estimation of flexibility needs, at least as frequently as the network development plans, with the intention to facilitate information of interest to market participants that may be useful for market participants business prospection. To give the service providers predictability, foreseen utilization patterns and expected volumes from the systems operators will also be provided when seen important for the market. However, this is only published in the cases where it is needed to ensure the proper functioning of the market.

Paragraphs 5 gives requirements for the systems operators, when this is necessary for the operation of the market, to give the providers of local services sufficient information on various properties such as regulation direction, time and location granularity as well as location. Other type of information, like impact factor, may also be relevant for the service providers, since it is a property that can influence the utilisation and competitiveness of a single or aggregated resource. This information is increasingly sensitive with potential effects on gaming and can thus only be shared, where it is strictly necessary for the proper functioning of the market. All published information must be provided in an accessible and transparent manner where the publication has two main perspectives.

- First, is to give market signals in long term and inform providers as applicable and needed in short term market period, with sufficient information on what, when, where, and how much the services are needed.
- Second, and equally important, is to provide the market participant and in particular the service providers important information to be able to provide the needed service.

When publishing information, there should be a balance between providing transparency to market participants on one side and avoiding the risk of market abuse on the other. Thus, sensitive information can only be shared where it is required to ensure the proper functioning of the market. The publication of volumes needed in daily market time may not be suitable in all cases, since it is market sensitive information that poses the risk of gaming and resulting higher prices, actually harming the proper functioning of the market. Thus, publication of this information would be applied depending on the circumstances of a given market, but not as a European mandate.

Paragraph 6 provides a requirement for the systems operators to describe information exchange and other mechanisms that must be implemented so that the national regulatory authority may be able to monitor possible market abuse or distortion. Whether the mechanisms are implemented automatically or by request must be described in the national terms and conditions. Possible mechanisms may include an automatic access of national regulatory authority to the market data and the possibility to configure alerts in case indicators like prices of volumes are attained.

Paragraph 7 sets requirements for systems operators applicable in the case of procurement of capacity products, where there is a need to publish the relevant information for the participation, including the required volumes, the selection criteria and the relevant details of the contracting process.

Paragraph 8 mandates procuring system operators or if applicable to operators of local markets the publication of market results. The ex-post information for both capacity and activation shall be published with price, volume and time. Information on the market session shall be provided no later than one day after activating products or one day after allocating the capacity.

NRA may indicate to systems operators the need to withhold information when justified for well-functioning of a marketplace as well as require the systems operator to provide all published information on a common national solution.

3.4.6. Article 53 Criteria for the coordination and interoperability between local and day-ahead, intraday and balancing markets

Article 53 sets principles for market coordination and interoperability between local markets and other local markets, day-ahead, intraday and balancing markets. Draft Network Code on Demand Response often refer to “and other electricity markets”. Where not otherwise specified, this refers to at least other local, day-ahead, intraday and balancing markets.

Recognizing the diversity of models currently employed, the finetuning of the new rules is delegated to the national level. This avoids inefficiencies due to the need of major adjustments in market designs and will streamline necessary adjustments and lead to quicker implementation of the Regulation.

Market integrity, and thereby the fair and secure operation of markets is the basis for market participants confidence in the markets and their proper functioning. One aim of coordination and interoperability is to enable resources to participate in different markets, thus increasing liquidity of markets, while excluding double activations. Thus, this article includes provisions for value stacking, although it is not explicitly mentioned by that term.

Stacking the value of the resources in SP portfolios can be achieved either by a market design where coordination to ensure market integrity and non-double activation allows SPs to bid in different markets, applying their own SP bidding strategies, or can be facilitated by features such as portability of bids and thus the option to translate bids made on one market to bids in another market in a standardized way.

These two possibilities for coordinating local markets with other electricity markets (forwarding of bids or coordination between markets to ensure non-double activation) are illustrated in the figure below.

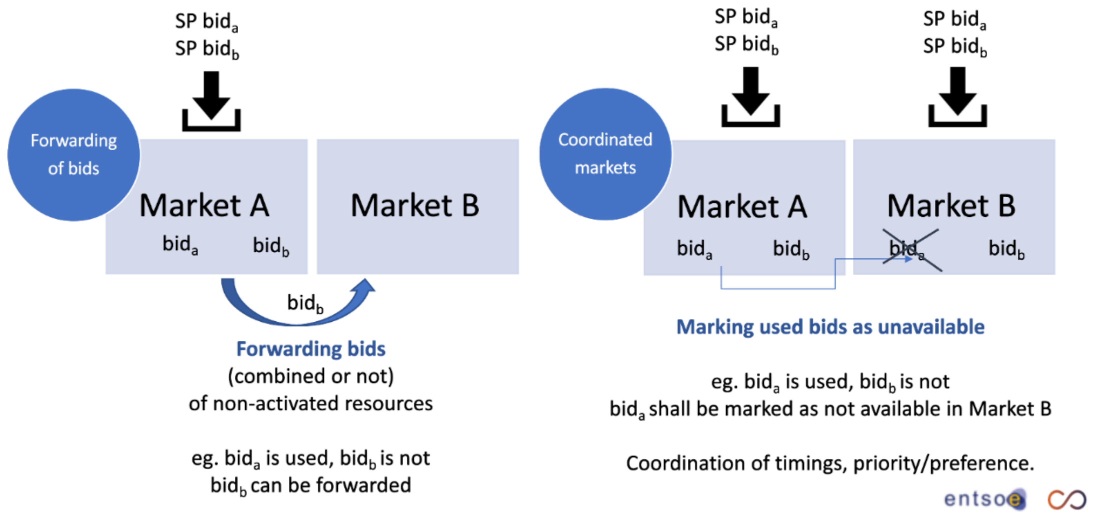

Figure 15 Non-exhaustive possibilities for the coordination of bids between different markets

In the case of interaction between local and wholesale markets, distortion of wholesale markets, and thereby a significant interference that affects prices, shall be avoided by design and by monitoring process. Examples of interactions between local markets and wholesale that do not distort market are GOPACS in Netherlands or Technical Constraints markets in Spain. In both cases, in the Netherlands and Spain, a separate process to account for limitations to the spot market bids is established, where the locational information is available, and the solution is coordinated with NEMOs ensuring non-affection to market-coupling prices.

While coherence between market timeframes and interactions is important, the Draft Network Code on Demand Response leaves room to reflect different needs at different voltage levels by enabling different minimum bid sizes and granularities in local markets following the national terms and conditions. Coherence means that all different local markets should interact in comparable time frames for their respective processes, respecting established deadlines for necessary data transfer. The scheduling and imbalance settlement process are to be seen as a minimum; more processes might need to be addressed depending on the national circumstances.

Interactions will depend on the national implementation of the market design. They could include exchange of information on volumes or market positions/nominated volumes, on restrictions or others. The number of local market places may influence the design of the coordination mechanisms, their complexity and ultimately efficiency as the necessary coordination needs to be taken into account. It is however not the intention for existing markets to be combined with local markets. This is not meant to change existing markets, e.g. by adding requirements for locational information. However, where market design allows to use bids on existing markets, for purposes such as congestion management or to resolve voltage issues, the terms of this have to be specified in the applicable national framework. Furthermore, this option shall not lead to the exclusion of creating local markets.

Article 53 also allows for reusing non-awarded bids under service provider consent if this is feasible. Since other market may require larger bid sizes or different granularity, or product requirements, aggregation of different non-selected bids is a necessary step to fully utilize the potential of existing bids. At the same time, selecting a bid twice shall be prevented, as well as any double payments for this. The national terms and conditions may assign this responsibility to the SP or may assign this otherwise.

It is not specified whether sequential, parallel, simultaneous or other market processes are to be used to leave more freedom for national implementation and the resulting market design. The choice of one method might vary depending on the number of local markets or market areas, market liquidity and whether forwarding of inactivated bids is allowed.

National terms and conditions shall clarify if and how offering non-selected bids or volumes to another market is made: it can be done either by the SP themselves, or by a third party or the market operator. Details shall be determined given the chosen market design, market model and especially the involved timeframes. In case of sequential markets (different GCTs) it is possible that the bids of the earlier market are forwarded to the next market, provided that the SP and the SPUs/SPGs offered in the bid are prequalified for that market. It facilitates the use of the bid. However, it also has to be considered, that it places additional technical requirements on the market, while the benefits for the SP are not always given. A SP may want to change SPU/SPG configuration and/or price of a bid before he places it on the second market.

Lastly, national terms and conditions may allow for CUs to participate in different SPGs for different services. This may be done to increase market access and liquidity in markets for different services, but would require accompanying processes to enable this, given prequalification of the concerned market.

Procurement of local services in different Member States: examples – use cases

The description of the examples has been structured in a way to illustrate concrete realisation of the main features of the market design and is provided as an illustration of the diversity of possible solutions applied to solve congestion and voltage issues:

1. **Which are the products and voltage levels traded in the local markets?**

It may be the case that different products and even different complementary markets coexist nationally, to cope with differentiated needs or targeting different type of resources (eg. generation vs. demand).

In particular, in some capacity markets, products are contracted time ahead of their activation, while in other markets products are only contracted in short term markets.

In some cases (GOPACS in Netherlands, Technical Constraints in Spain), the existing markets solve congestion and voltage issues at both transmission and distribution level, in other cases markets differ from voltage level.

Products are in some cases considered redispatching products, in line with Art. 13 of Electricity Market Regulation 2019/943 while in other cases, specific local products are defined or are under discussion:

- to cope with specific and highly local needs in the DSO grid – e.g., rural, PV dominated, low load areas (low voltage); Wind-dominated low load (medium-high voltage), urban, EV or heat-pump areas (low voltage) in both rural (mainly PV) and urban (electric vehicle) grids in the next 5 years: e.g., the case in Switzerland, Spain, France.
- some TSOs are considering procurement of congestion management at node level,
- in the form of contracted capacity with demand, to promote demand participation at all voltage levels: in France,
- as a mix of activation markets supplemented by some volume to be secured via voluntary bids on capacity markets.

2. **Which are the examples of coordination between local markets interacting with spot markets?**

We have found so far two examples of local markets interacting with spot markets:

- GOPACS in the Netherlands - GOPACS is connected to EPEX SPOT.

- Technical constraints in Spain - an interaction between the operator of the technical constraints market (TSO) and the Market Participants and the NEMO is realised to allow:
    - A final published solution of day-ahead market, after having solved constraints (local congestions, voltage issues).
    - Reception of day-ahead and continuous information on updated market participants positions that, complemented with disaggregated information received from market participants, serves as input for both transmission and distribution system operators security assessment.
    - The result of the technical restrictions process may have an effect on declared market participants allocation before the market results are published, that is communicated to NEMO in the form of schedule limitations. These limitations can also affect the balancing services allocation.

3. Which are the examples of interactions between local and balancing markets?

- **Central Dispatch Model (Ireland, Poland, Italy, Greece):**

In the case of central dispatch models, an integrated scheduling process is applied. This is not based on a separate "national market" for products related to system needs.Congestion and voltage are managed through the integrated scheduling approach to the balancing market, at the same time and through the same actions on the same units also meeting all other system needs including balancing energy, balancing capacity, and other non-energy requirements.

Transmission system congestion and voltage requirements are included within "the latest control area adequacy analysis and the operational security limits" (as per the EBGL definition) inputs to the integrated scheduling process. In the case of Ireland and Northern Ireland, this comes from a combination of a full transmission network model being included in the balancing market optimisation, and operational constraints with minimum or maximum MW or number of unit requirements depending on the specific congestion and voltage requirement being met. For instance, voltage requirements tend to be met through constraints where a minimum number of generator units from a set located in particular areas must be kept synchronised, and certain transmission congestion requirements can be met by setting a maximum MW output limit on a set of generator units located in a particular area (in addition to network models). If any actions are taken for voltage support or congestion management, it is done through the balancing market and by activating integrated scheduling process bids.

Given the co-optimised nature of the integrated scheduling process, all energy and non-energy actions are taken at the same time through the balancing market, all dispatches and actions taken are based on schedules where all energy and non-energy drivers are co-optimised at the same time in the same process. Therefore, all actions are taken for energy and multiple non-energy reasons (dispatch and redispatch rea-sons) at the same time, and each individual service provider and resource on whom an action is taken can be contributing to energy and multiple non-energy drivers at the same time. Therefore, it would be very complex to disaggregate between energy and non-energy reasons for actions being taken, and even more difficult to determine the extent to which an exact non-energy reason was a driver for an action on a particular unit – it may not be possible to disaggregate the actions taken for specifically congestion management or voltage control.

In this sense, there is no "national market" for congestion management or voltage control, at least currently – in the future there are plans for ex-ante auction-based voltage control products, and while there are currently no plans for TSO congestion management products the DSOs are planning products for distribution system congestion management.

- **'Integrated model' balancing-congestion management**

In the Nordic countries, bids offered in the balancing markets can be used for multiple purposes by the TSOs, depending on the operational situation. In addition to be used for balancing purposes the bids can also be used for solving congestion issues or voltage issues, if technically feasible. Firstly, any congestion or voltage issues related to grid issues are managed and secondly any need for ensuring balance between production and consumption of electricity and a voltage frequency of 50 Hz are managed. The selected bid is only remunerated once, either due to grid or to balancing issues. This integrated model provides equal treatment of service providers and ensures technological neutrality whilst having due regard to the particularities of the resources.

- **'Forwarding of bids' from local to balancing**

In sthlmFlex, CoordiNet Sweden and Norflex a time coordination between the balancing market mFRR and the local market was demonstrated where not activated bids from the local market could be forwarded to the mFRR market after the closure of the local market two hours before operating time, given the SP´s consent.

4. Application of unit or portfolio bidding and availability of locational information:

Unit and portfolio bidding may also co-exist if coordinated well, e.g. if mutually exclusive unit bidding is applied for local services in a small area and portfolio bidding for local services on the zonal level.

In the German balancing capacity and energy market portfolio bidding is applied, and no locational information is available in the DA and ID markets.

In the Spanish market, the bidding process in spot markets is followed by a 'nomination' process where the market participants send disagreed information about the physical units that compose their successful bids. This disaggregated information is the input for the security assessment by both TSO and DSOs. The locational information is not part of the bid itself, but an information available in the structural data base that supports the technical constraints market.

- **Cases dealing with specific operational limits, timely needs and small sizes of resources.**

Local markets can take the form of redispatching or other markets that can coexist with other local markets. Existing redispatching markets, today widely used by TSOs and in some cases also by DSOs, are complemented in some cases with additional markets to cope with more granular and specific needs, and to facilitate demand response.

For example:

- the local markets in Sweden stlmflex and Effekthandel Väst,
- procurement of local services in France by DSOs, while TSO procures congestion management through a different mechanism (mechanism d'ajustement) or
- sandbox for local markets currently under discussion in Spain.

Note that the balancing markets in Sweden address TSOs. In order to meet DSOs need to address operational limits, local services are needed.

It may be of interest to point out that, depending on the DSO need, a local service allowing lower size of bid than the one used in redispatching or balancing markets (typically 1MW) can be purposeful.

Also, DSOs may have the need to be able to procure local services that are activated before the daily market.

3.4.7. Article 54 and 55 Requirements for procuring system operators and for local market operators

Article 54 states fundamental requirements for procuring system operators neutrality, transparency and non-disclosure of preferential information with affiliated companies. Main responsibility of procuring system operators is to select or identify the units, bids or volumes, as applicable in line with the national rules, that are procured to solve a congestion or voltage issue. The options on the object (units, bids, volumes) that a procurement system operator selects correspond to the different European practices (see Article 53).

Article 55 states fundamental requirements to operators of local markets on their technical, financial and operational capability, on neutrality and adequate level of business separation, on respect of confidentiality and on acceptance of regulatory oversight. The functional requirements were drafted to ensure that local market operators act with sufficient independence from market participants and are equipped with the required tools and resources to fulfil their role.

3.4.8. Article 56 - Appointment of local market operator(s)

The Development Team has considered and extensively discussed different options as part of the drafting process:

- Assignment by national regulatory authority
- Third party local market operator per default
- Procuring system operator per default
- Assignment process part of the national terms and conditions
- 'Silent option', without any requirement on the assignation process

The Development Team agreed to present two options in the draft, for discussion with ACER and national regulatory authorities, which are explained below.

Option 1: ENTSO-E preferred option.

The procurement of local services can be organised in local markets facilitated by "local market operators" (LMO). This role is for the first time introduced in EU legislation. The Draft Network Code on Demand Response describes its main tasks and requirements for its designation. **LMO role is different than the role of procuring system operator**.

The LMO should facilitate the correct functioning of local markets. It is essential to ensure neutrality, transparency and efficiency in both the designation of the role and the conduction of its tasks. Therefore, there is a **need for the national regulatory authorities or competent national authority to approve or appoint the LMO and to oversight their activity**.

When this role is assigned, national circumstances regarding the structure of transmission and distribution as well as the national regulatory framework need to be considered. The assignment of the LMO role is to a certain degree dependent on the market design. For example: In the case it is deemed more efficient for multiple system operators to procure from one common local market to maximise the liquidity and ensure an efficient use of resources, there is no single procuring system operator in that market, but multiple, and the best suited party or parties (e.g., joint venture) need to be identified.

National authorities shall be capable to decide on efficient market-places and to nominate/designate their operators (TSO or DSO, TSO together with DSOs, DSOs jointly, mandate to a third party in cooperation with procuring system operators, etc). The decision by the national authority should also **avoid market fragmentation and inefficiency, promoting local market liquidity and ensuring neutrality and transparency**.

It is proposed that systems operators support national regulatory authorities or relevant national authority decision by submitting their proposals as part of the terms and conditions developing local markets. Systems operators may propose either an entity (including the possibility for a joint responsibility) or a process for an entity to become a possible LMO (process where the nomination of acceptable candidates, for latter selection by systems operators, is clarified).

It is of relevance to highlight that in some Member States national authorities have already taken or are taking a decision based on a unified national market design that promotes liquidity, an efficient participation of aggregators and service providers and a maximum coordination with other markets.

A drafting option that assigns the role of LMOs to each procuring system operator (Option 2) is considered unproportionate, not purposeful to achieve the goals of the Draft Network Code on Demand Response, bears a high **risk for market fragmentation and introducing barriers for aggregators and service providers** and it is **not considered a solution that fits all Member States**. This option pre-empts that the market design will be such that each DSO and each TSO operates their own market. This bears a high risk of market segregation and is likely to end up with very low liquidity in those markets, resulting in markets that are not functioning properly. This could lead to national regulatory authorities not allowing market-based procurement in the first place, since they must ensure that the conditions of the Directive (EU) 2019/944 and the Regulation (EU) 2019/943 are met. Therefore, the **need for a drafting option that allows national decision to be proportionally and efficiently made** by national regulatory authorities or relevant national authority, while still allowing for such an assignation (procuring system operator being its own LMO) at national level.

Finally, there is a lack of clarity regarding the 'common information platform' for procuring local services as it is proposed in option 2. The need or added value of multiple marketplaces that are connected to a common information platform compared to one or very few marketplaces is unclear. The timeline and governance to develop the common platform are also unclear and the cost-efficiency is questionable.

Option 2: DSO Entity preferred option.

Directive 944 article 32 is clear in its intent and scope: "Member States shall provide the necessary regulatory framework **to allow and provide incentives to distribution system operators to procure flexibility services** [...]", This network code shall aim at enabling distribution system operators to procure local services and shall not create unnecessary burden and barriers for system operators.

To guarantee that local markets are integrated, to avoid fragmentation and to achieve efficient solutions, every Member State shall have:

- a common information platform on market-based procurement for local services so that the service providers identify and recognize all the calls for local services;
- standardized definitions and locational information and national products;
- requirements of coordination and interoperability with and for all markets;
- common functional requirements for operating local markets; and
- NRA oversight of operations of local markets to ensure neutrality, transparency, efficiency and compliance of national terms and conditions.

These provisions will ensure that it is easy for all service providers to participate in all markets regardless of local markets. **The common rules, not one common local market operator, give the efficiency needed.** Liquidity for local markets is linked to the amount of local resources and the interoperability and market design, not to the number of local market operators. It is important that resources are not unduly limited from participating in all markets. Moreover, the possibility to use several market platforms operating at the same time enables this activity to be developed within a framework of competition, which clearly benefits end-customers in several ways: (i) only the most cost-efficient solutions are implemented, and (ii) local market operators have more incentives to engage new participants to the local services, which clearly benefits the liquidity and efficiency of the future local markets.

Systems operators have the responsibility of both procuring local services and ensuring the correct functioning of the local market. This responsibility shall include organizing operations of local markets with the responsibility to delegate or perform the different tasks of operating local markets aiming for the most efficient solution. Such decentralized decision making also enables to test and implement innovative solutions, as well as enabling new entrants to propose third party tools and solutions. Having several operators of local markets with explicit interfaces between markets gives further transparency and prevents lock-in of resources. A nomination process will create a burden and delay development of local markets with no added value.

In all countries where local markets have emerged or have been demonstrated, these are a result of system operators' will to use and procure local services to improve the efficiency of network development and operations. The use is combined with necessary learning for both systems operators and service providers. **The local markets which have emerged follow three different approaches: (a) organized by system operators alone, as in France or in Sweden, (b) organized by transmission and distribution system operators together on their own initiative, as in the Netherlands with GOPACS, or (c) several or all tasks of the local markets have been delegated to a third party as in Sweden, Italy, or Portugal.**

Finally, defining a process to assess and finally nominate LMO would clearly delay the implementation of the local services at the distribution grid level, which are clearly essential to unlock the connection of new consumers and generators to the grid and, ultimately accelerate the decarbonization of the economy.

For these reasons, each procuring system operator, responsible for the correct functioning of local markets and compliance with the national terms and conditions, shall decide on the solution to operate its local market.

Note: Common information platform on market-based procurement for local services is important to have when you have multiple operators of local markets allowing the service provider to get information on all procuring needs in one common place

3.4.9. Article 57 Tasks of local market operator(s)

Article 57 describes the core tasks of local market operators. Other tasks, not mentioned as a core task in the Article can also be assigned or delegated to the local market operator at national level. The network code attempts a clear separation between core and non-core tasks. Where core tasks are introduced 'as applicable', it is because these tasks are understood as a core task if it applies for the national implementation. For example, the processing of temporary limits is a core task of the local market operator if the process is designed in a way where the limits are applied within the market. In cases where the limits are directly communicated to the service providers, however, this would not be applicable. The main tasks of the local market operator are the processing of bids and facilitating communication between procuring system operators and service providers. For this purpose, an IT solution has to be provided by the local market operator. The publication of market results is also the responsibility of the local market operator.

3.4.10. Article 58 List of attributes

The purpose of this article is to provide rules to have a common list of European attributes used for standardised congestion management products and active power products used for voltage control. The common list of European attributes is not included directly or as annex to the network code demand response. The process to update such a list would result in an intensive process as it otherwise requires a full consultation of the network code with all required timelines and parties considered. With a flexibility and congestion market with new technologies which is developing within Europe the common list of attributes is expected to be changed anyway. The common list of attributes will be designed by the associations ENTSO-E and DSO Entity and published by the associations on their website. The list will be subject to public consultation to have market parties, NRAs and other parties the possibility to provide their views to this list.

3.4.11. Article 59 Requirements for the definition of congestion management products

Congestion management products in general are designed based on the different needs of system operators and depending on several factors as described within article 59(5). Standardisation provides clear rules to market parties in the requirements for products to be delivered, but standardisation will not be the default and not a goal on itself as it otherwise may limited new product developments, limited innovation in general and would not otherwise consider the network area specific needs or possibilities in delivering types of congestion management services.

The possibility for standardisation on national level depends also on the type of dispatch system (i.e. central dispatched versus self-dispatched), but in general also depends on differences (e.g. type of system users) between network areas of DSOs and differences between network areas of TSO and DSO. To have and keep sufficient space to develop new products is a concern raised by market parties during public consultation, but the NC DR and specifically this article 59 does not limit parties to develop new products.

During public consultation market parties have requested to include a list of products into the network code. In order not to create exhaustive lists in a network code this request is not fulfilled. Examples of products for congestion management services and active power voltage control services which can be given are:

- Capacity products:
    - flexible connection agreements;
    - dispatch limitation products;
- Energy products:
    - Redispatching products

3.5. TITLE V - SYSTEMS OPERATORS-OWNED STORAGE FACILITIES

3.5.1. Article 61 Procedure for sharing storage ownership or operations

The overall procedure regarding initiating systems operators owned storage is depicted by the following figure:

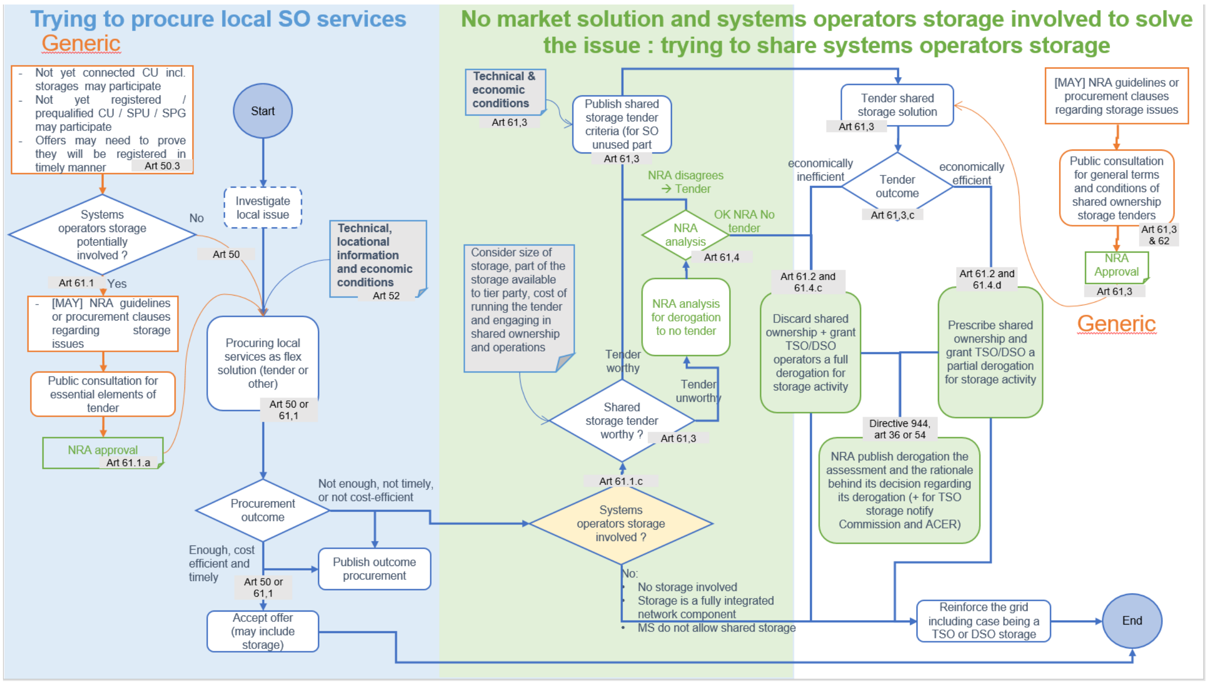

Figure 16 Procedure for sharing storage ownership or operations

The first sequence (in blue, on the left) relates to the market-test: first try to procure the needed services, on a technology neutral basis. In particular, service providers are entitled to make offers based on not yet connected assets, in particular using storages. If the outcome of the tendering procedure is that there is not enough offer, not cost efficient, or not in a timely manner, then systems operators are entitled to proceed to implement a solution involving a systems operators' storage. The procurement sequence in blue is similar to the tendering procedure of Article 50, with the additional provisions to be under NRA close scrutiny when the solution in the absence of adequate market procurement outcome involves a systems operators' storage.

The second sequence (in green, on the right) relates to trying to share a systems operators' storage. Indeed, at that point third party storage have already been invited to provide a service (first sequence in blue) but proven by the first sequence not to be an adequate or even proposed solution.

3.5.2. Article 62 Shared storage ownership and operations agreement

Article 62 describes the rights and duties of the third party related to the shared storage ownership and operations agreement with systems operators.

Note: Despite the fact that ACER's Framework Guidelines provide co-ownership as a possibility, ENTSO-E would like to raise a concern about the coherence of provisions in Article 62 and 63 with provisions for unbundling in the Directive (UE) 2019/944 in Chapter VI (to which article 54 belongs). Specifically, article 43.1 may prevent such co-ownership.

3.5.3. Article 63 Assessing and transferring ownership of systems operators owned storages.

The overall procedure regarding phasing out systems operators owned storage is depicted by the following figure.

Assessing and transferring ownership of SO owned storage every 5 years

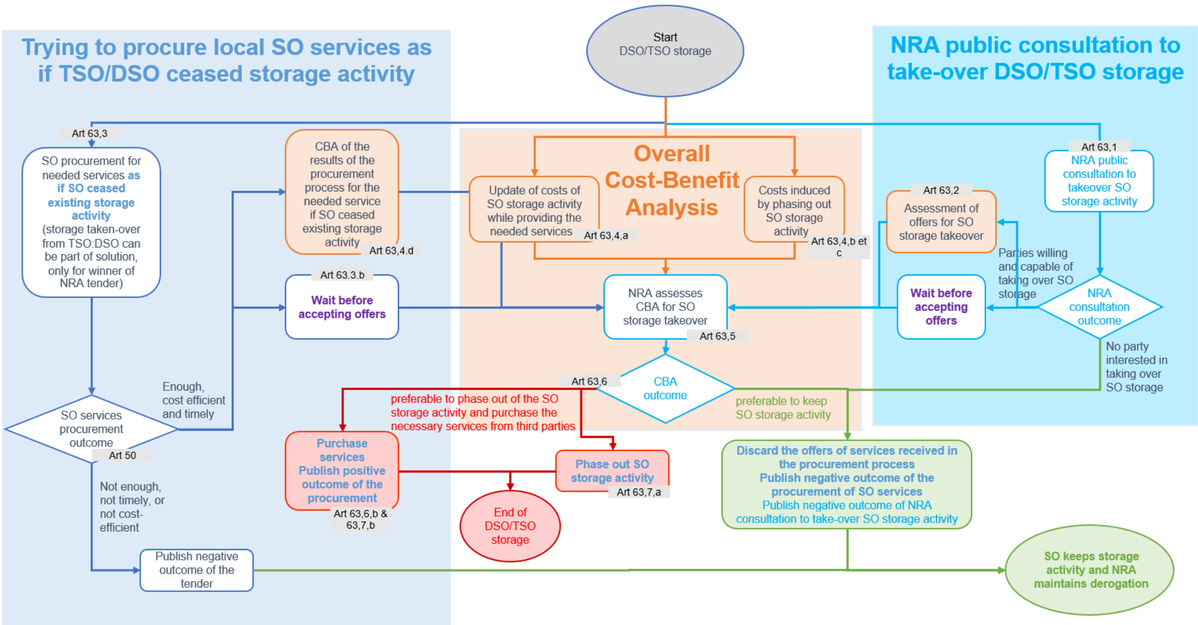

Figure 17 Assessing and transferring ownership of systems operators owned storages

In essence, article 63 describes 4 processes:

- An NRA public consultation regarding parties interested in taking over systems operators storage facilities
- A systems operators procurement to procure services, that would be substituted to systems operators ownership and operations of the storage facility
- An overall Cost-Benefit Assessment to determine whether it is preferable to phase out the systems operators storage and purchase the necessary services from third party rather than continuing the systems operators owned storage activity.
- The actual process to phase-out storage in case the above-mentioned CBA determines this being the better solution.

In some instances, it may not be possible to keep the storage asset on systems operator premises once systems operators have phased out ownership and operations. For example, if a battery is installed on a primary substation, working permit, access control, scheduling work activities, liabilities, prevent third party personal to perform maintenance (or replace/upgrade) of the storage. In such instances, the solution for systems operators to phase out the storage activity and for third party to take over the storage will be selling the storage asset, removing it from systems operators facilities, and handing it over to third party, whereas the installation elsewhere and the use of the asset by third party is out of the scope of the public consultation and shall remain under the responsibility of third party.

3.6. TITLE VI - DISTRIBUTION NETWORK DEVELOPMENT PLANS

DNDP – Distribution Network Development Plans are crucial for ensuring the reliability and long-term efficiency of electricity distribution networks.

The DNDP role is to describe the vision of distribution grid development considering all relevant principles. The DNDP contains provisions related to decarbonisation goals, which can be implemented by indicating the need for development scenarios considering national energy and climate plans, local energy strategies and other relevant development factors. All Member States are obligated to take decarbonisation goals into account while preparing national energy and climate plans. While coping with necessary capacity is the objective of the DNDP, the publication of available capacity is already covered by other obligations/regulations.

Article 32 of DIRECTIVE (EU) 2019/944:

> *3. The development of a distribution system shall be based on a transparent network development plan that the distribution system operator shall publish at least every two years and shall submit to the regulatory authority. The network development plan shall provide transparency on the medium and long-term flexibility services needed and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.*
>
> *4. The distribution system operator shall consult all relevant system users and the relevant transmission system operators on the network development plan. The distribution system operator shall publish the results of the consultation process along with the network development plan and submit the results of the consultation and the network development plan to the regulatory authority. The regulatory authority may request amendments to the plan.*
>
> *5. Member States may decide not to apply the obligation set out in paragraph 3 to integrated electricity undertakings which serve less than 100 000 connected customers or which serve small isolated systems*

To enable national regulations already implemented in accordance with the Directive 2019/944 to be maintained, particularly as regards to the obligation to set out the consultation process and the time for implementing the provisions of the NC DR, Article 64.1 mentions the Article 32 of the same Directive 2019/944. That is why the choice of the length of time for which investments will be planned is left to the national level. The timing of implementation of the new rules has been harmonized with the current cycle of publication of the DNDP at the national level.

The understanding of terms:

- ***five-to-ten years***: for next five years to ten years the planned investments in DNDP, it is the number of years for which the DNDP is prepared every 2 years at national level (number of years between 5 and 10). The range should be established at national level.

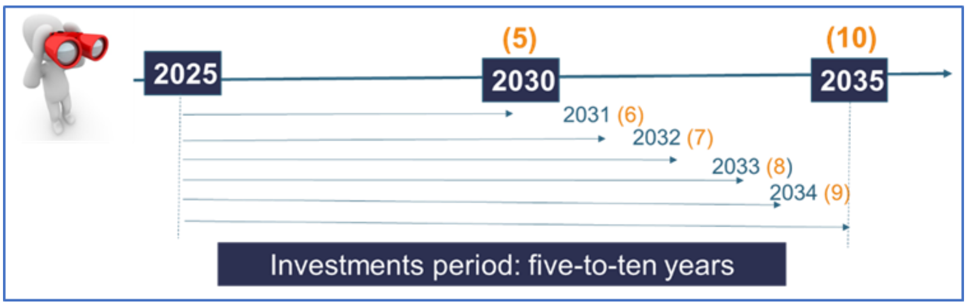

Figure 18 Understanding the term "five-to-ten years". Numbers in brackets means length of period in years (source: own elaboration)

In order to ensure that the provisions of the Directive 2019/944 are fulfilled, the DNDP regulations consist of the following articles:

- Process and Content of the Distribution Network Development Plan (DNDP)
- Local services in the DNDP

Recently, the European Commission has published the EU Grid Action Plan, which highlights the importance of the grid anticipatory investments and accelerating permits to anticipate future infrastructure needs and foster the energy transition.[2] Both issues were not included in the Directive 2019/944 approved several years ago. Articles from this Title already include this new approach.

Another relevant point in the national implementation refers to the rigidity of the DNDP process, that is, the possibility to have some flexibility in the approved grid investments. This is especially crucial as many distribution grid investments are essential to provide electrical supply to new economic activities such as shopping centers, industrial facilities, logistic facilities, etc. An extremely rigid process could excessively delay its connection to the grid with their corresponding impact on the economic activity.

3.6.1. Article 64 Process and Content of the Distribution Network Development Plan (DNDP)

The DNDP regulations have been developed taking into account the provisions of the Directive 2019/944, in a way that preserves the regulations introduced in the Member States as a consequence of the transposition of the Directive into national law. The obligation to create DNDPs is in accordance with the mandate established at the level of the Member State resulting from the implementation of the point of Article 32.5 of the Directive. It means that the obligation for preparing the DNDP should already be part of existing national regulations. At the national level the DNDP shall be prepared based on the same principles for all DSOs.

1. Each DSO shall develop the DNDPs pursuant to Article 32 of the Directive 2019/944 and in accordance with Title VI of this Regulation. Without prejudice to timelines foreseen in Member State law, the first publication of the network development plans shall be within three years after the entry into force of this Regulation.

Fulfilling the Article 32 of the Directive 2019/944, the new regulations require member states to have the DNDP prepared at **least every two years** based on existing and future supply and demand, be publicly available to interested parties and subject to public consultation, and the regulatory authority may request amendments to the plan. Importantly, the DNDP should provide transparency on planned investments, but also on potential demand for local services. The provisions of the DNDP do not prevent national decisions to take other activities besides described ones in the NC DR. A joint preparation of a DNDP for a group of DSOs at national level is allowed, if NRA accepts such an integration.
The DNDP should include:

- distribution network planning methodology,
- scenario and assumptions used to identify network development projects and local services needs with comprehensible description for stakeholders,
- description how, the DSO takes into account local services,
- Information on planned and ongoing investments for the next five to ten years,

The DNDP should ensure sustainable and cost-effective development of the distribution network. In addition, its assumptions should be in line with those made at national level and enable the national requirements for transmission and distribution system operators to be met, considering particular characteristics at national and DSO level. Taking such diversity into account, it should be left to individual countries to determine the scope and details level of the projects presented in the DNDP

[2] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2023%3A757%3AFIN&qid=1701167355682

based on the statement of the main grid infrastructure. However, the DNDP at national level shall be prepared based on the same principles for all DSOs.

The DNDP should also be consistent with the TSO's national scenario planning methodology and process, where relevant. However, this does not mean, that DSOs planning principles should be drafted the same way as by TSOs. It should be only consistent and not lead to discrepancies in the plans drawn up by operators (especially for DSOs with no direct connection to TSOs the relevance of TSOs approach might be limited). In this regard, coordination between TSOs and DSOs is essential. Moreover, in many cases, the plans drawn up by TSOs and by the DSOs at national level are not drawn up at the same time. This means that the process of drawing up plans for operators may be carried out with a time lag. The intention of the proposed regulations is not to unify the timeframes for the TSOs and DSOs planning process, but to only ensure that each operator considers the most up-to-date data adopted in approved plans and draws up its plan based on those. This will allow the continuity of planning and implementation of the various stages of the plan by both the TSO and the DSO.

Planning principles can affect how DSOs choose between different projects in network development planning. The planning approach should include also anticipatory investments, to enable to integrate in a timely manner, new electricity generation, especially installations generating electricity from renewable sources, storages and new loads including charging points for electric vehicles or heat pumps. In addition, the projects and investment overview and its estimated costs should be described as well. The level of detail of information may be differentiated considering the voltage levels or other criteria. While anticipatory investments are meant to proactively address expected developments, it is essential to acknowledge the inherent challenge of predicting future developments with exactitude in combination with the possibility to include additional grid investments when are essential to connect new facilities. Nowadays, every investment in the energy system is considered essential for facilitating the transition. The key distinction lies in the timing of utilisation, with anticipatory investments usually realising their full potential at a later stage compared to regular investments. With the latter, customers are kept waiting for grid capacity to achieve connection.

The important component of the plan is to properly evaluate and explain the interaction between planning principles and the procurement of local services. The principles allow the DSO to determine when a project improves the current situation of the existing network. For example, there may be application rules such as "reinforcement/optimization before expansion." More specifically, DSO projects on the distribution network and non-expansion alternatives can be implemented to reduce congestion, outage time, electricity losses and generation curtailment, and ensure integration of renewable energy sources according to agreed scenarios.

The DNDP is a vision of how to develop distribution networks, taking into account this, it should be underlined that the associated lost load and generation in power and energy due to limitations to connect new generation or demand units is not in scope of the DNDP. It is worth to mention that such an information is not available at DSOs level, what is more predicted generation of not connected installations is impossible to be established due to the fact of lack reliable information from investors applying for connection conditions in a given network location about actual investment plans.

Example: *one investor plans to build one PV installation, nevertheless, requests connection conditions at several points in the network. Eventually, he receives connection agreements for only one point. It means he received his goal of building one installation. Forecasting the energy not injected as a result of the refusal in this case doesn't reflect the current and actual situation on the grid. The information is useless for the DNDP.*

It should also be emphasized that energy sharing is irrelevant for grid load as well as self-consumption, it means that when planning energy demand DSOs do not see them as separate factors, but as calculated demand. The future demand and generation are important for precisely preparing grid development.

The development scenario could be more than one at national level, it is the decision taken by member states and applicable for all DSOs at national level such as development scenario of TSOs, National Energy Climate Plans, local/regional energy development plans of cities and/or federal states. The scenario general requirements should be taken into account and closely connected and included in the DNDP methodology.

The DNDP should be subject to public consultation. Relevant stakeholders and relevant system operators can participate in the public consultations. The consultation process will last at least 6 weeks.

The results from the consultation shall provide feedback to stakeholders on how the comments received have been considered. In addition, the results shall be made publicly available along with the DNDP and submitted to the competent national regulatory authority.

The competent national authority is entitled to propose amendments of the submitted DNDP while DSOs shall consider received amendments request and publish the final version of the DNDP.

Contrary to TYNDP that requires competent national regulatory authority approval, NC DR does not require that the DNDP is approved by competent national regulatory authority. The amendments requested by competent national regulatory authority are the subject of negotiations to reach a final version of the DNDP. Regarding the timing of the findings, it is important to emphasize the need to complete them in such a way that the tasks identified in the DNDP can be carried out in accordance with the deadlines set there.

TSOs and DSOs within Member State should ensure that their development plans are consistent, coordinated and properly aligned to enable implementation of the regulations introduced by the NC DR. In addition, they should ensure that the necessary information is exchanged during the planning process to determine network investment needs. Coordination should ensure that necessary data used during planning is exchanged between TSOs and DSOs and reconciled when relevant to the planning process. The periods for which the TSO's and DSO's plans are executed do not have to be the same, and if there is a shift in the planning periods, relevant system operators shall adopt the latest data and forecasts published in the final version of the plan. In the case of forecasts, if there are reliable and confirmed reasons to change them, they should be reviewed and revised to maintain continuity in the planning process for TSOs and DSOs using the most up-to-date data. Coordination of TSOs and DSOs planning should ensure the exclusion of duplication of investments leading to the solution of the same problem.

Taking into account the need to maintain the rules on published information set forth, in national regulations and DSOs requirements on confidentiality, and at the same time to avoid situations in the local market that could lead to market distortion and have an adverse effect on markets, a limitation on the scope of publication of information was introduced in paragraph 6.

The last provision of this article refers to confidentiality and the need to not distort the markets for procuring local services. It should be clearly pointed out here that although the shape and rules operating in the local market are at the stage of developments in some Member States, but like any market, this market should also be a subject to the provisions of REMIT (wholesale energy market integrity and transparency). Manipulation on energy markets involves actions undertaken by persons that artificially cause prices to be at a level not justified by market forces of supply and demand, including actual availability of production, storage or transportation capacity, and demand. Forms of market manipulation include placing and withdrawal of false orders; spreading of false or misleading information through the media, including the internet, or by any other means; deliberately providing false information to undertakings which provide price assessments or market reports with the effect of misleading market participants acting on the basis of those price assessments or market reports; and deliberately making it appear that the availability of electricity generation capacity, or the availability of capacity is other than the capacity which is actually technically available where such information affects or is likely to affect the price of energy/capacity products

3.6.2. Article 65 Local services in the DNDP

Local services may be used to alleviate, postpone the need of grid reinforcement, enable the connection of DER to the system or provide a solution until a decided grid reinforcement project is completed, where they are considered cost-efficient and if they fully ensure system security and the fulfilment of the quality parameters of the supplied and injected electricity to the extent permitted by national regulations. The need of procuring local services considered in the DNDP shall be based on the information available as of the date of the DNDP processing and methods relevant for DNDP, while the actual needs for local services are published in accordance with Article 52 of NC DR and with methods relevant to decide individual assets.

Using local services, DSOs shall prepare an assessment of current and predicted local service needs for solving congestions and/or voltage issues. For planned projects the information on when, where and which volumes are required, shall be predicted. Moreover, a description on how services have to be evaluated. The proposed article clearly states that needs assessed every other year can only be high level, while precise and updated data is computed at the time of procurement and published in the framework of procurement. The project name term should be recognized as an individual investment. The scope of projects should relate only to the main infrastructure. Depending on the case that is being considered as part of the future development of the network, DSOs in developing scenarios use equal methods to best describe the development of the network and the impact of various elements on its future development.

In order to assess how local services might improve efficiencies in the operation and development of the distribution system, DSO assessment methodologies may include the estimated costs of grid investment, the estimated costs of losses, the estimated costs to enable and implement local services procurement, the estimated cost of the procured local services or the volumes of new facilities or RES to be connected to the grid. It is also allowed to take into account other criteria, if prescribed nationally.

Such planning principles may compare solutions with different combinations of local services and solutions without local services in the operation and development of the distribution system. Moreover, these principles shall describe hypothesis on local services used in the assessment, which may include its estimated cost, its available volume, its reliability, its availability in time, duration or location, or other explicit criteria. When the procurement of local services is compared with grid investments, it is essential to consider the period of time since an investment is approved until the project is completed. Unfortunately, administrative process and permits are becoming more and more complex. Thus, if completing investments requires long time (or years), the procurement of local services will coexist with an approved investments and other solutions.

DSO must consider the time between an investment is approved and commissioned. If investing lasts 5 years, this period should be considered when local services are procured. This problem is becoming more frequent due to administrative process and permits.

It is assumed that local services are not used instead of investment tasks, such as:

- replacement needs, the legitimacy of which has been determined directly on the basis of the technical condition of the asset or the safe operation of equipment.
- requirements of external bodies or third parties. **For example:** *if local government according to the new local development plan would like to build new block of flats localized somewhere far away of the main grid infrastructure allowing connection, DSO is obligated to reinforce the grid in order to connect the new customers*.

- prescribed contractual or legal obligations. **For example**: *at a national level, some investments are prescribed by the government as a national priority and realization of them is DSO obligation (replacement of all medium-voltage overhead lines with cable lines. This means that regardless of the occurrence of congestion or not, the investments should be carried out in accordance with nationally accepted requirements. Hence, in this case, there is no possibility of replacing these investments with local services).*
- projects that have a different purpose function such as to reduce the probability of occurrence of an incident or reduce the time to recover from such incident. **For example**: the replacement of aged grids or assets with a high failure rate;

in the transitional period, projects started before the entry into force of this Regulation. The investment planning process is often a multi-year process, requiring a number of permits, agreements and approvals, which must be taken into account in this case. Therefore, projects started before the entry into force of this Regulation are not relevant for transitional period; As a consequence, directly for the analysis of the use of local services in the DNDP, it would be necessary to take into account modernization or development tasks, which are directly related to ensuring stable power flow of energy and it is economically and technically the best solution.

Consequently, the comparative analysis (investment/local services) may be subject to tasks, the implementation of which can be postponed, and the local services provided will fully ensure the maintenance of the quality parameters of the supplied electricity to the extent allowed by the regulations. In this case, might be considered, , the need to build a line connecting two lines or reconstruct a line to higher parameters - and until the task is completed, the use of local services in the form of acquiring the right to reduce/increase supply or increase/reduce demand for electricity for a time when stable and proper operation of the network cannot be maintained without restrictions.

When considering local services, it is important to have a non-discriminatory and technology-neutral approach, which means that all qualified sources should be taken into account regardless of the type of technology on which they base their services. A prerequisite, on the other hand, should be the ability to provide a service that solves the network problem indicated by the DSO/TSO. The DNDP provides indicative information for the expected need for local services. Actual information for market procurement is published under the provision of article 52 of NC DR.

3.7. TITLE VII - TSO-DSO COORDINATION AND DSO-DSO COORDINATION

3.7.1. Article 69 National implementation and condition for coordination

At national level, the TSOs and DSOs shall develop national terms and conditions for TSO-DSO and DSO-DSO coordination. Several aspects of TSO-DSO coordination are already covered by other legislation at national and European level, and this shall be taken into account when developing the national terms and conditions. For example, in the Regulation (EU) 2017/1485, especially the following chapters are relevant - Title I, Operational Security requirements:

- Chapter 1, art. 23.3: Preparation, activation, and coordination on remedial actions
- Chapter 5 - Contingency analysis and handling

NC DR establishes requirements for TSO-DSO and DSO-DSO coordination on more areas than what is already regulated at EU-level. The details of how this shall be implemented is left to national terms and conditions. The implementation can be adjusted to the variety of grid topologies, roles and responsibilities, market structure etc. However, NC DR includes requirements for both principles and content of the national terms and conditions.

The national terms and conditions for TSO-DSO and DSO-DSO coordination shall comply with the principles in the articles 18 and 71-77, and include:

- National criteria to define DSO observability area;
- Minimum relevant time horizons for each system operator to forecast and identify potential issues and to initiate the appropriate procedures between affected system operators;
- Defining which systems operators takes the following actions:
  - Identifies congestion and voltage issues
  - Identifies potential solutions
  - selects solutions from Art 47
  - procures of the local services, if applicable;
  - Initiates of actions to activate the local services, if applicable
- If relevant, a provision -if agreed between the affected and requested system operator- that the procurement and activation of service will be handled by other party than the relevant system operator;
- National processes for short-term procedures to account for DSO temporary limits;
- If relevant, system operators may define national criteria to identify the temporary limits;
- Procedure for grid prequalification;

Analysis of definitions already included in **Regulation EU 2017/1485:**

- '**Observability area'** means a TSO's own transmission system and the relevant parts of distribution systems and neighbouring TSOs' transmission systems, on which the TSO implements real-time monitoring and modelling to maintain operational security in its control area including interconnectors (Art 2.48)
- '**Reserve connecting DSO'** means the DSO responsible for the distribution network to which a reserve providing unit or reserve providing group, providing reserves to a TSO, is connected (Art 2.149);
- '**Reserve connecting TSO'** means the TSO responsible for the monitoring area to which a reserve providing unit or reserve providing group is connected (Art 2.150);
- **'Intermediate DSO'** is not explicitly defined, but used in Art 182 about prequalification of units connected at distribution grid in order to distinguish between a 'reserve connecting DSO' and others DSO between TSO and 'reserve connecting DSO'
  - 5. Each reserve connecting DSO and each intermediate DSO shall have the right, in cooperation with the TSO, to set, before the activation of reserves, temporary limits to the delivery of active power reserves located in its distribution system. The respective TSOs shall agree with their reserve connecting DSOs and intermediate DSOs on the applicable procedures.
- '**Affected TSO'** means a TSO for which information on the exchange of reserves and/or sharing of reserves and/or imbalance netting process and/or cross-border activation process is needed for the analysis and maintenance of operational security; (Art 2.94) Thus, "affected TSO" is related to the need of information exchange related to processes.
- **'Affected DSO'** is not explicitly defined, but used in several articles, such as in Art 74 about Day-ahead, intraday and close to real-time operational security analysis when referring to "affected" agents in general, but with a different meaning than "affected TSO" definition
  - 1. Each TSO shall perform day-ahead, intraday and close to real-time operational security analyses to detect possible constraints and prepare and activate the remedial actions with any other concerned TSOs and, if applicable, affected DSOs or SGUs.
- Article 40.6.c includes the term "**adjacent DSO**", "**downstream DSO**" and "**upstream DSO**" to refer to the DSO involved in the data exchange processes:
  - obligations for the adjacent DSOs and/or between the downstream DSO and upstream DSO to inform each other within agreed timescales of any changes in the data and information pursuant to this Title;

In the **NC DR**, some definitions are included:

- '**Connecting system operator'** means in this Regulation the DSO or TSO responsible for the grid to which a system user or controllable unit is connected.
- '**Affected system operator'** means any DSO or TSO significantly affected by congestion or voltage issues 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. (Art 2.15)
- '**Intermediate system operator'** means any DSO or TSO significantly affected by balancing and local services bids from SPU or SPG connected to another systems. (Art 2.16)
- In the NC DR we are using this term in a different meaning than SO GL
- **'DSO observability areas'** means the area constituted by DSO's own network elements, system user installations that might significantly affect existing or forecasted congestion issues or voltage issues in the DSO network. One DSO observability areas may cover parts of the grids from other systems operators and overlap with other DSO observability areas linked to different issues (Art.2.10).
    - In the NC DR we are neither using "affected DSO" in the definition of observability area nor "adjacent" or "upward/downward" from SO GL. We are just considering an affection in electrical terms.

In the whole NC it is used only "affected system operators" to consider all potential cases and identify which system operators:

- might be (electrically) "affected" and should participate in the Grid Prequalification processes
- might be (electrically) "affected" and should participate in the Temporary Limits
- might be "affected" and need data.

Moreover, **this definition of "affected system operator" already covers potential "intermediate system operators"** as are defined in SOGL (in the middle of two different system operators)

3.7.2. Article 71 Principles for the definition of DSO observability area

An efficient operation of the DSO grids requires information on the own network elements and system users connected to its grid. However, electricity grids from different system operators might be interconnected and meshed between them. Thus, flows in an electrical grid might be affected by flows from another electrical grid (owned by another affected system operator), and vice versa. In these cases, the system operator must consider the potential influence of the surrounding grid on its own grid area by analysing the external systems which have potential influence on its grid. This introduces the concept of DSO "Observability Area", which includes the DSO own grid and grids from other (affected) system operators. DSO observability areas means "the area constituted by the grid elements, grid users that might significantly affect existing or forecasted congestion issues or voltage issues in the DSO network. One DSO observability areas may cover parts of the grids from other systems operators and overlap with other DSO observability areas linked to different issues"[3] DSOs in cooperation with TSOs shall jointly develop a proposal for the national criteria to define the DSO observability areas considering the electrical connection points between DSO-DSO and TSO-DSO, grid voltages and the standard

[3] In the NC DR we have considered "observability areas" to identify the potential grid area affected by an existing or forecasted congestion or voltage control issues. In fact, the definition of observability is based on the "electrical influence".

network configuration. These criteria shall consider the existing or future scenarios on congestion issues or voltage issues significantly affecting the own DSO network.

In the SO GL, observability areas are completely defined and developed by TSO for performing TSO tasks. However, they are not defined by DSO. In SO GL, Observability areas are defined as:

> *'Observability area' means a TSO's own transmission system and the relevant parts of distribution systems and neighbouring TSOs' transmission systems, on which the TSO implements real-time monitoring and modelling to maintain operational security in its control area including interconnectors.*

In SO GL Art 40.10, DSO Observability areas are only considered by DSO with connection point to the transmission grid:

> *DSOs with a connection point to a transmission system shall be entitled to receive the relevant structural, scheduled and real-time information from the relevant TSOs and to gather the relevant structural, scheduled and real-time information from the neighbouring DSOs. Neighbouring DSOs shall determine, in a coordinated manner, the scope of information that may be exchanged.*

In the NC DR, observability areas are initially defined. Following its initial definition, DSO observability areas are assessed every two years or when the involved DSO identifies a need. The "potential influence" identified in Art 71.3 in the NC DR, may not be the same as defined in SO GL.

Observability areas are used to receive all the data necessary to forecast the status of their grid and to identify potential congestion or voltage issues (see Figure below).

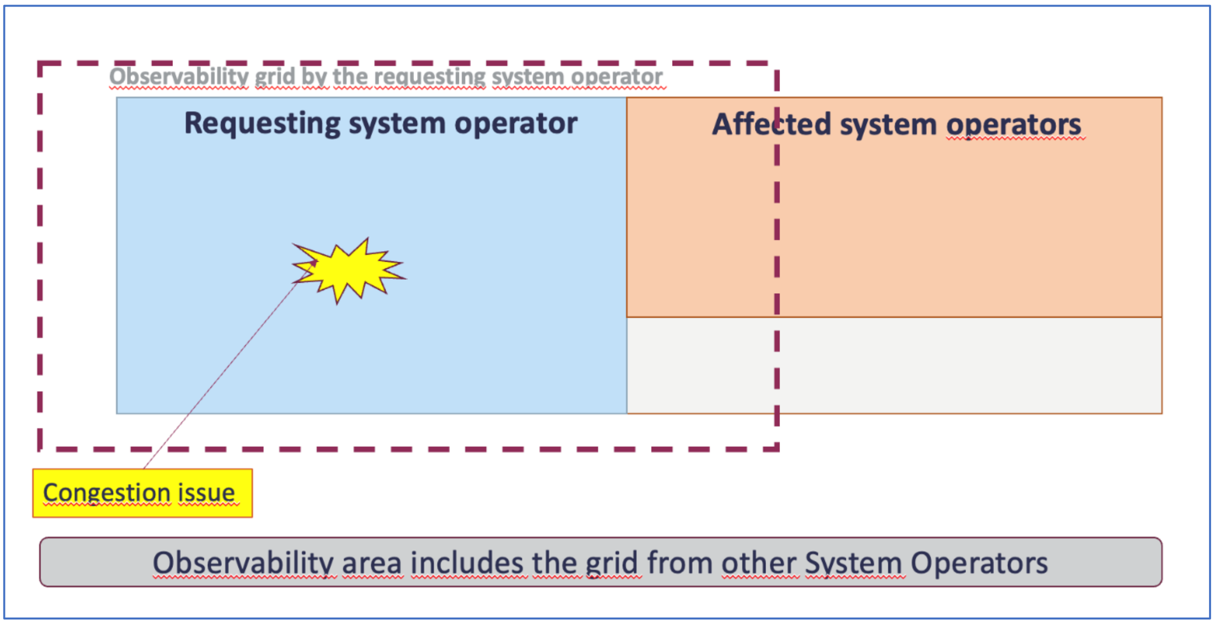

Figure 19 Observability area definition. Source: own elaboration

3.7.3. Article 72 Principles for forecasting, identifying congestion and voltage control issues through active power.

Forecasting is part of the core operational tasks performed by all system operators in order to anticipate future grid congestion or voltage issues when compared with operational limits, which are the thresholds used to identify when congestion or voltage issues happen. Thus, in the NC DR, each system operator is responsible for forecasting and identifying potential congestions in their grid. In this regard, each systems operators have its own needs with regards to forecast and identify congestion and voltage control issues, hence different time horizons are listed and possible.

The capabilities of systems operators shall be suited to the issues to be solved and shall enable to identify in time and location such issues, and the potential solutions. Further, systems operators need to work in cooperation with other systems operators to achieve the above.

Hence a minimum set of time horizons to forecast and identify congestion and voltage issues are defined at national level, that can be further supplemented between relevant systems operators if they agree for a DSO observability area. These time horizons should be coordinated with time horizons in other market processes already implemented. Finally, each systems operator can decide to use further additional time horizons if it better suit its issues and capabilities.

This article also defines the information used to perform this forecast such as different network configurations, scheduled data, previously awarded bids in wholesale, local or balancing services, as well as operational limits in its own grid.

3.7.4. Article 73 Principles for solving congestion and voltage control issues

Based on the forecast of their grid and their congestions and voltage issues, system operators shall initiate actions to solve them. As is described in the Art 73.1.a, system operators adopt an effective and efficient measures or a combination of them to prevent or solve these issues. These measures are listed in Article 47 and include, but are not limited to, network reconfigurations, changing of phase shifting transformers (PST) positions, flexible connection agreements, as well as the procurement of local services.

To facilitate the use of flexibility resources connected to the distribution grid a coordination between system operators (TSO(s) and DSOs) is required. This coordination shall not only ensure an effective and efficient use of resources. When a system operator activates measures to solve congestions in its grid, it shall be ensured that this does not cause issues in another system operator's grid. On the other hand, activation of active power capacities intended for solving DSOs issues (for example congestion management) must be properly coordinated with TSO(s) and other DSOs to ensure system balance effectively and efficiently.

Since the use of resources connected to the grid of another system operator may affect the secure grid operation of other grid operator, some coordination processes between systems operators, based on a grid prequalification process and a process to set short-term temporary limits.

Three potential following configurations can be implemented at national level:

- Grid prequalification process in combination with a process to set short-term temporary limits.
- Grid prequalification process without a process to set short-term temporary limits.
- A process to set short-term process without a grid prequalification process.

The selection between one of the previous options might depends on several issues such as the services and volumes of flexibility delivered from the SPU connected in the grid of each system operator, the grid characteristics of each system operator (radial networks, meshed networks, etc), and other national particularities. Moreover, this situation might evolve in the time when the implementation of local and balancing services by resources connected at the distribution grid level further develops. The details of the potential solutions are described in Article 74 and 75 of this document.

Regarding the process to solve a congestion and voltage issue, some roles should be defined at national level as specified in the Art 73.3 and 73.4.

At national level there might be several processes already implemented. However, these processes need to be assessed at national level in order to identify potential improvements, specially at the DSO level when implementing local services.

Examples of processes (non-exhaustive list):

- Example 1: each system operator is responsible to forecast the status of their own grid and their potential congestions and voltage issues. Based on the forecasted issues, each system operator solves its congestion or voltage issues in their own grid by selecting the best combination of options. A coordination is needed when a solution could be useful for different system operators to solve their issues, including counteractions, or affects the flows on the grid of other system operators.
- Example 2: each system operator (TSO and DSOs) is responsible to forecast the status of their own grid and to identify their own congestions as well as to trigger the possible solution. Based on the forecasted congestion and temporary limits TSO and DSO follow a nationally coordinates redispatch process. This is similar to example 1, but the selection of measures is based on an applicable mechanism.
- Example 3: A system operator on a higher voltage level set, among other solutions on its own grid, operational limits at the connection points with lower voltage connected systems operators. These lower voltage systems operators shall in turn solve the related congestion and voltage issues, using all options at their hand. This is of particular relevance when the topology/reconfiguration of lower-level distribution grids significantly affect the available options, and their efficiency. Since grid reconfiguration are a non-costly measure, they are likely to be among the first solutions to be activated but can only be decided by the systems operators in charge of that network.
- Example 4: a system operator on a higher voltage level is responsible to forecast the status of its own grid and grid of connected lower voltage systems operator, and their potential congestions and voltage issues. Based on the forecasted issues, the systems operator on the higher voltage level solves congestion or voltage issues in an integrated approach on own grid of connected lower voltage systems operator by selecting the best combination of options available. In this system, the lower voltage systems operators are responsible for providing the necessary data for forecasting and setting operational limits.
- Example 5: Congestions at distribution grid are forecasted and solved by the DSO. However, asks TSO the procurement of redispatching actions on their behalf in order to solve congestion or voltage issues identified after the spot market gate closure, intraday-market gate closure or real-time. If no redispatching solution is available, DSO is entitled to curtail specific generators or customers with last resource emergency solutions.

In all models, a system operator coordination is needed when a solution could be useful for different system operators to solve their issues, including counteractions, or could create or aggravate issues on affected systems operators.

When new procedures are developed at national level, already existing processes, including cross border redispatch processes, need to be considered regarding the timeline of the procedures.

Grid prequalification and short-term temporary limits

NC DR integrates detailed requirements to two coordination mechanisms between system operator:

- Grid prequalification process
- Short term procedure to account for temporary limits.

Grid prequalification and short-term procedure to account for temporary limits are both rights recognised in the SO Regulation, article 182(4) and 182(5) respectively for the purpose of coordinating limits to the reserve providing units (RPUs) and reserve providing groups (RPGs) during their prequalification or before the activation of reserves:

> *During the prequalification of a reserve providing unit or group connected to its distribution system, each reserve connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in its distribution system, based on technical reasons such as the geographical location of the reserve providing units and reserve providing groups.*
>
> *Each reserve connecting DSO and each intermediate DSO shall have the right, in cooperation with the TSO, to set, before the activation of reserves, temporary limits to the delivery of active power reserves located in its distribution system. The respective TSOs shall agree with their reserve connecting DSOs and intermediate DSOs on the applicable procedures.*

The Articles 74 and 75 of NC DR:

- Extend the concept of grid prequalification in SO Regulation article 182(4) and of temporary limits in SO Regulation article 182(5) to local services, in the understanding that there may be cases where, to cope with congestion or voltage issue in the network of one system operator, a local service activation may imply activation of resources in neighbouring grids, which would require the assessment of the connecting and other affected system operators.
- Describe detailed requirements further guiding the grid prequalification and temporary limits process, useful in particular in the context of provision of services by SPGs aggregating CUs.

At national level an effective and efficient implementation of both processes shall be established, aiming at:

- minimizing to the necessary the number of limits,
- applying both procedures, as introduced in the NC DR, where needed and adjusting them in efficient manner depending on the service and the type of units, and
- providing reasonable and predictable environment for provision of local services.

This is in an effort to ensure the liquidity of the local and balancing services is not compromised, while also ensuring that the delivery of these services is not compromising the safe operation of the grid.

3.7.5. Article 75 grid prequalification

When the implementation of the grid prequalification procedure as described in the NC DR has been decided, the process for grid prequalification considers the next priorities:

- Enabling the maximum number of participants, bids and liquidity to local and balancing services.
- Limiting the grid prequalification status only to those combinations of CUs that might create or aggravate issues. This is made by introducing the option to limit “parts of SPG” as alternative to limit “complete SPG”.

Local and balancing services can be provided by:

a) A single SPU, or
b) SPG made of a group of CU

When the delivery of flexibility is made by only CU behind the same SPU (case a), the subscription capacity must always be respected. If grid prequalification is processed without considering combination of several SPUs, the grid prequalification must reflect the grid connection agreement and capacity subscription provisions. It is noteworthy that a grid prequalification process might be needed when delivering a fast balancing or local service has not been considered when connecting this SPU to the grid.

In the case that systems operators may have already implemented efficient and fit-for-purpose simplified grid prequalification processes pursuant to article 182(4) of SO Regulation, that may be considered adequate for these RPU when implementing the requirements from this Article.

In the b) case, the coincidence factor arises.

The coincidence factor[4] (also named simultaneity coefficient) as a fundamental of design and operations

A fundamental concept for grid design is the coincidence factor (also named simultaneity coefficient), which is made of the next hypothesis:

- each grid user has its own consumption or injection pattern, independent from its neighbour, and
- statistically, grid users of the same type have a similar pattern, whose resemblance is the simultaneity coefficient.

As a simplified example[5], imagine a charging infrastructure of 50 charging points, each one having an individual capacity of 20 kW. Each customer has a 20-kW connection agreement with the DSO, that gives each customer the right to charge at full capacity at any time. However, it is unlikely that all customers will charge at the same time.

Statistically, the maximum observed may be that only 40 % of grid users will effectively charge their car at maximum capacity at the same time. In this case 40 % is the simultaneity coefficient. Therefore, the DSO does not design that infrastructure for 50 * 20 kW = 1 MW, that is by simply adding all connection agreement capacity; that would be an inefficient design. The DSO consider the simultaneity coefficient 40 % and built an infrastructure with a total capacity of 40% * 1 MW = 400 kW, which is a more CAPEX efficient design.

With such a design, each individual customer, behaving independently from its neighbours, can use the full capacity of its connection agreement at any time, and the DSO has optimized its design by building the necessary and sufficient infrastructure.

Flexibility principles affects the fundamental of the simultaneity coefficient.

By definition, flexibility services consist in changing in a synchronized manner the behaviour of specific grid users to alter their (aggregated) load or injection of the network. That is, the provision of flexibility services induces a different simultaneity coefficient for those grid users providing the service, different from the one used for grid design and operation forecast.[6] Consequently, whereas flexibility is sought to yield a positive effect to the requesting system operator and solve congestion or voltage issues, it

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[4] Literature:
https://www.enedis.fr/sites/default/files/documents/pdf/network-development-plan-2023-preliminary-document.pdf?VersionId=Gi0l0XONdb_HdXpaTxeSxTLeCh7TUE5M (access 15.03.2024)
IEC 60050 - International Electrotechnical Vocabulary - Details for IEV number 691-10-03: "coincidence factor" (access 15.03.2024)
https://www.endesa.com/en/blogs/endesa-s-blog/light/factor-simultaneity-calculation (access 15.03.2024)

[5] All values are theoretical and used to explain the topic. National implementation will differ.

[6] In the provision of flexibility services, simultaneously coefficients for those units providing the service might be close to one.

can also have negative effects on connecting or affected systems operators grid due to these different simultaneously coefficients.

Going back to the initial example, assume a service provider aggregates all 50 charging points to activate all simultaneously together and provide a 1 MW service for balancing or to provide a 1 MV local service. Thus, providing such services from these charging points would result on a load on the infrastructure of 1 MW, which clearly exceeds design of 400 kW total capacity.

In this context, the role of grid prequalification and temporary limits is to ensure that such detrimental situation does not occur while also enabling service providers and systems operators to maximize the possibility to make best use of flexible resources.

Grid prequalification

In the prequalification process, a service provider requests the prequalification of a list of potential charging points belonging to the same SPG. In this case, the connecting and if applicable the affected system operators shall assess whether the SPG can be activated without compromising the safe operation of the connecting grid and without creating congestion or voltage issues and, if applicable, of the affected grids.

Art 75.5.a describes the information used to perform the grid prequalification assessment, which includes the information available well in advance. This is made on the basis of scenarios.

In our example, a service provider can recruit and apply to aggregate all 50 charging points. However, the grid prequalification will end up stating that the SPG is only allowed to deliver 400 kW even though they have registered a total of 1 MW CU. In other words, service provider is only allowed to activate 20 charging stations at full capacity at the same time, or all 50 charging points at 40 % capacity each, i.e., SPG capped at 400 kW. In this case, the grid prequalification status results in a “prequalification conditionally approved” (Art 74.5.b).

Assume that each charging point is by solar panels, with a maximum accumulated output of 300 kW. Assuming still a maximum design of 400 kW net load, depending on the sun, the total maximum charging capacity can vary from 400 kW (no sun) to 700 kW (full sun). The conditional grid prequalification of a SPG of 50 charging points will be 400 kW, and up to 700 kW depending on sun, which is an example of conditional prequalification.

If two service providers recruit each half of the charging points on that same infrastructure, each one will register a total of 500 kW CU, but each one can only be allowed 400 kW at the grid prequalification stage. In other words, the system operator is not considering the potential simultaneously coefficient between two different SPG (of different SP), as this would end with excessive number of limitations.

The status of the grid prequalification is informed to the involved parties. Such information at the grid prequalification stage is useful for service providers: they may recruit and register CU on several charging infrastructures, to maximize the capacity of valuing all their assets at full capacity. Service providers may prefer to recruit 2* 20 charging points over 2 different charging infrastructures, enabling 2 * 400 kW capacity, rather than recruiting 40 charging points on the same infrastructure knowing their will only be allowed to value 20 of them at full capacity on each infrastructure, that is valuing only 400 kW.

Article 75.8 describes criteria to maximize the number of approved grid prequalification: focusing on frequent scenarios instead of extreme ones that could be dealt with by an additional process to set short term temporary limits when the time comes, optimizing the safety margins and efficiently coordination grid prequalification processes (made long term in advance) and short-term temporary limits (set in the day-ahead or intraday).

In some Member States, there might be some processes already implemented for the grid prequalification, which might be based on SO GL Art 182

The grid prequalification process is a right already recognised and therefore implemented in line with SO Regulation article 182(4). The requirements of article 75 of NC DR develop detailed provisions that may be unnecessary to implement in the full extend as required in article 75, for example, in the case of a well-established and mature procedure to set up short-term temporary limits to the Reserve Providing Units participating in balancing. A simple coordination of the prequalification test in the product prequalification may be enough. Asking the connecting and affected DSOs to typify the scenarios of possible limitation or to calculate and estimation of the limited volumes would be unnecessary, since the possibility to limit in the short-term procedure will ensure these constrained situations will be solved when they occur. Estimation of the conditions for possible future limitations lack of added value, since the process ensures that when constraining conditions happen, the limitations will be set in the daily and intraday balancing processes. Overcomplicating the product prequalification process of Reserve Providing Units may have otherwise counterproductive consequences, in terms of creating unnecessary barriers for BSPs, unnecessary administrative burden for distribution system operators and a risk for delaying the prequalification process.

3.7.6. Article 74 Short-term temporary limits

In the short-term (such as day-ahead or intraday), a service provider aims to deliver the flexibility with bids of SPG or SPU that might be previously grid prequalified. The limitations of the connecting or affected system operator shall respected. However, this process has some differences with regard to grid prequalification described above:

- Input and data used for setting temporary limits includes forecasts and schedules of generation and consumption, as well as unforeseen situations not previously considered. Among other things, this includes unavailability of some grid assets due to maintenance activities, or other unforeseen circumstances.
- Coincidence factor can differ from assumptions in the grid prequalification (see following example).

In our example, assume two service providers each place a bid of 400 kW based on their 20 charging points (both SPGs were prequalified as in previous example). However, the infrastructure can only handle a maximum total of 400 kW, which must be split between the 2 service providers, such as:

- Only allowing one of the service providers, and preventing the other service provider to place a bid when information is sent to the SP; if it is the procuring systems operators that is informed, then the procuring systems operator can select up to only one of the two bids)
- Allowing each service provider to place a bid of only 200 kW
- Or other splitting solutions

If a supplier has already scheduled a consumption (no flexibility) on 10 charging points (that is a schedule load of 200 kW), the capacity left for the service providers is only 200 kW, which also needs to be split among them. Similar to the previous situation, it could be for example:

- Each service provider is only allowed 100 kW,
- only one of them is allowed 200 KW, while the other is prevented to place a bid,
- or other splitting solutions

If there were solar panels and the scheduled or minimum forecasted production is 200 kW, then up to 600 kW of consumption can be allowed. If no supplier has scheduled consumption, a SPG of 50 charging point can be allowed 600 kW, consistently with the conditional prequalification up to 700 kW.

An important point of the temporary limits process is related to the communication of its limits. The parties responsible for applying or considering the limits should be informed as soon as possible. Despite the grid forecasts can be made several days in advance, scheduled consumption and generation is only available after the day ahead wholesale market gate closure. Moreover, accuracy of forecasts increases when we get closer to the real-time. In the Art 74 it is written that temporary limits should be communicated when identified. However, temporary limits should be communicated at least until the time defined in Art 74.3.c. If issues arise after this time, they are not considered temporary limits, but "emergency situations". In these cases, Art 73.5 applies.

- Process, methods and timeline to set temporary limits
- Temporary limits are set during the operational process before bids are awarded in their respective market procedures.

Article 74.3 list the criteria and information used by system operators when setting temporary limits, as well, as the process to communicate them. These limits should be communicated as soon as they are identified in the operational planning processes, but before bids are processed in balancing or local services. However, this does not mean that unforeseen situations identified by DSO cannot be solved later, but that they are part of the emergency processes defined at national level and out of the scope of this NC DR. In this context, Art 73.5 of this Network Code is intended to cover these unforeseen situations.

For congestion management this means the limits are set in the day-ahead process after the day-ahead schedules have been announced, since they are the basis of the assessment of the grid status and before they are awarded, at the latest before they are processed to be considered in cross-border coordinated redispatch procedures, such as the [7]DA CROSA of ROSC.

Bids that have not been awarded in the day ahead process or new bids placed in the intraday process may be reassessed in the intraday process. Based on the newest schedules and grid status system operators may place new limits applicable to bids that have not been awarded yet. Thus, the system operator can also set limits intraday before the bids in the intraday redispatch processes are awarded, but at the latest before they are processed in cross-border coordinated redispatch procedures, such as the ID CROSA of ROSC.

The temporary limits process is not used to cancel already awarded bids; once a bid has been awarded it can no longer be addressed by temporary limits.

At national level a process may be defined to tackle issues arising in the DSO network after bids have already activated, however this is not part of the temporary limit process. If there are sufficient time system operators may activate additional bids to solve the issue. If there is not enough time to solve the issue within the market process it would be subject to an emergency process, as defined at national level.

Potential options to implement temporary limits

Short term processes are conducted at least before and during the day-ahead redispatch/congestion management and intraday redispatch/congestion management processes. In the process of setting temporary limits, connecting and affected system operators shall assess their grids based on the schedules and forecasts. The result of this assessment could be a full acknowledgement for all the services or temporary limits to bids/SPUs/SPGs to avoid issues in the grids. In this process, the data exchanged is performed by system operators according to the DSO observability areas. Since there are so many ways of implementing these short-term limitations by DSOs, the drafting team has opted to use the existing terminology of SO GL “temporary limits” instead of “flag bids”. This is because flagging of bids is only one option to implement the temporary limits. However, there are also other methodologies such as communicating the free capacities and sensitivities, similar to the international flow-based procedures.

- **Flagging of bids** is a method where the DSO may assess all bids and flag them individually or that the bid can be matched to master data that contains the required locational information. If this option is implemented at national level, bids, or ad-hoc procedure to complement bidding information, shall include some locational information to be directly related to the grid electrical models used by system operators. When implemented this option, a transparent and clear set of criteria to flag bid(s) needs to be define how end when a bid would be flagged. Only if a bid individually causes an issue or if it causes issues in combination with others, while the latter would pose the risk of flagging combinations that wouldn’t have been chosen by the market mechanism/procuring system operator. In this case the limitations may be communicated directly to the service provider, who is then responsible for adhering to the limitation. In the case where the SP is allowed to reconfigure their SPG it needs to be ensured, that the new configuration does not cause an issue in the DSO grid, while ensuring stable procedures.
- **Identifying the volumes** to be limited and the set of units that are affected by the limitation in the ‘upstream’ markets (e.g., balancing or other local markets).
- In the **traffic light model** is a method where the DSO may set the light to green or to red depending on the free capacities in their network model. If this option is implemented at national level, transparent and clear criteria when the traffic light levels would be set corresponding to which free capacity on the DSOs network elements should be defined. While a green or red light is a clear indication to SPs, it also bears the risk of restricting offers that could have been delivered (if the threshold for a red traffic light is 5 MW but the offer would have been 3 MW it would be unnecessarily limited).
- In the **flow-based model**, is a method where the DSO assess the free capacities on the network elements and the sensitivities of the bids and their corresponding SPUs and SPGs. If this option is implemented at national level, bids shall include some locational information to be directly related to the grid electrical models used by system operators. An optimisation algorithm considers these capacities and sensitivities to ensure only the combinations that are compatible with the grid restrictions are available. The algorithm has to consider for each network element, that the loading resulting from the base case and the flows caused by the bids $L(x)$ does not exceed the maximum possible loading of the network element L_{Max} taking into consideration necessary safety margins (FRM):

$$L(x) + FRM < L_{Max}$$

- This algorithm may be part of the market platform itself or may be executed as part of a coordination platform. Since it is an automated process considering the exact capacities available on critical network elements, it would allow for an optimal consideration of the limitation thus limited bids or combinations of bids only where strictly necessary. The requirement to optimise safety margins has been included to minimise the number of limits while still considering DSO limitations sufficiently.

The national implementation of this process might be different depending on several issues such as market design, national grid characteristics, attributes of local services, criteria used to define SPG, or the possibility to forward bids from one to another market, etc. Moreover, the national implementations of coordination mechanisms might develop additional mechanisms made up of a combination of the previous ones or from other new solutions. It is understood that the variety of possible implementation should not be prematurely limited.

Process to minimize the number of temporary limits

Anyway, the method developed at national level to set temporary limits shall be transparently described as part of the national terms and conditions. Furthermore, service providers are informed when they have not been activated due to temporary limits.

In order to minimize the number of temporary limits, this Article includes several provisions:

- Art.74.1 includes a commonly agreed procedure to state temporary limits to the participation of SPUs and CUs within a SPG in services, following transparent and non-discriminatory criteria between units connected to different system operators. Procedure may vary depending on the service.
- Art 74.5 describes the process to minimize the number of temporary limits set by DSO. This Article includes two additional criteria from grid prequalification:
    - As in the above example, setting limits on the combination of bids, SPUs, parts of SPG, or SPGs, including by indicating limits or available capacities on grid elements[8]. As last resort, limits shall be set on individual bids, SPUs or SPGs.
    - when possible and agreed by the system operators, setting temporary limits as accumulated maximum delivery of balancing, congestion management or voltage control services considering the timeline of each market process. This case applies for a network that can allocate limited flexibility due to contingences. For example, the constraint is not related to a lack of grid capacity, but on the volumes that can be upward or downward activated because of voltage or inertia problems. In this case, temporary limits are not set by default, but apply when the accumulated volumes of balancing or congestion services exceeds a threshold. This case intends to minimize the number of temporary limits set by default.

The calculation and communication of temporary limits will be facilitated by an IT-supported process allowing automatized solutions as much as possible. The process of the application of the limits and will be executed before the bids are processed.

The role of "parts of SPG"

When assessing grid prequalification and temporary limits of a whole SPG, issues described above may occur on a single charging infrastructure, on a given feeder or transformer. By allowing to state the limit to parts of SPG, signalising that the problem concerns part of SPG while the rest of SPG does not create issues, the limitation to the rest of the CUs constituting the portfolio is avoided, and therefore the participation is maximised.

Compensation in case of temporary limits

NC leave the compensation to SPs as an option to be decided if and how to be implemented by the NRA at national level.

It is of importance to clarify that the process defined in the NC DR only foresees setting temporary limits before the bid is awarded, thus no costs have been caused at SP side.

If system operators were not entitled to set temporary limits, system operators would have to:

[8] This would always be the case when the flow-based approach is implemented: available capacities are calculated and are applicable to all combinations of units. The flow of all SPU and SPG combinations can be calculated and limits only the combinations that would exceed the free capacities of the network elements of the DSO.

- limit the participation in the grid prequalification process (potentially increasing the overall amount of limits set).
- activate additional services and costly measures to solve congestion or voltage issues, that could have been prevented by applying temporary limits, which would result in additional costs for customers.

It must be considered that:

- Service providers may not be granted with the right to economic compensation at national level, which is in line with European legislation.
- Economic compensation means a cost for the final customers and each NRA has the responsibility to decide if compensation to service providers is an adequate and required incentive to minimise the limitations due to network constraints.
- Setting economic compensation might affect specific national processes or increases the risk of gaming.

3.7.7. Article 75A Grid Prequalification and temporary limits reporting

Monitoring report tasks related to temporary limits and grid prequalification are included in the same article as both processes are highly interrelated in the case of CUs constituting SPGs. This assessment made for both grid prequalification and temporary limits together since reducing the number of temporary limits might need require an adaptation of the criteria for the grid prequalification process, and vice versa.

The aim shall be to minimise the total amount of limited bids, CUs participation in SPGs and parts of SPGs in an effort to facilitate liquid local and balancing markets, while also respecting the limitations of the connecting and intermediary system operator. System operators shall summarize, as applicable, their assessment in a common report to the NRA every four years. This provision also aims to improve the transparency of its application.

The number of limits and non-approved grid prequalification's as well as the reason for them will be reported on a yearly basis to the NRA as applicable per service (eg. TSOs shall report the limits to balancing services, in line with EB Regulation requirements).

3.7.8. Article 76 Data exchange between DSOs-DSOs and DSOs-TSO

To be capable to accurately forecast the flows and other electrical parameters of the network, it is essential that system operators have access to data from neighbouring systems that might affect own networks, which is why establishing observability for DSOs is proposed. Additionally, it is of interest to signalise the need for data exchanges with TSO beyond the observability area of the TSO, necessary for managing load-frequency processes or other relevant tasks like imbalance settlement.

Article 76 builds a complete framework, complementary to requirements in article 40(10) of SO Regulation, which legally entitles DSOs to receive relevant structural, schedule and real-time data from other DSO and TSO assets in its own observability area as defined in article 71.

TSOs are also entitled to receive relevant information on the procured and activated local services as well as requested data from service providers that DSOs may receive pursuant to implementation of article 79.

In order to ensure some coherence with the existing regulation, the categories of the information to be exchanged are the same as those defined in SO GL. The content of the structural, real-time and scheduling information considers the need that system operators have during the process of forecasting and solving congestion and voltage issues.

3.7.9. Article 77 Ensuring system balance

In order to ensure that the system is balanced, it is vital that measures taken to solve congestions in TSO or DSO grid are balanced as soon as possible as part of the redispatching actions, or as otherwise validated in national terms and conditions.

One possible way to ensure the balance of the load-frequency control area is by implementing measures that are by design balanced (for every upwards or downwards measure, there is a countermeasure). In this case system balance is always inherently ensured.

In case redispatch bids are activated unilaterally this creates an imbalance. These imbalances need to be counteracted in order to ensure the power system is balanced, therefore ensuring full respect of the requirements addressed to load-frequency control area and control block in SO Regulation.

Another possible way to ensure the balance of the load-frequency control area is by a mechanism that counterbalances not each individual redispatching action, but the net imbalance caused by the ensemble of activations. To that end, the information on the upwards and downwards redispatching actions of a same ISP is gathered and the net value is the input for the counterbalancing action. It is of interest to highlight that in that case there is not a biunivocal relationship between each redispatch action and counterbalancing action, but costs for customers and counteraction volumes are minimized.

In any case, market processes defined at national level should have sufficient coordination functions between downwards/upwards redispatch to alleviate a congestion or voltage issue and the counteracting actions.

The existing literature and practices exchanged among transmission and distribution system operators[9] have allowed to discover a diverse and non-exhaustive list of options for counterbalancing. It is up to National legislation to clarify the option(s) to take concerning counterbalancing of redispatching actions. The most suitable option(s) depend on specific situations of the market. NC DR mandates the national legislation to clarify the process or processes to ensure system balance as well as the assignment of the responsibility for the applicable counterbalancing actions. NC DR states the fundamental principles and criteria that need to be fulfilled regardless the selected option.

3.8. TITLE VIII - DATA EXCHANGE REQUIREMENTS FROM GRID USERS

3.8.1. Article 78 Organisation, roles, responsibilities, and quality of data exchange

System operators need information exchange from the units participating in services define in this NC DR because these data are necessary to make forecasts and identify congestion and voltage control issues. Some units should already provide information exchange according to the SO GL (Art 2.1 in SO GL) and its national implementation (Art 40.5 in SO GL), but other not. For these units, Article 78 rules the information exchange processes for those units (CU, SPU, SPG).

In this scheme, the service provider is declared responsible to deliver the necessary data from CU, SPU, SPG that will be specified in detail in national terms and conditions for providers of local services.

[9] Roadmap on the Evolution of the Regulatory Framework for Distributed Flexibility. A joint report by ENTSO-E and the European Associations representing DSOs (CEDEC, E.DSO, Eurelectric, EODE), June 2021. https://www.eurelectric.org/publications/joint-tsodso-roadmap-on-distributed-flexibility
'An integrated approach to active system management' (ASM report)' (2019) https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/TSO-DSO_ASM_2019_190416.pdf

The information is listed in this article, and classified in structural, schedule, and real-time data, as well as data required for prequalification and for service verification.

In order to avoid excess or default of applicability of requirements, it is proposed that the data exchange scope can be adjusted at national level, considering specific features of providing units groups and services. Requirements should be proportional and consider the size of the unit. In this line, Art 78.3 states that "national data exchange requirements shall be established in line with the principle of limiting the requested data to what is necessary information for system(s) operators to fulfil their tasks and therefore ensure operational security." The same article includes sending a justification of its need to the NRA. In this line, data exchange applicability, scope and granularity of the data exchanged should be defined for each service.

At this point, system operators should adapt the requirements to the size and characteristics of the SPU/SPG, the voltage, and the technical characteristics of the service. Information exchange requirements for balancing services might be different than for local services aimed to solve congestion or voltage issues in the distribution grids.

3.8.2. Article 79 Data to be provided by service providers

This article builds a series of requirements for data exchange following the same data structure than in SO Regulation, being one important difference that the responsibility of the data exchange is addressed to the service provider instead to the grid user.

Data provided by system providers are divided in three types: structural data, scheduled data and real-time data.

- The structural data refer to the general information about the facility needed for the models used to perform operational security analysis in any timeframe.
- The scheduled data refer to the information from the facilities for day ahead and intra-day used for operational security analysis during these timeframes of operational planning.
- The real-time data refer to the actual information from the facilities needed to know the real situation of the service provider grid/facilities to perform real-time analysis.

To maintain the operational security, it is necessary to know the situation of the distribution system/ service provider grid/facilities in a precise way, so the follow-up analyses are reliable. To achieve this, the system operator needs information from its own grid or from another system operator's own grid. Data from its own grid may come from the service providers, so the system operators rely on the information from the service providers to perform its tasks. Lack of accurate information to the system operator has significant impact on the operational security as it makes it difficult to know the demand, manage congestions, control voltage and calculate reserves in an adequate way. This also leads to higher costs as more reserves are required to face the uncertainties due to insufficient or inaccurate information. Taking into account the present and expected future evolution of the electric power systems in Europe, the requirements of information for the system operator become especially important.

In addition, it might be required to SP to deliver locational disaggregated information, which is known as "Part of SPG" in the NC DR. Such localisation data is not always required per connection point, and might correspond for example to a specific feeder, HV transformer or part of an electrical grid. It is in national terms and conditions for service providers where the details of the data exchange process with systems operators shall be clarified, for instance the prime recipient of the data, the granularity of the data to be exchange, and other technical requirements as protocols or communication standards.

and conditions for service providers of local markets as implementation to the requirements of this article. Service providers can delegate the exchange of real-time data in third parties, namely technical operators.[10]

3.8.3. Article 80 Data to be provided by grid users

This article 80 covers additionally next data exchanges, from units:

- In paragraph 1, additional requirement to significant grid users that are distribution-connected demand facilities, and which participate in demand response (SGUs pursuant to Art. 2(1d) and Art. 2(1e) of Regulation (EU) 2017/1485), since they currently have no obligation to deliver scheduled active power consumption, or as applicable in central dispatch systems. SGUs that provide a service are inherently relevant for system security and the relevance of demand (response) is expected to increase further in the following years. Thus, knowing their schedule, both as a baseline and as a basis to forecast the flows on the grid is essential, which is why this requirement is needed.
- In paragraph 2, possibility for DSOs to extend the applicability of data exchange, pursuant to NRA approval, to units below the declared threshold of significance. This data is needed by DSO for their forecasting processes, especially in those areas with higher congestions. A more accurate forecasts enable more efficient selection of solutions (Art 47), as well as a more precise procurement of local service volumes.
- In paragraph 3, possibility for TSOs in cooperation with DSO to request a streamlined data exchange (eg. by set of sample facilities that allow to estimate the behaviour of a cluster of units) from system users like type A units, self-consumption, etc, is declared. This intends to cover a need for visibility of the embedded small generation, that can be indeed very significant in the control area (dozens of GW) and that might affect the load frequency control processes. An individual exchange of data from all the units may not be needed, but a technically feasible and efficient exchange of data from sample units representing a panel can be realised. This data exchange will serve to forecast balancing needs in a more secure and efficient way.

Transmission and distribution system operators shall always justify to NRAs the need and added value of extending data exchange requirements defined in the Article 79 to other grid users that do not have the requirement to provide data exchange and are not SPU or SPGs. At the Distribution grid level, this is particularly important in order to improve the accuracy of forecasts in highly congested grid areas.

3.9. TITLE IX - VOLTAGE CONTROL

3.9.1. Article 81 Voltage control services with use of reactive power

Transmission networks and distribution networks are differently designed. While transmission networks are generally more meshed, distribution networks have a more radial design. Transmission networks have been traditionally designed with voltage control options, either or not via conventional power plants, coils, and capacitor banks. The voltage within distribution networks is traditionally controlled via tap changers of the distribution transformer, with mostly the connection at the end of the line having the lowest voltage or capacitors and reactances. With the infeed of the renewables on distribution networks

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[10] It can be the case that, similarly and in line with the implementation of SOGL and KORRR – where third parties delegated by SGUs can be SPs or other parties not involved in market activities, but only in collection and exchange of data, in particular in real time. It is important to acknowledge that data requirements shall be consistent, therefore these data requirements have a similar structure as required in SO GL.

this way of controlling voltage does not work nowadays. (Solar) converters increase the voltage where they feed into the radial distribution network. Here the voltage at the side of the distribution transformer is lowest and often the voltage at the end of the line is highest. By controlling distributed energy infeed (active power), the voltage also decreases as less power is injected into the network, more power is consumed in the area of the voltage increase effect of the converters is limited by that is increasing the voltage in the distribution network.

High Voltage transmission or distribution grids have lower R/X coefficients; hence voltage control is mostly performed by reactive power flows. Voltage increases with exports of reactive energy to the grid, while decreases with consumption of reactive energy from the grid. In the Low or Medium Distribution Voltage Grids, R/X coefficients are higher. Hence, the efficiency of reactive energy is lower and active energy flows might become more efficient for voltage control.

Article 81 set clear responsibilities to the system operators to regulate their voltage and reactive power within limits. Each country has set mandatory reactive energy requirements in the existing regulation, which are out of the scope of the NC DR. However, these reactive energy requirements might not be enough to have an efficient control of the voltage. In these cases, Art 81.2 sets the process to be followed by system operators. They should perform a technical assessment, identify potential solutions, and send to the NRA.

If the solution of the reactive energy flows consists of additional reactive energy requirements beyond the mandatory requirements, Art 81.3 defines the procurements scheme to be followed.

ENTSO E and EU DSO Entity are mandated to provide report on implementation of the market-based principle procurement on voltage control through reactive power. To provide complex and well-balanced report both associations shall be obliged to gain data from all relevant stakeholders and market participants. System Operators applied both market/nonmarket based approach fully in line with the provisions of Demand Response Network Code – therefore no additional consultation of the report is needed.

Recommendations for improvement stemming from report outcomes are to be provided where necessary, done based on system operators' assessment.