CONSULTATION RESPONSE

European Commission consultation on the establishment of the annual priority lists for the development of network codes and guidelines for 2024 and beyond

Brussels, 13 September 2024 - We thank the European Commission for the opportunity to comment on their annual priority lists for the development of network codes and guidelines for 2024 and beyond.

Key Messages

1. Implementation of existing network codes should be the priority in the coming years for electricity
2. New processes and governance around the development and modification of network codes should be the priority for gas network codes

Priorities for 2024-2027: electricity

We agree with the Commission proposal to focus on the implementation of the existing (and soon to be approved) Network Codes and Guidelines for 2024-2027. The priority should now be stability within the regulatory framework, and TSOs must ensure the consistent implementation of the remaining provisions in the relevant existing regulations.

On the electricity side, the implementation of the market Guidelines is not complete:

- Implementation of the Forward Capacity Allocation (FCA) and Capacity & Congestion Management (CACM) Guidelines (GLs) is progressing well, though at a slower pace than initially expected. These two GLs are also the ones that have been most affected by modifications as part of the 2019 Clean Energy Package and the 2024 Electricity Market Design reform.
- The implementation of the Electricity Balancing (EB) GL will likely last until at least 2026. Recent developments – partly linked to the surge of energy prices in 2021-2023 – make us fear further delays in the EB GL implementation, including the participation of all TSOs to the balancing energy sharing platforms and the enactment of all the necessary reforms of national balancing mechanisms.

- The implementation of the Demand Response Network Code is just about to start, once the final draft NC will be approved in 2025.

Focusing on the implementation of the Guidelines however does not exclude learning lessons already to improve and facilitate further implementation efforts:

- *We can be proud of everything that has been achieved already*: day-ahead and intraday market are coupled; capacity calculation methodologies for all timeframes are in place in most regions; TSOs are issuing long-term transmission rights through a single allocation platform and at a growing number of bidding zone borders; balancing energy sharing platforms have been set up and only waiting for more TSOs to connect to them, etc. Those are the big pieces of our internal electricity market puzzle, and we should remember they are well in place.
- *We see inefficiencies in the way certain methodologies are being developed and approved*: TSOs or/and NEMOs have in some cases taken long to develop methodologies to implement the Guidelines. In other cases, theoretical or political disagreements between national regulators (NRAs) have also slowed down the approval process. In both cases, many of the methodologies end up referred to ACER, if not to the Court of Justice, and this has a strong impact on the pace of the implementation process.
- *We see also a very lax attitude of certain regulators when it comes to enforcing the Guidelines*: whether it is a question of preserving historic national models or one of national priorities, we have observed a very wide degree of appreciation in the way in which TSOs and/or NEMOs are kept in check by their NRAs (e.g. application of the exemption for TSOs to issue long-term transmission rights in the Nordic area, national reforms of balancing mechanisms in many Member States, etc.). The implementation phase would greatly improve with stricter enforcement by NRAs and a greater oversight of the Commission.

We have a number of points of attention or amendment suggestions to the existing market Guidelines:

i. Forward Capacity Allocation Guideline (FCA GL)

The FCA GL will go under revision with an impact assessment of possible measures to improve the current design of forward markets by January 2026. The Commission will then make a proposal amending the FCA GL by July 2026 according to the Electricity Market Design reform (EMD) approved in 2024.

We ask to pay special attention to ensure that the revision of this network code will improve the capacity of market participants to manage risks over time on electricity markets. This includes the ability to hedge positions on the electricity markets, and to reduce exposure in cases of trading activities across borders.

Ensuring that market participants can hedge – and that this hedging capacity improves – decreases the cost of trading and ultimately benefits consumers. This will require:

- **Maintaining the ability that market participants have today to choose the electricity market(s) in which they trade, and the instruments that they want to use for this**
  → A change to alternative models such as regional virtual hubs require an independent, thorough and quantified analysis of their effects on liquidity, hedging options within and across borders, as well as social welfare.

- **Pushing TSOs to make available to market participants the natural cross-border hedge they possess with cross-border lines, by issuing Long-Term Transmission Rights (LTTRs)**:
  - **LTTRs should be issued at each bidding zone border and in both directions** → Tightening the criteria for deviations from the obligation for TSOs to do so and giving ACER a role to supervise the follow-up on related NRA decisions would help give market participants everywhere in Europe access to cross-border interconnection months and years before delivery.
  - **LTTRs should be allocated up to the maximum available capacity calculated by the TSOs before each auction, without reservation for subsequent timeframes** → Whatever volume of LTTRs is safe to allocate at a certain point in time should be offered to the market to reduce the cost of cross-border hedging activities.
  - **LTTRs should be allocated further in advance of delivery, i.e. three to five years ahead (compared to one year ahead at the moment)**
    → This will improve the capacity to reduce the cost of cross-border hedging activities further ahead of delivery, and start aligning the issuance of LTTRs with the maturity of Power Purchase Agreements (PPAs) to help them pick up also across borders.
  - **LTTRs should remain fully financially firm, including in cases of partial or full market decoupling** → This is important to maintain trust in LTTRs and their capacity at all times – except *Force Majeure* events – to provide a risk management tool against cross-border price fluctuations.
  - **LTTRs should be re-tradable in efficient secondary markets organised by the TSOs or JAO** → This is to ensure that cross-border capacity rights are best used by the market.

ii. *Capacity Allocation and Congestion Management Guideline (CACM GL)*

The main objective of the CACM GL is complete: day-ahead and intraday markets are coupled throughout the European Union[1] and deliver significant savings to European consumers by optimising electricity transactions with available cross-border transmission close to real-time.

The CACM GL is currently under revision with a possible entry into force of CACM 2.0 in 2025. Our objective is to ensure that CACM 2.0 builds on the successes of its first version on the one hand, and furthers the integration of European wholesale power markets on the other hand. Indeed, the significant discrepancies we can now observe between the different regional methodologies partly hinders the efficiency of market coupling at European level, as originally intended in the Guideline. We believe this can be remedied by:

- **Preserving the efficiency of day-ahead and intraday market coupling:**
  - **by pursuing maintenance and investment in the two coupling algorithms, Euphemia (for day-ahead and intraday auctions) and XBID (for intraday continuous)** → This will help make market coupling faster, more resilient to features (e.g. 15-minute products) and better equipped for the inclusion of new markets (e.g. Energy Community contracting parties).
  - **by ensuring that existing products of Linked and Exclusive families of blocks continue to be accommodated and implemented by all NEMOs** → This ensures that the expression of offer and demand on the market represents the true capacity of producers and consumers, for an optimisation of the system at the least cost.
  - **by guaranteeing cross-border trade in intraday right from their start with an effective intraday cross-zonal gate opening time (ID CZ GOT) with cross-border capacity at 15:00 (D-1)** → This will ensure true coupling of intraday markets (both auctions and continuous trading) right after the day-ahead market.
  - **by reducing the interruption time of continuous intraday trading (XBID) to 10 minutes once all the intraday auctions (IDAs) are implemented** → This will ensure that market participants can adjust their portfolio close to real-time
  - **by implementing portfolio bidding in IDAs in all bidding zones, as in intraday continuous →** This will ensure optimization and a level playing field among all market participants.
  - **by reviewing the decoupling communication and procedures** → This is to make sure that processes are rationalised and understandable in the rare cases when market coupling fails.

- **Reaching towards harmonisation of cross-border transmission capacity calculation across regions**:

[1] Except with the Irish Single Electricity Market, until the Celtic interconnector goes live in 2026.

- **by rationalising the capacity calculation regions (CCRs) and gradually integrating "buffer" CCRs into larger ones** → This means ensuring that the highest capacity calculation standards of the Core and/or Nordic regions should ultimately apply in the Hansa and Italy North regions.
- **by improving TSO transparency on capacity calculation in all regions on the highest standards developed in the Core Capacity Calculation Methodology (CCM)** → This should include the publication of allocation constraints and related justifications in DA and ID. More detailed reporting and justification on capacity reductions and curtailments, including via TSOs' Individual Validation (IVAs).
- **by creating a framework for coordination with – and ultimately inclusion of – third countries in market coupling** → This will help optimise our electricity system in Europe beyond the European Union.

- **Setting aside governance discussions on Market Coupling Operation (MCO)** → Significant progress has been made over the past 3 years on decision making and stakeholder involvement. We see centralising the MCO function as unnecessary and excessively complex, and we don't want that to slow down the CACM revision.

- **Putting on hold the co-optimisation of day-ahead markets and balancing energy sharing**
→ This project, which is equally challenged by market participants, TSOs and NEMOs impacts on the market, has yet to prove even theoretical benefits, considering the risks it poses for the functioning of day-ahead market coupling, as well as the transmission capacity it will withdraw from intraday market coupling.

iii. Electricity Balancing Guideline (EB GL)

The EB GL is probably the most complex of the market Guidelines as far as the European projects it entails, and the one that requires the vastest number of national adaptation through the adoption of national Terms and Conditions (T&Cs).

The European balancing energy platforms imply an improvement of security in the systems and an increase in the global social welfare of the European system. Their launch was a significant milestone.

However, 2024 was a challenging year with little progress in sharing between TSOs of balancing energy for aFFR and mFRR since most of the TSOs did not connect to PICASSO and MARI by the legal deadline of July 2024.

With balancing capacity cooperations, the harmonization of technical requirements and prequalification standards is becoming even more relevant. The balancing bids of BSPs from different countries are then not only in direct competition for the activation of balancing energy, but also in the balancing capacity auctions.

The revision of the EB GL is not yet planned. However we present some points of reflection already:

- Enforce the TSOs' obligation to connect to the balancing energy sharing platforms PICASSO and MARI.
- Further harmonise of monitoring, tolerance bands, communication, prequalification and penalties – through national T&Cs. This will require coordination with the new Demand Response Network Code.
- Clarify that marginal pricing refers to the highest-priced bid that was activated during the relevant ISP.
- Ensure that balancing energy bids activated for purposes other than balancing do not affect the balancing energy price.
- Preserve the technical price limits and avoid that TSOs introduce new price limits for balancing energy pricing, both for bidding and clearing after the 2024 ACER Decision.
- Remove the option for TSOs to reserve transmission capacity for balancing purposes.

Monitor the existence of specific products in Member States and ensure that all dispositions on the requirements for their introduction are met

iv. Demand response (NC DR)

In recent years, the EU has introduced a regulatory framework to support its decarbonisation pathway. This framework recognises the important role that distributed energy resources (DERs) and active consumers will play in efficiently achieving climate goals. It is now becoming increasingly clear that well-functioning decentralised electricity systems and markets are essential to enable DERs and active consumers to contribute to Europe's security of supply and efficient grid operation.

We ask the European Commission for an inclusive process to build on the network code draft developed by the TSOs and DSOs, improving and strengthening it where necessary. The aim should be to facilitate a quick implementation across Member States, to make implementation achievable, ensure all energy consumers can play an active role, and that System Operators have a harmonised set of rules for the market-based procurement of flexibility. We ask to pay special attention to ensure that the network code:

- **Firmly promotes market-based flexibility procurement first**

- Clearly assigns responsibilities and incentives for setting up local flexibility markets even before national terms and conditions are agreed (that should happen before 2029), sets out principles for market-based procurement and optimal use of resources and providing a clear signal for investment.
- Ensures that the goal of a secure and efficient energy system, at the lowest cost for grid users, is at the heart of all decisions.

- **Does not protect the status quo, as it risks failing to achieve a lower cost energy system**
  - Requires an NRA assessment to evaluate market-based and non-market-based procurement methods already set up in a Member State for compliance with the network code when it enters into force. Yearly monitoring, with the support of ACER, will ensure market-based procurement is applied when possible.
  - Provides NRAs with uniform and clear guidelines for the assessment procedure.

- **Is harmonised, interoperable and forward-looking**
  - Ensures through requirement harmonisation that all grid users and demand response and DERs service providers across the EU can participate in all services.
  - Limits the number of open-ended derogations for system operations and avoids the use of weak language (e.g., "may").

- **Recognises the urgency of having well-functioning and resilient decentralized electricity systems and markets**
- by tightening deadlines on system operators. Europe cannot afford to wait until 2029 for national terms and conditions.

Finally, and based on the urgency described above, the Demand Response Network Code needs to be enforceable, by providing penalties and consequences for failure to implement.

Priorities for 2024 and beyond: gas

The publication of the Gas Package[2] in 2024 paves the way for development of networks and markets in Hydrogen, and increased levels of production and consumption of renewable and low carbon gases that will be imported, transported, stored, and distributed using natural gas infrastructure. At the same time, we must ensure that natural gas systems continue to operate efficiently and securely and continue to enable energy security during uncertain times.

The development and implementation of network codes for gas has been an important and successful means to improve standardisation and transparency where their absence had raised barriers to the movement of gas in the internal market. Energy Traders Europe support the amendment of existing network codes and the development of new network codes where required to facilitate efficient, market-led decarbonisation and integration of the gas market.

Recent experience of using the FUNC[3] process to increase the level of capacity booking flexibility under CAM NC has demonstrated how long and how resource-intensive the process is. It is now more than 5 years since the original request was made and we are still awaiting a formal amendment proposal for subsequent implementation. If we are to review all network codes for integration of biomethane concurrently with the development of new network codes for hydrogen, the existing processes[4] are not adequate to enable this in a reasonable period with the resources available from stakeholders. We suggest as a priority that processes be reviewed and streamlined, and a timetable and priority list is continually updated so that the industry has the best chance to deliver the amended codes within a useful timescale.

On a related issue, as markets are becoming more complex, more global and more interactive, higher degrees of expertise are required to ensure that legislation is well-developed and implementable. Much industry resource is currently being spent seeking to understand how principle-driven legislation can be implemented where it contradicts or conflicts with current commercial and contractual arrangements. Stakeholder contribution is a vital part of ensuring that codes and other regulations can be implemented without incurring substantial costs and overheads, for example in contract renegotiations, when there are other ways that would substantially achieve the relevant objectives more directly.

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[2] Directive (EU) 2024/1788 and Regulation (EU) 2024/1789.

[3] The Functionality Process for Gas Network Codes www.gasncfunc.eu

[4] EC annual priority list, development of Framework Guidelines by ACER (6 months), Network Code drafting by ENTSOG with ACER opinion (12 months + 3 months), comitology process with or without Council qualified majority, subject to EP opinion or direct comitology where the EC replaces ACER and ENTSOG.

As a further general remark, we observe that negative assessments of the Network Code on Tariffs, as conducted by ACER, frequently are not acted upon and resolved. If Network Codes are to become useful, they must be more easily enforceable at the national level.

As a priority, we need to establish new processes and governance around the development and modification of network codes, and their enforceability.

The absorption of biomethane and other renewable and low carbon gases (such as a limited amount of hydrogen) into natural gas networks will likely have an impact on gas quality and the operation of the system. The Gas Package requires that biomethane can be entered into gas infrastructure via distribution systems and be tradable at Virtual Trading Points embedded in transmission systems. It is not yet clear whether this can be achieved merely by extending network codes on capacity allocation, congestion management, and balancing into distribution systems without substantial modification.

Quality issues may also arise, giving rise to increased quality management by TSOs (and DSOs), particularly where high levels of biomethane injected into the grid cannot be blended sufficiently to remain within spec, or where the hydrogen content is already at maximum and more cannot be absorbed. The introduction of a quality-based interruption criterion to capacity products may be one solution and, over time, quality-related ancillary services may also develop to help managing quality constraints at distribution and transmission level. In both cases amendments to network codes would be required alongside changes to transmission and distribution access terms.

A review of quality issues relating to the absorption of renewable and low carbon gases into natural gas systems will be necessary before we can establish a timetable and priority list for amendment of network codes.

The Gas Package also provides for new network codes for hydrogen. It is not yet clear how the hydrogen market will develop. Early prescription of detailed network access terms and cross-border coordination, may be unnecessary or even unhelpful (as can be the case for zeroisation of tariffs at hydrogen network interconnection points).

We suggest that the development of network codes related to hydrogen networks access should not be a priority at this time until more practical experience of hydrogen network development and operation is gained.

One exception where a network code relating to hydrogen may be more urgent relates to the proposed network code on *rules for determining the value of transferred assets and the dedicated charge* (Gas Regulation[5] Article 72.1(f)).

A major problem faced by the market in recent years has been the reduction in transparency and predictability of transportation costs. Unanticipated and substantial changes have arisen because of shortened amortisation periods, high costs related to ill-conceived security measures, reduced utilisation rates, and now the increased risk of cross-subsidisation. Without clarity, forward prices bear a higher risk premium, forward markets become less liquid and more volatile, price transparency is reduced, and higher costs will require higher spreads between trading hubs or utilisation will further decline.

This problem has arisen from costs that are defined under tariff methodologies and costs that have been added outside of transportation tariffs.

It is not immediately clear where tariff methodologies should be standardised across EU, (e.g. for RAB transfer values where pipelines are repurposed), and where different methodologies may be acceptable tailored to local conditions. However, it is essential that any changes are properly consulted, and that methodologies and tariff calculations are fully transparent. Increasingly, this will apply to DSOs with new entry points and virtual or physical backhaul into transmission systems.

Increased clarity will also be essential to allow ACER to conduct the efficiency comparison of TSOs as required under the Gas Regulation Article 19.

Extension of transparency provisions related to tariff-setting and the imposition of costs outside the tariff process should also be considered as a priority, and to include guidelines on the calculation of Regulatory Asset Values and the impact of asset decommissioning, repurposing and transfers.

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[5] Regulation (EU) 2024/1789 on the internal markets for renewable gas, natural gas and hydrogen.