CEER

Council of European Energy Regulators

Fostering energy markets, empowering **consumers**.

Regulatory Challenges for a Sustainable Gas Sector

Public Consultation Paper

Ref: C18-RGS-03-03
22 March 2019

Council of European Energy Regulators asbl
Cours Saint-Michel 30a, Box F – 1040 Brussels, Belgium
Arrondissement judiciaire de Bruxelles – RPM 0861.035.445

INTRODUCTION

Abstract

This CEER public consultation seeks to identify what energy regulation can do to foster the development of a sustainable gas sector. The goals are: (1) to identify the regulatory challenges for an efficient transition of the gas sector towards a low-carbon energy demand scenario; and (2) to identify enabling factors that the National Regulatory Authorities (NRAs) could apply to make this transition both possible and smooth. With this public consultation document, CEER intends to collect information and opinions from all stakeholders on those challenges.

Target respondents

Energy suppliers, traders, electricity and gas customers, industry, consumer representative groups, network operators, Member States, academics and all other interested parties.

How to respond to this consultation

Deadline: Friday 17 May 2019

This public consultation is carried out through a dedicated online questionnaire on the Council of European Energy Regulators (CEER) website. No login is required.

If you have any queries relating to this consultation process, please contact the CEER Secretariat: Tel. +32 (0) 2788 73 30, Email: brussels@ceer.eu

Treatment of confidential responses

In the interest of transparency and in accordance with the General data Protection Regulation (GDPR):

i. will list the names of the organisations that have responded but anonymise the personal data of any individual (such as members of the public) that has contributed.

ii. requests that any respondent who does not wish their contribution to be published, to indicate this preference when submitting their response via the online questionnaire. CEER will publish all responses that are not marked confidential on the website: www.ceer.eu

This CEER public consultation is carried out in line with the Guidelines on CEER´s Public Consultation Practices

Table of Content

RELATED DOCUMENTS

CEER Documents

- Conclusions Paper on New Services and DSO Involvement, CEER, March 2019, Ref. C18-DS-46-08.
- CEER Consultation Paper on Dynamic Regulation to Enable Digitalisation of the Energy System, 18 March 2019, Ref. C18-DSG-03-03.
- CEER's 3D Strategy (2019-2021) *Digitalisation, Decarbonisation, Dynamic regulation*: *CEER's 3D Strategy to foster European energy markets and empower consumers*, CEER, January 2019, Ref. C18-BM-124-04.
- ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, ACER/CEER, September 2018.
- CEER Future Role of Gas (FROG) Study, CEER, March 2018, Ref. C17-GPT-04-01.
- The Future Role of the DSO, CEER, July 2015, Ref. C15-DSO-16-03.
- European Gas Target Model – review and update, ACER, January 2015.
- CEER Vision for a European Gas Target Model Conclusions Paper, December 2011, Ref. C11-GWG-82-03.

External Documents

- Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): The Future Cost of Electricity-Based Synthetic Fuels
- Amprion/OGE presentation at 31st Madrid Forum: Smart sector coupling: future picture and start of implementation, October 2018
- European Commission (2018). Quo vadis EU gas market regulatory framework - Study on a Gas Market Design for Europe

Executive summary

On 6 March 2018 CEER published the Study on the Future Role of Gas from a Regulatory Perspective (FROG study) prepared by DNV GL. As a follow-up to that study, CEER is working on developing its vision on the future role of gas from a regulatory perspective. The aim of the document is to consult with stakeholders on the role that regulation should play in the context of a transforming gas sector.

At the 31st Madrid Forum in May 2018, CEER was tasked to provide a contribution to the 32nd Madrid Forum on two important regulatory issues: (i) avoiding unintended interactions between regulated and contestable activities, and (ii) potential decommissioning of gas infrastructures. Among other issues, these two issues are addressed in this consultation document. We discuss the identified regulatory challenges in three parts.

The first part addresses **regulatory challenges for renewable gases**. In this part we discuss the scope of network operator activities, the regulation of hydrogen networks in the future, the role and tariffication of power-to-gas infrastructures and an EU system for trading renewable gas guarantees of origin. Regarding the scope of network operator activities, we stress that the regulatory framework should be technology neutral but could allow for flexibility to develop pilot and demonstration projects. For that purpose, a “logical framework” similar to the one developed by CEER for DSOs should be applied.

In the second part we address **infrastructure investments and regulation**. We argue that, given the significant uncertainties on the evolution of the demand for gas/the gas sector in the long run, new investment decisions shall be carefully assessed. We identify a lack of coherence in some areas of EU legislation regarding infrastructure development and make a proposal to overcome that, i.e. a better coordination between the CAM NC incremental capacity approach for new investments (based on market tests) and the PCI selection process (based on CBA). Furthermore, we argue for a stronger oversight by ACER and NRAs of ENTSOG TYNDPs, CBA methodology and underlying scenarios. The possible decommissioning of gas infrastructures might have relevant cross-border impacts. A coordinated framework for the decommissioning of cross-border assets might therefore be needed.

In the third part we discuss remaining challenges that may require **adapting the gas market design**. As highlighted by the last ACER/CEER Market Monitoring Report[1], gas market integration has improved in Europe in recent years and gas wholesale prices have showed increasing levels of convergence in many hubs. Furthermore, the implementation of the TAR NC will substantially improve the current tariff systems. However, some problems may still remain, e.g. the termination of long-term capacity contracts and the possible decrease of gas consumption may induce higher hub spreads. Here we propose a careful bottom-up approach whereby NRAs could study simple cases for inter-TSO-compensations between two market areas, assessing key parameters, such as: flow patterns or minimum capacity to ensure security of supply.

[1] ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, September 2018.

1 Introduction

With the adoption of the Clean Energy Package which mainly focuses on the EU's electricity market, the European Union is putting in place a new legislative framework to enable it to achieve the objectives it has set in the fight against climate change and meet the commitments taken under the Paris Agreement. The reduction in greenhouse gas emissions, which should reach 40% by 2030 compared to its 1990 level and is envisaged to lead to a climate-neutral economy by 2050, requires a profound change in its energy mix and a considerable effort to improve energy efficiency. Indeed, the Clean Energy Package has also set the 2030 targets of 32% share of energy consumption from renewable energy, and 32,5 % increase of energy efficiency. The *EC strategy for a climate neutral Europe by 2050* recently published by the European Commission (EC) outlines its vision on how the EU can deliver on the Paris Agreement. In this context, there has been a growing debate regarding the expected development of the European gas sector. The target of a climate-neutral economy requires a transformation of the gas sector to be an integral part of the future energy system.

Natural gas may play an important role in supporting the energy transition, in particular by facilitating the integration of renewable energies. Firstly, natural gas is much more environmentally friendly than other fossil fuels and, as such, it represents an important bridging energy vector towards climate-neutrality. Moreover, gas is still crucial in power generation to provide the much-needed flexibility in the electricity sector due to the increasing share of renewables. Gas can also provide solutions for storage and energy transport. Nevertheless, to reach the ambitious 2050 emission target, in the long-term the use of natural gas has to be faded out or, at least, drastically reduced, unless decarbonisation technologies such as Carbon Capture and Storage (CCS) are widely deployed. However, it is important to highlight that, in the short and medium-term, if and where the natural gas demand will decrease is still uncertain; in the light of the upcoming phase-out of coal in electricity production one could rather expect an increase in gas demand at a European level in a mid-term perspective.[2]

In this context, the substitution of natural gas for renewable gases may represent an important option for achieving climate-neutrality in a cost-effective way, especially for those end-use sectors where electrification is more difficult, such as heating, industry and heavy duty and maritime transport.

The contribution of the renewable and low-carbon gasses to the target of climate-neutrality has been recently highlighted in the 2018 Madrid Forum. In its Conclusion the Forum states that "*renewable and low-carbon gasses should play a significant and growing role in the energy transition"*. Indeed, the energy transition *"will not be achieved at least cost by using a single energy source but requires a balanced mix of energy sources and technologies*". The technologies used to produce renewable gasses are at different levels of development, and most of them are not economically viable yet. Some technologies, like those for biomethane reached a maturity state while others, like those for power-to-gas, even if the technology is well known, are still at the level of pilot projects and it should be clear that power to gas should be fed by surpluses of decarbonised power generation., According to the 2018 Madrid Forum Conclusions, "…*analysis is needed regarding their impact and cost-efficiency in the*

[2] The CEER FROG study constructed three gas demand scenarios (high, average and low) to define the range of possible evolutions of natural gas demand by 2040.

transition ensuring the objectives of affordability, sustainability, competitiveness and security of supply."

In terms of regulation, elements of the current framework have to be reassessed to reduce potential regulatory gaps which may hinder the benefits of the expected developments. A first aspect regards the regulatory oversight of renewable gas injection, with a view to connection rules and gas quality, as well as new types of networks or reconversion from natural gas to hydrogen. Second, the role of infrastructure operators in facilitating the deployment of new technologies has to be assessed. While unbundling is a fundamental requirement, network operators may play a role in supporting pilot projects where the market alone seems not to be sufficient. Third, the need for infrastructure may change in nature and magnitude. Perspectives regarding demand and supply question the way infrastructure needs are assessed, notably within the ten-year network development plans (TYNDP), and how projects of common interest are selected. Risks of overcapacity may also occur, bringing questions about the responsibility of infrastructure operators and cross-border impacts in case of reduction of capacity levels. Finally, uncertainty on demand, renewable gases and the evolution of long-term contracts introduce new issues regarding the organisation of the European gas market, which could lead to opening a new reflection on some aspects of the gas market design and the regulation of cross-border interconnections.

2 Renewable Gases

Renewable gas is a gas whose energy content comes from renewable energy sources. Renewable gases are biomethane, biogas, green hydrogen, and synthetic methane produced with renewable energy.

Biomethane is a methane-rich gas which is derived from organic matter and that has properties similar to natural gas. Biomethane is generally produced by upgrading biogas. Biogas is a mixture of gases composed mostly of methane and carbon dioxide and coming from the anaerobic digestion of biomass derived from waste (agricultural waste, animal waste, waste from the food processing chain, organic fraction municipal solid waste) as well as dedicated crops in line with sustainability principles. The upgrading removes the components not compatible with the natural gas (in particular carbon dioxide) increasing the share of methane in the biogas to natural gas standards. Biomethane can be used interchangeably with natural gas and can be injected into natural gas grids or used for other proposes. The CEN (European Committee for Standardization) specified the European biomethane standards for grid injection and vehicle fuel use (EN 16723-1:2016 and EN 16723-2:2017). According to the EBA (European Biogas Association) in 2016 there were more than 500 biomethane plants in Europe with a production of 18.000 megawatt hours (MWh).

In the long run renewable gases could be produced also through the use of **power-to-gas technologies**. A precondition would be a scenario with high volumes of RES electricity excess. In that case power-to-gas installations could use the excess of electricity from renewable energy sources, which otherwise would have to be curtailed or injected at a cost, to produce gas which could also be injected into the network or used for other proposes. Those technologies use electricity to produce hydrogen or methane.[3] In a first step, they can convert electricity into hydrogen through electrolysis. In a second possible step, the hydrogen can be processed with CO_2 to produce methane (this process is called methanation). The methane can be used to create synthetic natural gas (SNG) which has technological properties similar to conventional natural gas and it can be used as its substitute. If power-to-gas uses electricity coming from renewable energy sources, the gas produced can be considered as renewable gas. In this case, the **hydrogen** produced is often called “green hydrogen”.

Power-to-gas can be seen as the reverse process of the electricity generation through natural gas. With this technology, the so called “coupling” between the electricity and gas sectors can be achieved: electrical energy could be converted to the gaseous energy and vice versa and used throughout the supply chain depending on the overall needs of the system. In the case power-to-gas technologies are sufficiently flexible, this can increase the flexibility of the energy system to cope with fluctuations in energy demand and supply, which will be more and more important in a context of increasing use of intermittent renewable power generation. Power-to-gas could enable to store large quantity of energy even over long periods complementing other types of storages under development, like batteries, which work on much shorter periods but are also continuously further developed with regard to storage capacity and time. Finally, renewable gas is also an energy vector to supply renewable energy in gaseous form directly to end-users.

[3] Power-to-gas may also produce oxygen and heat which should be considered in any business model.

Power-to-gas technologies are under development, and still far from being economically viable. They have high capital and operational costs and they need high volumes of electricity to produce a relatively small amount of hydrogen or synthetic natural gas.

Hence to be economically efficient, they need a huge amount of low-priced electricity which could come only from a very large surplus of renewable energy, much higher than the current level in EU, and also of the estimated level for the next years.[4] As of today, in most Member States conventional sources are still significant and, as result, the electricity that would be converted now into synthetic gas would carry a large CO_2-footprint. Nonetheless, there might be the option to import synthetic gas from more low-cost production regions widely based on existing gas infrastructure.

[4] Research is still necessary to define the share of renewable deployment that guarantees enough load hours for power-to-gas to make it a valid option, however this share is expected to be very high and far from today level. According to a recent study on Germany (Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): *The Future Cost of Electricity-Based Synthetic Fuels*), to be economically efficient power-to-gas installations required annually from 3000 to 4000 of full load hours and inexpensive electricity. The study shows that to have such a quantity of low-cost electricity, a large number of renewable power plants would need to be built explicitly for the purpose of producing synthetic fuels. The study analyses the possibility of producing power-to-gas using electricity from north Africa and Iceland because the estimated amount of excess of renewable energy that can produced in Germany is not enough to justify the operation of power-to-gas installations from an economic point of view.

3 Objectives and Structure of the Consultation Document

CEER has already contributed to the debate on the gas sector with the study on the Future Role of Gas (FROG) published in March 2018.[5] The study looked at the role of gas in the context of the Paris Agreement decarbonisation target and a growing share of renewable energy. A set of key issues for the development of the gas sector, both from a commodity and infrastructure perspective, were analysed and some proposals were identified. The study highlighted that the substitution of natural gas with renewable gases could support a cost-efficient achievement of the climate-neutrality target. However, the transition towards the climate-neutrality target gas sector requires a close and proper coordination between policy, regulation and industry in order to do it in an economically-efficient way making the best use of existing assets and attracting at the same time the necessary investments.

In 2018, CEER launched the 3D strategy: a 3-year regulatory policy strategy covering the topics of digitalisation, decarbonisation at least cost, and dynamic regulation. [6] In the context of the 3D strategy, particularly the “decarbonisation at least cost” objective, and building on the results of the FROG study, CEER is now focussing on how energy regulation could allow the gas sector to efficiently contribute to the energy transition. This new area of work aims at: (1) identifying the regulatory challenges for an efficient transition of the gas sector towards a low-carbon energy demand scenario; and (2) identifying enabling factors that the NRAs could develop to make this transition both possible and smooth. CEER, following a workshop with stakeholders and an internal questionnaire to NRAs, has identified a set of key regulatory challenges that were presented at the last Madrid Forum, and started to develop first thoughts on how the regulatory framework should be adjusted in order to face them.

This CEER public consultation aims at collecting the view of stakeholders on the challenges identified for an efficient transition of the gas sector towards a low-carbon scenario and on the needed adjustment of the regulatory framework to face them. The focus is only on **issues relevant from a regulatory point of view**. For example, we do not discuss whether Member States should subsidize renewable gas technologies as this is not under the remit of the NRAs but of policymakers.

In addition, the European Commission (EC) intends to launch a proposal for new legislations on gas in 2020 that will upgrade the gas sector in order to allow it to face the new challenges and, for this purpose, it has commissioned studies on several topics. At the last Madrid Forum in October 2018, the EC presented the three pillars on which this new proposal should be based, namely: Upgrading the regulatory framework, Regulatory framework fit for decarbonisation, and alignment of the gas legislation (with the electricity legislation). The present consultation paper also aims at contributing to the EC policy development in the gas sector from a regulatory point of view.

Against this background, the consultation document is divided in three parts. The first part is dedicated to the **regulatory challenges to the development of renewable gases**. National Regulatory Authorities (NRAs) have a “technological neutral” approach in this regard: the goal of regulators is not to decide which is the best technology to be developed for achieving climate-neutrality in the energy sector, but to define the regulatory conditions that would

[5] CEER, Study on the Future Role of Gas from a Regulatory Perspective, 6 March 2018. Available at: https://www.ceer.eu/documents/104400/-/-/6a6c72de-225a-b350-e30a-dd12bdf22378.

[6] CEER, CEER’s 3D Strategy (2019-2021) Digitalisation, Decarbonisation, Dynamic regulation: CEER’s 3D Strategy to foster European energy markets and empower consumers, conclusion paper, 9 January 2019. Available at: https://www.ceer.eu/1740.

allow the most cost-effective solution to be developed. Taking this into account, this first part aims at identifying possible regulatory challenges and enabling factors that could allow the development and deployment of renewable gases technologies. It will cover in particular four specific issues. The first issue regards the possible involvement of Transmission System Operators (TSOs)/ Distribution System Operators (DSOs) in competitive activities, like the development of power-to-gas installations. A second issue regards the possible development of hydrogen. It raises the question if and how hydrogen infrastructures have to be regulated. A third issue concerns the regulation of infrastructures that use power-to-gas technologies, and, in particular, whether the tariffication frameworks allow an efficient deployment of them. The fourth issue regards the implementation of a trading system for renewable guarantees of origin, as this can be a pivotal instrument for the development of renewable gases.

The second part focuses on **infrastructure investment and regulation** and in particular on three aspects. First, given the risk of stranded assets, it explores the need for a regulatory framework for infrastructure decommissioning. Second, given the crucial role of the TYNDPs and cost-benefit analysis (CBA) methodologies for the future development of the European gas infrastructure in a cost-efficient way, it questions the role of European Network of Transmission System Operators for Electricity and Gas (ENTSOs) and the NRA's. Third, it tries to better understand if the current investment framework is apt to face the future gas challenges or if it needs to be upgraded.

The third part of the consultation addresses the possible need for **updating the market design**. This might be needed given that the future changes in the gas sector would have a deep impact on the dynamics of the gas market, with potential negative consequences. In particular, a declining demand and increased injections at the distribution level could lead, in some areas, to a reduction of the wholesale market liquidity. Moreover, the perspective of the expiring of numerous long-term contracts could bring new fragmentations into the European market. These factors could lead to an increase in the hub spreads. Hence, the question on the design of the gas target model could be reopened, especially on the functioning of hubs and interconnections, in particular regarding the tariff structures.

3.1 Questions for Public Consultation

The following questions are provided at the end of chapters 4, 5 and 6 of this consultation paper. Interested parties are invited to answer these questions via a dedicated online questionnaire on the CEER website. No login is required.

[Q1] Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?

[Q2]: To what extent should a common European threshold for the blending of hydrogen in gas networks be mandatory and which timing should be taken into account? Please explain your reasoning.

[Q3]: Under which circumstances or conditions should hydrogen networks be regulated, and should this regulation be in the same way as gas networks or are there alternatives? Please explain your reasoning.

[Q4]: Is 'cost efficiency' a legitimate reason for pro-active market intervention which may be contrary to a general "technology neutral" approach? Please explain your reasoning.

[Q5] Which role do you see for power-to-gas infrastructures?

[Q6] In your opinion, do the electricity and gas tariff systems create possible distortions to the efficient deployment and use of power-to-gas technologies? If yes, how and in what circumstances?

[Q7] Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?

[Q8] What is required to facilitate efficient cross-border trading of renewable gas GOs?

[Q9] Which lessons from the EU-wide system for renewable electricity, if any, should be considered when setting up an EU-wide GO system for renewable gas?

[Q10] In your view what should be ACERs and NRAs' responsibility in the development and approval of the TYNDPs, their underlying scenarios and the CBA methodologies?

[Q11] How should the whole process be designed to maximize the efficiency of decision taking about new infrastructures? In particular, would you support the addition of cross-references between the infrastructure regulation 347/2013 and the CAM NC (2017/459)?

[Q12] Do you see a risk for stranded assets in your country? If it becomes of relevance, what could be the appropriate regulatory tools to reduce this risk?

[Q13] In your opinion, should decisions on decommissioning be assessed with methodologies similar to those used for investing in new cross-border infrastructures? Do you see the need of an EU framework for decommissioning infrastructure with a cross-border impact?

[Q14] What are the critical points that should be addressed regarding the gas market design?

[Q15] Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?

[Q16] In your opinion, do you see an issue with the current transmission tariff regime for the efficient integration of the EU gas markets, in particular considering a scenario where long-term contracts expire and gas consumption may decrease?

[Q17] If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?

[Q18] Are there other regulatory challenges for a sustainable gas sector not addressed in this document?

4 Regulatory Challenges for Renewable Gases

4.1 Scope of Network Operator Activities

The energy system transition may have a substantial impact on the gas sector. When advocating for the contribution of the gas sector to facilitate this overall system transition in a cost-efficient way, new business models and/or activities of gas network operators are increasingly discussed, in particular regarding the development and management of Compressed Natural Gas (CNG)/ Liquified Natural Gas (LNG) refueling infrastructures and power-to-gas plants. From a regulatory perspective this is particularly relevant, since several gas network operators are interested in getting involved in these activities.[7] At the 31st Madrid Forum in October 2018, CEER was requested to assess how unintended interactions between the regulated and any contestable activities performed by network operators can be avoided.

Unbundling, i.e. the effective separation of networks from activities of production and supply is a fundamental pillar for achieving the objective of a well-functioning internal gas market. It shall guarantee that network operators act as neutral market facilitators in undertaking their core functions. The Clean Energy Package, i.e. the revision of the Electricity Directive[8], reinforces the fundamental concept that network operators principally should not own, develop, manage or operate energy storage facilities and recharging points for electric vehicles. These activities should be subject to competition as the best means of meeting customer demands in the most cost-efficient way. Member States, however, may grant derogations if a number of conditions are fulfilled, e.g. in case of lack of market interest and the regulatory authority has granted its approval. Regarding energy storage facilities, Member States may also grant derogations if these facilities are fully integrated network components[9].

The current EU legislation for gas network operators indeed leaves some room for interpretation (“grey areas”) when it comes to the involvement of TSOs and DSOs in the provision of e.g. CNG/LNG refueling infrastructure and power-to-gas infrastructure. Regarding the involvement of TSOs and DSOs in natural gas filling stations (i.e. CNG refueling infrastructure), the existing European gas legislation does not explicitly prohibit such activity. According to Article 26 of the Gas Directive DSOs[10] must be independent from other fields of energy supply activity as regards their legal form. This legal requirement would be infringed if the DSO or TSO sells natural gas at filling stations to customers. Whether this is the case depends on whether the natural gas is piped to the filling station and how the "operation" of the filling station is organised. If the network operator only takes over the technical operation of the natural gas filling stations as a form of technical service, it must nevertheless be further examined whether this does not de facto amount to a management operation relevant to unbundling rules. This must then be examined on a case-by-case basis. For example, in the case of the German TSO ONTRAS, the business model is designed in

[7] See for example Amprion/OGE presentation at 31st Madrid Forum: *Smart sector coupling: future picture and start of implementation*, October 2018, https://ec.europa.eu/info/events/madrid-forum-2018-oct-17_en

[8] See https://data.consilium.europa.eu/doc/document/ST-5076-2019-INIT/en/pdf

[9] See definition in Article 2 (39a) of the revised Electricity Directive: ‘fully integrated network components’ means network components that are integrated in the transmission or distribution system, including storage facility, and are used for the only purpose of ensuring a secure and reliable operation of the transmission or distribution system but not for balancing nor congestion management.

[10] This principle equally applies to TSOs according to Article 9 of the Gas Directive.

such a way that neither gas is supplied to customers nor are the filling stations part of the regulated asset base of the TSO and thus financed by network charges. Therefore, the activity was not prohibited under the given legal framework.

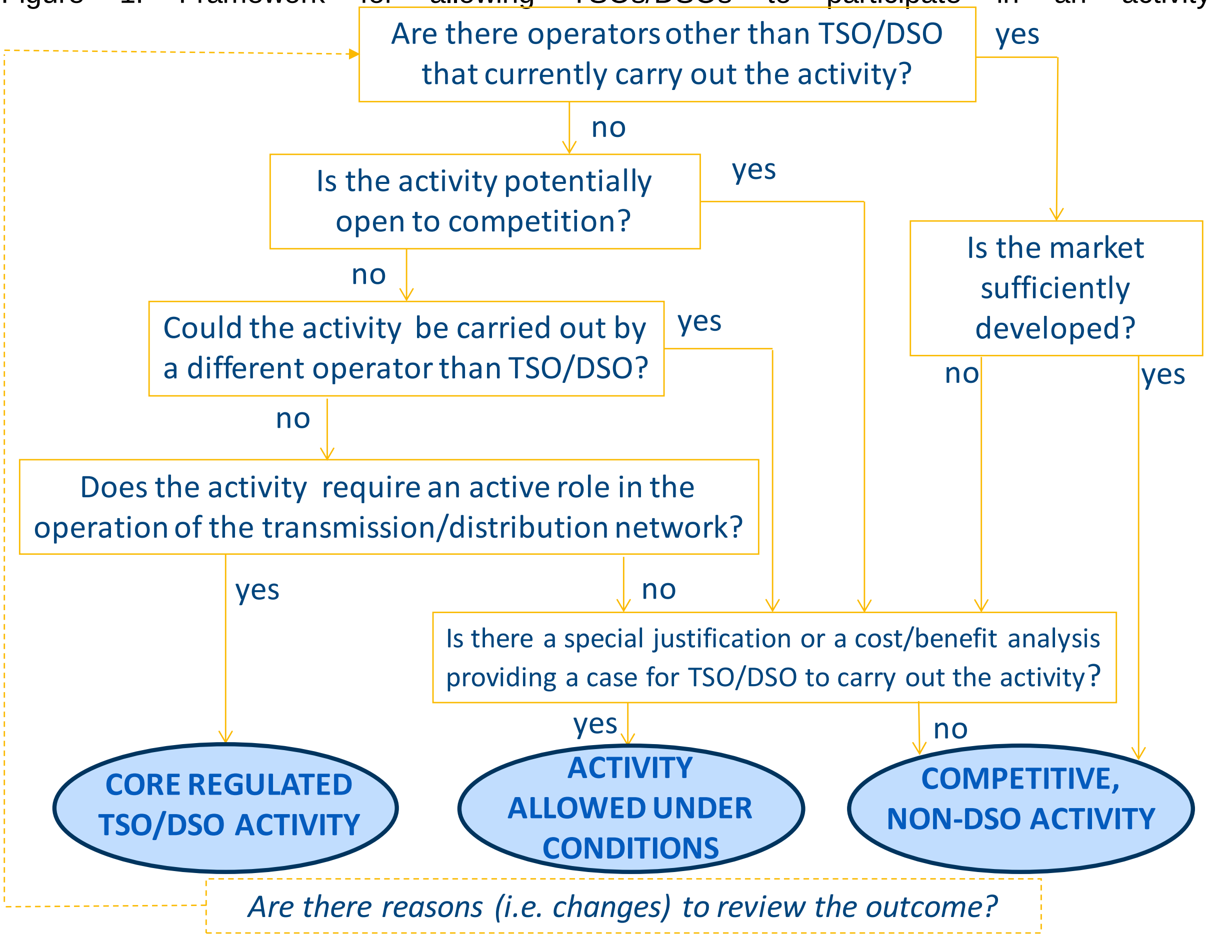
Regarding the involvement of TSOs in power-to-gas plants, the room for interpretation is smaller than in the case of CNG refueling infrastructure due to the fact that power-to-gas plants are usually classified as gas production plants. In principle, network operators are not allowed to operate any gas production plants based on the current legal provision in Article 9 (1) of Directive 2009/73/EC (Gas Directive). This prohibition is addressed not only to gas TSOs but also to electricity TSOs. This follows from Article 9 (3) of the Gas Directive, according to which a competitive activity of the other sector is also relevant to unbundling.

Looking forward, existing European legislation, national legislation and regulatory decisions may need to change to reflect the evolving role of network operators or to enable new markets to develop. The assessment of the involvement of network operators in grey areas or the role that they might carry out in the future, could be based on the conceptual tool (see figure below) developed by CEER in its conclusions papers "The future role of the DSO"[11] as well as "New Services and DSO Involvement"[12], while acknowledging the different legal provisions applicable regarding unbundling of TSOs and DSOs.

[11] See: *The future role of the DSO - A CEER conclusions paper*, July 2015, https://www.ceer.eu/documents/104400/-/-/60e13689-9416-047e-873a-2644a74c9640.

[12] See: New Services and DSO involvement - A CEER Conclusions Paper, March 2019, https://www.ceer.eu/1740.

Figure 1: Framework for allowing TSOs/DSOs to participate in an activity



The basic logic of the conceptual tool ("logical framework") is to categorise the range of network operator activities, from core to not allowed. This helps to provide some clarity about what network operators should and should not do and results in three main categories of activities:

i. Core regulated activity;
ii. Activity allowed under conditions and with justification; and
iii. Not allowed, competitive non-TSO/DSO activity

The activities addressed in this chapter, i.e. the provision of CNG/LNG refuelling infrastructure and power-to-gas plants would typically either fall in the category "not allowed" or "allowed under conditions". CEER notes that for certain activities the answer depends on the specific conditions within each Member State.

Activities allowed under conditions should be subject to a special justification or cost/benefit analysis related to the involvement of network operators. This justification should also consider an integrated view for the electricity and gas sectors. Looking forward, this framework may require a clear European legal basis, which does not exist at the moment. In general, the participation of TSOs and DSOs may be beneficial as sector coupling technologies such as power-to-gas plants and to a lesser extent also CNG/LNG refueling infrastructure in certain areas are currently relatively under-developed and limited participation by the TSOs and DSOs might help "kick start" the development of these technologies, e.g. by creating an economy of scale. However, conditions limiting the level of engagement (e.g. up to a certain critical size e.g. expressed in megawatt (MW) of installed capacity) and/or limiting the period of involvement of network operators should be set together with respective transparency requirements. In any case, the conditions set should ensure that the TSO or DSO will not foreclose competition to develop in the future.

[Q1] Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?

4.2 Regulation of hydrogen networks in the future

Hydrogen might play an important role in an efficient transition for the gas sector to a low-carbon energy demand scenario. Transport of hydrogen can take place by trucks or rail cars, or through pipelines. The latter can mean that a certain proportion of hydrogen is mixed with natural gas in a natural gas network. Alternatively, it can be based on a full conversion, meaning the transportation of pure hydrogen via a hydrogen network.[13] Hydrogen clearly has potential, but at the moment it is impossible to foresee what the developments will be. Therefore, we address different possible 'scenarios' that could be developed in the (near) future; first blending (an increased amount of) hydrogen with natural gas and second the use and transport of pure hydrogen instead of or in addition to natural gas.

A transition towards higher hydrogen quantities blended into the gas networks may require attention from regulators and/or policymakers. Blending a small proportion of hydrogen with natural gas can be accommodated in the existing gas infrastructure without substantially changing the specification of natural gas as it already contains small amounts of hydrogen. Currently, Member States apply their own norms and regulations with respect to maximal hydrogen blend. In addition, technical specifications of every pipeline system might influence which limit of hydrogen blend is feasible without large technical constraints. Although there might not be an immediate need to align such regulation across Europe the relevance for this might change in the near future. Clear technical specifications on the proportion of hydrogen that can be injected in natural gas networks would be necessary to react to a possible future increase of demand for hydrogen transport through pipelines and to allow for a smooth cross-border exchange of natural gas blended with hydrogen. On the transmission level, there may be a need to revisit the Interoperability Network Code and the CEN provisions on gas quality.

In case of a full conversion of a gas network to become a pure (100%) hydrogen network – or the development of a new pure hydrogen network – there might be reasons for intervention by policymakers or regulators. Any intervention depends on the current and future development of a hydrogen (transport) market and the presence of possible market failures that, preferably, should be addressed by ex-ante regulation like e.g. the risk of abuse of market power, or the existence of externalities.

Given the current market context for hydrogen and the transport of hydrogen in EU - by trucks or even through private industrial pipelines– there is little relevance for government intervention at this moment. Currently the development of hydrogen is not widespread and is often limited to pilot projects or studies.[14] The existing hydrogen pipeline networks are mainly owned by companies which produce gases for industrial purposes and have a limited geographical scope. Possible competition problems could be addressed by competition law.

[13] See also FROG study.

[14] See FROG study, page 74-76.

This was also the outcome of a study done at national level. The Dutch Ministry of Economic Affairs and Climate recently requested a consultant to analyse the possible market structures regarding the transport of hydrogen.[15] The study shows that further reflection is required on the notion of hydrogen in the relevant legal/regulatory framework. At the moment there are no fundamental market failures in The Netherlands that require direct intervention (in particular due to the limited role of hydrogen at the moment). However, for the future the existence of externalities and a risk for market dominance could be reasons for government intervention. Such intervention should be based on a thorough market analysis.

In the future, depending on the development of the hydrogen (transport) market, possible risk on abuse of market power, like e.g. refusal of third-party access, could arise. This is especially the case if a larger demand for hydrogen for e.g. household consumers, and consequently an extended distribution pipeline network are foreseen. As mentioned in CEER's FROG study, it is likely that such new (or converted) large scale hydrogen pipelines will have similar economic characteristics as the existing natural gas networks and therefore should be regulated. Alternatively, depending on the specific (national) situation alternative models based on tenders for designated operators to construct and own hydrogen pipelines could be applied.

A specific factor to take into account here is that the full conversion of an existing gas network, might contribute to a more cost-efficient transition to a low-carbon energy demand scenario. Possible redundant gas pipelines can be reused for the transport of hydrogen. The use of green hydrogen and possibly blue hydrogen, contribute to decarbonising the energy system and reduce current negative externalities. In addition, a lack of coordination could hamper hydrogen transport networks reaching a socially optimal scale of transport network. Even from a European perspective this is of relevance. Like for gas, if a well-connected European market for hydrogen is the desired perspective in the future, coordination at European level will be required. The existence of these negative externalities and the opportunity for a more cost-efficient transition to a low-carbon energy demand scenario may justify a more pro-active intervention by policymakers and/or regulators to allow for the development of a (transport) market for hydrogen in a cost efficient manner.

[Q2]: To what extent should a common European threshold for the blending of hydrogen in gas networks be mandatory and which timing should be taken into account? Please explain your reasoning.

[Q3]: Under which circumstances or conditions should hydrogen networks be regulated, and should this regulation be in the same way as gas networks or are there alternatives? Please explain your reasoning.

[Q4]: Is 'cost efficiency' a legitimate reason for pro-active market intervention which may be contrary to a general "technology neutral" approach? Please explain your reasoning.

[15] https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/rapporten/2018/05/31/waterstoftransport-%E2%80%93-verkenning-marktordeningsalternatieven/Waterstoftransport+%E2%80%93+verkenning+marktordeningsalternatieven+2018.pdf

4.3 Role and Tariffication of Power-to-gas Infrastructures

In a scenario with high and variable volumes of renewable power, power-to-gas could help reducing the cost of decarbonising the energy system. The excess of electricity from renewable energy, which have to be curtailed or injected at a cost, could be converted by power-to-gas installations to renewable gas which can be transported via the existing gas network to end-users and/or reconverted to electricity in a later time. This could increase the overall contribution of renewables to the Europe's energy supply. Moreover, with this technology the so called "coupling" between the electricity and gas sectors could be enhanced. Power-to-gas is the reverse process of the electricity generation through natural gas: while gas power plants convert the gas energy vector into the electricity energy vector, the power-to-gas installations do the opposite. Hence, by adding power-to-gas installations, the gas could be converted into electricity and vice versa depending on the needs of the system. This would make the two sectors to be coupled increasing the overall efficiency of the energy system and facilitating the decarbonization of it, in the case of high excess of renewable energy. Power-to-gas technologies are currently under development, there are several pilot projects ongoing in Europe, but they are still far from being economically viable.

Against this background, it is worth reviewing if the current regulatory framework does allow such technologies to unfold their potential on a level field playing, considering that power-to-gas technologies, depending on how they operate, may be in competition with other technologies. This should be done considering the principles of the liberalized energy markets. In Section 4.1, we discussed the regulatory framework regarding the involvement of TSOs/DSOs in the development of power-to-gas technologies. In this section we focus in particular on the issue of tariffication, asking if the current regulatory framework may create distortions to the efficient deployment and use of these sector coupling technologies. As said, with distortion, we mean the situation where those technologies are not on a level playing field with respect to other competitive technologies. It is important to highlight that we are not talking about network tariffs as a way to subsidise technologies. Subsidising technologies, which is not the responsibility of regulators but of policymakers, should be done using specific policies.

Most of the national electricity and gas frameworks do not acknowledge any specific roles to power-to-gas infrastructure. For example, regarding electricity tariffication, power-to-gas producers are generally treated as consumers and, as such, they are charged with the same tariffs and levies as any other consumer of the same size and features. To review if tariffication creates possible distortion, it is important to understand the role that these infrastructures fulfil, to which extent they use electricity and gas networks, and if they are in competition with other technologies. Hence, there is not a single case as the issue depends on how the power-to-gas technologies would work on a specific system and how regulation is therein designed. Here we present two different cases.

A first case is when power-to-gas plants produce gas taking electricity from the network, and this gas is exclusively stored and used to locally re-generate electricity which is then re-fed into the electricity network. In this case, they only use the electricity network. Those installations can be considered as electricity storage infrastructures and they could be treated as such in terms of tariff settings. For example, in some countries pump storages are not charged with network tariffs for the electricity used to pump water in order to avoid double charging. Similar provisions could also be applied to power-to-gas plants.

A second more general case is when gas produced through power-to-gas installations is injected in the gas network. In this configuration, power-to-gas installations make use of the gas network and, in case electricity is taken from the network, they also use the electricity network.[16] From the gas sector point of view, power-to-gas installations could be considered as gas producers that inject gas into the network. From the electricity point of view, they are high-intense consumers, where the electricity is the main input of production. If there are special provisions for high-intense consumers, they could be applied also to power-to-gas installations.

[Q5] Which role do you see for power-to-gas infrastructures?

[Q6] In your opinion, do the electricity and gas tariff systems create possible distortions to the efficient deployment and use of power-to-gas technologies? If yes, how and in what circumstances?

[Q7] Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?

4.4 EU System for Trading Renewable Gas Guarantees of Origin

Guarantees of origin (GO) for renewable gases can serve to differentiate the “green” molecules in the gas system from the “grey” molecules. Such systems are established for electricity based on the current Renewable Energy Directive. The revised Renewable Energy Directive requires such a system also for renewable gases[17]. In a number of MS, systems for GO for renewable gases have already been established. In order for such national GO to be tradable across borders, standardization with regards to their function and use as guarantees of origin towards end-users (labelling) and cooperation of the respective issuing bodies is required.
To avoid confusion of consumers, these certificates shall only cover gases with a proven pure green source. Gas produced from electricity is as green as the average electricity generation is green in the particular country or market area. Black electricity cannot be converted into green gas.

The increasing number of national GO systems for renewable gases and the corresponding need to enter into bilateral agreements, as it is currently the case, may actually lead to opacity and complexity for cross-border trading across at regional and European level. Alternatively, a European-wide system for such a cooperation could be established. Such a system needs to take properly into account the conversions between different forms of energy i.e. renewable energy converted to renewable gas in power-to-gas installations should also imply that the guarantee of origin changes its nature and becomes a GO for renewable gas.

[Q8] What is required to facilitate efficient cross-border trading of renewable gas GOs?

[Q9] Which lessons from the EU-wide system for renewable electricity, if any, should be considered when setting up an EU-wide GO system for renewable gas?

---

[16] There may be also the configuration where the power-to-gas installation is directly connected to renewable power plants and do not make use of the electricity network.

[17] The revised Renewable Energy Directive defines “Energy from renewable sources“ as energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and, geothermal energy , ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases. According to this definition, decarbonised gases, e.g. hydrogen derived from natural gas through steam methane reforming or thermal methane pyrolysis, would not be considered as renewable gas but could be included in the national GO systems as decarbonised gas, thereby making transparent to gas customers the low-carbon nature of this gas.

5 Infrastructure Investments and Regulation

5.1 The Strategic Importance of TYNDP Development

In the current EU regulatory framework, the development of gas infrastructure is addressed in different texts which are meant to be complementary. The concept of ten-year network development plan (TYNDP) was elaborated within the Third legislative package. Originally considered as non-binding, its purpose and role were enhanced in Regulation 347/2013, where new objectives were determined, in particular dedicated to the selection and treatment of Projects of Common Interest (PCI). The TYNDP has thus become a cornerstone of the European strategy of gas and electricity networks development, with the ambition to make decisions on a solid basis. Costs and benefit analyses carried out by the ENTSOs are supposed to provide a "monetisation" of the various positive outcomes of projects. In terms of methodology, ENTSOs have now a crucial responsibility as they have to model the functioning of the European gas and electricity systems in order to analyse the effects of the inclusion of new interconnections in the long term. They are responsible for elaborating concepts of benefit (also called social welfare), which are, in summary, essentially based on the evolution of cross-border spreads on wholesale markets. The Regulation 347/2013 has given ENTSOs the duty to make the gas and electricity TYNDPs converge in terms of modelling and scenarios. Coordinating long term planning is indeed necessary to properly address the challenge of climate change mitigation.

However, beyond the principles, some key challenges remain when assessing projects. The first one relates to transparency. In its opinions and recommendations, the Agency for Cooperation of Energy Regulators (ACER) has often underlined the necessity to allow stakeholders to have a proper understanding of the models, which is the only way of having a balanced debate on how to represent the energy systems. Second challenge, scenario building: elaborating a long-term vision of the future energy developments is a fundamental responsibility. Even if ENTSOs have made great efforts to include stakeholders in the process of selecting storylines and scenarios, the final outcomes remain based on choices of ENTSOs and their members while, often, regulators' views were not retained. In particular, ACER and NRAs had requested that conservative (called "behind the target") scenarios were kept ensuring a balanced representation of the future, which is seen as necessary when evaluating interconnection projects. Finally, the assessment of positive externalities such as security of supply and the contribution to reducing CO2 emissions, remains complex and debated.

It is important to ensure that methodological orientations and scenario building are not influenced by the sole interest of TSOs. Actually, assumptions and scenarios elaborated by ENTSOs directly influence the identification and evaluation of infrastructure projects.
The overall process of TYNDP development has to provide guarantees of neutrality and, as far as gas is concerned, priority should be put on making best use of existing infrastructure. Hence it is important that NRAs and ACER, as independent authorities, be responsible for properly assessing and, potentially, approving the TYNDP, the underlying scenarios and the CBA methodologies[18]. Such a proposal was formulated in ACER's second Position Paper on the energy infrastructure package in 2017 which reads "*The Agency should be conferred the power to approve the ENTSOs' proposal on Scenario Development Report and CBA Methodology, request amendments by the ENTSOs, or directly amend it after consulting the*

[18] Currently, the Agency only provides opinions on the TYNDP (Article 8 & 9, Regulation 715/2009) and the Cost Benefit Analysis methodology (Article 11, Regulation 347/2013).

ENTSOs and publish it on its website." In this document, the Agency also recommended that it "be conferred the power to issue binding guidelines on the major CBA-related deliverables (the Scenario Development Report, the CBA Methodology and the TYNDP)".

[Q10] *In your view what should be ACERs and NRAs' responsibility in the development and approval of the TYNDPs, their underlying scenarios and the CBA methodologies?*

5.2 Ensuring a Sound Assessment of Projects' Value

Projects of Common Interest (PCI) are intended to reflect European energy policy priorities. Regulation 347/2013 established a number of principles for the selection of eligible infrastructure projects, including the contribution to the objective of reducing the carbon footprint. As such, it would be advisable to extend the selection scope to projects dedicated to green gas, as well as to gas-electricity integration in the context of power-to-gas in particular.

Regarding other gas projects, in the light of the uncertainty on future gas demand, prudence is a key recommendation. The analysis of projects' value and, as a consequence, the selection of PCI has to be stricter than in the past, and regulators should have the means to properly address investment requests from PCI promoter, including rejecting the request when not solid enough. For that purpose, the assessment of projects has to combine all the relevant instruments, notably the incremental procedure that is included in the network code on capacity allocation mechanisms (CAM NC). This procedure aims at formally assessing market demand in the decision-making process via an economic test based on the outcome of auctions. Projects are validated if reaching a certain threshold in terms of capacity bookings and associated revenues. This procedure is particularly adapted to projects aiming at alleviating contractual congestions and accompanying competition development, it does not prevent including aspects like security of supply, market integration or other externalities via the determination of the "f factor", which states the minimum amount of costs to be recovered from capacity bookings.

More generally, positive externalities may justify some investments even if market demand is not sufficient to support them, but the principle of a sound cost-benefit analysis (CBA) to validate an investment has to be a prerequisite. The Regulation 347/2013 aims at dealing with such situations, yet, it specifies that, when project promoters submit an investment request, the CBA has to take into account the results of market testing. However, the principle of a market test is presented in generic manner and does not specifically refer to the CAM NC incremental procedure, which was not adopted yet when the Regulation 347/2013 came into force.

European Energy regulators therefore advocate for clarifying the articulation between these two regulations and call for unifying them into a coherent regulatory framework. A helpful improvement would be to clarify that an incremental procedure, e.g. the one provided by the CAM NC should be used as a standard market testing procedure to be included in the CBAs carried out by project promoters. In this way, market players' willingness-to-pay would be properly assessed. Reciprocally, the NRAs should determine the settings of this incremental procedure (in particular the f-factor) based on an assessment of positive externalities. This assessment should be consistent with ENTSOG CBA methodology.

[Q11] *How should the whole process be designed to maximize the efficiency of decision taking about new infrastructures? In particular, would you support the addition of cross-references between the infrastructure regulation 347/2013 and the CAM NC (2017/459)?*

5.3 Potential Decommissioning of Gas Network Infrastructures

The development of renewable energies and the potential decrease of European gas consumption might make some gas transmission capacities less necessary. While gas infrastructures depreciation lasts up to 50 years, the current perspectives may raise the risk that gas systems are oversized and excessively costly in relation to flows. The CEER FROG study explored different approaches to address this risk, using different parameters such as depreciation (which could be accelerated), asset valuation, adjustment of cost of capital or explicit compensation outside of network tariffs. European Energy Regulators are however prudent about these proposals which have pros and cons. Most NRAs do not see a reason to act in the near future.

However, if the question of capacity reductions was to occur, such reductions should be addressed in a transparent and balanced way, ensuring there is no third party unduly affected. This is particularly true when cross border transmission capacity is at stake: any change in capacity regimes should be addressed in a coordinated manner with neighbouring countries. In addition, the decommissioning of infrastructure must be considered with great caution because gas systems are integrated and, although little used, assets can retain significant value, particularly in the event of a supply problem or a peak of consumption. The principles of solidarity expressed in the Security of Supply Regulation should guide the decisions taken by the parties involved.

The background principle for regulators is that operators are responsible for the good management of their assets. According to this responsibility principle, actions on tariffs or accounting rules would be seen as last resort. Any modification of important parameters of tariff regulation to reduce the risk of stranded assets would, at minimum, require evidence of a significant and durable drop in infrastructure capacity needs. In any case, stability and predictability have to be guaranteed for system users and a case-by-case approach that takes into account the specific circumstances appears being the most relevant.

In terms of decommissioning, the regulatory treatment should include the possibility for neighbouring countries to demonstrate that the assets have a benefit to them, for example for security of supply. They should at least be offered to cover a fair level of the costs to maintain the assets alive. Hence, as identified by the FROG study, "*any decommissioning of gas assets should be considered in a coordinated way and to the extent possible, based on existing infrastructure planning/coordination procedures such as the TYNDP or the process defined in Regulation (EU, Euratom) No 617/2010 concerning the notification to the Commission of investment projects in energy infrastructure.*" If reaching a large scale, decommissioning (divestment) would deserve methodologies similar to those currently applied for new investments under Regulation 347/2013 (CBA, cost allocation). Decommissioning may be a complex decision to take and cooperation between TSOs and NRAs is essential.

[Q12] *Do you see a risk for stranded assets in your country? If it becomes of relevance, what could be the appropriate regulatory tools to reduce this risk?*

[Q13] *In your opinion, should decisions on decommissioning be assessed with methodologies similar to those used for investing in new cross-border infrastructures? Do you see the need of an EU framework for decommissioning infrastructure with a cross-border impact?*

6 Adapting the Gas Market Design

6.1 Achievements and Remaining Challenges

The general objective of EU gas regulation is to foster market integration through "*a combination of entry-exit zones with virtual hubs [enabling network users] to freely ship gas between market areas and respond to price signals to help gas flowing to where it is valued most".*[19] The implementation of entry-exit areas with harmonised rules for capacity bookings, the deployment of balancing market arrangements and transparent methodologies for tariff setting are the cornerstones of the creation of a single gas market in Europe. In particular, the new Tariff Network Code (NC) (Regulation (EU) 2017/460) provides stricter transparency requirements on transmission costs to be covered by transmission tariffs. The Tariff Network Code frames the way in which transmission costs are recovered, under the overarching principle of cost-reflectivity (mostly based on the cost drivers of capacity and distance).

In general, the market model implemented under the 3rd Package, which was formalised in the 2011 CEER Gas Target Model**Error! Bookmark not defined.** and later renewed and updated in the 2 015 ACER Gas Target Model[20], has proved its worth. The creation of entry-exit zones has led to the emergence of functioning hubs while the harmonised rules for capacity booking and for the design of balancing markets have fostered liquidity in many wholesale markets in Europe. As highlighted by the last Market Monitoring Report[21], gas market integration has improved in Europe in recent years and gas wholesale prices have showed increasing levels of convergence in many hubs. Moreover, the EU gas system has shown a high level of Security of Supply (SoS) proving its resilience also in critical situations (for example for Baumgarten accident[22]).

However, some problems remain. Some hubs are still illiquid, market concentration is still very high in many Member States and some of them are completely dependent on a single supply source. In several Europeans hubs, prices are structurally higher than in the reference markets of Title Transfer Facility (TTF) and National Balancing Point (NBP). Moreover, new challenges may put at risk the recognised achievements of the Gas Target Model also in the regions which have so far achieved the best results. First of all, there may be the risk that the possible decrease of gas consumption (forecasted in some scenarios on the basis of the decarbonisation policies) and the termination of long-term capacity contracts (between 2026 and 2036 the majority of the existing long-term contracts are set to expire) could bring back higher hub price differentials in the future, reducing the currently high market liquidity. A detailed analysis of future developments is certainly necessary to understand the extent of the risks and opportunities involved but, from the perspective of a potential future gas legislative package, we can already start reflecting on the possible options for addressing the issue which will be better described in the next paragraph 6.2.

Moreover, the possible large development of renewable gases could cause a major reorganisation within the gas value chain. The potential large injection of renewable gases at local/regional level may entail a substantial revision of the functioning of regional transport and distribution networks. As the electricity sector shows, the increase in renewable energy

[19] CEER Vision for a European Gas Target Model Conclusions Paper, December 2011.
[20] ACER, European Gas Target Model – review and update, January 2015.
[21] ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, September 2018.
[22] The 12 December 2017, following an explosion in the compression facility in Baumgarten (Austria), gas flow from Austria to other countries, in particular Italy, was temporary slashed, causing a temporary spike in day-ahead prices. Thanks to demand-side measures and alternative supply options, the system was flexible to cope with it and there was not need to cut gas demand.

production is changing the relationship between upstream and downstream. Moreover, differently from the electricity case, in the gas system the flow direction is less flexible, and this may create problems to the amount of downstream injection of gas which the networks may accommodate.

In this new context, what will be the role of wholesale markets, how will the contractual relations between actors will evolve and how will the gas value chain will be organised is yet to be fully understood.

[Q14] *What are the critical points that should be addressed regarding the gas market design?*

[Q15] *Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?*

6.2 Regulation of Access to Infrastructure

The role of regulation is to drive market developments in a transparent and non-discriminatory framework by promoting competition and economic efficiency. Network usage rules and tariffs are the essential components of the toolbox available to energy regulators. Considering the new challenges that the gas sector will face in the next years, the questions of the relationship between the types of capacity products allocated and the way in which tariffs are calculated deserves to be raised.

The current tariff system consists in shippers paying transmission tariffs at entries and exits of market areas. The methods to calculate the tariff levels, as set out in particular in the Tariff NC, are based on the principles of cost-reflectivity and of minimisation of cross-subsidies among user categories. The tariff levels reflect the full network costs under the principle of a correspondence between tariff levels and cost factors. This model does not eliminate price differentials between wholesale markets as shippers have to pay cross-border transportation costs which are internalized in their price offers. However, in the absence of congestion, price differentials should not exceed logistics cost and, hence, "wherever spreads exceed tariffs, market integration tends to be incomplete".[23]

In the current context with a large volume of long-term gas capacity bookings, historically associated to long-term commodity contracts, day-ahead price spreads pairs are often below transportations tariffs between many hubs[24]. In fact, as highlighted in the last ACER/CEER Market Monitoring Report, the historically long-term capacity contracts are now sunk costs and, hence, market players bid from one hub to another around the short-run marginal costs of shipping the gas between the two hubs. Given that the marginal cost is only a small part of the transportation tariffs, this effect has contributed to set several hub spreads frequently below the cross-border transmission cost. A potential problem may arise when the long-term capacity contracts will expire (the bulk of them will end in the next decades). These expiring contracts might be renewed by shorter instruments with the effect that market price spreads can be expected to increase if incorporating the full transportation cost. Such upward pressure on price spreads would be expected to unfold with different strengths in different markets, depending for example on local conditions, such as number of supply sources and

[23] ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, September 2018.

[24] ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, September 2018.

market concentration. For some market areas, however, the relative price increase could be relevant.

A similar problem may be caused by the changes in the energy system due to the decarbonisation target (such as the expected developments of green gasses, the increase of energy efficiency, the possible electrification of the heating sectors). Targeting climate neutrality could lead to a decreasing and more variable gas demand in some areas and, as a result, make some infrastructures become underutilised. In this regard, it should be considered that the entry-exit zones are mostly based on national borders which, as highlighted by the Gas Target Model, do not necessarily define the optimal market zone size. In particular where tariffs combine capacity and distance, a decline in flows (and bookings) at certain interconnection points (IPs) could translate into significant tariff increases, which, especially if long-term capacity contracts will be replaced by short-term ones, could make price differential among some hubs higher than the current levels. Higher reserve prices at IPs could reduce trading and market liquidity leading to a more fragmented European gas market. Moreover, they could reduce the income of TSOs thus leading to further tariff increases and, possibly, to issues of cost-recovery.

As an example, there may be situations where an increase of transportation costs along the most expensive route would imply a higher gas price on the destination market. In that case, if gas suppliers using other supply sources have the possibility to price their gas with a small discount[25], the result is that the whole price converges with the most expensive route and these suppliers benefit from a rent. The rent is amplified when gas-fired power plants are the marginal technology in the electricity market.[26]

In any case, the termination of long-term contracts and a possible decreasing and more variable gas demand would lead to significant changes in the use of the European infrastructures and, potentially, in price formation on certain hubs. This evolution needs to be monitored by NRAs and ACER in order to intervene and introduce policy measures whenever and wherever the above-mentioned risks materialise.

Tariff issues were raised in the CEER FROG study, which concluded that "*the declining demand and excess transportation capacity in the low demand scenario may necessitate a basic re-thinking of the network tariff design*". Recently, in the Madrid Forum 2018, the EC highlighted the need to further investigate tariffs and commissioned a dedicated study on *Distortive effects of non-harmonised tariffs*.

To find solutions to those problems, it requires to have a sound analysis of the possible changes in the gas sector that may result in a less liquid and more fragmented European market, assessing if and where specific actions are appropriate. Important intervention areas are the capacity allocation mechanisms, the tariff structures and the design of market zones. As suggested in the Gas Target Model, a bottom-up approach where problems are experienced seems the most appropriate way to design possible solutions. When there is the risk that lower bookings could lead to higher tariffs or where the use of short-term contracts could increase hub spreads, regulators could be allowed to elaborate those *ad hoc* solutions.

[25] This problem, in general, cannot be solved by increasing the number of sources.

[26] In this case, since the electricity price is linked to gas price, all inframarginal generators (as coal, hydropower and renewable producers) benefit from a rent associated to the transportation costs along the most expensive route.

A solution which has been under discussion and which could work in some regions, regards eliminating some IPs[27]. As described by in the CEER Gas Target Model, many options may be adopted to do so. Regardless of the chosen option, NRAs and TSOs on both sides of the IPs should define an inter-TSO compensation (ITC) mechanism to distribute the costs among different TSOs and ensuring a fair cost allocation among different system users. There are already some examples of ITCs in EU, also among TSOs in different countries. Belgium and Luxemburg merged their zones in 2015 and discussion on merging zones are ongoing in the Baltic countries and in the Iberian countries. These experiences show how complex the design of such mechanisms is and how difficult it is to find a shared solution.

Another possible way is to consider a cost-allocation methodology that includes all the benefits provided by the gas infrastructures and that tries to allocate the costs to all the beneficiaries. For example, in some emergent or illiquid markets, LNG terminals provide benefits like SoS, market integration, increasing competition or decarbonisation which may justify keeping them working even if they are underutilised.[28] Hence, it could be justified to go beyond the cost-recovery principle solely based on capacity bookings paid by shippers and associate other beneficiaries. Identifying the benefits and the beneficiaries is not an easy task, in particular for existing infrastructure, and a clear and transparent methodology consulted with stakeholders would have to be defined[29], ensuring however that strict rules on transparency and non-discrimination are applied.

[Q16] In your opinion, do you see an issue with the current transmission tariff regime for the efficient integration of the EU gas markets, in particular considering a scenario where long-term contracts expire and gas consumption may decrease?

[Q17] If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?

[Q18] Are there other regulatory challenges for a sustainable gas sector not addressed in this document?

[27] For example, the Quo Vadis Study analyses three scenarios with reduced or eliminated IP tariffs. In the first scenario, the IP tariffs are set to zero and the revenue loss are recovered on entry/exit points with non-EU countries. In this case, transmission domestic exit tariffs would remain constant. In the second scenario, entry-exit zones are merged into one entry-exit system with one trading point and a common balancing regime. In the third scenario, a conditional merger among zone is done. In this case, the zones retain separate balancing regimes and there is one wholesale market price as long as transmission capacity is available. When capacity is not available, the markets will be split by the transmission tariff premium and distinct market prices emerge in each zone.

[28] The Tariff NC allows a discount for LNG in case of SoS issues.

[29] This approach could be applied at national level (in this case the different beneficiaries could be different types of costumers) and/or in an ITC (in this case the different beneficiaries could be the customers of the different TSOs).

Annex 1 - Abbreviations

Term	Definition
ACER	Agency for Cooperation of Energy Regulators
CAM NC	Capacity Allocation Mechanisms Network Code
CBA	Cost-benefit analysis
CEER	Council of European Energy Regulators
CEN	European Committee for Standardization
CCS	Carbon Capture and Storage
CNG	Compressed Natural Gas
DSO	Distribution System Operator
EC	European Commission
EBA	European Biogas Association
ENTSO-E	European Network of Transmission System Operators for Electricity
ENSOG	European Network of Transmission System Operators for Gas
FROG Study	Future Role of Gas Study
GO	Guarantees of origin
ITC	Inter-TSO Compensation
MS	Member States
MW	Megawatt
MWh	Megawatt hour
NBP	National Balancing Point
NRAs	National Regulatory Authorities
LNG	Liquified Natural Gas
PCI	Project of Common Interest
SNG	Synthetic Natural Gas
SoS	Security of Supply
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
TTF	Title Transfer Facility

Annex 2 - About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's members and observers comprise 38 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

CEER supports its NRA members/observers in their responsibilities, sharing experience and developing regulatory capacity and best practices. It does so by facilitating expert working group meetings, hosting workshops and events, supporting the development and publication of regulatory papers, and through an in-house Training Academy. Through CEER, European NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

In terms of policy, CEER actively promotes an investment friendly, harmonised regulatory environment and the consistent application of existing EU legislation. A key objective of CEER is to facilitate the creation of a single, competitive, efficient and sustainable Internal Energy Market in Europe that works in the consumer interest.

Specifically, CEER deals with a range of energy regulatory issues including wholesale and retail markets; consumer issues; distribution networks; smart grids; flexibility; sustainability; and international cooperation.

CEER wishes to thank in particular the following regulatory experts for their work in preparing this report: Claudio Marcantonini, François Léveillé, Benoît Esnault and Markus Krug.

More information is available at www.ceer.eu.