Survey response 6

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Greenpeace Energy eG

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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?

Infrastructure Investments and Regulation

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?

Adapting the Gas Market Design

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?

Other question

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

Survey response 7

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Centrica plc

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
•We believe that competition and innovation have an important part to play in delivering a cost-effective transition towards a net-zero economy. •Accordingly, the proper role of TSOs/DSOs should be the facilitation of renewable gas production and supply. They have a key role to play in areas such as grid connection and providing maximum flexibility for renewable gas supplies to access existing gas pipelines and other infrastructure. They should be flexible in accepting new gases and not be unduly rigid by imposing unnecessary costs and requirements. •CEER is right to consider that there should be a clear separation between the ownership/operation of the infrastructure and the production, buying and selling of gas. DSOs and TSOs should act as neutral market facilitators. If the market is not able to deliver, they may be allowed to step in, but only under clearly defined and restricted conditions. If TSOs/DSOs decide to invest in non-network elements of renewable gas projects, then they should do so via unregulated entities at arm's-length from the System Operator, subject to both EU and national rules on unbundling and separation.

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.
•The first step should be to determine what level of hydrogen blending is technically feasible and safe, having regard to the gas appliance population (including industrial plants and power stations) and existing gas infrastructure. Trials carried out in the UK have concluded that retail customers are generally less sensitive to gas quality variations than larger businesses and power stations. Initial evidence to date suggests that 2% blending of hydrogen should be feasible for larger Industrial & commercial customers, but 10% would cause problems. By contrast, households and other smaller users on the local distribution networks could cope with 10-20% of blended hydrogen (source: DNV GL). •We note that the blending limits might be different between local distribution networks (often polyethylene) and gas transmission networks (generally steel). Due to technical and safety reasons, a single blending limit may therefore not be suitable for an entire national gas network. A common European threshold would therefore be very premature. •Once the safe and technically feasible limits have been determined and approved for each TSO/DSO, we consider that the blending of hydrogen should generally be mandatory within those approved limits.

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.
•Please see our answer to Q1. The transition towards net-zero is not a good reason to abandon the benefits of effective competition in gas production and supply. •Accordingly, we consider that public networks for the transportation and distribution of pure hydrogen should, in principle, be regulated in a similar way to natural gas networks today. The same criteria and principles should apply, including third party access. •This is especially the case, as we do not yet know the future mix between blended gas networks (for bio-methane, bio-SNG and blended hydrogen) and pure hydrogen networks. •We can foresee many distortions if the regulatory regimes adopted in the two cases were fundamentally different.

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.
• Several studies have demonstrated that decarbonising the economy with renewable and decarbonised gases (and using existing gas infrastructure) is more cost-efficient than decarbonisation in a high-electrification scenario. The recent Gas for Climate study (March 2019, Navigant) concluded that the use of green gases (biomethane and hydrogen) through gas infrastructure saves society €217 billion annually across the energy system by 2050 (compared to a ‘minimal gas’ scenario). • It remains important, in our view, for policymakers and regulators to adopt an even-handed approach to well-established low carbon technologies. • There can be a case for additional time-limited support low-carbon technologies which are not yet well established (i.e. still at the demonstration scale or first-of-a-kind commercial roll-out phase). However, this should only be provided for those technologies which appear, as far as can be determined, to offer a reasonable prospect of being cost-effective contributors to carbon abatement in the longer term. • Studies such as the one mentioned above appear to indicate the longer-term welfare value of green gas technologies which are not yet established and suggest a case for initial policy support.

Q5 Which role do you see for power-to-gas infrastructures?
• In our view, power-to-gas (via electrolysis) is likely to be an interim technology, even if the power is renewable, since ‘synthetic’ natural gas will still create CO2 emissions when burned. • In the longer term, provided it is economically viable, Europe would need to look to renewable gas supply sources such as power-to-hydrogen, and/or steam-reforming of methane plus CCUS. • Power-to-gas (or power-to-hydrogen) is likely to be more attractive in those locations where renewable electricity would otherwise be ‘spilled’ or where wholesale prices are more often low or even negative, considering also the costs of gas (or hydrogen) transportation from such locations to the point of use.

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?
• We are not familiar with any specific distortions caused by network charging regimes for Power-to-Gas. • As a general note, we would advise regulators to take into account the cross-sector cost-benefit impact of charging regimes. Historically, gas and electricity have often been legislated for separately, at an EU and at a national level. • As we move towards greater sector integration of electricity and gas (of which Power-to-Gas is a great enabler), the impact of electricity network charges on new gas technologies should be examined (and vice-versa). • This growing need to consider ‘sector-coupling’ costs and benefits is likely to require revisions to the regulatory regime, at least in some Member States. The (sector-specific) ‘Relevant Objectives’ against which Ofgem is required to assess proposed changes to network charging methodology in Great Britain is one specific example with which we are familiar.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
• Please see answers 5 and 6. Over time, it will be important to ensure that markets and regulations together create the appropriate incentives to transition from power-to-gas towards even lower carbon technologies such as power-to-hydrogen.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
• GOs for renewable gas present more challenges than GOs for electricity, given the diverse nature of renewable gases (due to the different feedstocks used, the different qualities, etc). Given that renewable gases may not be equally ‘green’, they may not all qualify for the same number of certificates. • To address these challenges, we believe the key elements would include a standardised European definition of ‘renewable gas’, the creation of a tradeable certificate which is recognised and valued across national borders and a system which allocates the appropriate number/value of such certificates to the different sources of renewable gas (e.g. bio-methane, bio-SNG, P2G, hydrogen). • Some of this work has already been undertaken by the European Renewable Gas Registry (ERGaR), composed of 24 members across 12 European Member States. They have set up a voluntary GO for biomethane and have established hub connecting the registries. The IT work has been completed and the hub is in testing phase. This voluntary scheme set up by the European gas industry is a solid basis for the development of an independent, Europe-wide biomethane certificate scheme to be certified by the European Commission. We were pleased that the principle of GOs for renewable gas was formally introduced by the newly agreed revision of the Renewable Energy Directive (RED II). • If such a voluntary (industry) scheme works well, there is every reason to make them compulsory and certificate it for obligation.

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?
• In our opinion, much can be learned from the creation of GOs and related cross-border trade in renewable electricity. • Whilst primary legislation states that electricity GOs should be tradable across borders, this is not always the case. There are a number of reasons why this is the case: o First, there is no pan-European guidance or common framework for GOs in terms of issuing them, trading them or using them by the buyer. This has led to a patchwork effect across Europe, which has impacted the ability of companies to trade their renewable electricity across borders and has impacted the ability of consumers to reliably produce renewable electricity. o On the supply side, GOs are not universally issued to all renewable generators. The theory of GOs is that they are issued per unit for renewable production to the asset owner. This is not universally the case. In some countries, GOs are not issued at all if the asset owner is in receipt of state subsidies. In some others, whilst GOs are issued for renewable production, they are not issued to the renewable asset owners but auctioned on behalf of the government who retains any revenues. o On the demand side, the use of GOs is not consistent across Member States. There is no universal use for GOs in the value chain of renewable electricity. In many jurisdictions they are used by electricity suppliers as evidence of the renewable component of the electricity fuel mix or to enable a supplier to provide the renewable credentials of a renewable electricity to end-consumers. This is not universally the case. In some countries the fuel mix disclosure is done using other certificates or statistics provided by the TSO or central authority. o Finally, as regards buying & selling GOs, there is no consistent set of rules on how this should be done. Even where GOs are issued to renewable generators and required to be used by electricity suppliers to prove the fuel mix disclosure, the rules relating to the GO trading are not always the same between countries, especially when it relates to the use of GOs from another member states. In some jurisdictions, GOs may be purchased on the market separately from any power trading. In other jurisdictions, in order to use the GO certificate, a parallel contract is required for the associated electricity from the same generator, along with contractual proof of cross border trading of the power and transmission capacity. • To conclude, we therefore believe it would be essential to establish upfront a common framework of rules and also potentially a common database of certificates to facilitate the trading of those certificates by all parties with certainty as to their validity to prove renewable gas credentials.

Infrastructure Investments and Regulation

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?
• By way of background, we are aware that different approaches to network investment development and approval apply in different EU Member States. Some NRAs such as the CRE in France, review and (where appropriate) approve network investment proposals ex ante; others, such as Ofgem in Great Britain, consider investment plans when setting network price controls but do not give any formal ex ante investment approval. • We do not see a compelling case for such differing approaches to be harmonised cross-border, provided that sufficient information is available for NRAs and (ultimately ACER) to assess whether cross-border costs and benefits have been taken into account, on a consistent basis. • There is therefore value in consistent, cross-border TYNDPs and ENTSOG plays an important role in this respect. • We do not consider that a further overall review of roles and responsibilities is required at this stage, whether for reasons to do with green gas development or otherwise. • It is, however, important that ACER should be open to representations from wider stakeholders and resourced to intervene effectively, in a timely manner, in cases where material cross-border inconsistencies in network planning and development cannot be resolved via co-operation between the relevant NRAs.

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)?
no answer

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?
• The risk of stranded assets is top-of-mind already for all gas infrastructure projects across Europe. Each project is rigorously looked at and every project needs to address a specific market issue that is putting security of supply at risk. • We believe current approval processes are suitable, but would advise the EU to regularly review approval processes to grant status of PCI (Projects of Common Interest) to gas infrastructure projects. As natural gas demand is expected to go down, a robust cost-benefit analysis should be rigorously conducted for every gas project. • We are aware of consideration being given to the possible 're-purposing' of natural gas transmission assets in Great Britain (in this case, for carrying CO_2 intended for storage offshore). In future, alternative uses for gas infrastructure could potentially include hydrogen transportation. Generally speaking, we consider that gas network operators should be required to review and assess such alternative uses before coming forward with proposals to decommission pipeline assets.

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?
• Decisions on decommissioning could indeed be assessed with methodologies similar to those used for investing in new cross-border infrastructures. This would make sense and should be considered. • However, we believe this is currently premature and not an urgent problem to be addressed. • Before decommissioning gas infrastructure, network operators should be obliged to consider whether it could not be converted to hydrogen or CO_2 (for CCS), as mentioned above.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
• Implementation first: Before defining new changes, we would support the full implementation of the Gas Target Model and the gas network codes. This should take priority before any new changes are being proposed, especially as there are clearly some Member States and/or national TSOs which are not yet fully compliant. We are pleased to this that the evaluation of NC implementation forms part of the ongoing work carried out by the European Commission in preparation for a potential Gas Package. • Mirroring: There will also need to be some 'mirroring' of CEP retail electricity market design into the gas market, where relevant.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
• We would not support the development of European model for renewable gas support mechanism. National support mechanisms for the production and deployment should be at least compatible (and therefore observe sufficient common principles, as with capacity market design in electricity, for example), but should not be precisely the same. • Regarding blending limits, definitions, tradeable GOs to allow cross-border trading, see previous answers.

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?
• We don't believe there are fundamental issues with the functioning of the European gas market. • We believe priority should go to the full implementation of the network codes, including the TAR network code on harmonised transmission tariff structures for gas. The TAR NC includes increased transparency requirements for TSOs to explain their methodology behind the calculation of tariffs. Not all TSOs are doing it fully and this should be addressed as a matter of priority.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
• The Quo Vadis study included some interesting models, but we don't believe they were very practical to put in place. We would caution against a radical reform of the current tariff models.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
No answer

Survey response 8

Contact details and treatment of confidential responses

Contact details: [Organisation][]
ENTSOG

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
To foster the energy transition, TSOs are well placed to be involved in activities that enable decarbonisation and promote future sector coupling. ENTSOG believes that the assessment should consider activities such as, but not limited to, Power-to-Gas facilities, biomethane plants, Carbon Capture and Storage (CCS) and Carbon Capture and Utilisation (CCU) technologies and CNG/LNG filling stations for transport. By allowing TSOs to invest in either a regulated or fully commercial way, they can support the development and scaling-up of these markets. TSOs can have a positive impact on enabling the integration of renewable and decarbonised gases, especially where there are no existing investors. TSOs owning, operating and maintaining such facilities, and selling services to network users will comply with unbundling rules. Regarding Power-to-Gas facilities – it is necessary to consider all available technologies. By building an overarching energy system, integrating electricity and gas, it is more cost-efficient, more reliable and quicker to achieve decarbonisation targets. There is a need to review the regulatory framework and, where necessary, to amend it to ensure the development of Power-to-Gas alongside other decarbonisation technologies (see our answers to questions 5, 6 and 7). Power-to-Gas facilities should not be classified as gas production plants. Power-to-Gas may be provided as a conversion service that transforms electricity from a renewable producer, or any other electricity network user, into gas (such as hydrogen or synthetic methane) for further use in the energy system. Therefore, no obstacle for TSOs to be the owners and operators of a Power-to-Gas facility should arise from an unbundling point of view. Regulated/Commercial – gas TSOs should be allowed to invest in any type of facility enabling decarbonisation and sector coupling. The question should not be which activities are considered relevant for potential TSO involvement, but which activities need additional enabling regulation to facilitate their wide deployment. TSOs would then like to be able to invest in a regulated or in a commercial way. Investing in a commercial way, in competition with commercial investors, TSOs should not have any specific commercial advantage or disadvantage. They should be in compliance with unbundling rules and a transparent separation between regulated and non-regulated activities set up, supervised by the relevant NRA. For some activities, where there is limited commercial development of new facilities or if the assets are essential facilities (natural monopoly character), it may be necessary to establish a regulatory framework to ensure that the underlying technologies reach the required scale and maturity, by which time they will become essential for the operational integrity of the energy system. A regulated business allows for low-risk and cost-efficient development of relevant economic activities and energy transition facilities, creating new services open to all market participants in a non-discriminatory way and under the NRA's oversight. The TSO would provide open and transparent access to the facilities for all market participants. The appropriate framework could be left to the authorities in the Member States, depending on their particular circumstances, however, the options should not be limited to regulated investments. Objective criteria could be put in place by Member States to evaluate market appetite for investments in new decarbonisation facilities, such as a market test. As some of these activities are still in development, TSOs should be allowed to engage in research and development to help bring these technologies forward. Additional types of support complementing the regulatory frameworks exist, such as subsidies and funding for the most promising technologies to favour their evolutions and cost decrease. Support provided in the electricity sector for decarbonisation activities should be replicated in the gas sector. There should be a level playing field for all decarbonisation technologies.

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.

As recognised by CEER, there are different possible approaches towards hydrogen integration: blending hydrogen with methane (natural gas at a transition phase and biomethane and/or synthetic methane in the long-term) and hydrogen-only networks. While there is evidence that gas applications could be able to integrate different fractions of hydrogen (see Marcogaz paper on “Impact of hydrogen in natural gas on end-use applications“. UTIL-GQ-17-29. 2017), the optimal choice and pathway will be determined by national or even local conditions.

A level playing field should be established to develop the different technologies that support the various pathways to a gas system which is close as possible to carbon neutral.

Gas quality will be more and more diverse in the future and hence there is a clear need to increase the system’s resilience - including infrastructure and end use - to handle it.

Therefore, Member States should be free to choose the pathway they want to follow and the relevant timeline. The use of hydrogen either in combination with natural gas or in pure form will require at least an assessment and possibly an adaptation or substitution of gas infrastructure elements and end use applications. As CEER has correctly identified, providing technical clarity at EU and local level on the different pathways is necessary to identify which technological developments and investments are needed.

In the short-term, there is an urgent requirement to remove technical and legal barriers that could hinder further development of hydrogen systems, including blends.

Short-term technical barriers
>⍰In order to unlock the current 2% limitation in hydrogen/methane blends, it is key to test the ability of UGS facilities and CNG mobility application to use higher fractions.
>⍰The current relative density requirement in the CEN standard EN16726 (from 0.555 to 0.7) should be revised in the context of current CEN harmonisation work as the lower value hinders the development of hydrogen. It is worth mentioning that test gases in the standard EN437 already foresees the testing of H-gas appliances with up to 23% hydrogen.
>⍰In any case, EN16726 should recognise the different hydrogen tolerance of end use applications and infrastructure elements. Rather than settling for the common least denominator (e.g. 2% for CNG), hydrogen injection requests should be assessed by the relevant operators on a flexible case by case approach with the oversight of the competent authorities. Otherwise, the development of business cases for renewable and decarbonised gases in the short term could be hindered.

Short-term legal barriers
>⍰National legislation and accordingly bilateral interconnection agreements need to be revised to allow the flow of blend gases at Interconnection Points.

Evaluation of the current system and implication of future changes
>⍰From the technical point of view the realisation has to be started with a proper feasibility study of the existing system from production (hydrogen/biogas), storage, transport to consumption to handle aimed renewable and low carbon targets. The technical evaluation should suggest what modification have to be done to achieve the targets (modify existing installation, design criteria for new installation, new separate hydrogen system for transport/storage). Through an iterative process, the most economic path should be evaluated between utilization of existing systems, rebuilding separate H2 infrastructure or H2 conversion in synthetic methane.
>⍰Before taking any decision, a proper impact analysis should be carried out, including on the financial effects and impact on tariffs by the foreseen changes – costs of the infrastructure upgrades, costs of end-user appliances, implication to the consumer bill. Regulators shall play important role in transition of the European gas market into carbon neutral system, especially by accepting these costs as eligible in regulated sectors.

In the medium and longer-term, natural gas end-use applications standards should increase their readiness for hydrogen fractions. It is also important that gas applications are provided with the necessary controls to withstand the foreseeable variability in the hydrogen fraction. An EU roadmap setting minimum hydrogen readiness targets for new appliances by 2030, 2040 and 2050 would be beneficial. Based on the roadmap, the analysis of costs and benefits of such a transformation should be performed.
In order to enable a smooth transition, potential minimum readiness thresholds could be in the range of e.g. 10% by 2030, 25% by 2040 and 50% by 2050 without prejudice to member state to extend these limits nationally or locally. The implications of this minimum readiness would be:
•⍰All new domestic and commercial applications -including CNG- should be able to withstand a variable concentration of hydrogen up to the established threshold.
•⍰Transmission system operators should be allowed to include in the RAB the cost of new assets and/or replacing or adapting depreciated assets by ones that are ready to integrate at least the hydrogen fraction indicated by threshold with the possibility to go beyond.
•⍰For industrial and power generation customers, a specific case by case assessment should be done locally once and where hydrogen injection is foreseen. NRA’s may need to be involved to decide on possible mechanisms for socialising costs where

needed.
•Member States should cooperate in order to ensure the safe and reliable cross-border flow of gas and gas-hydrogen mixtures and coordinate their readiness to transport and use certain hydrogen fraction. Minimum thresholds for gas networks should be set on national levels.

ENTSOG is currently working on a hydrogen roadmap to integrate the different pathways and options and address the issues mentioned above.

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.

The use of hydrogen as an energy carrier has significant potential as part of the energy transition and its use is envisaged to increase in the coming years. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its growth.

Hydrogen networks, connecting diverse production and demand centres, can be considered as natural monopolies as building parallel network structures would not be efficient. 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. This idea is aligned with ENTSOG's view that it will be necessary to allow for non-discriminatory third-party access to support and further develop the Internal European Energy Market, and therefore such hydrogen networks could be regulated and managed by TSOs (but not only). The level of regulation would depend on the level of maturity of the market, objectives the regulator is trying to achieve and national circumstances. In any case, new regulation should be carefully assessed subject to the detailed technical and economic analysis including the impact on the final customer.

Based on the above, the scope of the gas directive should be enlarged to include hydrogen. Hydrogen networks do not have to be under the same regulatory framework as natural gas networks, some nuances are possible, please see the table below:

Level	Aim achieved at that level	When should it be put in place?
3	Regulated tariffs	When one wants to control the cost for the final end-users
2	Non-discriminatory third-party access	When we want open access for all parties and when the market power of the various users differs too much
1	Natural monopoly	When the size and/or the risk of the investment is so large that there is no point to double the investment and/or recognised by law

However, independently from being fully or partially regulated or not, benefits of TSOs building and managing hydrogen pipelines are:
•Infrastructure optimisation and cost savings as a result of coordinated planning reflecting the development needs of the sector.
•Development cost can be reduced using existing infrastructure by adjusting or converting some parts of the existing network into hydrogen networks and integrating existing hydrogen pipelines.
•Guaranteeing non-discriminatory third-party access, so that all interested market players can benefit from access to the hydrogen network, maximising the potential of sector coupling
•Guaranteeing the viability of pipelines in the development stage, as the load factor progressively increases.
•Allows for the potential integration of hydrogen and (bio)methane markets to deliver one price signal for gaseous energy, in a similar manner as H gas and L gas are integrated in some EU markets. This integration will prevent market fragmentation as hydrogen usage develops alongside (bio)methane gas usage.

Blending hydrogen into the existing gas network will require the removal of technical barriers for cross border trade. The regulated framework already in place for gas infrastructure should be used and possibly adjusted in order to facilitate and incentivise their evolution towards future-proofing assets. These points are dealt in our response to question 2.

As the use of hydrogen increases in the future, development costs can be reduced using the existing infrastructure, by adjusting or converting some parts of the existing gas network into a hydrogen ready network, or blended hydrogen/methane network with higher concentration of hydrogen. Conversion from methane to hydrogen will take time, R&D and investments for future proofing existing infrastructure will need to be carried out. These investments will have to be taken into consideration by NRAs and appropriately incentivised.

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.

ENTSOG believes that ‘cost efficiency’ is a legitimate reason for pro-active market / policymakers and/or regulators intervention where sustainability is the main driving force of the energy transition, but a focus on Security of Supply (SoS) and affordability must also be maintained. ‘Technology neutrality’ is needed for the efficient development of a decarbonised energy market and its associated regulation. Support schemes should not favour one technology over another e.g. biogas support mechanism for the production of electricity but not for injection into in the gas system. Besides cost efficiency, other criteria like SoS of the whole energy system, diversification of sources, peak demand, societal and environmental impacts (externalities) and future potential of the technology should be considered to promote activities like Power-to-Gas, hydrogen networks, CCUS, biomethane and CNG/LNG for the transport sector. In addition, any decision that will impact the future of gas and gas infrastructure, like a shift from a methane network to a pure hydrogen one, should be carefully assessed taking into account long-term cost efficiency.

Nowadays, there are supports and an adequate regulatory framework in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of treatment assuring a level playing field between all technologies and all energy carriers.

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

In ENTSOG’s view, Power-to-Gas is a technology that will further enable sector coupling, fully enabling the development of a hybrid energy system that can provide, affordable, sustainable and secure energy. A Power-to-Gas facility should not be treated as a gas production facility but instead as a conversion facility which transports energy from the electricity system to the gas system.

Power-to-Gas has a number of benefits:

• It would facilitate sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner.

• It allows the maximisation of the renewable electricity production by converting renewable electricity to renewable gas which can be injected into the existing gas network and used among others as a raw material by industry.

• It will contribute to better functioning of the energy market by reducing the occurrence of negative/very low prices on the power wholesale market and enabling the development of additional market-based renewable electricity generation whilst providing a renewable source of gaseous energy.

• It will ease the balancing of the power grid by providing both up and downwards operational reserve and will contribute towards the reduction in electricity grid congestion.

• It allows storage of large quantities of energy derived from renewable electricity over long periods in the gas system.

• It improves SoS in both electricity and gas sector.

Furthermore, TSOs are ideally suited to contribute to the ramp-up of Power-to-Gas infrastructure as they have the knowledge, experience and resources to develop this type of infrastructure. TSOs want to invest in Power-to-Gas as a conversion service and should be allowed to start now in order to ensure that the technology reaches the required scale.

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?

In ENTSOGS’s view, electricity and gas tariff systems could create distortions to the efficient deployment and use of Power-to-Gas technologies.

Electricity and gas TSOs should be allowed to propose a discount on the electricity and gas network tariffs justified by the benefits that Power-to-Gas facilities generate to the overall energy system in terms of positive externalities (SoS, supply diversification, balancing of the grids, support to renewable energy sources and decarbonisation etc).

However, in the first case mentioned in paragraph 4.3 of the consultation paper (i.e. Power-to-Gas used to store gas and, then, transform it again locally into power), where CEER assumes that gas infrastructure is not used, we are of the opinion that most of the Power-to-Gas benefits will not materialise. Furthermore, ENTSOG believes that there shouldn’t be a differentiation between whether the gas produced is used to generate electricity or used for a different purpose.

It would be difficult and counterproductive to restrict the use of renewable gas as described in that first case, that’s why the discount similar to the one described in the second case (i.e. “special provisions for high-intense consumers”) could be a workable solution.

In addition, Power-to-Gas facilities should be classified as a conversion service so that Power-to-Gas users will not bear tax and levies associated with their electricity consumption.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legislative and regulatory frameworks were designed prior to the development of Power-to-Gas infrastructure, therefore not taking into account its potential and possibilities. A review and amendment of the legislative and regulatory frameworks are needed to ensure their adequacy for the development of Power-to-Gas infrastructure. The Gas Directive, among others, should be reviewed. ENTSOG thinks it would be beneficial to make the following changes: •A definition of Power-to-Gas in the context of sector coupling should be included to enable the transition to a decarbonised energy system. Indeed, with a clear distinction between the facility operator and the facility user, it would be easier for TSOs to operate such a facility. •A supportive framework is needed to enable the roll-out of Power-to-Gas. Regulation and/or the possibility to apply for European investment funding should be taken into account. •There should be no barriers to renewable and non-renewable low carbon gases traversing borders and sectors. •Furthermore, TSOs should be allowed to transport hydrogen and other gases to enable the scale-up of renewable hydrogen production from Power-to-Gas facilities. •Both electricity and gas sectors should work together to evaluate the efficient development of infrastructure. Regarding a supportive framework, regulation could have a role to play - it is an efficient way to develop infrastructure as it allows for financial benefits. Regulated investments are a mechanism that is likely to have a lower cost than the cost of support schemes such as explicit subsidies. Additionally, the costs linked to regulated activities are under the supervision of the NRA. CEER indicates in the consultation that “subsidising technologies, which is not the responsibility of regulators but of policymakers, should be done using specific policies”. However, during last Madrid Forum, the Commission clearly indicated that there will not be new specific subsidy schemes. That is why ENTSOG proposes regulation as a mechanism that could be used to incentivise the development of Power-to-Gas.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
ENTSOG is of the opinion that the cross-border trade of GOs for renewable gas should be supported by ensuring ‘interoperability’ of different GOs. In this sense, ‘different GOs’ stand for different energy carriers (e.g. gas, electricity) and different issuing bodies. Interoperability would manifest itself by way of the following two mechanisms: •All GOs need to be convertible from one energy carrier into another when such conversion is physically taking place. •The national issuing bodies for different energy carriers are encouraged to work towards setting up clear and recognisable schemes for all GOs. These schemes can then be interoperable since they are based on the same widely accepted rules. These schemes include criteria and processes for recognition by every issuing body of GOs issued by every other issuing body – to allow the transfer of GOs. Any double support for the same MWh produced must be avoided. Additionally, a European-wide solution for the above-mentioned cooperation could be established. ENTSOG also supports the establishment of GOs for energy from “non-renewable” energy sources that have a positive impact on the reduction of Green House Gas (GHG) emission (e.g. decarbonised/low-carbon gas), as in the terminology of the recast Renewable Energy Directive (RED II), which allows Member States to put this option in place.

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?
ENTSOG draws attention to our response to the previous question for interoperability of different GOs. That said, instead of copying the solutions from the renewable electricity to renewable gas, we should work towards being able to convert GO from one carrier to the other carrier. Lessons learnt from the electricity sector include the necessity of a common understanding of data that should be included in the GO and certificate. All GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements. To that end, the common understanding of concepts and corresponding terminology is needed. Additionally, when designing common data requirements for all GOs, it is important to pay attention to operational aspects, such as data format, data fields and data protection. Lessons learnt from renewable electricity also underline the importance of avoiding any double support between an EU-wide GO system and MS support schemes.

Infrastructure Investments and Regulation

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?
ACER (and NRAs) role should be kept as it is foreseen today in order to provide important recommendations to improve TYNDPs while still preserving an open, transparent and non-discriminatory process towards all stakeholders. The ENTSOs already assign a primary role to ACER and evaluates with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements. Regulation confers an important role to ACER (and NRAs) in providing opinions to ENTSOs Draft TYNDPs and CBA Methodologies. The recommendations provided to ENTSOG are published in the final version of the ENTSOG TYNDP as well as an explanation on how those where taken into account (see page 21-22 of Final TYNDP 2017 - Final TYNDP 2018 is not available yet). Also, the CBA Methodology includes a dedicated document where ACER opinions, as well as other stakeholder feedback, are published together with how it was taken into account (https://www.entsog.eu/sites/default/files/2019-03/3. ADAPTED_2nd CBA Methodology_Accompanying document - Stakeholders feedback_for Commission Approval_EC APPROVED.pdf). Additionally, with regards to the ENTSOs CBA Methodologies and their possible update, art. 11 (6) of Regulation (EU) 347/2013 states that "the Agency, on its own initiative or upon a duly reasoned request by national regulatory authorities or stakeholders, and after formally consulting the organisations representing all relevant stakeholders and the Commission, may request such updates and improvements with due justification and timescales". In line with Regulation (EC) 715/2009, ENTSOs TYNDPs represent a non-binding Community-wide ten-year network development plan. Under the current legislative and regulatory frameworks, the TYNDP non-binding nature is an important feature to be preserved to avoid incompatibility with other more prescriptive planning tools, such as national plans. The ENTSOs are responsible for creating an open process for any project promoter to submit their project to the TYNDP (facilitating the collection of information). As a regulatory requirement, projects applying for the PCI label are required to be part of TYNDP. Project submission is regulated by the TYNDP Practical Implementation Document (implementing the European Commission Recommendation "on Guidelines on equal treatment and transparency criteria to be applied by ENTSO-E and ENTSOG when developing their TYNDPs") that sets rules and criteria promoters and projects have to comply with in order to be part of their respective TYNDPs. ENTSOG's TYNDP plays a role as a starting point in the PCI section process. As part of TYNDP, ENTSOG assesses and tests in a transparent manner and with level-playing field the infrastructure against the possible future scenarios, jointly developed with ENTSO-E. Submitted projects are analysed based on the methodology approved by the European Commission. The 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements to measure the level of completion of the pillars of the EU Energy Policy from an infrastructure perspective. But it is the role of the Regional Groups (including EC, Member States, ACER and the NRAs) to propose and review Projects of Common Interests. For the first time, ENTSOG's TYNDP 2018 published the results of the project-specific assessments carried out. Gas and electricity TSOs are in a unique position to provide quantitative European focused scenarios on the impact of the energy transition on European electricity and gas infrastructures long-term needs and challenges. The scenarios represent the first step in any network development exercise, and they provide a view on many elements e.g. energy demand, prices, technology developments, etc. The demand scenarios are built jointly with ENTSO-E with an objective approach, guided by the need for the infrastructure assessment to look at the range of possible futures. They are built taking a holistic approach to the energy system in order to ensure consistency and capturing all the interactions between all energy sectors. Stakeholder workshops and public consultations s have been undertaken to improve both the scenarios themselves and the supporting publications. The ENTSOs consult stakeholders on the different steps of the Scenarios Development ensuring transparency and impartial treatment of all stakeholder feedback. As already said, in this context, the ENTSOs already assign to ACER a primary role and evaluate with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements. It should be noted that there is a decreasing trend and narrower range with each scenario development exercise. When the gas demand scenarios in previous ENTSOG TYNDPs (since TYNDP 15) are compared with actual gas demand figures, the results show that over-estimation does not occur, and that the predicted data falls within the observable range of results. For example, TYNDP 2017 scenarios show a lower demand for 2017 than that which was observed. In the range of TYNDP 2015 scenarios for 2015 – 2017, the actual demand fit well within the range. In addition, in TYNDP 2018 scenarios, 2020 yearly demand start with a lower demand than any of the TYNDP 2017 scenarios. In TYNDP 2018 all scenarios go beyond the 2030 target and on track with 2040. When compared to other Institutions' scenarios (like IEA World Energy Outlook) ENTSOG TYNDP 2018 scenarios are in the range (https://www.entsog.eu/sites/default/files/2018-12/ENTSOG_TYNDP_2018_Executive Summary_web.pdf TYNDP 2018 Executive Summary).

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)?
First of all, ENTSOG shares the auspice to extend the PCI selection scope to projects dedicated to renewable and decarbonised gases and is currently working in that direction in order to be ready to collect those type of projects in TYNDP 2020. With regards to the possibility of including any market testing in the CBA Methodology and the CBA assessment, it is important to underline that Regulation (EU) 347/2013 and CAM NC have different targets, with Regulation (EU) 347/2013 having a broader scope covering both market-based and non-market-based projects. This does not mean that those two Regulations are in conflict with each other. The Incremental Capacity process was designed for market-based investments, whereas PCI projects may be market-driven, but are important also for other reasons like SoS or supply source diversity. At the same time, the settlement of f-factor can also incorporate these external effects. We see no contradiction of both frameworks. In contrast, the actual frameworks of Incremental Capacity and PCI seem to be compatible and there is no need for major changes. A market-based investment, supported by a positive economic test, should also get the PCI-status in case of an application by the project promoter and the conditions are met. At the same time, the market test as a pre-condition for CBCA or financial support, could be done in the framework of Incremental Capacity. Nevertheless, if the project promoter has gone through the Incremental Capacity process included in CAM NC, the outcome of the process should be valid as the market test necessary for the CBCA or financial support. Given the role of its CBA Methodology, ENTSOG does not see the need for the inclusion of market testing in the 2nd CBA Methodology itself and in the PCI selection process where, as already said, benefits stemming from a project realisation should be considered regardless the commercial viability of the project. However, this does not prevent that, as already envisaged by the Regulation 347/2013, a market test, which could have the structure of the economic test foreseen in the context of the incremental procedure provided by the CAM NC (whenever available) or other appropriate forms in line with market needs, could be used as tool to accompany the project-specific cost-benefit analysis in the phase of submitting an investment request or applying for grants of works. Additionally, CBA criteria, identifying whether a project brings social benefits in terms of positive externalities, can be useful to inform the choices of f-factor levels, together with the other parameters that NRAs have to take into account when setting them (amount of technical capacity set aside, duration of binding commitments of network users compared to the asset economic life and expected demand after the end of the time horizon used in the economic test). In order to be considered potentially eligible for the PCI label, only projects having reached a sufficient degree of maturity have to also provide a project-cost benefit analysis based on the ENTSOs CBA Methodologies. Also, “not mature enough projects” can apply and be considered eligible for PCI label (even without a project-specific CBA analysis). Aim of the PCI selection process should be in fact to identify which projects can have positive impact for Europe, regardless of their commercial viability. Each PCI process edition is becoming more rigorous than in the past, building on methodologies to define infrastructure needs at regional and country level as well as to rank projects mitigating those needs. Applying for PCI does not implicitly mean that all project getting the PCI label are looking for or will automatically benefit from European funding. Projects apply for the PCI label in order to benefit from different type of advantages: from accelerated planning and permit granting, a single national authority for obtaining permits, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, and increased visibility to investors. They also have the right to apply for funding from the Connecting Europe Facility (CEF) in terms of grants for studies or for works. To ensure consistency and level-playing field, ENTSOG runs project-specific cost-benefit analysis on all projects applying for PCI. Indeed, Regulation 347/2013 envisages the possibility that positive externalities may justify some investments even if market demand is not sufficient to support them. The role of the project-specific cost-benefit analysis carried out by promoters consistently (but not necessarily exactly the same) with the ENTSOs CBA Methodologies is to identify whether the project brings positive social benefits (also in terms of positive externalities) without evaluations on the commercial viability of the project. For this second analysis in many cases some confidential financial information might also be required and therefore the assessment should always be carried out by the promoter itself. The results of market testing become relevant when in order to be eligible for Union financial assistance, in the form of grants for works, the project has also to be non-commercially viable according to the business plan and other assessments carried out (art. 12 of Regulation 347/2013). Stating that “project promoters submitting an investment request shall accompany the cross-border cost allocation by a project-specific cost-benefit analysis (consistent with ENTSOs CBA Methodologies) and a business plan evaluating the financial viability of the project including the results of market testing”, art. 14 of Regulation 347/2013 properly reflects the fact that such market testing should not be considered part of the project-specific assessment but as a complementary analysis looking into a different aspect. Additionally, ENTSOG notes that in its opinion on the Draft 2nd ENTSOG Cost-Benefit Analysis Methodology

(https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2015-2017.pdf) ACER has asked ENTSOG to remove any reference to investment requests (including CBCA) originally included in the Draft version of the 2nd CBA Methodology.

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?
ENTSOG welcomes the European Energy Regulators view on taking a very cautious and prudent approach with relation to decommissioning choices and agrees that there are no reasons to act in the near future. There is strong evidence that gas will remain prominent in the future energy mix in the coming decades and beyond. The transmission networks will play a key role in providing affordable energy, maintaining SoS whilst becoming increasingly sustainable. Due to the strong role gas will play in the Europe's future energy system as other fuels are phased out of the energy mix, ENTSOG would like to highlight that it is premature and counterproductive to introduce the issue of stranded assets. For example, several scenarios in the EC study in 2018 on the role of trans-European gas infrastructure by 2050, in the EC ASSET study on Sectorial Integration (https://ec.europa.eu/energy/en/studies/asset-study-sectorial-integration), or the Pöyry study for 2050 (https://www.poyry.com/sites/default/files/media/related_material/poyrypointofview_fullydecarbonisingeuropesenergysystemby2050.pdf) envisage stable or increased gas demand levels. In addition, peak-demand levels and higher flexibility needs are likely to increase in coming decades. By considering general demand reduction over the year, CEER overlooks the fact that peak demand may not reduce and may even increase in at least some Member States, due to changing demand patterns and SoS requirements. Especially in the case of hydrogen being transported using existing gas assets, more capacity and compression power will be needed to transport the same amount of energy. So, the current networks could be fit for that purpose and calling for their dismantling could increase the need for future alternative infrastructure investments. Gas infrastructure will be one of the main enablers of a decarbonised energy sector. Due to the current and future integration of the energy system, a holistic approach to the energy sector is required to assess the value of infrastructure. Therefore, no regret options (i.e. keep the assets until proved actually superfluous) and careful evaluations should be preferred to hasty choices. Regulatory tools should reduce the risk that assets are considered wrongly as stranded and get decommissioned. They should primarily consist of measures incentivising TSOs to keep existing assets in operation so that they can increase the pace of the energy transition. ENTSOG is of the opinion that, instead of working on potential decommissioning, efforts should focus on how to maximize and ensure an efficient use of gas infrastructure during the energy transition and beyond.

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?
As already expressed in the answer to Q12, the assessment of any asset decommissioning needs very careful consideration. There are significant benefits provided by assets, and full consideration of all these benefits are needed prior to any further discussion on the development of a decommissioning CBA. The benefits to SoS, market integration and diversification, optionality in managing uncertain future energy requirements, impact on neighbouring markets (and beyond) need to be considered prior to a formal process and initiation of a decommissioning CBA. Given the clear indications on the key role of gas in the energy mix, it is premature to introduce discussions on the development of a formal decommissioning framework. On the contrary, efforts should be made on how to maximize and ensure an efficient use of the gas infrastructure during the energy transition and beyond. Should decommissioning become needed, ENTSOG is ready to cooperate with CEER and work on a common EU framework. As a general principle, ENTSOG shares CEER approach which envisages that any possible decommissioning processes with cross-border impacts should be addressed in a transparent and balanced way in full coordination with all relevant authorities (Member States and NRAs) and TSOs of the impacted systems.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The current gas legislation provides a sound basis for ongoing development of an integrated gas market. Implementation of the regulations is almost complete and the impact on market development is already providing significant benefits, e.g. with better price convergence on many hubs, improved market liquidity and prevention of congestions and their management. The implementation of the current legislation has already had a clear positive effect in many market areas, resulting in liquid and functional market places, as indicated in ACER's Market Monitoring Report (MMR) in 2018. There are a number of EU gas markets that are mature. Where gas markets have not fully developed and are illiquid and still not fully functional, targeted measures that address the specific market needs should be considered. On this topic, ENTSOG understands that the EC intends to launch a study of the possible need for tailor-made regulation. As stated in ACER's MMR in 2018, some Member States do not have all the building blocks of a functioning hub system in place, i.e. they display low liquidity and/or a persistence of bilateral deals. EU-wide measures should only be considered where there is strong evidence of an EU-wide problem. In addition, ENTSOG would like to underline the possible issues outside of the Network Codes that need to be addressed, e.g. homogenous shipper licencing arrangements. This could contribute to the improvement of the EU internal market. Therefore, the focus should be on fully implementing the current legislation and where issues or problems are identified, additional measures could be considered. The incorporation of decarbonised gases into the current market should also be fully considered. Whether the current arrangements are not fit for purpose and additional or different measures might be needed, ENTSOG is ready to make available its expertise on NC developments. In addition, how to manage hydrogen within the current market arrangements needs full consideration e.g. whether creating a separate hydrogen market or incorporating hydrogen into the current gas market.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
ENTSOG believes that future changes in the gas sector can have an impact on the dynamics of the gas market with the need to update it. Increasing injection of renewable gases at the distribution level can lead to market needs that currently are not a reality. Excess of local renewable gas production that won't be consumed on a DSO level may need to be injected into the TSO network using reverse flow infrastructure to supply the demand of other location or to be stored. Investments should be carefully assessed so that capacity allocation mechanisms, tariffs, quality assurance and operations that will have the necessary regulatory framework for transparent, non-discriminatory and secure use. Additionally, the interchangeability of local renewable gases production at national and even cross-border levels should be facilitated as much as possible, since a local market can undervalue them, with possible negative effects on their production potentials. The production of renewable hydrogen from Power-to-Gas units in a decentralised way and the ability to inject it into the gas grid, will also face challenges. One possible challenge being the need for the creation of a separate market for hydrogen that will have a different value from natural gas. GO is the way to give market value in this case for the renewable hydrogen. When considering the development of a decarbonised society, a one-size-fits-all solution is not ideal for a pan-European energy market so diverse, with so many different requirements, political drivers, stages of maturity and geographical distribution of resources. The main concern will then be how to connect all available solutions without hampering the integration of the European energy market already achieved.

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?
ENTSOG considers it premature to evaluate the current tariff regime. Together with ACER and other relevant stakeholders, ENTSOG has substantially contributed towards implementation of the TAR NC in all Member States. There are still a number of market benefits to be gained associated with the full development of the entry-exit model in the EU, most significantly the creation of liquid markets with beneficial effects for final customers. We are aware of the debate on the potential need for tariff reform, as proposed by CEER's FROG report. However, prior to considering potential changes to the tariff arrangements we need to see the full effect of the implementation of the TAR NC first. While ENTSOG recognises that an excessively high cross-border tariff can become a "de facto" barrier to gas trade, the 'pancaking' effect, i.e. the cumulative IP costs for a shipper along a gas route, is a feature of the current EU gas market design and it should be considered as a normal effect provided that IPs tariffs are correctly determined. Changing the tariff regime providing less weight to cost-reflectivity would create winners and losers among network users. ENTSOG would also like to make the following comments regarding CEER's solutions. ITC mechanisms are complex and could price market integration more than cost-reflectivity. CEER's second suggested solution of allocating TSO costs to gas beneficiaries refers to a more global approach to gas value. Tariffs might indeed better mirror the value of a gas source, based on its market value, but also its contribution to SoS, sustainability, market integration etc. taking into account the requirements of the TAR NC. To conclude, it is too early to assess the impact of the TAR NC, which is not yet fully implemented. Once Member States have implemented the TAR NC provisions, especially with the application of the new tariff methodology principles and transparency requirements, it will be relevant to reassess the TSO tariff regime. At this stage, reform proposals can be premature and might disrupt the ongoing implementation of TAR NC. ENTSOG recommends that regional initiatives for voluntary market integration also continue to be taking into account with regards their potential negative effects on the overall European market integration, such as cost reflectivity issues.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
To assess the impact of cross-border tariffs on cross-border trade, ongoing monitoring of the markets is needed. As tariffs develop, the impact on cross-border trade needs to be assessed. If there are general trends that suggest a deterioration in cross-border trade, then consideration on how best to address the change should be considered.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
To realise the creation of a decarbonised society, TSOs, amongst other players, should be allowed to progressively invest in such activities as Power-to-Gas, hydrogen networks, CCUS, biomethane facilities, CNG/LNG for transport, digitalisation, and related R&D and pilot project expenses. Regulatory sandboxes can play an important role to encourage as a first step R&D and pilot projects by TSOs to test and roll out the required new technologies. NRAs would be asked to take such costs into account as necessary infrastructure investments to be incentivised. With the growth of offshore renewable energy production, solutions like Power-to-Gas in an offshore environment may need to be considered. Also, the transport of the hydrogen produced using offshore pipelines may need some regulatory oversight. Carbon Capture and Storage (CCS) and Carbon Capture and Utilization (CCU) technologies should be considered.

Survey response 10

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Vereinigung der Fernleitungsnetzbetreiber Gas e.V. (FNB Gas e.V.)

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

The German Association of Gas TSOs (FNB Gas e.V.) welcomes CEER's initiative to address regulatory challenges linked to the facilitation of renewable and decarbonized gases through investments in infrastructure and adaptions to the current gas market design. We appreciate the possibility to contribute to this important assessment via this public consultation.

Several comprehensive studies (e.g. the Green Gas Initiative Study on the value of gas infrastructure in a climate-neutral Europe) have shown clearly, that achieving the ambitious climate targets of the Union by making use of the electricity and the gas grid in a coupled manner would be significantly cheaper and more efficient than an all-electric solution. Such a hybrid energy system of electricity and gas needs to be based on a variety of decarbonizing technologies such as Power-to-Gas, Biomethane, CNG/LNG mobility and CCS/CCU. At this point in time, the advancement of these technologies is critical to ensure that they reach the required scale and efficiency by the time they are needed to enable the required steep reduction in emissions. Any step to limit the involvement of individual market roles in these technologies today may unnecessarily hinder the required technological advancement in the future.

The existing regulatory framework does not sufficiently consider new technologies to enable the decarbonisation of gas infrastructure. The uncertainty about these technologies hinders their advancement since it does not provide a reliable and stable basis for investment. We therefore see an urgent need for a clear, coherent and supportive regulatory framework to be introduced quickly.

As German Gas TSOs, we are committed to contribute to decarbonizing our industry and are ready to invest in infrastructure to enable the energy transition while fully respecting the unbundling provisions. Within the regulated framework, TSOs are able to offer cost-efficient and reliable services to network users on a non-discriminatory basis and under regulatory oversight. We therefore strongly recommend to CEER to consider the benefits of involving TSOs in this assessment.

In particular, the following merits should be taken into account by CEER:
- As a means to store large amounts of renewable energy, gas transmission networks have much greater capacity than gas distrubution networks. This is due to their size, their year-round utilisation and their access to gas storage facilities which enable long-term storage of large energy volumes.
- Only gas transmission networks have the ability to transport large amounts of renewable and decarbonised gases over long distances from remote production locations to areas of high demand.
- Only gas transmission networks allow for a cross-border trade of renewable and decarbonised gases, thus enabling a European market to the benefit of all consumers.
- Only gas transmission networks allow the greatest possible distribution of the permitted concentration of renewable and decarbonized gases. Thus, the maximum possible injection of these gases is only guaranteed via the transmission networks.

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.
The German TSOs note positively that there is a growing consensus in the political and regulatory debate that especially hydrogen-based energy scenarios represent a robust, sustainable and cost-efficient solution for reaching the European climate targets. These observations are underlined by the results of several relevant studies such as the EC study on “The role of trans-European gas infrastructure in the light of the 2050 decarbonization targets”. In this context we would like to emphasize that the gas infrastructure is already capable of transporting hydrogen and that we are supportive of long-term scenarios which foresee the transport of increasing shares of hydrogen up to 100% via the transmission grids. Regarding the blending of hydrogen in gas networks we clearly see the need for a European coordination for a gradual increase of hydrogen in the transmission grids. Currently the levels of hydrogen are set by each member state based on the natural gas composition. This can be observed as a barrier. However, in our opinion a common European mandatory threshold will be challenging because of regional differences regarding network flows, differences in the amount of hydrogen to be fed in, the place for the production, the assets, industry and end-user appliances. Furthermore, a common mandatory threshold would restrict the TSOs from having flexibility to opt for either blending or pure hydrogen networks. Instead of one common mandatory threshold, regional thresholds may be defined according to the main international gas flows. Without regional thresholds, the large cross border gas transport will be interrupted and bi-directional flows may become one-directional due to different shares of hydrogen allowed in the national grids (like the barriers caused by different odorization practices today). Therefore, we recommend the development of a European Hydrogen Roadmap by the TSOs in cooperation with the regulatory authorities considering regional differences and speeds for the adaption of systems.

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.
In the opinion of FNB Gas comprehensive hydrogen networks connecting diverse supply and demand in the energy sector need to be regulated the same way as gas networks. The same rules should apply to secure the principles of the European internal market such as security of supply and competition via a non-discriminatory third-party access. What is more, using the existing gas infrastructure for the transport of hydrogen would be economically sensible compared to developing new hydrogen networks.

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.
In our view “cost efficiency” is a principle which should be considered when assessing the optimal and reasonable pathways for reaching the long-term climate goals along the whole value chain. The criteria of cost efficiency should be applied not only comparing the current costs, but also considering the long-term developments of new technologies. Especially, since high initial investment costs are often needed for the benefit of a long-term cost-efficient solution. Nonetheless, in the view of FNB Gas a “technology neutral” approach should be a fundamental principle for the transition of the European energy sector based on a “level playing field”. Proactive market interventions may be required to enable the advancement of new technologies and to reach long-term cost efficiency.

Q5 Which role do you see for power-to-gas infrastructures?
As TSOs, we regard Power-to-Gas infrastructure as a key instrument to enable the integration of renewable energy into all energy sectors (heating, industry, mobility). Power-To-Gas technology combined with the gas transmission system is an efficient way to transport energy over long distances and across state borders and enables long-term storage of electricity from renewable energy sources. . As such, we would like to stress that Power-to-Gas facilities, coupling electricity and gas infrastructure, convert energy from one carrier to another and do not generate new energy or produce gas. Therefore, an operation of such assets by TSOs as an integral part of the energy system is fully in line with unbundling rules. To ensure that Power-to-Gas is available at the required industrial scale at the latest in 2035, the implementation of underlying technologies has to start now. TSOs are willing and able to start developing and operating Power-to-Gas facilities within the regulated framework at least in an early phase of introducing the technology (introduction phase), at the locations feasible for an efficient coupling of the electricity and gas systems.

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?
Electricity and gas transmission tariffs, as well as existing taxes and levies (e.g. EEG fee in Germany), create distortions for the advancement of Power-to-Gas technologies since they increase the price of green hydrogen and reduce its competitiveness compared to cheap fossil products. Power-to-Gas aims at bringing flexibility to the electricity system that would otherwise be very difficult and/or expensive to realize, e.g. by reducing the load in the electricity system in periods of high RES generation and by enabling seasonal storage of energy using other storage technologies such as batteries. As such, the application of Power-to-Gas technologies reduces/will reduce the demand for extending the electricity system. The application of taxes and levies on the electricity side linked to consumption does not reflect these benefits and should therefore be avoided. In addition, in order to incentivize the advancement of Power-to-Gas technologies, we think that electricity and gas TSOs should apply discounts of 100% on transmission tariffs for injections to and from Power-to-Gas facilities.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The existing legal and regulatory framework of the gas market was drafted and introduced without having in mind Power-to-Gas technologies and the handling of increasing shares of hydrogen in the gas mix. We therefore see the need to revise the current gas market design to enable and support the integration of renewable energy in the gas sector. Regarding Power-to-Gas technologies, at least the following issues should be tackled in the upcoming legislative Gas Package: • The regulatory framework for Power-to-Gas facilities as grid-coupling assets needs to be defined and its use should be recognized as an energy conversion service. • To incentivize the roll-out of Power-to-Gas as quickly as possible, mandatory target values for renewable and decarbonized gases are necessary. As an instrument for fulfilling these targets, a quota system for renewable and decarbonized gases should be introduced. • To enable an efficient coupling of the energy sectors, network planning for gas and electricity should be integrated in a step by step manner.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
FNB Gas welcomes the initiative taken by ENTSOG and GIE at the last Madrid Regulatory Forum to work on a comprehensive, EU-wide system for the certification / guarantee of origin of renewable and decarbonized gases. We believe that there is and will be a high level of demand for renewable and decarbonized gases as citizens and corporations are putting more and more focus on the sustainability of their energy consumption. Transparency and traceability of renewable and decarbonized gases is therefore critical to ensure that the origin of energy can be disclosed to the consumer in a clear and documented manner. With the increasing role of Power-to-Gas in the energy system, more and more gas in the gas network will be sourced from renewable electricity generation via energy conversion. It is therefore crucial that this energy conversion will be supplemented by a corresponding conversion of certificates /GOs to ensure that the energy remains its green status. Cooperation and mutual recognition between the issuing bodies for certificates/GOs of the different energy carriers is required. The possibility of transporting and trading renewable energy across borders within the Union at very high amounts is one of the key advantages of the gas system. It is therefore also critical that certificates and GOs do not hinder the free tradability of gases. This can only be achieved by either ensuring that national certificates/GOs are fully accepted by all member states of the Union or by implementing a European certification / GO system in the first place by involving also producers from third countries. As TSOs, we urge regulators and policy makers to ensure that the European gas market will not be fragmented due to higher shares of renewable and decarbonized gases not being recognized as such by neighboring member states of the Union.

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?
As indicated in question 8, a European certification/GO system for renewable and decarbonized gases would prevent disruptions in the cross-border tradability of such gases. If such a European system cannot be reached, mutual recognition of national certificates/GOs needs to be ensured to support the cross-border tradability of renewable gases.

Infrastructure Investments and Regulation

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?
In the view of FNB Gas, ACER, and thus the NRAs, already play an important and active role in the TYNDPs, the underlying scenarios and the CBA methodologies via providing opinions which are respectively published. Especially the framework and processes for the TYNDP defined by regulation (EC) 715/2009 has proved to work well. Therefore at this point in time, the German TSOs consider the current role of ACER and the NRAs in these processes as meaningful and do not see a need for an adaption.

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)?
Incremental Capacity is a process to ensure market-based investments, whereas PCI projects are important mainly for other reasons like security of supply or supply source diversity. We see no contradiction of both frameworks. In contrast, the current frameworks of Incremental Capacity and PCI seem to be supplementary. Additionally, a market-based investment via the Incremental Capacity process, supported by a positive economic test, can receive PCI-status in case the conditions are met and the settlement of f-factor within the Incremental Capacity process can also incorporate external effects of PCI projects. Therefore, the German TSOs do not see any problems and contradictions regarding these two processes and thus no need for the proposed cross-references.

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?
FNB Gas shares the view of the NRAs that there is currently no need to have a detailed assessment regarding a potential European framework for decommissioning of the gas infrastructure. Against the background of the German political decision to phase out coal-fired power plants there will be an increasing importance of gas-fired power plants and thus of the gas infrastructure in Germany for the upcoming years. Besides that, the shift from fossil to renewable and decarbonized gases keeps the gas infrastructure being crucial also in the long run. Considering these aspects, the German TSOs do not see the risk for stranded assets in Germany.

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?
As argued in the response to question 12, FNB Gas does not believe that decommissioning of gas infrastructure is an issue. Instead, regulators and policy makers should focus on the possible contributions of the existing gas infrastructure towards reaching the ambitious climate targets of the Union. It is therefore not necessary to work on a European framework for decommissioning.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
As indicated in our response to question 7, the current gas market design was developed and introduced with a clear focus on market integration and liquidity instead of the possible contributions of the gas sector to reaching climate targets. As such, we believe that the current gas market design has delivered quite significant results and has successfully led to very liquid wholesale markets for gas in most parts of Europe. We agree to CEERs assessment that there are still gaps in some parts of Europe, where market concentration is still high and hubs have not gained the desired liquidity levels yet. The experiences from many member states in Western Europe however show that the Gas Network Codes are clearly able to remedy such problems if they are fully and consistently applied. We therefore believe that the remaining issues in a very limited number of member states would not be efficiently addressed by revising European legislation for all member states. Instead, the European Commission should work together with the concerned member states on individual, tailor-made solutions to assist in implementing the existing regulatory framework and to reach the desired market integration goals. While the aforementioned is true for provisions on the functioning of the internal gas market, we do believe that there is a clear need for a revision of the European gas market design on matters that relate to sector coupling and renewable and decarbonized gases, as these principles concern all members of the Union equally. FNB Gas believes that the future gas market design needs to be made fit for the purpose of incentivizing necessary investments to accelerate progress with regards to our climate challenges.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The current gas market design has proven to function very well, given the targets it aimed to address such as SoS, competition and market integration. Despite this, we see a clear need to update the gas market design on matters relating to the integration and the European wide exchange of renewable and decarbonized gases, since this is not adequately addressed in the existing framework. FNB Gas believes that the development of renewable and decarbonized gases in the EU needs to be encouraged at an early stage, e.g. by the determination of quotas. The increasing share of renewable and decarbonized gases will lead to regulatory questions and oversight which must be addressed on a European level. Following the German provisions regarding the injection of biogas into the gas grid, we see the need for a European regulatory framework for renewable and decarbonized gases considering additional mechanisms for capacity allocations (e.g. a priority access, exemption from grid charges, separate balancing accounts etc.). In addition to that the regulatory framework should allow and incentivize TSOs to invest in future-proof, sustainable and innovative technologies and pilot projects that facilitate and speed up the decarbonization of the energy system. It is therefore essential that there is a European regulatory framework that allows for an efficient use of the energy system and to promote a European internal market for renewable and decarbonized energies.

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?
After five years of intensive discussions, Regulation (EU) 2017/460 (TAR NC) was published in March 2017. The full implementation of the NC TAR is ongoing and will be finalized in the forthcoming years. The now established rules regarding transparency, consultation obligation and determination of tariffs ensure cost-reflectiveness and will foster market integration. The effect of the new NC TAR provisions will be monitored by ACER and ENTSOG. Furthermore, it is unclear today, how existing long-term contracts will be replaced by new contracts. However, as gas infrastructure will have a big role in a decarbonized world, there is still a high investment need. Therefore, it is necessary to ensure, that TSOs have the opportunity to remunerate their investments.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
The effect of the established TAR NC should be monitored first by ACER and ENTSOG before a need for an amendment of this NC can be identified.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
In the opinion of FNB Gas, a coordinated network planning between electricity and gas TSO is a crucial basis for a successful integration of an increasing share of renewable and decarbonized gases in the European energy sector. Therefore, we see the need for a stronger focus on the implementation of this measure, also from a regulatory point of view. Furthermore, there is a general growing awareness that imports of renewable and decarbonized gases might be needed in order to reach European climate targets. Thus considering a technology neutral approach, FNB Gas proposes to expand the focus of this CEER document also to decarbonized gases and to analyze potential regulatory measures regarding the facilitation of imports of these gases.

Survey response 11

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Hydrogen Europe

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
In the context of sector coupling and in line with EU legislation, Hydrogen Europe calls for a clear, predictable and non-discriminatory policy framework that enables and supports the roll-out of power-to-gas activities/investments, by any players, as a non-regulated activity. It should be stressed that such a policy framework shall not distort existing and future competitive markets, in the context of sectoral integration. Nevertheless, should the following conditions apply: ·The need for investments in power-to-gas assets have been identified within the context of decarbonisation efforts, and/or within the context of EU network development planning (as approved by European and National Regulatory Authorities (e.g. through a cost-benefit analysis); ·A subsequent gap in private investment is recognised (through, inter-alia, market tests). Competent authorities shall: ·Launch a tendering process open to all players to enable investments through support mechanisms; the tendering process should offer the same support, at the same level and at the same moment so as to ensure that there is a level playing field between all actors . ·if unsuccessful, provide that Transmission System Operators/Distribution System Operators (TSOs/DSOs) can directly invest as a regulated activity until the market conditions develop significantly. In case of investment by TSOs/DSOs as a regulated activity, an adequate regulatory oversight should be in place, ensuring transparent and non-discriminatory access to the service. In such a regulated framework, National Regulatory Authorities (NRAs) should regularly monitor market developments. Should markets develop significantly, NRAs might prescribe how: ●Regulated entities shall transfer their respective activities and assets from a regulated to a fully commercial/non-regulated entity; or ●They shall opt to phase-out their activities in this regard. Hydrogen Europe supports the need for power-to-gas assets, in the context of sector coupling, to be analysed in the Ten Year Network Development Plan (TYNDP) as a joint work involving ENTSO-E and ENTSO-G taking into account the input provided through relevant consultations e.g.: industrial stakeholders such as electricity and gas-intensive industries and representatives of all networks users, to define the level of investment needed. The final aim should be to allow market players to develop long-term viable business models which can compete in the market with as little regulatory intervention as possible.

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.

A target setting approach for the injection and consumption of renewable and low-carbon gases will send clear signals to investors and businesses alike to act and work effectively towards the greening of the gas infrastructure and the scaling up of hydrogen and other forms of renewable and low carbon gas.
The objective should be to decarbonise the existing and new gas markets and not just the gas grid. It would otherwise encourage production for the sole purpose of injection and decarbonisation of gas grid, leading to divert volume from other higher value markets.
An EU wide target as opposed to national targets is the preferred option as this would allow more flexibility, thus recognising and respecting the varying national and geographic specificities of the different Member States.
In view of the EU's long-term climate objectives, the maturity and scaling up of renewable and decarbonised gases would be further supported by targets linked to specific timeframes :

- 2030: minimum of 7% of natural gas by volume is replaced by hydrogen
- 2040: minimum of 32% of natural gas by volume is replaced by hydrogen
- 2050: 100% renewable and decarbonised gases of which a minimum of 50% is hydrogen

The targets should contribute towards the achievement of the EU's objectives for renewable energy, as a sub-target to the Renewable Energy Directive (REDII). As such, contributions of EU Member States towards the achievement of their renewable targets and the role envisaged for renewable and decarbonised gases should form part of the National Energy and Climate Plans submitted by governments to the Commission in accordance with the EU Energy Governance Regulation.

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.

It is now too early to see whether hydrogen networks may be regulated. see answer to Q7.

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.

see answer to Q18

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

Sector coupling means the connection of the power and gas infrastructure.
Under this structure, Hydrogen Europe sees the role of hydrogen as a coupling agent for energy storage/balancing service providers and as such recommends the following definition for power-to-gas:
Power-to-gas, in the context of sector coupling, means the conversion, by water electrolysis, of electrical power into hydrogen or its further conversion to a gaseous energy carrier such as synthetic methane.

Sectoral integration & power-to-hydrogen
As mentioned earlier, hydrogen is a molecule that should not be confined to sector coupling. Indeed, hydrogen is capable of integrating several sectors together. It is time that Europe gets away from the silo thinking of sectors. The 21st century systems need to be truly efficient and integrated. This would allow Europe not only to keep its vast and integral assets functioning but also to use this gas to decarbonise energy-intensive industries such as steel, cement or refineries and increase its energy independence:
Sectoral integration means the integration of several sectors such as the power, transport, agriculture, the energy-intensive industries and/or the heating and cooling sectors via the use of energy carriers such as hydrogen.
Under this structure, Hydrogen Europe sees the role of hydrogen as an integrating agent and as such recommends the following definition for power-to-hydrogen (PtH2):
Power-to-hydrogen, in the context of sectoral integration, means the conversion, by water electrolysis, of electrical power into hydrogen that may be used as an energy vector, a fuel and/or a feedstock.
Such a market should be solely based on commercial agreements including Power Purchase Agreements, GOs, etc. across sectors (e.g.: Renewable Fuels of Non-Biological Origin under the REDII). Essentially, it should be treated as a commercial agreement and be kept as a non-regulated market with the typical use of regulated asset (i.e.: existing natural gas pipelines) as transport means through Third Party Access where available. This shall not prevent the development of privately-owned unregulated pipelines serving dedicated customers.

Energy storage
Clarity is needed on how the definition of energy storage relates to other classifications, e.g. industrial production activities, of Power-to-gas/Power-to-hydrogen. Indeed, the current version of the Electricity Market Design Directive defines energy storage as following:
'energy storage' means, in the electricity system, deferring the final use of electricity to a later moment than when it was generated or the conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy or use as another energy carrier.
The interpretation of this definition could restrict power-to-gas/power-to-hydrogen to the sole of function storing energy, while, as demonstrated above, it could play an integral part of the new energy system (i.e.: hybrid energy system and beyond). Therefore, we recommend the European Commission to complement the definition of energy storage to ensure that power-to-gas/power-to-hydrogen is not limited to an energy storage function from the perspective of the electricity market by e.g.: defining its role in sectoral integration and sector coupling.

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?
A power-to-gas plant which provides response services, reserve services or congestion management services to the electricity grid is helping to manage the variability caused by renewables, helping to integrate more renewable energy by reducing curtailment and helping to reduce the CO2 emissions of conventional grid balancing techniques. Use-of-system grid fees for such power-to-gas systems should be waived and the hydrogen they produce classified as renewable hydrogen. Even if the production costs of renewable energies have significantly reduced, the level of investments in infrastructure (electrolyser, storage, etc.) and the cost of electricity are such that renewable hydrogen is not yet competitive. Some measures have to be implemented to avoid market failure and accelerate the deployment of power-to-gas to decarbonise the gas grid sector;

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Hydrogen Europe commends the initiative by the European Commission to look at the future role of gas in Europe and that hydrogen is considered as an integral part of the pathway to decarbonisation. However, we would stress that, in order to grasp the full potential of hydrogen as a decarbonisation enabler, a specific hydrogen market design be created, in line with the electricity and gas market designs in such a way that it gives full flexibility to the markets so as to integrate fully in the most efficient and cost-competitive manner. Indeed, due to its versatility, the potential for hydrogen to play a key role across sectors needs to be tackled in a systemic manner, realising a true sectoral integration. Therefore, Hydrogen Europe calls on the European Commission to integrate a review clause, subject to a significant market development, within a new gas package. Although hydrogen does not yet account for a significant proportion of European energy consumption, it is the view of Hydrogen Europe that by the mid-2020s, the European Commission should launch a consultation process with stakeholders on a possible hydrogen market design target model as part of a review clause in any upcoming gas legislation proposal, providing that significant market developments have been realised, including sufficient volumes.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
An EU-wide Hydrogen guarantee of origin scheme is crucial for both renewable and low-carbon hydrogen. A Guarantee of Origin scheme should be developed at European level: ●Article 2.12 of the RED II defines a ‘Guarantee of Origin’ as ‘an electronic document which has the sole function of providing evidence to a final customer that a given share or quantity of energy was produced from renewable sources’; ●In parallel, non-renewable low carbon Guarantees of Origin will be needed to demonstrate the contribution to decarbonisation via gas of a lower carbon footprint. According to Recital 59 of RED II, the extension of the guarantee of origin systems to non-renewable energy sources should be an option for Member States. Hydrogen Europe supports this extension in order to be able to quantify GHG benefits of low carbon hydrogen. The Guarantees of Origin should allow for the inclusion of additional optional information including greenhouse gas savings, the type of feedstock used and other benefits towards a circular economy. The GOs must be transferred, independently of the energy to which they relate, from one holder to another (e.g.: electricity to hydrogen or biomethane to hydrogen, etc.). Therefore, it is important that they are mutually recognised among the Member States. According to the proposal for RED II, the extension of the GOs systems to non-renewable energy sources should be an option for Member States. There must be a clear and unambiguous distinction between renewable GOs and (non-renewable) low-carbon GOs, so that stakeholders can be confident in the GOs system. Hydrogen Europe considers that CertifHy is the correct framework to utilise for the set-up of a hydrogen GOs scheme across Europe. However, Hydrogen Europe recommends to align CertifHy with the above-mentioned requirements for renewable and low-carbon hydrogen for injection into the gas grids26. This European-wide voluntary scheme would coordinate national registries, if existing, or establish itself as registry in a country lacking the capacity to have such facility until such facility is appointed by a competent authority, should the need arise.

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?
see answer to Q8.

Infrastructure Investments and Regulation

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?

The mapping of potential interactions between electricity and gas systems in relation to hydrogen is crucial for the development of future policies for the decarbonisation of the energy sector and achievement of EU climate goals.
Closer cooperation and coordination between electricity and gas systems in the context of renewable and low-carbon hydrogen technologies can contribute to achieving the climate goals in a more cost-efficient way.
According to Regulation (EU) 347/2013, by the end of 2016, ENTSO-E and ENTSO-G have submitted for approval to the Agency for the Cooperation of Energy Regulators (ACER) an interlinked electricity and gas market and network model, including both electricity and gas transmission infrastructure as well as storage and LNG facilities. ACER required further investigations concerning: gas and electricity prices, interaction (potential competition and synergies) of electricity and gas infrastructure developments, cross-sectoral influence of gas and electricity projects.
Therefore, it is crucial to emphasise the capabilities of hydrogen technologies to transport and store energy and their importance for the long-term decarbonisation of the energy sector through integration of significant quantities of renewable energies and to identify and assess all possible interactions between electricity and gas systems in relation to low-carbon and renewable hydrogen, existing and planned electricity and gas networks, electricity and gas storage capacities, demand-respond capacities, electricity and gas prices etc.
Examples for such interactions are:
1. Power to hydrogen/gas for direct use
2. Power to synthetic methane
3. Power to hydrogen/gas to power (F-Cell, Gas turbine)
4. Ancillary services in electricity grid
5. H2/CH4 injection into gas grid
Criteria for eligibility for Projects of Common Interest status should be adapted to make the contribution to decarbonisation a decisive criterion (i.e.: hydrogen-ready transport grid). This would ensure the long-term relevance of future investments while avoiding the risk of stranded assets. Furthermore, projects that promote the connection of renewable and low-carbon hydrogen to the grid, thereby contributing to the achievement of European decarbonisation objectives should be included.
Acknowledge the role of power-to-gas in providing ancillary services
There are different market arrangements in place throughout Europe regarding ancillary services procurement and balancing market design, including energy storage and demand response at TSO and DSO levels.
The Commission Regulation (EU) 2017/2195 provides a detailed guideline of electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for their activation.
The integration of balancing electricity markets should be facilitated with the establishment of common EU platforms for operating the imbalance netting process and enabling the exchange of balancing energy from frequency restoration reserves and replacement reserves. In order to allow an exchange of balancing services, it is necessary to create a common merit order and to regulate the standardisation of balancing products. The Regulation lists the minimum set of standard and additional characteristics defining standard products.
When a TSO uses a European platform, it shall use only standard and, if justified, specific balancing products in order to maintain the system's balance.
According to ENTSO-E, the guideline creates a level playing field for all potential providers of balancing services, including demand side response and energy storage. Therefore, it is important that the capabilities of power-to-gas and related energy storage to provide ancillary services and to meet the requirements for standard products will be recognised and the participation of power-to-gas and hydrogen energy storage in balancing markets for ancillary grid services will be promoted.
Power-to-gas instead of curtailment
At present, renewable energy producers are usually partially compensated for not being able to inject their production into the grid due to limited grid capacity or limited demand. By creating a legally binding merit order, compensation for curtailment should only be paid if no alternative exists.
This would result in the avoidance of curtailment, with hydrogen being produced if a power-to-gas plant nearby can remove the bottleneck in the electricity grid or can utilise the power currently not being demanded in the electricity market. 'Compensation' should only be paid if there is no power-to-gas plant available.
This would allow the full potential of electrical renewable production to be integrated in the electricity and gas grids, maximising the EU social welfare by reducing funding support for "non-production". Power-to-gas would allow the maximisation of RES potential and RES would not be limited by the size of the electricity market. Moreover, by providing a solution to an excess of renewable electricity production, power-to-gas will reduce negative/very low prices on the electricity wholesale market. Power-to-gas will support the wholesale electricity prices enabling the development of additional market-based RES generation without any subsidies.

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?

see answer to Q18

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?
see answer to Q18

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
●The framework for permitting and operating power-to-gas and power-to-hydrogen plants and grid connection/injection requirements should be included within relevant EU regulatory frameworks, including support schemes for production of electrolytic hydrogen; ●An EU-wide basis for injection of renewable and/or low-carbon hydrogen into the gas grid should be a priority to ensure a ‘level playing field’ and the continuing operation of trans-national interconnecting gas pipelines; ●Technical and gas composition rules should be reviewed to establish legal pathways to support power-to-gas/power-to-hydrogen operations; ●A framework for permitting and operating of gas reformation units with CCS should be established at EU level, including support schemes for production of low-carbon hydrogen; ●Safety and technical integrity limitations for hydrogen connection and injection into the gas grid should be studied in comprehensive and coordinated manner across the EU; ●Establish pricing principles covering connection fees and charges and remuneration for hydrogen supplied/injected; ●Review billing, measurement and administrative requirements with appropriate legal frameworks to allow increased hydrogen flows in European gas networks; ●An EU wide end user appliance assessment is essential to define the acceptable safety and operational threshold of end-user appliances; ●Develop the implications for refuelling infrastructure. + see answer to Q18

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

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?
see answer to Q18

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
see answer to Q18

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
We invite you to analyse the recently published document: Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy – A Contribution to the Transition of the Gas Market https://hydrogeneurope.eu/sites/default/files/2019_Hydrogen%20Europe%20Vision%20on%20the%20role%20of%20Hydrogen%20and%20Gas%20Infrastructure.pdf

Survey response 12

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Ørsted

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
PtG infrastructures such as electrolysers should be owner by market participants, which in addition to their main energy generation business can support the grid through ancillary services (by switching off when power demand is too high). TSOs/DSOs as a general rule should not own PtG infrastructure, unless there is a specific need but no market interest in developing/operating the infrastructure at a specified location (i.e. last resort).

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.
We do not have a view on whether there should be a mandatory blending mandate for hydrogen into the gas networks, keeing in mind also that there are technical requirements in relation to this. In any case, we believe the main focus of green hydrogen is to support the decarbonisation of sectors that are hard to decarbonise, such as industry and heavy transrport - through direct use of the hydrogen (rather than via grid blending).

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.
Yes. Cost efficiency, together with decarbonisation potential, can in some selected cases justify market intervention. In particular, in our experience with offshore wind, thanks to tailor-made subsidy schemes we have been able to bring costs downs at an unprecedented rate.

Q5 Which role do you see for power-to-gas infrastructures?
PtG infrastructures offer an enourmous potential to green sectors that would otherwise be hard to decarbonise, such as industry and heavy transport (due to lack of alternatives).

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?
Yes. Electricity tariffs are not cost-reflective of the impact an electrolyser has on the grid. Furthermore, there is an impending need to create a level playing field around the cost of electricity: large, industrial electricity consumers (that also consume hydrogen) benefit from a number of tariff exemptions; if other electrolyser operators do not receive the same treatment, the system effectively ringfences green hydrogen production to these players only, as independent hydrogen producers (catering these consumers) would not be able to compete on cost due to this price distortion.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Yes. Aside from a level playing field on the cost of electricity (as mentioned above), the following regulatory conditions would need to be met to materialise the market opportunity of PtX: - Financial support for the first projects, until the electrolyser technology is fully mature; - Same amount of free CO2 allowances within the EU-ETS for equal product; - For refineries, eligibility of renewable liquid and gaseous transport fuels of non-biological origin to fulfil part of the belnding requirements within REDII.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
We are broadly in agreement with the recommendations from the Prime Mover group (https://entsog.eu/sites/default/files/2019-04/190426_GO%20recommendations_Final.pdf), particularly: - A robust set-up for documenting "green" and "low carbon" - Allowing for cancellation of GOs in neighbouring markets.

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?

Infrastructure Investments and Regulation

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?
ACER and NRA should make sure that the TYNDP and the national contributions are comaptible with long-term objectives. CBA of single projects that are not based on renewable energy should be stress-tested to see if it does not risk being a stranded asset. ACER and NRA should to the extent possible adopt a holistic view in their assessments, taking account also cross-border interlinkages, and necessary cooperation across borders that is reflective of the climate objectives we have set.

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?
Yes. The demand for renewable gases (or gas in general) in the future should not be overestimated. Today, we use more fossil gas than we use electricity (and only about 35% of the electricity is renewable energy), but the net-zero scenarios of the EC suggest roughly that fossil gas use is reduced by 90%, which electricity use is increased with more than 100% (while being >80% renewable energy). Renewable gas is an important contributor to a decarbonised energy system in Europe, but sustainable volumes are limited to between 500 and 1000 TWh, which is between 10 and 20% of today's fossil gas consumption in Europe. New investments in gas infrastructure should ensure that demand assumptions are realistic and account for our decarbonisation targets, to avoid burdening consumers with the cost of investing and subsequently decommissioning underutilised assets via grid charges.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The gas market design will need adjustments to cater for a larger span in gas types and qualities. Hence, issues around gas quality (and standardisation), blending, capacity products and balancing needs to be addressed. In addition, the overall governance of the increasing intregated system and the financing system should be a point to be discussed as well. This in any case does not preemt the assessment of future gas demand as discussed under Question 12.

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?
The efficient integration of the gas market, including additional renewable gases, requires more than changes to the transmission tariff regime. However, if gas use is diminishing, then care should be taken to avoid a negative spiral where use is crowded out by excessive gas transmission tariffs.

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

Other question

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

Survey response 13

Contact details and treatment of confidential responses

Contact details: [Organisation][]
AB Amber Grid

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Apart from existing involvement (connection of RES gases producers, transportation of their gas, being national registry for Guarantees of Origin (in some countries), a potential involvement of development of RES gas production facilities, where no commercial interest is enough, while development of such project provide a certain socio-economic benefits.

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.
A thorough analysis shall be made on impact of hydrogen for existing gas consumers and their types as well as gas systems and depending on that one or few thresholds (depending on locations where hydrogen would be injected) shall be set. One (lower) concentration might be where CCGTs are operational, and completely another (higher) where gas offtake is for heating purposes.

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?
Power-to-gas facities can increase the share of renewables penetration in power sector, by allowing storage (especially long-term) of surpluss electricity from RES sources, also it can help balance electricity grid, as well as to avoid the certain level of investment in electricity grid by removing the peaks of production (arising with low probability) in particular places of the network (if Power-to-gas facility can do that the savings could be made in not installing electricity grid capacity to serve the full possible capacity of wind parks).

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?
At least in gas sector for power-to-gas entry points a certain discount would be purposeful to make (at least for interim period, until the this facilities gains momentum), as in the path of decarbonization gas infrastructure will lose load, while power-to-gas facilities will create additional load for the systems, as at least part of gas entering will be directed to gas storages, as well as being RES gas it will increase consumption. Therefore having positive effect on collection of revenues in exit points and gas storage entry points, power-to-gas entries could be discounted to incentivize their deployment.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
If power-to-gas facilities would face the similar regulatory burden as TSOs/DSOs it might preclude the new-entrants to this business area. Therefore, the regulation framework, if any, should be light for this sector, unless the costs of facilities are socialized.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Harmonized EU-wide framework on transfer of GOs between national registries. Current work is ongoing in ERGaR and other cooperative forums between the registries.

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?
-

Infrastructure Investments and Regulation

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?
Guidance on the content; monitoring that the national/EU policy goals and the needs of the market are taken into account; approval (of at least TYNDPs).

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)?
Any relevant information, including coming from CAM NC covered process, should be taken into account in development of PCIs

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?
It will depend on EU/national policy decision, but the risk of stranded assets exists. The accelerated depreciation might be the best tool to deal with the management of 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?
Yes, there definitely should be coordination between member states on decommissioning of assets with cross-border impact. Common EU framework might be helpful.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The framework under which the market mergers could happen, incl. guidance on principles of ITC mechanisms, and framework for facilitation of decision making, if case of local deadlock. The assessment of costs and benefits of potential market merger might be governed similarly as for PCIs project (EU wide methodology, ENTSOG involvement in modeling, etc.), as the effects of market mergers are similar as of investments having cross-border impact, while implementation process is more complex one.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Yes, at least regarding the treatment of Power-to-gas facilities, entry tariffs discounts and possibility for gas infrastructure operators to involve in these activities.

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?
The issue is that there is no guidance on cross-border ITC mechanisms, and the framework to facilitate the market mergers. Also, the TAR NC provisions on making discounts on cross-border points could be more flexible.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
TAR NC could be more flexible on discounts in cross-border points between Member States, as well as to provide guidance on cross-border ITC mechanisms, as if there are tariffication decisions with cross-border impact, there could be as well a CBCAs in the form of ITC similarly as in case of PCIs

Other question

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

Survey response 14

Contact details and treatment of confidential responses

Contact details: [Organisation][]
NGF Nature Energy A/S

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
TSO/DSO ability to incorporate renewable gasses, primarily in the form of methane either from biogas/biomethane or from P2G. The current regulation for DSO/TSOs may be a good fit for natural gas regulation, but there are some potential problems with applying this methodology to regulation of how DSO/TSOs treat renewable methane.

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.
In our view it is more important to adress the issues some countries have with accepting biomethane rather than focusing on hydrogen as hydrogen appears very immature.

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?
In the sense of dedicated P2G infrastructure, we don't see a huge role for this, but a substantial role for how the current gas infrastructure ties into P2G and methanation is very important.

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?
Significant distortions, together with taxes and how it is possible to Massbalance Power derived products.

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?
Most of these seem to have been adressed in the new Reneable Energy Directive. The GOs are now written into law. But GOs may not be the right documentation path as a GO is only a vehicle for demonstrating end consumer documentation.

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?

Infrastructure Investments and Regulation

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?
It is very important to focus attention on the biomethane pathways as this is a product which is immediately relevant for renewable gasses.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Allowing for cross border trade of mass balanced renewable gassses and how the country of production can be different from the country of consumption.

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

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?
there is a risk that the current unbundling may lead to inefficiencies in the whole valuechain that may lead to discarding good immediate solutions because the loss of assetvalue can not be integrated across valuechain

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

Other question

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

Survey response 16

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GD4S

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

The strict separation of essential infrastructure activities (especially TSO and DSO) from supply and trade is fundamental in the gas market design established by the European energy regulation in place. DSOs and TSOs have a key role as market enablers to ensure fair and effective competition. As such, they are regulated monopolies focused on (i) the performance of their core activities and (ii) neutral facilitators to develop the market in the interest of end-users.
The objective of decarbonising the economy requires an energy transition which involves the creation of new business models and a deep evolution of the energy markets. The way these changes will occur is still uncertain. Therefore, there are significant regulatory challenges to achieve a fully sustainable gas sector, especially concerning the potential contributory roles of DSOs and TSOs in facilitating the transition through new activities and necessary changes in the relationships between DSOs and TSOs.

1) New activities to foster renewable gas development
Network operators must be fully dedicated to their core activities: design, develop, operate and maintain their assets and organise their use in a transparent and non-discriminatory manner.
In addition to this, the specific position in the value chain of the network operators gives them a key position as neutral market facilitator. The current involvement of DSOs and TSOs to support the development of renewable gas such as biomethane injection or sustainable mobility show their potential as a market enabler for nascent activities conducted by third parties (biomethane or hydrogen producers for instance).
That is why regulation should give sufficient flexibility to allow DSOs and TSOs to leverage their unique knowledge of the market as well as being initiators through, for instance, pilots and demonstrators in new activities while the market is not mature enough to develop them. Such new activity, approved by the regulation authority, should be allowed under specific conditions and especially with the objective of supporting competition and benefitting end-users. We would like to highlight that in the energy sector and across Member States, diverse examples of activities developed by different stakeholders subject to different regulatory frameworks can be found, such as gas storage, LNG plants, interconnection projects or supported renewable energy sources. Depending on the Member State, the activity and the state of the development, these activities were developed or not by TSO/DSOs.
The shift to a fully decarbonised gas industry will require support for initiatives which are currently in the innovation phase of development to bring these to the point of commercial viability. DSOs and TSOs are well positioned to promote decarbonisation of the gas sector, but they need a flexible and appropriate regulatory framework to allow them to invest in new businesses such as decentralised management of a dynamic network, blending of natural gas with renewable gases, large scale experimentation of CO2 and/or H2 grid management.
Furthermore, a way to solve the question of supply-demand balance on distribution grids raised by major injection of renewable gases in local networks could be to develop the demand according to a circular and local economy. Regulated entities like DSOs should be authorised to contribute to the investment in infrastructure for gas mobility such as gas refueling stations or bioLNG storage in the case that the market is not mature enough to propose it spontaneously and that such development brings value by avoiding network investments.
Power-to-Gas facilities should not be classified as gas production plants. Power-to-Gas may be provided as a conversion service that transforms electricity from a renewable source, or any other electricity network user, into gas (such as hydrogen or synthetic methane) for storage and further use in the energy system. A clear definition of the role of Power-to-Gas technology is required in the regulation to enable sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner.
Finally, the possible involvement of DSOs in building or managing biomethane/Power-to-Gas plants if the market is not ready to do so should be considered in the assessment.

2) Reinforce cooperation between DSOs and TSOs to support renewable gas penetration
Considering the decarbonisation, decentralisation and digitalisation of the gas sector in the coming years, the role of DSOs ad TSOs will evolve. It will require operators to work closely together.
The development of renewable gas is a priority. It is crucial to make the right move today to reach a decarbonised gas market in 2050. As production could take place in areas with a lower gas demand than production levels (particularly the case of biomethane production in rural areas) it could be necessary to send the renewable gas to other areas capable of consuming or to storing the excess gas locally. To do this, several means are possible including a reverse flow installation (consisting mainly of a compression unit enabling the movement of the gas from the distribution to the transmission grids) which is not the current network design. Therefore, DSOs and TSOs need to cooperate when it comes to renewable gas development – including Power-to-Gas plants - to plan together the required infrastructure, depending on the location and the characteristics of the injection points, and to ensure the adequacy of their operations.
Local storage units are another means to balance supply and demand over the year and to avoid grid congestion. Such installation also needs to be planned between DSOs and TSOs as they participate in the development of renewable gases. This alternative should be compared to the reverse flow installation and other options like virtual pipelines. Cost/benefits analyses should be performed for each of the options to find the best solution for the gas system as a whole.
At a European level, the right channel to facilitate the work between DSOs and TSOs should be through the potential EU gas DSO Entity and ENTSO-G:
- DSOs are ready to actively participate in the TYNDP with regards to renewable gas plants, reverse flow pipes and network operations having an impact on the distribution network,
- DSOs and TSOs should exchange data and best practices on their respective networks and work on cybersecurity issues.
GD4S is willing to actively participate and contribute to the progress of renewable gases at a European level and would welcome taking part in joint discussions concerning elaboration of the rules for such evolution of the industry.

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.
In our opinion, the allowed percentage of hydrogen being injected in the gas grid should be harmonised at a European level. The level of this percentage should be defined within the discussion on norms such as CEN/TC 234 and EN16726. A harmonisation of hydrogen levels will facilitate the exchange of gas with hydrogen potentially flowing between countries, therefore contributing to security of supply. The question of the maximum percentage blend of hydrogen in the gas grid is a technical subject. Indeed, it depends mainly on the grid's characteristics (material and components), which vary significantly among Member States, and of the appliances used by the end-user. We fear that a definition of a harmonised hydrogen percentage would reflect the worst-case scenario leading to a relatively low value as the reference. However, Member States should be free to choose the pathway(s) they want to follow and relevant timelines. The use of hydrogen, either in combination with natural gas or in pure form, will require at least an assessment and possibly an adaptation or substitution of gas infrastructure elements and end use applications. Providing technical clarity at the EU and local level on the different pathways is necessary to identify which technological developments and investments are needed. In the short-term, there is an urgent requirement to remove technical and legal barriers that could hinder further development of hydrogen systems, including blends. In the medium and longer-term, natural gas end-use applications standards should increase their readiness for hydrogen blends. Gas applications should also be provided with the necessary controls to withstand the foreseeable variability in hydrogen blends. An EU roadmap setting out the hydrogen readiness of new appliances would be beneficial. It seems too early to fix a threshold for hydrogen injection in the gas grid in the present situation. Further studies and experimentation to establish what is the desirable/maximum percentage of hydrogen injectable without affecting security are underway, especially by Marcogaz. The issue of the measurement of the calorific values of blended gases still needs further examination.

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.
The use of hydrogen as an energy carrier has significant potential as part of the energy transition and its use is envisaged that this will increase in the coming years. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its development. The reason for the regulation of the natural gas network in Europe is that it constitutes essential facilities and as such, without regulation, competition in such activity would not be possible or would be negatively impacted for the industry as a whole. Such regulation was possible because most of the infrastructure was already build under a completely different framework based on long term supply contracts and global supply routes including transit, shipping, and storage. Assuming the development of a network dedicated to hydrogen transport and distribution, separate from current natural gas grids, such networks would constitute natural monopolies in the same manner as the gas networks. Therefore, there is no reason to treat them differently. Hydrogen networks should therefore be regulated in a similar way, taking into account the peculiarity of a developing network, a reduced number of connections to redelivery points in the early stage and capex likely to be higher than that of the gas network. We believe that the regulatory authorities should allow, depending on the relative maturity of the activity and its situation in terms of competition, the possibility for a regulated entity such as DSOs and TSOs to invest in hydrogen networks. This is the optimal way to develop a hydrogen industry at scale and ensure third party access and enable the safe and cost-effective development of hydrogen networks.

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.
The “technology neutral” approach should be the common rule and should be preserved as far as a holistic methodology is respected. For instance, the biomethane industry has been disappointed by the way zero emission has been considered in the transport regulation while considering a “tank to wheel” rather than a “well to wheel” approach. We remain convinced that life cycle analysis should always be promoted in the impact assessments. However, markets also require some policy or regulatory signals to deliver expected objectives in time. This is why, in the light of EU energy and climate strategy, some kind of intervention would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades: Decarbonisation gas targets, support schemes, definition of regulated activities and planning, etc are possible instruments that deserve further examination. In the case that market practices such as tender are not able to sufficiently account for both positive and negative externalities, specific rules should apply to allow the best investment decisions. For example, the development of renewable gas makes even more sense while considering the numerous positive externalities in terms of emission reduction of the agriculture and waste management, the promotion of agricultural sustainable practices and the creation of local jobs. Therefore the “cost efficiency” principle should be used to bring decisions in effective system optimisations and achievement of the long-term strategy of full decarbonisation by 2050. In particular, exemption of the “technology neutral” approach could be necessary to support nascent activities for which positive externalities are significant such as biomethane production and injection in the gas networks. There are supports and an adequate regulatory framework in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of supports, assuring a level playing field between all technologies and energy carriers.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas is a promising technology allowing the production of two different renewable gases that could be injected in the existing gas networks: •renewable hydrogen produced through electrolysis of water with renewable electricity, •synthetic methane via the process of methanation of the hydrogen with CO2 captured from the air, industrial processes or from a biomethane plant. Power-to-Gas could bring flexibility to the electricity grid as the gas network has the ability to enable large scale energy storage in an efficient way. Power-to-Gas allows the conversion of renewable electricity into a form of energy that could be consumed later, either directly or used to generate electricity. As such, Power-to-Gas is a new link between power and gas systems contributing to better integration through sector coupling. In other words, Power-to-Gas may offer the flexibility in time and space needed by non-dispatchable renewable sources at a marginal cost. This will help to keep the gas network functioning properly while natural gas consumption may decrease. The existence of a back-up in case, for instance, of a major disruption in the electricity sector will help the resilience of the energy sector as a whole. Power-to-Gas infrastructures is expected to strongly contribute to the decarbonisation of the gas sector and the question of ownership and management of this infrastructure is important. DSOs who wish to invest in Power-to-Gas as a conversion service should be allowed to start now, in order to ensure the technology reaches the required scale and maturity. Particularly where there is a lack of interest from the market, DSOs could be involved in these activities while respecting the unbundling regulation. Regarding the process to produce synthetic methane, it will be necessary to move CO2 from the producer (biomethane plant for instance) to the Power-to-Gas infrastructure. We are favourable to regulatory changes allowing under certain conditions DSOs to distribute CO2.

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?
Power-to-Gas technology could be considered as a pure consumer of electricity and apply the same rules as the other consumers. Nevertheless, considering such activity as a service for the energy system as a whole and the difficulty to develop business cases today, specific tariff should be envisaged for this activity as a storage, energy conversion, or a congestion management plant for instance. Considering that in the long-run, the power system would be mainly supplied by intermittent sources, the value of Power-to-Gas plants to provide flexibility and dispatchable energy should be related to security of supply concerns. Therefore, the regulation should be flexible enough to allow the development of various business models and avoid double charging in the tariff looking at effective synergies for both power and gas systems. Concerning the issue of tariffs and potential double charging when it comes to Power-to-Gas-to-Power (P2G2P), any unwarranted fees should be avoided as this could limit the development of hydrogen and act as a barrier to sector coupling. An example of this is that storage and conversion of one form of energy into another (which can be classified as an end-user in the electricity sector) should be treated as a separate conversion process, exempt from end-user taxes and levies.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legislative and regulatory frameworks were designed prior to the development of Power-to-Gas infrastructure, and therefore does not take into account its potential and possibilities. A review and amendment of the legislative and regulatory frameworks are needed to ensure their adequacy for the development of Power-to-Gas infrastructure.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Guarantees of Origin (GO) allow transparency for relevant parties (including end consumers), as they certify the conditions of production of the energy. Guarantees of Origin should be based on similar technological thresholds and the system should be overseen by a competent authority, in charge and able to collect reliable production data, to run appropriate control systems and – if needed – to impose appropriate sanctions in case of any Guarantees of Origin misuse. In addition, Guarantees of Origin give useful information on the development of renewable gas supply and alignment with demand.   Regarding the development of a cross-border trading of renewable gas GOs, the following should be considered: -this scheme must be based on “mass balancing” and not on “book and claim”. It is necessary to keep the link between the GO and the molecule to ensure transparency for the end-user. -the system must include the sustainability criteria defined into RED II regarding biomethane. Cross-border trade of GOs for renewable gas should be supported by ensuring ‘interoperability’ of GOs across all Member States. Standardisation, interoperability and harmonisation of GOs across all Member States will allow for the efficient cross-border trading of the sustainability characteristics of renewable gas produced in the EU. The ‘European Renewable Gas Registry’ (ERGaR) has been established for this purpose and aims to incorporate all national renewable gas registries into the ERGaR system. The ERGaR project also aims to establish a European hub for GOs and, in doing so, to allow for mass balancing at a European level. Regulatory support will increase the chances of the successful implementation of the ERGaR system.

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?
One lesson to learn from the renewable electricity GO scheme is that it should not be based on a “book and claim” system, rather than a “mass balancing” system: it has more value to sell the green electricity to the person who receives the GO. Another lesson to be learnt from renewable electricity is the importance of avoiding any double support between an EU-wide GO system and Member State support schemes. The EU-wide GO system for renewable gas should be set-up ensuring that double counting of renewable gas volumes is avoided. Successful implementation of an EU wide scheme with mass balancing, will ensure that volumes are only counted once.

Infrastructure Investments and Regulation

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?
The regulatory authorities should make sure that DSOs' contributions are effectively taken into consideration in the elaboration of the development plans such as TYNDP. Transparency is essential in the elaboration of the TYNDP and in the assumptions. ACER should have the power to establish the rules for the approval of the TYNDPs that individual NRAs must adopt. The system should work in a similar way in all countries, even though being sufficiently flexible to take into account the different structures of the gas systems amongst them, the gas penetration rate among consumers and the specific objectives connected to the decarbonisation and energy efficiency path established in the National Energy and Climate Plan (NECP) for each Member State, approved by the EU.

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)?
Sustainability is one of the key criteria for the evaluation of PCIs as described in Regulation (EU) 347/2013. GD4S welcomes the fact that there is now a focus on renewable and decarbonised gas projects by the industry, which will help ensure the transition to a decarbonised gas grid across Europe. To reduce the risk of over-investments, and in the light of market needs and regulatory and energy policy objectives, new infrastructure investments should be based on the results of the application of validated CBA methodologies and appropriate market tests. The use of F factor stating the minimum amount of costs to be recovered from capacity bookings is paramount, to avoid selecting PCIs without a minimum market interest behind them. As mentioned by CEER, we support the extension of the PCIs' selection scope to projects regarding the connection of decentralised and local gas generation, including renewable and decarbonised gas, as well as to gas-electricity integration in the context of Power-to-Gas and sector coupling as well as for the conversion/adaption of gas grids to new gaseous carriers. A wide range of projects and technologies should be supported through the PCI framework, including biomethane injection.

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?
We do not see a risk of stranded assets in terms of our DSO activity. Furthermore, based on existing and projected gas demand we do not see a risk for stranded assets, at the very least in the next 10 years. This is in line with CEER's observations, as well as the EC's 2050 scenarios and draft National Energy and Climate Plans 2020-2030 recently published, among others. A risk for stranded assets may arise in the case of a decline in natural gas consumption beyond 2030, if this is not accompanied by its substitution with renewable and decarbonised gases such as biomethane, green hydrogen or blue hydrogen injected into the grids. Alternative uses for potential stranded assets in the longer term should be considered by regulatory mechanisms to favor investments that are already made in essential facilities. A possible regulatory tool could be a financial incentive for the production of electricity converted into gas in the case of reduced electricity demand for a given plant, in order to avoid the formation of negative prices for the renewable electricity producer and indirectly support the production of gas from power.

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?
In our opinion, the strengths of the natural gas infrastructure system include the numbers of interconnections, its extensive network across the EU and its access to energy sources located in different countries and arriving in Europe through different routes. These are the characteristics that allowed Europe to enjoy a long-lasting and secure energy supply, able to satisfy demand even through critical moments, of a political nature or linked to natural factors, which have affected specific producing countries and / or supply routes. It is because of these characteristics that the natural gas system can support the energy transition path towards an increasingly decarbonised economy. For this reason, the choices concerning the decommissioning of significant portions of natural gas infrastructures should be evaluated not only with regard to its effects on the country in which they are physically allocated, but also for the cascading effects on neighboring countries. Any development of a formal decommissioning framework should ensure efforts are made to maximise the efficient use of the gas infrastructure to ensure that investments in the overall energy system occur in a balanced manner. In particular, optimal and integrated planning of gas and electricity infrastructure should be a key focus to ensure that the least cost pathway is taken to achieve the energy transition.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The fast and wide development of renewable gases (biomethane, synthetic methane, green hydrogen) is critical. All the energy mix scenarios, including those of the electricity sector, show that we could not go above 60% electrification in Europe. Therefore, gas will continue to play an important role in the European energy mix. However, considering the Paris agreement, it is necessary to decarbonisse this sector to meet the climate objectives. Therefore, it is important that gas market design further examines the topic of renewable gas development. The development of renewable gas will increase the level of energy decentralisation. Therefore, it is necessary to ensure an appropriate regulatory framework to enable DSOs to become key actors of this evolution, while respecting the unbundling rules. Since 2009 and the last revision of the gas market design, the economy has become more digitalised. Therefore, the new gas market design should reflect this evolution.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Some kind of policy or regulatory signals will be required to deliver expected ambitious decarbonisation and transformation: Decarbonisation gas targets, support schemes, definition of regulated activities and planning are possible instruments that deserve further examination. Some of these instruments are likely to be needed to enable necessary transformation of the gas sector in the coming decades. To this extent it’s pertinent to look at the transformation occurred in the electricity sector in the last 20 years, as well as to the many lessons learned from it. We see a strong need to update the gas market design to develop renewable gases. Several regulatory changes are required to ensure the takeoff of renewable gases production. First, it is necessary to define precisely renewable gases. It is fundamental to have a definition including the main technologies allowing us to have more visibility on the sector. “Gas produced from renewable sources”: Gas produced - with respect of the rules listed in article 7, 25 and 26 of the RED II directive on the use of energy produced from renewable sources, either via anaerobic digestion, gasification of biomass, Power-to-Gas or via any of the technologies using renewable energy sources”. “Anaerobic digestion”: Biological conversion of biodegradable materials by micro-organisms in the absence of oxygen creating two main products: biogas and digestate. Once purified, biogas results in the production of biomethane. “Gasification”: Thermochemical process at high temperature (> 700 °c), producing gases composed mainly of carbon monoxide and hydrogen, usually followed by a methylene stage for conversion to biomethane. “Power-to-Gas”: Conversion process allowing the transformation of renewable electric energy into a gas vector produced from renewable sources: hydrogen by electrolyse of water or synthetic methane by electrolyse and methanation. “Biogas”: Gas produced by anaerobic digestion of organic matter, gasification or even Power-to-Gas, before purification stage. Therefore, these definitions will allow investors greater clarify on the renewable gases production technologies. Several other regulatory changes would also contribute in this objective, such as the introduction of renewable gas targets. On this point, RED II objectives should be defined in the gas sector. Thus, we could have three different renewable gas objectives at the European level: -A general objective by 2030 of renewable gases injected in the grid, mandatory at the European level and indicative at Member States level, -An objective by 2030 of renewable gases in total final consumption of gas in the transport sector, -An objective of an increase of renewable gas per year in the total final consumption of gas in the heating and cooling sectors. The development of renewable gases must be sustainable. Therefore, it is key to make sure that the next gas market design refers to the sustainability criteria defined in the RED II directive. In addition, the next gas market design should include a principle of priority access to the gas network for renewable gases while ensuring the respect of unbundling and the security of the network. This priority right will allow us to harmonise the existing European practices. The producers will have the certainty that their projects will have priority over natural gas. The future gas market design should also require Member States to oblige operators to socialise all or part of the costs for the development of renewable gas production sites (connection costs, reinforcement of network). To conclude, this new role of DSOs will require an update of the definition of “distribution” and of “distribution system operators” in the gas directive to include the fact that they distribute today natural gas and gas produced from renewable sources.

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?
GD4S doesn't commit to answer to this question

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
GD4S doesn't commit to answer to this question

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
1)An EU gas DSO Entity We would like consideration to be given to the tasks and form of the EU DSO Entity. In our opinion, the EU gas DSO entity should be different from the EU electricity DSO entity as there are several issues which are specific to the gas sector. Besides, the above-mentioned role of the entity when it comes to cooperation with the TSOs, the EU gas DSO entity will be responsible for facilitating the exchange of best practices on energy efficiency, digitalisation, demand side management, data protection and cybersecurity. DSOs should also have a contributing role in the development of renewable gases, storage capacity and gas mobility. 2)The digitalisation of the network Smart meters are currently being rolled out in several EU countries. The next gas market design should support this development. Smart meters allow for the reduction of energy consumption, therefore participating in the energy efficiency objective defined in the EED directive. Moreover, they bring social benefits to consumers who are better informed about their energy consumption. Similarly, more DSOs are installing sensors on their network at pressure reduction stations and at biomethane injection plants. This evolution allows for optimised management of the network and better integration of renewable energies into the grid.

Survey response 17

Contact details and treatment of confidential responses

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eustream,a.s.

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
It must be noted that TSOs and DSOs are not single players at the gas market. However, it is a matter of course that these key players will play their important roles also in the future as keeping stable level of natural gas consumption does not necessarily mean inability to achieve given enviromental targets, mainly due to an important position of natural gas as the back-up source of renewables, coal alternative and its cleanest nature from all fossil fuels. It is expected that TSOs and DSOs could also facilitate the integration of any forms of gas and their transmission and distribution in the long-term future. In any case, detailed technical, economic and legal analysis is needed in order to set realistic targets and functional solutions before any commitments are going to be binding. TSOs and DSOs should actively participate in analysis preparation and research. The appropriate framework should be left to competent authorities of Member States depending on their particular circumstances.

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.
Technical standards for hydrogen injection into gas grids are expected to be harmonized in the future taking into account technical limits of gas appliances and gas infrastructure. Any other solutions which would represent a difference from an actual situation (pure hydrogen, blended hydrogen) will represent extra costs. Eustream thinks that a detailed assessment should be firstly elaborated at a national level as national circumstances differ from one country to another one. It is an exclusive responsibility of each Member State to set its energy mix including necessary thresholds and other aspects based on technology development. Before taking any decisions, proper impact analysis must be carried out including financial and tariffs impact of the foreseen changes – costs of infrastructure upgrades, costs of end-user appliances, and impact on consumer bill. There are many challenges to be answered before any decision is taken such as energy content and emissions, assessment if actual pipeline material is resistant enough to accommodate H2 volumes without making them prone to cracking, explosiveness limits of H2, tolerances of gas appliances in new conditions, research and development of new technologies. In this respect, as one size solution does not fit to all, Eustream proposes to stick on further research and development with the aim to propose technical solutions and legislative changes after mid-tem horizon (after 2030) when a more clear view of this topic based on a development and evolution will be reached.

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.
Eustream considers this question to be premature one as at first a detailed impact analysis is needed in order to identify all necessary steps to be done. However, the level of regulation should depend on a detailed impact analysis, objectives the national regulatory authority will intend to reach and national circumstances.

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.
Eustream does not share an opinion that “cost efficiency” is a legitimate reason for pro-active market interventions at any price. From Eustream´s point of view the energy sector is already overregulated. The market and its patterns should be let work properly in order to avoid any distortions. If, in the future, the market calls for assistance in the form of interventions, it will be time for doing it but not sooner. At the same time, the economic position of natural gas in the energy mix is in the Eustream´s opinion strong until 2030. In this light, we are of the opinion that representations going to 2050 substantiated by ambitious scenarios (with particular figures), mostly with respect to deployment of the renewable gases in a very large scale, will have immediate value impact on transmission network operators. Eustream does think that a mid-term period (until 2030) should be used for a further research and development of technologies and possibilities that may be achievable and not to the detriment of business plans of TSOs in long-run.In other words – the technology and related know-how is so immature that any proactive market intervention by regulatory bodies could be a pure gamble.

Q5 Which role do you see for power-to-gas infrastructures?
It is feasible that coupling of electricity and gas systems, as two important demand sectors, relating to possibility connected with key values such as peak capacity and flexibility needs brought by important energy carriers and associated huge existing infrastructure, might have a potential in the future. However, Eustream considers this issue to be a premature one as it is necessary to elaborate a detailed research, precise impact analysis and technology development. Till that time other precautions can be taken such as a more progressive coal decommissioning plans which will help reaching environmental plans easily. New technologies require further research and development and significant investments to be viable and energy efficient. It is important to note that energy losses are significant in this process and will be a key driver for successful technology implementation. Therefore, further detailed analysis is essential and cost efficiency criteria could indicate that support of gas and existing gas infrastructure is more effective than Power to Gas technology which results in extreme energy losses.

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?
Eustream does not see any problems on this issue as it is premature for this moment to make any conclusions without having results of a detailed impact analysis. However, at present tariffs are regulated and approved by NRAs on a cost reflective basis. In case this principle would be followed also in the future then Eustream sees no room for possible distortions. As development of power-to-gas technologies is in its very early stages with many open issues it is very risky to take any commitments not being on account of other stakeholders.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legislation and regulatory framework were designed prior to the development of P2G technologies. A review and subsequent amendments of legislation and regulatory framework are feasible in order to prepare transparent and functional conditions. However it shall be done after a detailed research, technology development, and subsequent impact analysis.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Eustream is of the opinion that European gas sector is in a very premature stage to determine the precise indicators that need to be taken in order to enable or even facilitate efficient cross-border trading of GOs for renewable or decarbonised gases and much more information are needed on the GO. According to Eustream´s view, more discussions and negotiations among the different prime movers (issuing bodies of GO, European Commission, TSOs, other market participants) need to be taken on the GO.

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?
Eustream draws attention to the response for the previous question. Additionally, there is the necessity of common understanding of the data that should be included in the GO. Further, all GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements.

Infrastructure Investments and Regulation

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?
Such ACER and NRAs roles should be kept as it is today in order to provide important feedback to enhance TYNDPs as they are important participants of a TYNDP process in line with legislation. NRAs are key players at a national level during assessment process of the national development plans. ACER has an important role in providing their opinions to ENTSOs drafted TYNDPs and CBA Methodologies. However, it is important to ensure that methodology and scenarios preparation are valid for everyone in the same manner and not influenced by a sole interest of anyone.

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)?
Up to this moment Eustream has been of the opinion that the whole process is being designed and managed in order to maximize the efficiency of a decision taken about new infrastructures. However, it must be noted that infrastructure regulation 347/2013 and CAM NC 2017/459 have different targets so Eustream does not consider this issue as relevant one.

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?
Eustream thinks that it is premature to open a discussion relating to stranded assets as it is more than feasible that gas will keep its key role in the energy mix also in the future mainly due to its important position as the back-up source of renewables , coal alternative and its cleanest nature from all fossil fuels. Instead of thinking of stranded assets and working on their decommissioning, regulatory and other tools should be used for incentivizing TSOs to keep existing gas infrastructure in operation with the target to provide market participants with reliable and sustainable services. Eustream is of the opinion that the role of natural gas as an environmentally friendly fuel in combination with a balanced regulatory approach (pragmatic, inexpensive solutions reflecting a cost effective approach) will eliminate a problem of stranded assets. On such grounds any thresholds settlements are in principle harmful.

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?
Eustream does not think that this issue is the agenda of these days. As Eustream considers this topic as a premature one it is proposed to adjourn it for a later time. As this issue is very important with irreversible consequences it must be analysed and assessed in details. If the risk of stranded assets would become of relevance, the regulatory tools to reduce this risk should be implemented. Till 2030 the gas demand decrease is not expected and therefore this issue is highly hypothetical and not relevant at this moment. Please refer to Q12 answer.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The current gas legislation including gas network codes represents a basis for ongoing development of integrated gas markets and predictability of business models of key gas players. Based on the ACER´s Market Monitoring Report (2018) implemented gas legislation has led to enhancements in many market areas resulting in more functional market places. A contemporary trend which ensures gas market predictability and maximum infrastructure utilization should be kept also in the future.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Presumably it is feasible that changes in the energy sector might cause the need to update gas market design in the future. However, this issue is a premature agenda for these days. The main issue of a new market design, based on a detailed analysis, should be how to interconnect all available solutions without putting back the energy market integration and its reached results. Eustream does think that a mid-term period (until 2030) should be used for a further research and development of technologies and possibilities that may be realistic and achievable and not to the detriment of business plans of TSOs in long-run.

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?
There are no relevant arguments on the table which would definitely prove a scenario of gas consumption decrease. In order to avoid any market distortions Eustream considers being necessary to let the gas market work and focus on proper and timely implementation of existing acquis communautaire. Moreover, actual TAR NC provisions have had no sufficient time to be implemented and work properly.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
Eustream does not see any significant problematic issues in tariff area. As actual TAR NC provisions have had no sufficient time to be implemented and work properly Eustream considers this issue as a pre-mature one. Ongoing monitoring to assess the impact of current tariff system on cross-border trade could be essential.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
From Eustream´s point of view a sustainable gas sector should mean solutions which would allow to reach binding environmental targets being set till 2030, affordable energy for all EU citizens including a decreasing number of people affected with energy poverty and also affordable energy as an input for competitive EU industry worldwide. Moreover, specifically for infrastructure operators sustainability means further proper utilization of existing energy infrastructure. Experience taken from the PCI projects shows that energy infrastructure construction is mainly cost and time demanding. That ´s reason why stable and predictable conditions are key ones for long term sustainability. From this perspective the basic challenge should be to keep a present position of gas as gas represents a very good and reachable alternative to meet all aspects of sustainability comparing to more polluting energy carriers (coal, oil,..) including biomass for a direct utilization being assessed from all aspects (health aspects – COx, NOx, micro particles, land utilization - preferably food production, etc.). Public acceptance of the solution is one of key elements to be successful. Eustream considers detailed assessments important before taking any binding commitments. Lessons learnt could be taken from a situation in France as a response to increase taxes for fuel (yellow vest movement). Eustream welcomes rather smaller steps towards a sustainable gas sector and its predictability till 2030 horizon which would be realistic and achievable than a nice but unrealistic picture of the gas sector for the year 2050. As it has already been mentioned in some of Eustream´s answers a mid-term period (until 2030) should be used for a further research and development of technologies and possibilities that may be realistic and achievable and not to the detriment of business plans of TSOs in long-run. Eustream thinks that we can afford to spend this time in this manner as other precautions can be taken such as a more progressive coal decommissioning plans which will help reaching environmental plans easily.

Survey response 18

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GAS CONNECT AUSTRIA GmbH

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
We support ENTSOG`s consultation response.

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.
We support ENTSOG`s consultation response.

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.
It may be too early to decide on a mandatory regulation of hydrogen infrastructure. There may be cases where both regulated and unregulated infrastructure can exist beside each other and different national context and background may justify both alternatives

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.
We support ENTSOG`s consultation response.

Q5 Which role do you see for power-to-gas infrastructures?
We support ENTSOG`s consultation response.

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?
We support ENTSOG`s consultation response.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
We support ENTSOG`s consultation response.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
We support ENTSOG`s consultation response.

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?
We support ENTSOG`s consultation response.

Infrastructure Investments and Regulation

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?
We support ENTSOG`s consultation response.

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)?
We support ENTSOG`s consultation response.

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?
We support ENTSOG`s consultation response.

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?
We support ENTSOG`s consultation response.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
We support ENTSOG`s consultation response.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
We support ENTSOG`s consultation response.

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?
We support ENTSOG`s consultation response.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
We support ENTSOG`s consultation response.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
We support ENTSOG`s consultation response.

Survey response 19

Contact details and treatment of confidential responses

Contact details: [Organisation][]
SEAS-NVE

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
We believe that natural gas should be phased out and green gasses phased in during the next decades. Hence, we strongly recommend close cooperation between TSO/DSO in order to remove barriers to cross boarder trade e.g. common standards for gas quality and balancing zones.

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.
A common threshold should be mandatory to ensure cross boarder trade and to enable the flow of gas. Timing depends on the speed of electrification.

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.
It is cost efficient to use the gas system in place. An alternative grid system should be avoided, however if such system is needed it should be regulated.

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.
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Q5 Which role do you see for power-to-gas infrastructures?
P2G will ind the future play a significant role providing flexibility in the energy system. Hence the tariff-system and regulatory framwork should be designed in order to help forward P2G Technologies.

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?
Ref. answer Q5

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
During a specific P2G project, we have experienced that the local TSO would not categorise P2G as "green gas", hence the TSO could not issue GOs for the produced volumes. The example given illustrates that P2G production should be considered as green gas.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Common framework for GO trading.

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?
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Infrastructure Investments and Regulation

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?
Dual focus on both interconnectors to external suppliers and sector coupling (power and gas).

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?
Yes, in Denmark there is a risk of stranded assets as gas is being squeezed by enhanced focus on biomass. Regolatory tools should enhance sector coupling.

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?
Yes

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Decarbonisation, digitalisation and decentralisation - the consumer should be activated and use gas and power smart and climate-friendly. Supplier centric model, smart meters and datahub could enable such a system.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Yes, as the consumer should be able to use gas when it is "green" and cheap. This requires a market design providing smart meter and easy access for the consumer to real time data.

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?
Both DSO and TSO tariffs sould be designed to stimulate the consumer to use gas when it is cheep and climate friendly.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
80-100 % flexibility (variability) in the tariffs.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
EU should accept that sustainable gas technologies are still dependend on state-subsidy regimes and in parallell should remove/phase out barriers to cross boarder trade.

Survey response 22

Contact details and treatment of confidential responses

Contact details: [Organisation][]
PGNiG SA

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Most of new gas technologies require close cooperation between shippers and DSOs - development of refueling stations' chains, gasification of regions of the EU, hydrogen/biogas/methane transport, P2G, smart metering. As unbundling regime is less restricted for distribution system operators than for transmission system operators, they should be allowed to conduct own research and contribute to more advanced solutions bringing clean energy to EU citizens.

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.
There should not be mandatory threshold for the blending of hydrogen in gas networks. Member States should have a right to decide on their energy mixes. UE should encourage MS to increase share of renewable gases in their energy mixex, rather than introduct binding targets. Moreover, according to IEA report 'Technology Roadmap - Hydrogen and Fuel Cells', blending hydrogen into the natural gas grid involves some challenges such as ability of hydrogen to embrittle steel materials used for pipelines and much lower volumetric energy density of hydrogen (compared to natural gas) what significantly reduces both the energy capacity and efficiency of natural gas system. It can be expected that the maximum acceptable % of hydrogen in gas networks will depend on local conditions and will not be common across the EU. Additionaly, blending of hydrogen with natural gas will affect the Wobbe Index and we support CEN's current work on this matter. Therefore MS should independly asses the possibility of blending hydrogen in their gas networks.

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.
Most aspects concerning hydrogen networks should be regulated in the same way as gas networks, but physico-chemical properties of hydrogen should be taken into account. However, more important is to focus on efficient utilisation of the existing gas infrastructure. Therefore, while considering hydrogen transportation possibilities, existing gas infrastructure utilisation opportunities need to be assesed.

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.
Support for emerging technologies, which are cost inefficient in the development stage can be considered as reasonable and justified if the level and scope of support does not cause market distortion.

Q5 Which role do you see for power-to-gas infrastructures?
The storage of surplus electricity is one of the main challenges currently faced by the electricity sector. Power-to-gas technology gives an opportunity to store surpuls electricity produced from Renewable Energy Sources such (e.g. solar, wind etc.). This technology can contribute significantly to increase in the use of RES. Moreover, existing gas infrastructure, particulary distribution systems and gas storage facilities, can be used for this purpose. However, transportation of hydrogen with the use of existing gas infrastructure is linked to technological limitations. See also response to question 2.

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?
We do not see the gas tariff system creates distortion for the use of power-to-gas technologies as they are to be considered as producers that inject gas into the network.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
No.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
No opinion.

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?
No opinion.

Infrastructure Investments and Regulation

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?
Development of TYNDPs should be the responsibility of ENTSO-G (and TSOs). Obviously, while preparing TYNDPs, ENTSO-G should cooperate with network users. We do not share the opinion that TYNDPs or their underlying scenarios should be subject to ACER approval, also having in mind TYNDPs non-binding character. On a national level, the NRAs have monitoring and approval tasks with respect to the binding network development plans. Additionally, more attention should be given to the assessment of the extent to which the projects considered in the TYNDP process meet the energy objectives of EU and Energy Union.

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)?
Addition of cross-references between the infrastructure regulation 347/2013 (PCI regulation) and the CAM NC (2017/459) could have negative impact on new gas infrastructure projects. PCI are often initiated at an early stage in the project, prior to any market testing under CAM NC. Moreover, PCI may deal with infrastructure that is not subject to CAM NC, such as LNG terminals and gas storages.

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?
Some regions in European Union (CEE) are to a large extent depended on a single gas supplier. The diversification effort made by some MS such as Poland (eg. Baltic Pipe which will bring gas from Norway, LNG Terminal in Świnoujście or FSRU in Gdańsk Bay) require the reinforcing of existing gas infrastructure to new sources of supply. Moreover, by 2022 PSG (Polish DSO) plans to extend its gas network by 4,871 km, which is enough to ensure access to natural gas for 90% of Polish citizens and will contribute to air quality improvement and achievement of climate targets. In the view of above, new investments in gas infrastructure in some EU regions (CEE) are essential and should be supported with EU financing (eg. from ERDF under cohesion policy).

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?
Decisions on decommissioning should be taken following careful consideration of impact on security of supply in concerned Member State and in the nearby regions.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Decentralized IEM with multiple hubs cooperating with each other should be considered as one of the most important points that should be addressed regarding the gas marker design. The construction of Nord Stream 2 contributes significantly to creation of central hub for Russian gas in the EU. Such scenario will make the CEE region dependent on German hub strenghtening domination of Gazprom who possesses legally guaranteed export monopoly. Relying on single hub should be avoided as it can pose a significant threat in terms of energy security. In case of any disruption, either of technical or political purpose, there would not be, or would be insufficient alternatives for this main hub, what can result in serious gas crisis.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
While considering the possible development of renewable gases, the most important issue that should be addressed are limitations for blending renewable gases into the natural gas grid. Please see also response to question 2.

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?
PGNiG advocates framework facilitating establishment of regional hubs based on diversified sources of supply with aim of ensuring liquidity in particular regions. Provided that these hubs will be well-interconnected, above mentioned risks would be mitigated. Such scenario will ensure easy access to gas hubs for all Member States, and therefore will enhance development of these markets (by i.a. avoiding tariff pancaking) and competition among these hubs.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
As mentioned above, instead of focusing on changes in the current tariff system, the EU efforts should be concentrated on efforts facilitating establishment of regional hubs.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
One of the issues not addressed in the document is the use of innovative technologies such as CoalBed Methane. CBM is innovative technology, which contributes not only to methane emission reduction but also to significant improvement in terms of energy supply. The development of CBM can reduce EU dependence on single gas supplier. In view of the above, such technologies should be promoted and supported by EU.

Survey response 23

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GEODE

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
•The inclusion of distribution system operators (DSOs) in the process of reforming regulation is essential since network standards and conditions can differ significantly across Member States but also within regions. The input of DSO experts is highly valuable and necessary when new technologies are tested or technical norms are adopted (at the local, national, European level). •Distribution networks are built in very different ways – such as urban networks connected to transmission pipelines or wide spread networks with several feed-in points. Special attention should be paid to the generation and supply of renewable gas and biogas and the respective roles of each actor. In general, DSOs are responsible for the security of supply and network and product quality, assuring the compliance with technical standards. When it comes to feeding-in biogas, the responsibilities have to be clearly assigned. Cleaning, processing and compressing gas must remain within the producer's responsibilities while the DSO is responsible to monitor the quality of the fed-in biogas. •Promising innovation linking the gas and electricity sector – such as power to gas – are not yet economically viable and the existing installations are mainly pilot projects. In order to kick-start new innovative solutions and technology, DSO should have the right to be involved in such activities as long as there is no market interest. In such cases, DSO should have the right to own and operate P2G-installations and / or CNG-filling stations. •Given the technology neutral approach, DSOs should be allowed to take part in research and development projects as long as no functioning markets are established. Generally, new technologies should not be hampered by over-regulation.

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.
•In general, we would like to underline that hydrogen is one among other solutions for decarbonising gas and its infrastructure. •This topic requires very specific and technical insight. Although using existing gas infrastructure for transporting hydrogen offers a promising solution and should be further pursued, requirements for gas quality as well as technical standards differ significantly, not only across Member States but also among different (local) gas grids. •Setting a threshold much depends on the current technological maturity of the infrastructure and whether end customer appliances are for fit and safe for consuming hydrogen. Upgrades can be very cost intensive and time consuming, given the fact that different networks can transport different amounts of hydrogen. Disproportionate impacts on customer bills need to be prevented, for instance through well-coordinated replacement of appliances at the end of their lifetime, in order to neutralise costs. •Therefore, it is too early to set specific targets or thresholds for hydrogen. Instead, a gradual increase of hydrogen in the gas grids in close cooperation with (local) gas DSOs is advisable.

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.

• In general, economic regulation should not be defined by the gases / molecules transported in networks.

• In general, regulating parallel sectors in different ways which are competing with each other on the retail side can lead to market distortions and favour and/or disadvantage one actor over another. If proper hydrogen networks exist or are to be developed, they should be regulated according to the same principles like gas networks and comply with the same rules and obligations. Under no circumstance separate hydrogen and gas networks should be put in competition, but rather complement each other.

• Gas network operators are well positioned to also operate hydrogen networks, if such were to be built. Still, from a whole system approach, the better regulatory option is upgrading the gas infrastructure to make use of existing assets. The network operator is well place to judge whether to parallel hydrogen infrastructure is to be developed, or if it is more cost efficient to upgrade existing gas networks to accommodate hydrogen. Synergies should be used where possible. This does not refer to hydrogen networks for (private) industrial purposes which are already in place or those inducing certain percentages of hydrogen into local gas grids.

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.

Most new technologies are at first not economically viable or cost-efficient. This is why their market entrance has to be facilitated by means of (financial) support mechanisms which are then being phased out. DSOs can play an important role in this context, given their technological neutral approach, and should be allowed to take an active role in research and development projects to use & test new technologies, until market functioning is established. This would reflect the DSO’s role as neutral market facilitator.

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

• P2G-infrastructure will play an important role in future energy systems. The existing gas infrastructure can be used for storing and transporting energy carriers and could avoid building new electricity networks, achieving considerable cost savings for the energy system as a whole. By using P2G, the existing gas infrastructure will contribute to meeting EU climate goals and reduce CO_2 emissions. In this context, DSOs can be important actors for contributing to decarbonisation, in cost efficient ways.

• In practice, gas grids can absorb,store and transport intermittent renewable electricity generation to cover the residual load in winter months or whenever else needed.

• DSO should have the right to be involved in such activities as long as no market exists - because P2G can support guaranteeing security of supply. Also, although P2G offers promising solutions, it is not yet economically viable, with the existing installations being mainly pilot projects. In order to kick-start P2G deployment, cases, DSO should have the right to own and operate P2G installations and/or CNG-filling stations.

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?

At DSO level, specific tariffication for P2G technologies could be useful – limited over time during an introductory phase - in order to promote the deployment of this promising technology, with the premise to phase out, as soon as markets have emerged. The costs borne by DSOs supporting P2G deployment need to be reflected in grid tariffs.

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

To unlock synergies from integrating different sectors the required technical, legal and commercial framework conditions have to be established. DSOs should be reimbursed for additional costs through tariffs. On the production side, incentives for the establishment of new innovative installations will be necessary, until market maturity is reached.

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

In the course of revising rules for the gas market, the development for a cross-border trade regime with GOs with renewable gases should be pursued. Coherent standards will be necessary, among others, an EU-wide definition of renewable gas.

Further, the following points are important: a market place and clearing house for the trade of such certificates, similar to the trading of CO_2-certificates and total price transparency regarding buying and selling offers.

European standardisation is needed for cross border trading and 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?

Infrastructure Investments and Regulation

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?
Yes, as such decisions have massive consequences, and should be treated like investments decisions. If there's cross border implications, the EU should be competent.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
•Gas will have a future in the energy sector whereas special focus should be drawn to the generation and supply of renewable gas and biogas, and the respective roles of actors. In general, DSOs are responsible for the security of supply and network and product quality, assuring the compliance with technical standards. When it comes to feeding in biogas, the responsibilities have to be clearly assigned. Cleaning, processing and compressing gas must remain within the producer's responsibilities while the DSO is responsible to monitor the quality of the fed-in biogas. •Promising innovation linking the gas and electricity sector – such as power to gas – is not yet economically viable and the existing installations are mainly pilot projects. In order to kick-start new innovative solutions and technology, DSO should have the right to be involved in such activities as long as there is no market interest. In such cases, DSO should have the right to own and operate P2G-installations and / or CNG-filling stations. •A gradual increase of the amount of hydrogen in the gas grid in close cooperation with (local) gas DSOs is necessary. Further, manufactures of appliances might benefit from EU regulation to upgrade devices that are capable of enduring higher amounts of hydrogen. •The EU framework should provide a level playing field and prevent favouring one actor over another.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
GEODE sees a need to update the gas market design, recognising that increasing distributed generation of renewable gases will enhance the role of DSOs – which in return will contribute to decarbonising gas and its infrastructure. DSOs as active and neutral market facilitators will help making use of the significant advantage of renewable gases, such as the fact that production and consumption do not have to take place at the same time or in the same quantity, as compared to electricity. Gas can be stored in storages as well as in the grids (linepack) and used whenever need be. DSOs have shown throughout decades to have the expertise when it comes to distributing and storing gas. Also, it is important to involve DSOs at the earliest stages, and to coordinate the deployment of production units of renewable gases, storages and networks.

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?

Other question

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

Survey response 24

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GIE

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Flexibility and the transportation over long distances is the key-value brought by gas and the whole gas infrastructure in a coupled energy system of the future in general including transmission/distribution, storage and LNG terminals. Several comprehensive studies (e.g. the Gas for Climate Study or the Green Gas Initiative Study on the value of gas infrastructure in a climate-neutral Europe) have shown clearly, that achieving the ambitious climate targets of the Union by making use of the electricity and the gas grid in a coupled manner would be significantly cheaper and more efficient than an all-electric solution. GIE is committed to contribute to decarbonisation and hence believes that the assessment should consider all possible decarbonisation activities such as, but not limited to, Power to Gas (P2G) facilities, Biomethane plants, Energy Storage, CCU and CCS (Carbon Capture and Use – Carbon Capture and Storage) technologies and CNG/LNG filling stations for transport. P2G will play a crucial role not only in balancing fluctuating electricity supply from renewable sources but also in the process of integrating more and more renewable energy sources to all energy sectors. and in decarbonizing the industry, heat and transport sector via renewable gas. GIE therefore believes gas infrastructure operators should play a central role in providing P2G services. In fulfilling the current EU legislation, all market players should be given a possibility to invest during such a crucial period of the development and deployment of this technology. In order to ensure the necessary market scale-up it should be considered that gas infrastructure operators shall be entitled to own, develop, operate, and manage P2G installations in order to provide the most cost-efficient conversion services of energy carriers in a non-discriminatory way. This is essential in scaling this technology whilst gaining important experience in how to integrate these facilities into the existing energy system.

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.
GIE welcomes the increasing infeed of hydrogen into the gas networks as an important step to higher shares of renewable and decarbonised gases. GIE shares the view that there are different possible approaches towards hydrogen integration: hydrogen-only networks and blending hydrogen with methane (natural gas at a transition phase and biomethane and/or synthetic methane in the long-term). GIE supports a stepwise approach for the blending of hydrogen in gas infrastructure under the condition that it ensures a safe and reliable cross-border flow of gas while assessing the whole value chain. In order to facilitate the process close coordination between Member States and Gas Infrastructure Operators as well as increasing hydrogen-readiness of appliances and infrastructure components across Europe is crucial. The use of hydrogen either in combination with natural gas or in pure form will require further assessments on the possibilities of adapting gas infrastructure elements and end use applications, and of developing dedicated networks. Therefore, the optimal choice and pathway will be determined by a supportive business environment and local conditions.

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.

The use of hydrogen as an energy carrier has significant potential as part of the energy transition and its use is envisaged to increase in the coming years. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its growth.

Where hydrogen networks connect diverse supply and demand in a public manner, a similar regulatory frame as the one applied to gas should be introduced to ensure third party access in a non-discriminatory manner. Some nuances to the level of regulation are possible depending on the objective the regulator is trying to achieve and national circumstances. Please see the table below:

Level	Aim achieved at that level	When should it be put in place?
3	Regulated tariffs	When one wants to control the cost for the final end-users
2	Non-discriminatory third-party access	When we want open access for all parties and when the market power of the various users differs too much
1	Natural monopoly	When the size and/or the risk of the investment is so large that there is no point to double the investment and/or recognised by law

Blending hydrogen into the existing gas network will require the removal of technical barriers for cross border trade. The regulated framework already in place for gas infrastructure should be used and possibly adjusted in order to facilitate and incentivise their evolution towards future-proofing assets.

As the use of hydrogen increases in the future, development costs can be reduced using the existing infrastructure, by adjusting or converting some parts of the existing gas infrastructure into a hydrogen ready network and storage, or blended hydrogen/methane network and storage with higher concentration of hydrogen. Conversion from methane to hydrogen will take time, R&D and investments for future proofing existing infrastructure will need to be carried out. These investments will have to be taken into consideration by NRAs and appropriately incentivised.

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.

'Technology neutrality' is needed for the efficient development of a decarbonised energy market and regulation, or support schemes should not favour one technology over another. The principle of "cost efficiency" can also be seen in setting cost reflective grid charges that recognize the contribution of gas transmission and gas storage systems to avoid investment in the electricity infrastructure. It is important not to see cost efficiency with an only short-term perspective but should rather focus on the long-term cost efficiency of decarbonisation technologies. The current 'silo' approach should be moved towards a more holistic view in optimization of an investment planning across the entire energy system.
Besides cost efficiency, other criteria like security of supply, diversification of sources, peak demand, societal and environmental impacts and future potential of the technology should be considered. All technologies that contribute to the decarbonisation of the energy system should benefit from the same kind of treatment assuring a level playing fields between all technologies and all energy carriers. P2G allows under a technology open approach to store large quantities of energy derived from renewable electricity in existing infrastructure over long period of time in the most cost efficient and social accepted way.
It's also important to look beyond the 'cost-efficiency' and focus on the values that gas infrastructure operators deliver. These values include flexibility, transport, system insurance values as well as enabling the delivery of different kinds of renewable energy sources at an earlier stage.

Q5 Which role do you see for power-to-gas infrastructures?
GIE believes that providing for storage, transport, peak capacity and flexibility needs is the one of the key values brought by gaseous energy carriers and associated infrastructure. P2G and hence the gas infrastructure are key elements for accelerating the energy transition and reaching a decarbonized economy in the most cost-effective way. GIE shares the view that the key role of P2G in coupling electricity and gas systems as well as between important demand sectors. Through sector coupling, gas infrastructures to transport and store gas can be leveraged to provide flexibility to the power system and transport renewable and decarbonized gas through the gas network. P2G has a number of benefits: •It facilitates sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner. •It allows the maximisation of the renewable electricity production by converting renewable electricity to renewable gas, which can be injected into the existing gas system and used in all sectors. •It contributes to better functioning of the energy market by reducing the occurrence of negative/very low prices on the power wholesale market and enabling the development of additional market-based renewable electricity generation whilst providing a renewable source of gaseous energy. •It eases the balancing of the power grid by providing both up and downwards operational reserve and will contribute towards the reduction in electricity grid congestion. •It allows for the storage of large quantities of energy derived from renewable electricity in existing infrastructure over long period of time. •It improves security of supply in an entire coupled energy system based on electricity and gas infrastructure. Since P2G will also facilitate the storage of renewable electricity via renewable methane or renewable hydrogen and thereby provide an important system value, it is important to also assess the services and valuation of storages in a coupled energy system in parallel with the development of P2G.

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?
Electricity grid charges have a substantial impact on the overall cost and profitability of P2G plants. By using energy conversion services and the underlying gas infrastructure, additional investments in the electricity grid might be avoided. This system value provided by the gas infrastructure to the future energy system needs to be reflected in the regulatory framework. Hence, the principle of cost reflectivity in setting grid charges should be extended to recognize the contribution of energy storage systems to avoid (i) electrical grid constraints and grid extension costs and (ii) curtailment of intermittent renewable electricity generation. In particular no additional levies and taxes should be applied to any energy unit transferred from one sector to another. The remuneration would enable electricity users to capture the full value of transport and storage capacity provided by the gas infrastructure and their potential for a decarbonized coupled energy system. The regulatory framework should then allow an adjustment to electricity and gas network usage tariffs that would enable to receive cross-sectoral benefits.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legal and regulatory framework in place was designed without having in mind P2G technologies and the handling of increasing shares of hydrogen in the gas mix. It is, therefore, necessary to adapt the current framework to enable the scale up of renewable energy in the gas sector and to gradually align the network planning for gas and electricity. Key cost drivers in operating P2G plants are the electricity price, electricity tax, renewable levies, electricity grid fees, CAPEX of plant and utilization hours. Currently many P2G plants need to pay the renewable levies, even though they are a renewable energy production. P2G plants in many countries are classified as final customers and have to pay high grid fees as well as levies and taxes although they usually alleviate the grid and are complement to grid development. Grid charges have a substantial impact on the overall cost and profitability of energy storage devices if one compares them to total operations and maintenance costs. From pilot projects operators learned that there is significant and immediately visible potential for deceasing in costs resulting from an increase in production quantity (economies of scale). See for more details GIE paper on “Barriers to gas and power sectors coupling” where FTI-CL Energy has been commissioned by GIE to conduct a review of some of the key barriers to sector coupling based on personal interviews with market participants. This paper is an Annex to the GIE paper on policy recommendations on Sector Coupling and includes the results of this survey and can be found under https://www.gie.eu/index.php/gie-publications/position-papers It is important that the regulation provides the possibility to transform a green energy source into another green energy source in the best possible manner. The reason for this is a need to ensure that the energy source can stay “green” through the entire value chain from production to end consumer. For example, if you want to produce green hydrogen from green power via electrolysis, perhaps store it, and then further develop it (by use of CO2, Nitrogen) and/or deliver it to an end consumer. The problem can arise if you use the power grid and not all power production is 100% green at all times. If you want to preserve the energy as 100% green because this has the highest value the regulation should make it possible to use traceability tools, digitalization etc. to prove that you only use green power and therefore the outcome of the electrolysis process also should be considered 100% green.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
A methodology on trading at platforms which enables trading renewable and decarbonized gases is needed in order to create a Europe-wide market. The cross-border trade of GOs for renewable gas should be supported by ensuring 'interoperability' of different GOs. In this sense, 'different GOs' stand for different energy carriers (e.g. gas, electricity) and different issuing bodies. Interoperability would manifest itself by way of the following two mechanisms: •All GOs need to be convertible from one energy carrier into another when such conversion is physically taking place. •The national issuing bodies for different energy carriers are encouraged to work towards setting up clear and recognisable schemes for all GOs. These schemes can then be interoperable since they are based on the same widely accepted rules. These schemes include criteria and processes for recognition by every issuing body of GOs issued by every other issuing body – to allow the transfer of GOs. Any double support for the same MWh produced must be avoided. Additionally, a European-wide solution for the above-mentioned cooperation could be established. GIE also supports the establishment of GOs for energy from "non-renewable" energy sources that have a positive impact on the reduction of Green House Gas (GHG) emission (e.g. decarbonised/low-carbon gas), as in the terminology of the recast Renewable Energy Directive (RED II), which allows Member States to put this option in place

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?
Instead of copying the solutions from the renewable electricity to renewable gas, we should work towards being able to convert GO from one carrier to the other carrier. Lessons learnt from the electricity sector include the necessity of a common understanding of data that should be included in the GO and certificate. All GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements. To that end, the common understanding of concepts and corresponding terminology is needed. Additionally, when designing common data requirements for all GOs, it is important to pay attention to operational aspects, such as data format, data fields and data protection. It is important to stress that a European GO system for renewable and decarbonized gases would prevent any disruption in the cross-border tradability of renewable and decarbonized gases. If such a European system cannot be reached, mutual recognition of national certificates/GOs needs to be ensured to support the cross-border tradability of renewable gases. Lessons learnt from renewable electricity also underline the importance of avoiding any double support between an EU-wide GO system and MS support schemes.

Infrastructure Investments and Regulation

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?
Gas and electricity TSOs are best experienced to provide quantitative European focused scenarios on the impact of the energy transition on the European electricity and gas infrastructure needs and challenges for the long-term horizons. GIE welcomes all efforts that have been made to provide a view on many elements e.g. energy demand, prices, technology developments, etc. jointly between ENTSO-G and with ENTSO-E. GIE supports a holistic approach to the energy system in order to ensure consistency and capturing all the interactions between all energy sectors including the storage and LNG infrastructure. GIE representing all infrastructure areas in gas is already involved in the Scenarios Development ensuring transparency and impartial treatment of all stakeholder feedback. For example, TYNDP 2018, new market features such as infrastructure tariffs were introduced for the modelling. GIE (LSOs and SSOs) provided all necessary input on storage and LNG tariffs. The regulatory framework shall also consider more flexible approaches based on practical examples as recently demonstrated by Gasunie together with Tennet. This assessment shows that not only the electricity, but also the existing gas transport infrastructure in Germany and the Netherlands will play a crucial role in the future energy systems. Above that, it shows that although electricity storage will be widely available by 2050, only the gas system will provide a solution for seasonal storage in a system based on solar and wind power. The whole report (with detailed analyses of The Netherlands and Germany) can be found here: https://www.tennet.eu/fileadmin/user_upload/Company/News/Dutch/2019/Infrastructure_Outlook_2050_appendices_190214.pdf With regards to ACER (and NRAs) role, it is the view of GIE that ACER and the NRAs already play an important role in the TYNDP process. The framework and process for the TYNDP defined by regulation (EC) 715/2009 has proven to work very well and there is currently no need to adapt. The current framework under 715/2009 provides important recommendations to improve TYNDPs while still preserving an open, transparent and non-discriminatory process towards all stakeholders. The ENTSOs already assign a primary role to ACER and evaluates with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements.

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)?
GIE views, that the two processes – Incremental Capacity and PCI projects – are supplementary. Whereas Incremental Capacity is a process to ensure market-based investments, PCI projects are important mainly for other reasons like security of supply or supply source diversity. Additionally, a market-based investment via the Incremental Capacity process, supported by a positive economic test, can receive PCI-status in case the conditions are met and the settlement of f-factor within the Incremental Capacity process can also incorporate external effects of PCI projects. Besides, the market test which is a pre-condition for CBCA or financial support could be done in the framework of Incremental Capacity. Nevertheless, if the project promoter has gone through the Incremental Capacity process included in CAM NC, the outcome of the process should be valid as the market test necessary for the CBCA or financial support. However, in order to better manage the balancing of supply and demand of energy, GIE recommends establishing institutionalizing at EU and national level communications schemes between electricity and gas network operators. The focus of PCI projects should be enlarged to projects delivering the potential benefits of sector coupling. In doing so, the current 'silo' approach should be moved towards a more holistic view in optimization of an investment planning across the entire energy system including also the storage and LNG infrastructure.

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?
GIE welcomes European Energy Regulators view on taking a very cautious prudent approach with relation to decommissioning choices and agrees that there are no reasons to act in the near future. An energy system with higher shares of renewables a sufficient flexibility and balancing capabilities. Security of supply will be guaranteed through the inherent resilience and flexibility of the gas infrastructure and gases will continue to be the main provider of energy on days of normal demand as well as during periods of seasonal peaks when electricity supply cannot meet demand. Flexibility and transport capacity provided by the gas infrastructure to balance the variable renewable electricity supply will be valued as increasingly vital since power is more and more generated from renewable energy sources. Using the existing gas infrastructure to deliver and store increased quantities of renewable and decarbonized energy, avoids the built-up of new electricity networks, will result in significant cost savings. Therefore, GIE recommends focussing on how to maximize and ensure an efficient use of gas infrastructure during the energy transition and beyond and on the right regulatory framework where existing gas system infrastructure plays a vital role in the energy transition and beyond rather than focus on stranded assets. Without any proper assessment of the needed storage and transport capacity and an adjustment of the regulatory framework, there is a risk that important infrastructure needed for a coupled energy system may become unavailable in the wrong location, putting at risk the resilience of the energy system as a whole and the potentials for decarbonisation of a coupled energy system. General note on sector coupling, let's not to forget that in Europe, unlike in other parts of the world, the new paradigms such as sector coupling and sectoral integration can be discussed and developed precisely because there is a mostly well-meshed, diversified and developed gas system with large-scale storage solutions and a well-developed pipeline system.

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?
GIE supports the view that with the realisation of a more coupled energy system based on the electricity and gas infrastructures there is high probability that gas and gas infrastructure will play the significant role in the future transition of energy systems. It is premature to discuss the development of a formal decommissioning framework. Efforts should focus on how to maximise and ensure an efficient use of the existing gas infrastructure during the energy transition and beyond. In a point of time, where the future becomes increasingly clear, it may make sense to further develop on the current CBA methodology to meet the future challenges. GIE recommends considering the impact on security of supply and market functioning in all affected Member States and to take into account effects to the entire gas system, including storage and LNG infrastructure.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The current gas legislation provides a sound basis for ongoing development of an integrated gas market. Implementation of the regulations is almost complete and the impact on market development is already providing significant benefits, e.g. with better price convergence on many hubs, improved market liquidity and prevention of congestions and their management. The implementation of the current legislation has already had a clear positive effect in many market areas, resulting in liquid and functional market places, as indicated in ACER's Market Monitoring Report (MMR) in 2018. There are a number of EU gas markets that are mature. Where gas markets have not fully developed and are illiquid and still not fully functional, targeted measures that address the specific market needs should be considered. On this topic, GIE understands that the EC intends to launch a study of the possible need for tailor-made regulation. As stated in ACER's MMR in 2018, some MSs do not have all the building blocks of a functioning hub system in place, i.e. they display low liquidity and/or a persistence of bilateral deals. EU-wide measures should only be considered where there is strong evidence of an EU-wide problem. In addition, GIE would like to underline the possible issues outside of the NCs that need to be addressed, e.g. homogenous shipper licencing arrangements. This could contribute to the improvement of the EU internal market. Therefore, the focus should be on fully implementing the current legislation and where issues or problems are identified, additional measures could be considered. On storage, wherever the current framework does not already recognize/reward the full value of the underground gas storages, GIE supports an evolving EU regulatory framework that enables to move to market-based pricing, in order to achieve efficient gas storage, use in a level playing field. The future gas market design needs to ensure that value of positive insurance and system externalities created by gas storage are assessed and adequately captured in the regulatory framework. The incorporation of renewable and decarbonised gases into the current market design and the effective coupling of the electricity and gas infrastructures should be one of the key priorities of a new gas market design. Whether the current arrangements are not fit for purpose and additional or different measures might be needed, ENTSOG could be best placed to make available its expertise on NC developments. In addition, how to manage hydrogen within the current market arrangements needs full consideration e.g. whether creating a separate hydrogen market or incorporating hydrogen into the current gas market.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Market design barriers relate to the internalizing of the scarcity and dependability value in both gas and electricity markets. Without recognizing the value gas adds to the energy system in this new role under sector coupling, it will be difficult to attract the investment required for its progression. The scope of the gas directive should be enlarged to include renewable and decarbonized hydrogen under the current gas market design. There are also barriers with the interplay between the gas and electricity markets, such as the alignment of time frames and products. For more information GIE published a paper on policy recommendations under https://www.gie.eu/index.php/gie-publications/position-papers

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?
Current tariffs aim to reflect a balance between cost-reflectivity and market integration. Changing the tariff principles could undermine liquid trading Hubs. GIE considers it premature to evaluate the current tariff regime There are still a number of market benefits to be gained associated with the full development of the entry-exit model in the EU, most significantly the creation of liquid markets with beneficial effects for final customers. We are aware of the debate on the potential need for tariff reform, as proposed by CEER's FROG report. However, prior to considering potential changes to the tariff arrangements we need to see the full effect of the implementation of the TAR NC first. While GIE recognises that an excessively high cross-border tariff may become a “de facto” barrier to gas trade, the ‘pancaking’ effect, i.e. the cumulative IP costs for a shipper along a gas route, is a feature of the current EU gas market design and it should be considered as a normal effect provided that IPs tariffs are correctly determined. Changing the tariff regime providing less weight to cost-reflectivity would create winners and losers among network users. GIE would also like to make the following comments regarding CEER's solutions. ITC mechanisms are complex and could prize market integration more than cost-reflectivity. CEER's second suggested solution of allocating TSO costs to gas beneficiaries refers to a more global approach to gas value. Tariffs might indeed better mirror the value of a gas source, based on its market value, but also its contribution to SoS, sustainability, market integration etc. taking into account the requirements of the TAR NC. To conclude, it is too early to assess the impact of the TAR NC, which is not yet fully implemented. Once MSs have implemented the TAR NC provisions, especially with the application of the new tariff methodology principles and transparency requirements, it will be relevant to reassess the TSO tariff regime. At this stage, reform proposals can be premature and might disrupt the ongoing implementation of TAR NC. GIE recommends that regional initiatives for voluntary market integration also continue to be taking into account with regards their potential negative effects on the overall European market integration, such as cost reflectivity issues.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
To assess the impact of cross-border tariffs on cross-border trade, ongoing monitoring of the markets is needed. As tariffs develop, the impact on cross-border trade needs to be assessed. If there are general trends that suggest a deterioration in cross-border trade, then an Impact Assessment according to the current process of revision of Framework Guideline and Network Codes process can be considered.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Storage challenges needs to be addressed in the future gas market design: From a storage perspective it appears that the situation of non-regulated TPA gas storage market is lacking. Storage System Operators (SSOs) find themselves in a situation which requires them to compete with price signals that are below the costs they incur to operate and maintain their facilities. If the current market situation persists, it would put at risk at parts of the storage industry and harm the security of gas supply in Europe. Additionally, we believe that the relevance of imported renewable and decarbonized gases will be increase substantially in the future and therefore the regulatory framework for the import of these gases should be considered in an upcoming legislative overhaul.

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Contact details and treatment of confidential responses

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CEEP

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The boundary between the TSO/DSO's core activity and the provision of other services must be drawn clearly. Where activities are open to competition, the TSOs/DSOs should not be allowed to be active in that area. Nevertheless, in order to facilitate better outcomes in circumstances where the market cannot (yet) provide the activity, there should be exceptions under regulatory control. This general approach must be applied to ownership by TSOs/DSOs of P2G-installations and / or CNG-filling stations. Nevertheless, given the technological-neutral approach of DSOs, they should be allowed to participate in research projects as long as no functioning markets are established. Generally, new technologies, which are still in the development phase, should not face over-regulation. Concerning Power to Gas, CEEP considers that even if this activity shall potentially be opened to competition, the technology is not yet mature and has some difficulties to find its business model. Therefore, subsidies could be needed to bring this technology to the market. The potential subsidies should be strictly regulated by the next "gas package", limited over time and the associated costs should be clearly identified. The vital role of TSOs and DSOs as neutral market facilitators means that they have to be included in the process of regulatory reform is central since network standards and conditions can differ significantly between member states but also within regions. The input of DSO experts is highly valuable and necessary when new technologies are tested or technical norms are adapted (at the local, national, European level). Special attention should be paid to the generation and supply of renewable gas and biogas and the respective roles of actors. Generally, DSOs are important guardians of technical standards. When it comes to the feed-in of biogas into the grid, the responsibilities have to be clearly distributed. The cleaning, processing and compression of the gas must remain within the producer's responsibilities. The DSO is responsible to monitor if the quality of the feed-in biogas meets the quality criteria.

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.
The technical feasibility of injection of large volumes in the existing transmission and distribution gas network is yet to be established as technical standards differ significantly not only between Member States but from (local) grid to grid. Depending on the topology of the grids, on pipeline materials, on instrumentation, on end-user devices and appliances, on safety requirements, the cost of blending at a normative level may be prohibitive. That is why it is too early to set a specific goal or threshold for H2-feed-in. Not all gas networks are capable of carrying the same amount of H2 in their grids. Further, many products of end-users are not made for a higher H2-infusion. It should be prevented that end-user entail negative consequences due to a too high infusion of H2 in the gas grid. Therefore, a gradual increase of the amount of H2 in the gas grid in close cooperation with (local) gas DSOs is necessary. Further, manufactures of end-products must also be obliged to produce devices that are capable of enduring a higher percentage of H2. For all these reasons, it is difficult to predict a certain timing for the blending of hydrogen in the gas network. However, certain prerequisites are definitely needed to trigger the development of a hydrogen market Flexibility should be kept to allow Member States to choose the best conversion solution on local analysis of TSO/DSO networks.

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.
In general, the focus should be on the use of existing gas infrastructure for the transport of H2 over the creation of a costly new one. Synergies should be used where possible, which is obviously the case here. Certainly, this does not refer to H2-grids for (private) industrial purposes that are already existent or rather, H2-grids that are utilised to induce certain percentages of H2 into the local gas grid. If H2-grids exist / develop they should certainly be obliged to follow the same rules and obligations as the gas grids do. H2 infrastructure should be operated under the same rules as gas grids. Parallel competitive areas which share the same customer market, but are disposed to different regulation, would automatically lead to market distortions.

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.
Most new technologies are today not economically viable or cost-efficient. The market should be designed to give the right economic signals, taking into account the positive or negative externalities.

Q5 Which role do you see for power-to-gas infrastructures?
Power to Gas (P2G) will certainly play a role in the future energy system. CEEP is convinced that an all-inclusive approach, in which all sectors work closely together, is necessary in order to reach the net zero CO2-emission-target in 2050. Developing a sustainable gas and electricity market will be key to this goal. A further electrification of the system, especially when it comes to individual mobility (cars) and heating and cooling is important and beneficial but will not be enough to meet the emission reduction targets, especially not in heavy-duty-transportation and in some industrial processes. Moreover, for cooling and heating, electricity will also not be sufficient enough particularly in urban areas where district heating and cooling systems play an important role. As a general principle, CEEP supports that the decarbonization process in the energy sector must be cost-efficient for all sustainable technology types. Therefore, sector integration and sector coupling must play a greater role in European policies. As underlined by the European Commission in its long-term Strategy, it means that stronger connections must be made between the electricity sector, and other sectors as heating, transport, industry and gas. For the latter, innovative technologies such as Power-to-Gas (P2G) will link the sectors together. In this respect the existing distribution gas infrastructure (DSOs) will likely play an important role especially in reaching the goals in a cost-efficient way.

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?
If public support is needed to prepare the deployment of power to gas technologies, to support future very high shares of RES in the electricity mix, this public support should be direct (direct subvention for instance) to ensure visibility and avoid distortion for other grid users, while being adapted to the maturity of relevant technologies. Electricity and gas tariff systems are not a tool to subsidize development of new technologies but they must be designed taking into account all uses of the networks including those from P2G installations.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
In order to unleash consistent synergies between the different sectors the right technical, legal and commercial framework conditions have to be established.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
In the course of the revision of the rules for the gas market, the development for a cross-border trade regime with GOs with renewable and/or low carbon gases should be pursued. After an analysis of the gaps between the different support mechanisms in the different Member States coherent standards should be envisioned. Common definitions should be adopted for renewable and low carbon gases. CEEP remarks that a lot of terms are currently being used (green hydrogen, blue hydrogen, grey hydrogen, green gas….) which adds to confusion given that there are a lot of different technologies to reduce the CO2 footprint of gas and hydrogen. As regards to the operational implementation of renewable and/or low carbon gas GO systems, CEEP considers that the following measures can foster efficient cross-border trading of renewable/low carbon gas: • Any double counting of renewable and/or low carbon gas should be avoided to ensure the credibility of the system. Special attention should be paid to conversions between different energy carrier GOs, for instance : o between electricity GOs and hydrogen GOs in case a stakeholder wants to certify electrolytic hydrogen, o between biogas GOs and hydrogen GOs in case a stakeholder wants to certify hydrogen produced with an SMR biogas. • Member States should be encouraged to issue GOs both for renewable and / or low carbon gas produced whether it is injected in the gas grid or not. This will kickstart the development of a market with enough volumes, and ensure a level playing field between producers and investors in different Member States. • Renewable and/or low carbon gas GO national registries should be interfaced and in each Member State and the mandated organization in charge of operating registries should use standard systems and procedures which aim at objectivity, non-discrimination, transparency, avoidance of double–counting and costs effectiveness. Such harmonization will facilitate the exchange of guarantees of origin, both within EU and between EU and third countries. • Member States should harmonize deadlines for issuance, cancellation, expiry of renewable/low carbon gas GOs to allow market players to have clarity, predictability and the ability to trade across the EU in a uniform manner. • The information required in GOs from smaller installations should be commonly defined. Although RED II allows simplified information in GOs for smaller installations, GO needs to remain a fact-based instrument and seen as an undisputed representation of the actual MWhs produced by a production device, regardless of size. • According to RED II, Member States must recognize guarantees of origin issued by other Member States. In case of refusal, the European Commission should ensure openness and transparency in this area by publicizing any notifications of refusal it receives in a timely manner, followed by its final ruling as to whether it upholds a Member State’s reasons for refusal. Furthermore, the following points are important: a marketplace and clearing house for the trade of such GOs, similar to the trading of CO2-certificates and total price transparency regarding buying- and selling-offers.

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?
In general, the current renewable electricity GO system appears to be a well-designed and suited tool, as it constitutes a guarantee of reliability, while also enabling “green offers” to develop for consumers having a willingness to pay a premium for it. It should be recognized that the purpose of GOs is “disclosure” and not “support”. To avoid confusion, it should therefore be preferable to clearly distinguish support mechanisms and GOs and make sure that “windfall profits” do not arise when RES production benefits from both a support scheme and the sale of corresponding GOs. RED II has not retained the CO2 footprint among the minimum information to be included in the GOs. However, CEEP considers that as long as GOs do not carry the value of associated carbon emissions, a piece of the puzzle is missing, as consumers may not find it meaningful to purchase a renewable/low carbon gas product if the carbon content is not clearly mentioned and specific to that product. While GOs currently is the instrument that empowers customers to make active choices for the energy transition, the incentive would be much stronger if carbon was included in the picture. Such approach has been retained in the European project CertifHY, funded by EC FCH JU, whose aim is to design the 1st EU-wide Guarantee of Origin (GoO) pilot scheme for renewable and/or low carbon hydrogen. The introduction of a CO2 criteria in hydrogen GOs also allows: • To recognize the role of non-renewable but low carbon hydrogen to reduce EU GES emissions in a cost-effective way. Under CertiF’HY, hydrogen productions installations can be eligible to GOs if they display a carbon footprint lower than 131 gCO2eq/kWh, whether hydrogen is renewable or not. This is in line with RED II, which opens the possibility to establish GOs for non-renewable energy sources. • To make a clear difference between carbon neutral and renewable. As an example, renewable hydrogen produced with biomass as an energy source doesn’t show a zero CO2 content. This applies to biomethane which already benefits from GOs in some countries while its CO2 content has not been definitely established. Such displayed CO2 should be consistent with commonly agreed international standards/recommendations, such as the GHG Protocol Scope 2 Guidance.

Infrastructure Investments and Regulation

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?
ACER and NRAs should be more involved over the TYNDP process, in particularly for the elaboration of scenarios. ACER and NRAs should monitor that at least one scenario takes into account the energy policies of each Members State.

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)?
CEEP considers that the selection process for projects of common interest (PCI), and in particular the process for awarding financing, should be modified. It is clear that, today, many PCIs and associated financing decisions are not based on technical criteria and cost-benefit analysis results only. Projects should be reviewed when all data are available, with a robust cost-benefit analysis. A general scheme at European level would be necessary: •Projects selection, CBA when the project is at a sufficiently advanced stage, and proposal for sharing costs and congestion revenues. •The decision by each regulator approving the costs that would be covered by tariff. •Comparison by the European Commission of all the projects according to the ratio "amount of subsidy requested to balance the budget vs expected benefits of the projects". The lowest ratios should be prioritized in granting subsidies and any derogation should be duly justified. It should be possible to integrate the projects in the list but only to benefit from the administrative facilities from the beginning, without prejudging the financing decisions, which would intervene later in the process when all the information is available for a sufficiently robust ACB. CEEP also considers that the criterion of common interest should be made clearer. In addition, the perimeter of the PCI should be expanded to take into account the evolutions in the energy market, with a specific focus on storage or projects of digitalization and / or harmonization at European level that generate a benefit at the European level.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
CEEP shares CEER's view that "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". Therefore, the gas market design should support gas to become progressively carbon neutral in order to play a role in a carbon neutral economy. The development of renewable gases should be achieved at the lowest cost (incl. potential re-organisation of the gas value chain). Carbon-neutral gas will play a role in the future energy sector whereas special importance should be attached to the generation and supply of renewable gas and biogas and the respective roles of actors. Generally, DSOs are important guardians of technical standards. When it comes to the feed-in of biogas into the grid, the responsibilities have to be clearly distributed. The cleaning, processing and compression of the gas must remain within the producer's responsibilities. The DSO is responsible to monitor if the quality of the feed-in biogas meets the quality criteria. Promising innovations that link the gas and electricity sector together – such as power to gas – are not yet economically viable and the few existing installations are mainly pilot projects. In order to kick-start new innovative solutions, TSOs/DSOs should have the right to be involved in research activities as long as no market exists. A gradual increase of the amount of H_2 in the gas grid in close cooperation with (local) gas DSOs is necessary. Furthermore, manufactures of end-products must also be move to the production of devices that are capable of enduring a higher percentage of H_2. EU-rules must lead to a fair level playing field and must not to promote one actor over the other. For instance, the SOS regulation: in this regulation member states with storage facilities have to provide cross-border help in the case of an emergency and are, currently, bearing all the costs. It should be discussed how such emergency mechanisms could be implemented in a more balanced way.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Subsidies will be needed to develop renewable gas. In the power market, the development of subsidized production has put downward pressure on hub prices and has jeopardized the profitability of other assets, which can lead to security of supply issues. Similar problems should be anticipated for the gas markets. It is important that „renewable / green gas“ will be accepted by the consumer and, therefore, a good communication – similar to “green electricity” – is key. So, gas can be stored in storages and in the grid (linepack) and used when needed. Therefore, the role of DSOs as market facilitators for all energy carriers has to be emphasized.

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?
Over the long term, gas consumption is expected to decrease, which will necessarily lead to increase the unit cost of the transport network. The current network tariff methodology might not be sustainable.

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

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
The definition, deployment and application of a CBA approach integrating long term effects is of utmost importance to ensure consistency in energy investments in the EU, preventing stranded costs. All decarbonization EU scenarios show a substantial decrease in gas consumption, a decrease which should be accounted for in defining future regulatory measures.

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Contact details and treatment of confidential responses

Contact details: [Organisation][]
Energie-Nederland

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

General remarks

Energie-Nederland welcomes the initiative of CEER to consult stakeholders on regulatory challenges for renewable gases. The consultation poses very relevant questions about future regulation. The merit of this consultation is opening this debate and to stimulate thinking about possible answers. Given the state of development it may be too soon to reach firm conclusions on all issues. It is important however to stimulate the thinking and understanding of these issues.

The focus of CEER in its consultation paper is on the regulatory challenges for renewable gases. We advise however to broaden the focus: in the energy and climate transition a broader spectrum of new gas carriers may emerge. This may include decarbonised gases as for instance “blue” hydrogen. We recommend CEER to develop a clear definition of “new gases” and which energy carriers fall under this heading, such as renewable, decarbonised and low-carbon gases.

These different types of new gases may develop hand in hand in the transition towards a fully decarbonised energy system depending on cost effectiveness, stage of the transition and function in the system. A fair competition between them on a level playing field contributes to a cost effective and successful transition. Regulators should promote this competition and enable a level playing field.

Finally, our input to this consultation is based primarily on a Dutch perspective and reflects the current status of hydrogen and renewable gas developments in the Netherlands.

Section B – Regulatory challenges for renewable gases

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

• The guiding principle for involvement is that TSOs and DSOs in principle should refrain from activities where the market can provide solutions. The conceptual tool developed by CEER is useful to identify activities which TSOs and DSOs can undertake naturally and where a possible role may exist under certain, limited conditions.
• A key question in the proposed tool to assess if and where network operators are allowed to be active concerns the status of market development. If this would not be the case activities by TSOs/DSOs could be allowed when justified.
• At this point we remark that a very important element is missing in the proposed framework. When the market for certain technologies or options currently is under-developed, a role for governments emerges. By providing incentives to the market (e.g. through subsidies or other instruments) government policies can and should help to develop technologies and their deployment in the market. This policy approach is to be preferred over a route where governments refrain from their role and market development should come from start-up activities by network operators.
• We see the following potential involvement of network operators:
o The most logical TSO/DSO involvement relates to providing a transport and distribution infrastructure when and where this is needed.
o Power-to-Gas activities should be considered as competitive market-based activities without any role for TSO/DSO involvement. Power-to-Gas installations have similar characteristics as any other plant in the electricity market. Building and operating these installations is a core market activity. Allowing network operators to build and operate Power-to-Gas installations would give TSOs/DSOs an opportunity to become actually involved in the electricity or gas market, while this role is not by any means required for the operation of networks. While the market for Power-to-Gas might be underdeveloped at this moment, there are other ways to address such issues than allowing a role for network operators. Governments can and should step in to develop the market by public funding of technology development and by incentives (e.g. subsidies or other instruments) to overcome current financial barriers in the market.
o For other activities such as storage a (limited) TSO/DSO involvement may be appropriate when specialised know-how is required and a functioning market does not yet exist due to low market interest which cannot be solved by government policies to stimulate market development. Appropriate involvement can include experiments and pilot projects. The aim of this involvement should be to incentivize the market until a functioning market starts to develop. A TSO/DSO could be able to invest in such projects, but under clear conditions:
- Projects are experiments, pilots and demonstrations and are preferably carried in cooperation with market parties
- The role of the TSO/DSO should be limited to the investment. Operation of the project should be done on behalf of market parties. The TSO/DSO is not allowed to become a market participant itself or take a financial position in the market by operation of the project. The capacity of the project should be made available to market parties
- Services provided by the TSO/DSO to market parties should be based on clear and reasonable costs
- An exit strategy from the project by the TSO/DSO should be defined when a functioning market is within reach

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.
• Unclear if this a question about technical possibilities or mandatory blending • Setting a threshold for blending of hydrogen will depend on a number of factors: Which level is technically safe for specific parts of the transport and distribution system in various countries What is the availability of blue or green hydrogen in countries across Europe at a given future date and how will this develop into the future Is the available blue or green hydrogen bought and used by certain specific users or sectors (served through dedicated infrastructure) or is it sold in a blended form to all customers What is the most cost-effective approach considering both short and long-term Will blending help to accelerate a transition from natural gas or may it preclude a full switch to hydrogen at a later stage • In our view it is difficult to provide a clear answer now. Different strategies and approaches for the development of hydrogen are available. The current approach in the Netherlands to develop hydrogen is to focus first on use in larger industrial clusters which are served by a dedicated hydrogen infrastructure. A blending strategy which might serve in particular residential customers is not yet foreseen in the coming decade. More experience and further development is needed in our view before a decision on setting a threshold can be set • If a target for blending is set, then it should be preferably one target for all decarbonised/sustainable/green gases.

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.
• The step towards regulating hydrogen networks should be set when such a network starts to develop and it has reached a certain scale, feed-in points, customers and volume. • The regulation of the gas market can be followed for hydrogen. This would allow for other gasses a similar regulation (when shipped on regulated transport networks) and ensure a level playing field. It will also set clear rules and provide the appropriate protection for a new emerging natural monopoly. • In the mean time national regulators may consider to use the current electricity and gas regulation to oversee appropriate TSO/DSO involvement.

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.
• In principle, the market should lead to the lowest cost situation. However, when market failure takes place this might not be the case and interventions may be necessary. This can happen in situations with natural monopolies – such as networks. • Another situation is when market mechanisms do not lead to the desired investments in assets. The first preferred policy option to ensure that investments in new developments take place is that governments create incentives through energy and climate policy. A second best option is that TSOs and DSOs temporarily facilitate new investments until the market picks up and an exit from TSO/DSO involvement can follow.

Q5 Which role do you see for power-to-gas infrastructures?
• Power-to-gas will play a role in order to reduce the curtailment of renewable electricity production and to provide seasonal flexibility by storage of renewable electricity. Large amounts of renewable electricity may lead to situations in the future, where market demand otherwise couldn't cope with available electricity production. Converting excess power to gas will help to manage this situation and prevent curtailment. Pricing should be market based and power-to-gas should compete equally with other flexibility options, such as demand side management, international electricity exchange and curtailment. • Power-to-gas could also prevent curtailment in situations where the electricity network is not able to distribute renewable energy from production centers to demand centers (for instance form north to south Germany or from the North Sea to the mainland). In such cases, transport of hydrogen gas made from the renewables might be a better alternative. Power-to-gas should be based on a market solution and solved by congestion management systems (and price signals).

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?
• Power-to-gas should be regarded as a regular electricity customer for which in principle the regular electricity tariff structure should be applied. An exemption should be possibly made for energy and/or carbon taxes to avoid double taxation. • Flexibility services supplied through power to gas technologies should be enabled and valued on the specific markets the services are targeting (demand response, capacity markets, reserve). Network tariffs should be used to cover network costs only and not interfere (disturb) the market of flexibility services.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
• Power-to-gas will be subject to both electricity and gas regulation and network codes with different requirements. This may possibly lead to issues concerning differences between physical characteristics of the power and gas systems and respective applicable legislation.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
• The implementation of a trading system for renewable guarantee of origin can be a pivotal instrument for the development of renewable gases. • A European-wide system enables transparent and trustworthy trading across borders. This includes standardisation of certificates, definitions and procedures of national registries • Certificates should be clearly defined to which type of renewable gas they apply. Certification should extend beyond renewable gases also to other “new” gases, such as blue or green hydrogen. Differences in type or quality should be clearly labelled on the certificate. This would allow the market to set different prices depending on quality • We refer to ERGaR’s website

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?
• See answer to question 8.

Infrastructure Investments and Regulation

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?
• No answer

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)?
• Assessments for the need for new infrastructures should be carried out in a coordinated and hybrid manner between electricity and gas TSOs. • The assessment should address assess if (subject to the technology becoming mature and commercially available) or how gas-to-power interactions are able to provide an appropriate answer able to meet the demand (whether it refers to flexibility, security of energy supply or to congestion lifting). • Coordinated approaches for grid planning networks management and identification of investment needs are important to avoid costly grids reinforcement and to ensure a cost-effective and optimised management of existing infrastructures.

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?
• Yes, there is a risk for stranded assets. For parts of the current infrastructure the remaining economic lifetime may be longer than the lifetime these parts may be used to serve customers due to the foreseen phase-out of natural gas in order to meet long-term climate goals. • A first step to avoid stranded assets is to apply a planning and policy approach for phase-out of natural which takes into account the remaining lifetime of assets. This implies a coordination of energy and climate policies with the management of gas network assets. Such strategies should be aimed at preventing unnecessary re-investments in gas infrastructure where possible and promote timely investments in alternative solutions which lead to CO2 reduction. In particular, in the residential sector this coordination of policy and asset management can be helpful to reduce the risk of stranded assets. • A second step to avoid stranded assets is to find alternative forms to use these assets, e.g. for the transport and distribution of hydrogen or renewable gases. • Finally, an appropriate regulatory tool would be to move back to tariff regulation instead of allowed revenue regulation. This would offer the TSO an incentive to remove stranded assets in a timely way, unless these assets can be used and paid for by users of renewable gasses.

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?
• The involved NRA’s should work better together to solve such issues. • Some sort of market test should be used. E.g., if capacity bookings are below a certain threshold during a duration of x years, a mechanism could be used to ask market participants for interest in future use of the asset in question. • It should be checked if there are alternative infrastructures that could be used for the same purpose, or alternative products that could be shipped through, avoiding the need for (full) decommissioning

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
•Gas market design should focus on providing cost-effective solutions •Market design should support gas to become progressively carbon neutral in order to play a role in a carbon neutral economy. Therefore, market design should allow for “new” gases to be supplied and traded on an equal footing as natural gas is traded today. Where barriers for entry into the gas market exist for these new gases such barriers should be eliminated •Due to growing interdependencies between gas and electricity in Europe, consistency in the evolution of gas and electricity market design (e.g. tariff & capacity allocation regimes) should be addressed. Meaningful CO_2 price signals will also be required to sufficiently incentivize full decarbonisation •Ensure the development of renewable gases at a lower cost (reorganisation of the gas value chain)

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
•The basics of the current gas market design can be used to include the development of renewable gases. •The principle goal should be that “new” decarbonised and renewable gases can be supplied and traded on a level playing field with natural gas as part of the gas market. Possible barriers for entry (e.g. in the form of undue technical requirements) should be eliminated

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?
•First, we note the current regime works rather well. We also note that the share of long-term bookings has already diminished. •However, we also note that under the current regime tariffs can increase as a result of decreasing gas consumption. This could be addressed by first of all employing smart climate policy aimed at optimal, timely and cost-effective CO_2 reduction strategies. Such strategies can promote the development of new, decarbonised and renewable gases and thereby enable that (parts of) current assets remain used. Optimal and cost-effective strategies for CO_2 reduction also help to reduce the consumption of natural gas in a timely fashion. Secondly, a redesign of the tariff regime seems necessary at a certain point. Otherwise, tariffs may go up substantially when natural gas use decreases, which may lead to more customers switching away from gas and prompting new tariff increases, etc. Setting tariffs based on the regulated asset base may be a useful alternative. •Although a revision of the tariff regime appears necessary in the near future, it is difficult to set an appropriate timing of such a revision. This will strongly depend on future CO_2 reduction policies, the development of natural gas demand and of alternative solutions.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
•See Q16

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
•Possible contradictory national regulation

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Contact details and treatment of confidential responses

Contact details: [Organisation][]
Eurogas

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Eurogas agrees with CEER that 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. DSOs and TSOs play a crucial role in facilitating the development of a competitive market. Unbundling rules guarantee that network operators act as neutral market facilitators in undertaking their core functions. As such any involvement of TSOs and DSOs in competitive or potentially competitive activities should be carefully assessed to avoid any unintended consequences. It should furthermore be underlined that at no time should DSOs/TSOs trade or sell an energy product, but rather that their function may lie in building a facility and providing a service. R&D projects may help to improve grid operation and linked activities and we note that different Member States may develop different pathways. As new markets take shape, the principles above should be maintained, and emphasis should first and foremost be put on creating the policy and regulatory framework which supports the commercial development of new technologies for the production of renewable and decarbonised gases. This may require explicit support to commercial development until new technologies reach maturity and gradual phase out of support as innovation and competition drive a reduction of costs. If, however, an adequate framework to support commercial deployment of new technologies is not developed and the market is not reacting and developing autonomously because there is not enough appetite to kick-start some activities, for example power-to-gas installations, gas fueling stations and CNG/LNG/renewable gas storage, a role could be envisaged for other interested parties, including network operators, to own and develop these assets. This should be allowed only for a limited period, until a market test reveals market uptake, with potential new revenue streams linked to this market facilitator role. This role for network operators should be subject to appropriate regulatory oversight, to avoid any detrimental impact on existing and future competition, with clear principles/criteria to determine the degree of contestability in an agreed set of activities. Similar to the proposed electricity provisions in the Clean Energy Package, these new activities should only be done by gas grid operators if other parties, following an open and transparent tendering procedure, have not expressed an interest to carry out those activities. In case TSOs or DSOs develop P2G facilities, these should operate under TPA rules and network operators should not own the electron or the molecules. A regular market test should monitor whether the market situation is evolving. Furthermore exit conditions should be clearly expressed and defined in advance. We note the proposal of the CEER on a decision tree but would suggest working on an alternative which would better translate the requirements of the system and ensure a level playing field between the electricity and gas sectors

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.
To achieve the Paris commitments at least cost European gas infrastructure will be needed to transport and distribute high levels of renewable and decarbonised gases, such as H2 and biomethane, by 2050. The injection of different gases shall not endanger the existing interoperability of the EU gas infrastructure which is crucial for the integrity of the internal market. As such and considering this, the first step could be to assess the maximum blending level based on the possible hydrogen intake of grid material and appliances connected to the grid. This level could be considered as a starting point especially for the cross-border-pipelines. Higher levels in certain parts of the TSO or DSO grids might be possible according to the different materials making up the grid. Polyethylene or PVC pipelines, for instance, would be able to accommodate larger amounts of hydrogen. A close cooperation would then be required between the DSO and TSO – similar to the L-Gas/H-Gas-conversion planning – to optimize the gas being fed in. In certain areas H2 could be methanated and transformed into synthetic gas, for example with local CO2 from biogas plants, to ease the transition towards a decarbonized future. The most cost-effective solution, depending on local conditions, would ensure minimal impacts on tariffs for final consumers. In addition gas quality fluctuations in the grid outside the allowed ranges could be adjusted through filters separating H2 and CH4 molecule at the exit for example. All options would need to take into account technical feasibility in terms of end users and appliances. Over time, the latter will be replaced in any case (lifetime of 15-20 years) and new appliances that can take higher levels of hydrogen up to 100% could substitute the existing ones. These appliances which are already in the design phase should be able to operate not only in a wide range of the Wobbe Index but have the possibility – e.g. through an exchange of the burner unit - to be operated also at 100 % of H2. The gas quality according to the CEN standards should be ensured for final users by TSOs and DSOs. Therefore, the DSO will need more timely information from the TSO to inform their sensitive consumers in case of unexpected changes outside the designated Wobbe index ranges. They could be complemented by the installation of in-grid sensors that could adequately map the evolutions of quality of the blend along the grid and deliver relevant data to applications with the future possibility in the future also to provide additional information to installers and smart meters. In order to meet the needs of sensitive consumers the possibility of producing synthetic gas from methanation should also be considered to keep parts of the grid on more narrow gas quality ranges for prolonged time through stable mixtures.

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.
As the term “gas” evolves as an energy carrier, to include various molecules such as methane, hydrogen or other, the grid will accommodate gases of different types. Considering this, an inclusive regulatory framework covering different technologies may be more appropriate than separate pieces. Furthermore, for networks that aim to provide gas to a wide range of consumers from the European market at large, the idea of having a regulated regime for H2 pipelines would make sense, and as such, they should fall under the same regulatory rules as gas networks. This is particularly true for blends where it would be ill-advised to have diverse treatment for part of the mixture being transported by the pipeline. But it is also true for dedicated H2 pipes: from a market design perspective H2 is just another energy carrier transported and distributed in networks that represent essential facilities or natural monopolies. On the other hand, this should not preclude existing private pipelines which are based on specific production agreements to remain in operation in their private capacity, as long as they meet the legal requirements for exemptions from 3rd party access that apply to other energy vectors. Eurogas believes that this would facilitate market development and tradability.

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.
A technology neutral approach is by definition the least-cost approach where tenders are published and answered by interested market parties in a competitive way. Pro-active regulatory intervention can be supported only in case of a proven market failure due for example to externalities which cannot be internalised by market participants Technology specific approaches should be avoided, except if they take into account a proven overall value for the energy system. The latter solution would widely improve a business case which is not considered mature yet as outlined in the paper. Furthermore, the paper outlines the use of P2G as a conversion and storage tool for renewable electricity. We would argue that P2G would also depend on the spread between the price of electricity and gas, particularly with regards to the aspect of P2G as a production facility, particularly if its use is foreseen to be commercial. Furthermore, the “cost-efficiency” criterion should not only be applied with regards to short-term effects but should also consider the long-term development of new technologies. In particular as high upfront investment costs are often necessary to reap the benefits of a long-term cost-efficient solution. The advantages of biomethane production with regards to emission reduction, waste treatment, promotion of agricultural sustainable practices and local employment, are a case in point. As a final note, it is the mission of regulators to ensure cost-efficiency but also to work with the general public interest at the core of their decision-making; as such and even though CEER are not policy-makers, recommendations made to policy makers by regulators should have the considerations above as a priority; part of this can include a suitable regulatory framework to facilitate investments in R&D and pilot projects delivering the optimal solutions to final customer.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-gas is key to the achievement of the EU climate targets and we consider that a P2G facility has three functions: - Storing electricity as gas - Transport electricity as gas - Producing renewable gas or decarbonised gas As such a P2G facility should be seen as production/conversion tool to turn electricity into hydrogen, and subsequently potentially methanating it into synthetic gas. This tool can be used •as a flexibility service whereby P2G2P can be the end goal. Electricity production can then either be based on hydrogen or synthetic gas following methanation •can serve to convert with a view to store, particularly on a longer term/seasonal perspective that electricity storage options cannot cater for P2G is a key technology for the integration of all sectors as hydrogen or methanated synthetic gas can be used across the electricity, industrial, heating and transport sectors. With all the possibilities of the use of hydrogen we strongly challenge the message, that all energy end uses should be electrified. Indeed, recent studies have proven that an all-electric world would cost a lot more than taking a mixed technology approach and that overall resilience of the system would decrease. The situation in the UK last year with the "beast from the east" showed how weather conditions can put pressure on the energy grid. Linked to this is the fact that every kWh of electricity has to be produced close to the time of consumption as batteries and demand response will only be able to bridge hours or a day, but not more. Indeed, neither cold weather nor the Dunkelflaute can be influenced by people. Instead, hydrogen from P2G or blue hydrogen from natural gas + CCS can allow for energy storage to be used in cold winters. As a market tool a P2G unit should be readily available to any user who wishes to nominate electricity in order to be transformed. This will also allow for a more market-based approach to the development for H2 depending on its final uses: blending, mobility, industry,etc… In addition, the development of methanation technologies will allow for synthetic gas to be more readily available as an upgrading tool for market players. Related to this, will be the development of the market itself, including the development of blue hydrogen which will contribute to structuring demand and supply. Although not directly linked to electrolysers as such, the development of blue hydrogen will already influence the availability of retrofitted and converted infrastructure to link the production centers to final demand, whether from industry, residential or mobility uses. In the long term, we note that dedicated RES-E could be developed and converted into hydrogen as a cost-efficient decarbonisation technology. Eurelectric's Decarbonisation Pathways study for example foresees that important dedicated volumes of renewable generation could be fully converted into renewable gas to tackle intermittency and seasonal limitations.

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?
The challenge for P2G technology is – as is the case for many other infant technologies – to achieve economies of scale that would make it economically viable. Options such as reducing fiscal burden, and specific explicit support schemes for the development of PtG facilities can facilitate the way towards that achievement. It is also paramount to carefully allocate costs of utilization of the facility to the part of the system benefitting from it (and thereby its end-consumers), based on an assessment on costs incurred and benefits, such as avoiding curtailment costs, achieved in either the electricity network or the gas grid, as only this will allow for a robust decision on the future role of gas vs electricity in a decarbonized economy. Furthermore, it will allow for decision-making which will eventually reduce the overall cost to the system in a decarbonised world and as such reduce the final bill incurred by customers. With regards to the issue of tariffs and potential layering of charges when it comes to P2G2P, any unwarranted and burdensome fee that is unjustly levied should be avoided as it could negatively impact the development of hydrogen and act as a barrier to sector coupling. An example of this is for example that storage and conversion of one form of energy into another (and which are sometimes classified as end consumers in the electricity sector) should be treated as a separate process, exempted in particular from end consumer taxes and levies.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
We would suggest assessing: 1) The aspect of Demand-side response, whereby a P2G unit could be incorporated into the idea of a local energy community and serve as DSR also on the gas side. 2) The mechanisms by which the customers’ ability to be a prosumer on both the electricity, gas, agriculture, transport or heating side could be examined further. 3) As one of the abilities of P2G is to relieve constraint on electricity grids at the local level, adequate incentivization to develop this service should be considered in the CEER’s assessment. 4) In order to stimulate demand and market uptake for renewable and decarbonised gases, adequate incentives have to be put in place across different sectors. An example of this for the mobility sector, it should be possible for vehicle manufacturers to meet the CO2 emission standards for cars and light duty as well as heavy duty vehicles by using renewable and decarbonised gases. This should apply to other sectors covered by the ESD such as the agricultural or building sector (Energy performance requirements of buildings). 5) The adequate acknowledgement would allow to link these sectors and thus avoid higher carbon abatement costs, which would arise w/o such link. 6) Finally, both the question of how to consider converted electricity which would otherwise be lost, and whether hydrogen produced from P2G with a direct connection to a renewable energy production plant can be considered fully renewable if connected to GOs rather than equal to the average level of renewable electricity in the country, should be considered.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Guarantees of Origin disclose the source of the specific renewable and decarbonised energy transparent to the customer. They are indispensable to prove the renewable, decarbonized or low-carbon nature of gas and to ensure that supply of r-/d-gas can meet demand on a European level. Eurogas notes the existence of European and national GO registries on which we propose to build. Eurogas recommends 1) A standardised framework with a set of information to be included for different GO categories: “renewable”, “low-carbon” and “decarbonised” gases form the basis for developing the traded market for GOs. Such GO should be based (1) on the minimum requirements of article 19 of RED II; and (2) upcoming CEN 16325 standard on renewable, low carbon and decarbonised gases. 2) This upcoming CEN 16325 standard should be developed in cooperation with AIB, Certifhy, ERGaR and, if any, other issuing bodies. We encourage all parties to present a first draft as soon as possible, preferably by the next Madrid Forum in October 2019 3) It should be possible to add additional information on top of the standardised GO and offer more sophisticated products to target specific customers 4) Cancellation of allowances in other countries should be possible as it is currently possible for power GOs. This could be achieved through a model similar to the power GOs model: a)MS registers remain, but they coordinate through an EU body like AIB for power b)Requirements for acceptability of GOs in neighbouring countries c) Coordinated cancellation system to avoid double counting 5) Support to compatibility between different GOs schemes 6) Issues identified: a) for RES-E installation that are not injecting directly into the grid, a GO will often not be created for the electricity. By extension this could make it impossible for a GO to be created for hydrogen produced from renewable electricity. b) For RES-E installation that are injecting into the grid, the issue of whether a conversion factor/efficiency factor should be developed to account for the energy used to produce electricity to gas c) Compatibility between ETS and GO already recognised in some MS (i.e. use of biogas as certified by GO implies no need for carbon abatement). Eurogas recognises the rationale and supports the extension of the principle. However ETS allowances need to be adjusted to reflect lower demand for allowances so that ETS market remains robust. Eurogas would underline the need to apply RED II definitions with regards to the difference between certificates and GOs. This would clarify potential issues such as possible compatibility with support schemes or issues linked to double counting.

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?
Whilst primary legislation states that electricity GOs should be tradable across borders, this is not always the case, and this for four main reasons: a) First, there is no pan-European guidance or common framework for GOs in terms of issuing them, trading them or using them by the buyer. b) Second, on the supply side, GOs are not universally issued to all renewable generators. In some countries, GOs are not issued at all if the asset owner is in receipt of state subsidies. c) On the demand side, the use of GOs is not consistent across Member States. d) Finally, as regards buying & selling GOs, there is no consistent set of rules on how this should be done. We therefore believe it would be essential to establish a minimum harmonization upfront and a common framework of rules to facilitate the trading of those certificates by all parties with certainty as to their validity to prove renewable gas credentials. The development of a common European Standard for Energy Certificates through AIB should be regarded as one of the core lessons learned when it comes to the development of a European trading ecosystem for GOs for Gas. Eurogas would encourage associations like ERGaR, Certifhy and AIB to foster their already existing discussions and engage in working on such a common standard with great urgency. We would also encourage CEN to dedicate robust resources into their relevant work on standardization of GOs. However, to ensure success to GO for gas Eurogas particularly encourages all relevant stakeholders to agree on a disclosure requirement for R-gas and D-gas to be included into a EU Gas Directive. In order to establish liquid markets, it is essential that the commodity can be traded regardless of its origin. Therefore, a certificate system for gas, similar to that for electricity, should be structured in such a way that a certificate can be traded independently of the commodity. This ensures, for example, that the commodity can be produced in Germany, transported and consumed in France, but that the GO is sold and cancelled in Belgium. This would also allow to trade certificates from different countries at the same trading hub.

Infrastructure Investments and Regulation

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?
The regulator should be sure that adequate consideration has been given to coordinated planning of the TYNDP between the electricity and gas sectors and that all necessary variables that could impact the stability of the network are included. Additional work on joint scenarios and the interlinked model will further facilitate such planning. In addition to this, Eurogas would call for the transparent inclusion of the following variables in the TYNDPs/joint scenario exercise: - Physical results in terms of curtailment for e.g. "dunkelflaute" periods - Identification of the main bottlenecks in the EU transport network - Sensitivity scenarios showing the effect of the change depending on one given major hypothesis (e.g. electrification of heating, of transport) to allow some form of marginal cost estimation (not possible today to isolate such effect with three main scenarios mixing many different issues), - All investment costs should be published, including FID - In the power modelling, generation is automatically adjusted and optimised to answer demand. This is an enormous hypothesis, and sensitivity on what is happening if generation investment is not occurring e.g. in the best possible locations should be added. This transparency is needed as the power network will be more and more sensitive to climatic constraints, something gas has done for many years because it was exposed to such constraints; a debate should take place on which extreme climatic scenarios the network should be resilient to. European citizens must be aware of what a "worse case" climate scenario would look like. We think that it would more important for the scenario process to align the national grid development plans – which are the base for the national transition scenario – between electricity and gas. The joint exercise on EU level has proven to be very efficient. If in the national grid development plan, electricity and gas do not take each other into account the results risk making the EU level exercise less consistent. An extreme case would see an electricity TSO to plan for 100% residential heating electrification whilst the gas TSO in the same country would plan for 100% gas heating. With separate scenario processes this could easily happen. Finally, as the energy transition will be very decentralized, in the electricity sector but potentially also in the gas sector as renewable gas can be produced at a local level, we advocate for a stronger inclusion of the DSO in the processes, national and European.

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)?

Incremental Capacity is a process that disclose willingness to pay of market participants. Through the F-factor, it can perfectly take into account the possible usefulness of projects that are not necessarily taken into account by the market, such as security of supply or diversification of supply sources.
Therefore, we do not see a contradiction of both frameworks. In fact, the current framework with the Incremental Capacity and the PCI processes are complementary; PCI projects could be allocated through an incremental capacity process.
In addition, the benefits of unifying the CAM NC and TEN-E into a coherent regulatory framework should be assessed, in order to extend the rights under NC CAM to project promoters, such as those linked to incremental capacity. The latter should then apply equally to Project Promoters as well as TSOs. Care should be given to avoid creating a different and possibly incoherent assessment of the economic value of a project through the PCI process.
We note that at DSO level, a CBA should be the primary element orienting decisions and that the use of CAM would not be warranted in the same way it is for cross-border infrastructure.

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?

Eurogas underlines the continued relevance for gas infrastructure in the future. Based on existing and projected gas demand we see limited risk for stranded assets in coming years. This is in line with CEER’s observations, as well as the EC’s 2050 scenarios and the recently published draft National Energy and Climate Plans 2020-2030, among others.
Moreover, beyond the uncertain future levels of demand, it should be noticed that the gas system is dimensioned to cover important seasonal and daily variations of demand. In other words, it’s dimensioned to meet peaks and throughputs. This will likely be exacerbated by a more volatile demand in the electricity sector.
Taking the above into account, and in case the issue of stranded assets were to arise, Eurogas would encourage the development of options to avoid a vicious circle of spiraling tariffs to deal with possible stranded transmission infrastructure (i.e. low utilisation triggering higher tariffs which further discourage utilisation), as well as with the need to maintain the attractiveness of the EU gas market, competitiveness of gas as a fuel, supply diversification and security of supply. In particular, Eurogas recommends:

• Policy clarity on the future role of renewable and decarbonised gas to enable a forward-looking regulatory approach to infrastructure
• Coordinated decommissioning or mothballing of stranded infrastructure which is not critical for security of supply. Explicit compensation outside network tariffs to avoid spiralling tariffs
• A forward-looking and integrated approach to gas and power network planning
• Recognising the value of new infrastructures developed on a merchant basis (i.e. do not restrict exemption processes when these are justified), consistent with the concern to avoid stranded assets
• Avoiding the accelerated depreciation of TSO infrastructure
• Eurogas also considers that new and existing flexibility services and other services, such as bunkering, which could be offered on a commercial basis, should be provided by the market and facilitated by transmission infrastructure operators.

On the EU level, establishing the long-term decarbonisation potential of natural gas means that current investments in gas technology and gas infrastructure remain warranted. These assets should not be stranded, as there is an opportunity to convert them for transportation of renewable gas, hydrogen and CO2. including the need to avoid cross subsidies across TSO. In many countries the need of industrial users for pure hydrogen will increase with the rate of decarbonization of industrial processes. Therefore, prior to any decommissioning, the potential for a pipeline to accelerate the deployment of hydrogen in and across countries should be assessed.
The advantage of the gas transmission system in comparison to the electricity transmission system is the high rate of cross border transport capacity. This offers a high level of security of supply and flexibility to the market especially in those cases where gas can flow in both directions. This level should be maintained in the future.

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?

Considering the relative importance of overall demand, which is likely to remain at current levels for the next decade, and considering the potential of renewable and decarbonised gas, we would like to underline the resilience of gas infrastructure.
In case decommissioning is being considered, it should follow the same type of methodological framework as commissioning goes through, with a cost-based economic decision. In case of uncertainty, mothballing of infrastructure is the preferred option if it isn’t crucial for SoS (in which case it shouldn’t be stranded in any case). Cross-border cooperation should be further developed between member states and should be facilitated by ACER. To this extent, the proposal made by CEER to encourage Member States to consult cross-border neighbours before decommissioning infrastructure so as to ensure SoS is maintained should be commended.
Furthermore, as underlined by CEER, the possibility to reuse “Possible redundant gas pipelines (…) for the transport of hydrogen” should not be overlooked and could be considered as an alternative by member states as a way to “reaching a socially optimal scale of transport network”. This being said, the level of intervention from policy-makers should be limited and the market should take precedence to ensure cost-efficient and sound solutions for final consumers to the extent possible, in a context where countries cooperate with regards to cross-border issues.

Adapting the Gas Market Design

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

Regarding the Gas Target Model, Eurogas reiterates its support of the work done to achieve this and wishes to underline the important advances that have taken place with regards to market integration and third package implementation.
In past Madrid Forum, Eurogas has suggested a review of governance to support the removal of national regulatory barriers to market development and instances of non-compliance. The 2020 process offers an opportunity for this and to improve the current process for implementation and enforcement of EU rules. In particular, Eurogas would support:

- A review of the Commission's enforcement powers to ensure that the Commission is able to address instances of consistent lack of progress in implementing EU rules more effectively and quickly
- A review of ACER powers to monitor and assess the level of competition, and actively support the implementation of EU rules (for example: Member States should be obliged to follow structured processes supported by regional roadmaps). ACER has currently very limited ability to go beyond the reporting of formal compliance and to play a role in implementation processes.

In addition, Eurogas believes additional work is needed on the elements below in order to maintain a well-functioning and sustainable Internal Gas Market:

- Guarantees of Origin
- Clarity on role and responsibilities of market participants in competitive segments of the market
- Technical clarity on levels of hydrogen injection into the grid
- R-gas/D-gas target to act as a pull factor
- Obligation for joint gas/electricity infrastructure planning to take an integrated system view
- Regionalisation and an adequate framework to ensure competitive planning and operation of power-to-gas facilities to facilitate sector coupling and integration. Flexible measures should allow for divergences depending on MS' specific conditions.
- Future tariffs issues (cf. question 16 and 17)
- Sector coupling is crucial for the future. In our view it was not addressed in the CEP and is missing
- Creation of a DSO entity for gas
    - To deal with issues of cross-sectoral relevance, the EU DSO entity for electricity Distribution system operators shall ensure coordination, on an equal footing, with Gas Distribution system operators.
    - Indeed, several topics of which the proposed entity will take charge, such as data management, cyber security or the coordinated planning and operation of TSO and DSO networks, are areas in which decisions will concern and impact both the electricity and gas sectors and the energy system as a whole.
- We note that the gas directive and regulation should ensure alignment with definitions with the terminology exercise including renewable, decarbonised and low-carbon gases.

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

Ibid with the addition that regarding the impact on the physical grid, a revision of TSO/DSO interactions as well as a potential review of certain NC could be justified.
The development of local energy communities will provide additional opportunities for the gas sector to provide solutions for waste disposal and electricity storage and conversion.

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?

Eurogas would encourage the development of options to avoid a vicious circle of spiralling tariffs to deal with possible stranded transmission infrastructure (i.e. low utilisation triggering higher tariffs which further discourage utilisation), as well as with the need to maintain the attractiveness of the EU gas market, competitiveness of gas as a fuel, supply diversification and security of supply. In particular, Eurogas recommends:

1) Policy clarity on the future role of renewable and decarbonised gas to enable a forward-looking regulatory approach to infrastructure
2) Coordinated decommissioning or mothballing of stranded infrastructure which is not critical for security of supply
3) Explicit compensation outside network tariffs to avoid spiralling tariffs
4) A forward-looking and integrated approach to gas and power network planning
5) Recognising the value of new infrastructures developed on a merchant basis (i.e. do not restrict exemption processes when these are justified), consistent with the concern to avoid stranded assets
6) Avoiding the accelerated depreciation of TSO infrastructure

Eurogas also considers that new and existing flexibility services and other services, such as bunkering, which could be offered on a commercial basis, should be provided by the market and facilitated by transmission infrastructure operators.
The gas grid will remain crucial in terms of providing adequate flexibility to the energy system in the future.
Finally, an assessment of possible cross-subsidies between domestic and cross-system usage as defined in article 5 of CAM code could be considered as over simplistic, and possible alternatives to review this article could be studied.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
CEER should make sure to examine storage and LNG as flexibility tools providing additional options for shippers and the market, all the while ensuring that they are adequately integrated in the market and subject to appropriate regulation. Should an inter-TSO compensation fund be needed, Eurogas would like to emphasize that, from a system users' perspective, two points are important regarding this option 1) it should be ensured that such a mechanism would not lead to higher grid fees 2) an independent auditor would be needed to oversee the TCF and the fee structure

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Eurogas would recommend 1) additional research be made on technical issues such as blending and that R&D funding for innovation be available to that end. 2) Eurogas would suggest consideration of what differences and issues may exist with regards to the evolution of the market towards 2050, and notably the difference between the transition period and the steady-state to be reached in 2050. 3) Eurogas considers the need for the creation of a DSO entity for gas a) To deal with issues of cross-sectoral relevance, the EU DSO entity for electricity Distribution system operators shall ensure coordination, on an equal footing, with Gas Distribution system operators. b) Indeed, several topics of which the proposed entity will take charge, such as data management, cyber security or the coordinated planning and operation of TSO and DSO networks, are areas in which decisions will concern and impact both the electricity and gas sectors and the energy system as a whole. 4) Eurogas underlines the importance of digitalization in the gas sector, notably to empower customers and allow a better operation of the system, Eurogas wishes to thank CEER for the very comprehensive consultation document and remains at your disposal for additional discussions and clarifications if required.

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Contact details and treatment of confidential responses

Contact details: [Organisation][]
GRTgaz

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

Nowadays renewable and low carbon gases are far from contributing enough to the energy transition. This is partly explained by a low commitment of market players due to the low maturity of associated technologies when compared to the electricity sector. The latter benefits from at least 15-year advance in technology development and has benefited from a wide-range of incentives. As a result market players prefer to invest in low risk electricity renewables.

At this stage there is still no incentive to fill that gap and to trigger sufficient market-based investment in renewable and low carbon gas production and energy coupling. This situation endangers:
•Europe’s ability to achieve high decarbonisation at 2030-40 horizon when renewable electricity will not be sufficient;
•EU carbon budget by delaying the decarbonation of a large part of the energy mix.

New regulation, as for example a future Gas Package, should include specific measures to foster renewable and low carbon gas development. These measures should enable TSOs to better support the energy transition. Where gas markets are sufficiently open to competition, the unbundling rules could be loosened for some activities and for a limited timeframe. Depending on the technology maturity the support could have two shapes:
•At R&D and innovation stage, DSOs/TSOs could benefit from a regulatory sandbox;
•For technology under deployment stage, DSOs/TSOs could be directly involved when economically sound (e.g. on the basis of a cost-benefit analysis taking into account externalities and long term value of the facility) and where market fails to invest.

Typical activities that could be entitled to DSO/TSO support are:
•Power-to-gas, in order to optimize the deployment cost of wind and solar energy taking maximum benefit from energy coupling on the basis of the principle of the right energy at the right place at the right time (flexibility of gas energy carrier and pan-European existing network);
•Refuelling stations for maritime, river and road gas-mobility (especially light vehicle segment which is the most risky for merchant sector);
•Biogas upgrade to biomethane in order to benefit from economy of scale;
•thermal gasification and methanation facilities;
•Carbon capture and usage to support the deployment of a CO_2 chain supporting the decarbonation of the industrial sector.

Finally, the transmission and distribution activities of TSOs/DSOs should be enlarged to hydrogen, carbon dioxide and raw biogas.

All these activities should be carried out as regulated activities and TSOs/DSOs should ensure a third-party access in order to let market players maximize the value of the investment.

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.
As European gas networks are interconnected, it seems beneficial to have harmonized thresholds for the blending of hydrogen in European gas networks. First of all, different portions of the gas systems (high pressure, low pressure, storages…) could accommodate different proportions of hydrogen blended with methane (in particular regarding the integrity of gas infrastructures, but also usages). Hence the need for a careful assessment of gas specifications at the Interconnection Points across the entire gas chain, taking into account possible cross-border or cross-infrastructure flows. That is why norms regarding maximal hydrogen blends should be addressed at European cross border points, e.g. through Interconnection Point Agreements foreseen in the Interoperability Network Code. At least coordination between countries with interconnected gas networks is required, bearing in mind that the accepted hydrogen content exiting at an Interconnection Point might limit the ability to accept hydrogen injection in the downstream flow. GRTgaz Fenhyx project intends to investigate the impact of hydrogen on the gas network. One regulatory challenge is to identify if thresholds of hydrogen content accepted in the upstream gas networks/countries will be compatible with a downstream cross-border network, or if they require a processing stage (e.g. methanation, decreasing the H2 share). Therefore, the ultimate goal should not be to converge towards a single threshold across Europe, which would either be extremely low, or penalize « downstream » countries compared to « upstream » countries, but rather to provide equal opportunities to develop hydrogen injection into the network in each market. Therefore, a work of normalization should grant an equivalent capacity for each country to blend a minimal threshold of hydrogen. Regarding the question of timing, and considering the complexities of interoperability issues, the sooner this issue is addressed, the better. In France, GRTgaz has already received questions from project promoters about the feasibility and the cost of hydrogen injection in the natural gas network. The first studies on-going with all French gas infrastructures (transmission, storage, distribution) show the complexity of these analyses and the potential need for coordinated research and development actions to be able to adapt the present gas infrastructures and thus maximize acceptance for hydrogen blending as a tool for decarbonation of gas usages. That is why one major regulatory challenge in the coming years will be to establish a set of support and regulatory rules to promote cooperation between TSOs on this question. Support to TSO cooperation projects in the field of hydrogen, for instance via FCH JU (GRTgaz has answered one of the calls for projects together with other operators), should be encouraged in order to contribute to the development of a harmonized European framework for the blending of hydrogen in gas networks.

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.
Today hydrogen is mostly used as a chemical product in defined activities, be it as a specific raw material in industry (produced and used by a limited amount of major industry players), as a specialty product (delivered in bottles or truck), or as a nascent fuel for transport. However, when hydrogen use as an energy will develop (for mobility, heating, industrial process…), its relevance for the wider public will become major compared to its historical use. Regulation of hydrogen networks should be considered for the same reasons that led to regulation of gas networks: they can have the characteristics of essential facilities, with considerable fixed costs and growing returns. In addition, existing regulated gas networks will potentially be used for the transportation of hydrogen. Regulation will be relevant when the hydrogen market is developed enough, with a variety of players which will need to access the infrastructure on a level playing field: producers, end-consumers with different sizes and different capabilities of influencing the market organization, prices… Under these circumstances, hydrogen networks regulation (non-discriminatory third party access, regulated prices for a monopoly infrastructure) will help develop a fluid market with a transparent and non-discriminatory access to hydrogen transport. Furthermore, as electricity and gas networks coupling is a key challenge to achieve energy transition and the climate change objectives taken by the European Union, the regulatory framework for hydrogen should take into consideration from the beginning the coupling of gaseous energy infrastructures, and not fragment the market between a market for energy in the form of a methane carrier, and another market for energy in the form of an hydrogen carrier. Consistent market model for both methane and hydrogen would facilitate this challenge and avoid unnecessary fragmentation of the markets, which are detrimental to a fair competition and would create local monopolies. In this respect, the management of L gas and H gas in several EU countries might provide a relevant example. Besides, coupling possibilities between hydrogen and methane carriers (methanation, blending, separation) require a global view of the management and operation of the hydrogen and methane networks in order to be optimised. This global management of the networks (including management of gas quality tools which are already operated by gas system operators) would be made easier by regulation of hydrogen networks. Last, considering that decarbonation of gas usage is of general interest, a coordinated regulation of hydrogen networks and methane networks enables to partly tackle the question of funding investments for conversion or adaptation of some parts of the existing gas system to hydrogen blending, or conversion to pure hydrogen. Indeed, regulated tariffs, when substantiated by robust Costs Benefits Analyses will enable to mutualize investment costs relevant for the general interest purpose of decarbonation over a wide range of end-consumers. Without this regulation, a risk remains that investments, in line with energy transition goals, will not arise.

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.
There is no opposition between cost efficiency and technology neutrality when they both take into account system resilience, externalities (e.g. use of scarce and strategic resources) and the long term need of the energy system with very high RES penetration. As a result, both approaches can be used as far as they go beyond short term profitability for investors. Otherwise, the deployment of the most mature technologies (e.g. wind and solar) will hinder the development of new technologies that may be desirable on the medium and long term.

Q5 Which role do you see for power-to-gas infrastructures?
From a technology perspective, Power-to-gas is a facility converting electricity into hydrogen or synthetic methane. From an energy perspective, it may have a wide range of use cases, enlarging over time with higher RES deployment and progress towards carbon neutrality. Use cases cover: • Production of renewable hydrogen and synthetic methane • Optimization of RES deployment from a spatial and temporal perspective: mitigating some electricity bottlenecks and taking benefit of gas flexibility • Managing short to long term electricity system flexibility • Increasing biomethane production by combining anaerobic digestion with methanation • Valorisation of carbon dioxide from existing processes In fact, these use cases will certainly be combined together. Investment in such use cases, especially hybrid ones, are challenging for the merchant sector as complex business plans are the riskiest. As mentioned under Q1, where the merchant sector fails to get involved, there should be a role for TSOs under well-defined conditions.

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?
A Power-to-gas facility does not create primary energy, it converts one energy carrier into another one. As such, any double taxation should be avoided. In addition, a Power-to-gas facility connected to a gas grid behaves as a source of short term to seasonal flexibility for the electricity sector. Such ability enables a significant optimization of the electricity system. Therefore, it could be entitled to a discount on the exit capacity tariff from the electricity network on the same basis as underground storage in gas.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Under the occurrences defined in Question 1, TSOs may build a P2G facility as a demonstrator or as a commercial unit (in case of lack of market interest). In both cases, there is a need for regulatory rules to: • Integrate the facility in the TSO regulated asset base; • Implement third party access for the electricity to gas conversion service. Beyond P2G technology, regulation should incentivize R&D and cooperation between gas and electricity European TSOs especially regarding the preparedness of the energy system to a low carbon future. This would ensure economy of scale and knowledge sharing. Unfortunately, the present regulatory framework makes cross border cooperation challenging. For example, a NRA may be reluctant to authorize a TSO to recover its participation in a R&D project abroad through the national transmission tariff. Therefore, the European regulatory framework should define the way to operate new regulated services and incentivize cross border cooperation in the field of R&D.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
One key point to enhance renewable but also low-carbon gases development is to guarantee to the final consumer the traceability of these two products. We support the establishment of one standardised GO scheme for both renewable gas and low carbon non-renewable gas, with a clear and separate terminology. To ensure interoperability of different GOs, the conversion of the GO from one energy carrier (e.g. electricity) to another carrier (e.g. hydrogen) needs to be possible. Within each MS, setting up interoperable schemes for the GOs for different energy carriers should be encouraged. Furthermore, an EU-wide solution for implementing GOs requires an extension of the CEN 16325 to include GOs for gaseous carriers. Cooperation of national issuing bodies between Member States is also key to facilitate GOs trading: interoperable schemes based on widely accepted rules will allow transfer of GOs. Particular attention is required to avoid any double support for the same renewable MWh produced. As such, and to prevent market distortion, it would be beneficial that Member States progress towards a harmonisation of national support schemes for renewable or low-carbon gas (where currently some support schemes apply on the production side while others apply on the consumer side).

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?
As mentioned in our response to Q8, the development of an EU-wide solution for renewable gas and the conversion of the GO from one energy carrier to another carrier are key to enhance the development of renewable gas. Lessons learnt from the electricity sector underline the importance to pay attention to avoid double support for the same renewable MWh produced. Additionally, a common design for data (data format, data fields, data protection…) is required for GOs for renewable as well as other low carbon gases.

Infrastructure Investments and Regulation

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?
The current regime where ACER and NRAs are involved in the TYNDP process and formulate opinions on the draft report is satisfactory. The priority should be that TYNDPs and national plans fully take into account the whole potential of energy coupling in terms of cost minimization of the energy transition.

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)?
No specific comment compared to ENTSOG response.

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?
On the medium term, GRTgaz sees a rather low risk regarding its own assets. For example, the development of decentralized renewable gas production will not impact existing pipes but may at one point impact compressor stations which have a shorter economic lifetime thus offering adaptation opportunities. Nevertheless, it is important to put in place a framework minimizing the risk of stranded assets with measures such as: •a strong coordination when developing new gas or electricity investments taking into account the long term potential offered by existing infrastructures •the development of renewable and low carbon gas production •a capacity-based tariff taking into account not only the day-to-day use of infrastructure but also its intrinsic value (e.g. SoS externalities, optionality…) •long term visibility provided to network operators in order to avoid inappropriate decommissioning or reinvestments in the long run. Such measures cannot completely mitigate the risk of stranded assets. As a result, a regulatory framework is needed to deal with the remaining cases. On the other hand, many infrastructures will continue to be useful beyond their economic lifetime. TSOs/DSOs should be incentivised to maintain them in operation even if the infrastructure may require additional monitoring and maintenance. This could take the form of a residual CAPEX remuneration or additional OPEX.

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?
The existing framework for developing new infrastructures (incremental capacity process, TYNDP and Cost-Benefit Analysis), already provides all the necessary tools to manage potential decommissioning. It enables the assessment of both direct market demand and contribution to the energy policy objectives. The importance of the geographic scope of the assessment has to be highlighted as within the pan-European meshed network, the impact may be distant from the underlying infrastructure. As a result, any decommissioning project has to be dully assessed and coordinated.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The results achieved in many European gas markets show that the existing framework is able to offer secure and competitive gas to end-consumers. Setting some implementation standards of the EU regulatory framework as a condition for benefitting from the TEN-E regulation could accelerate the achievement of the single energy market. At EU level, the main challenge to be addressed by gas market design is to unleash renewable and low carbon gas contribution to the energy transition.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Market design should ensure meaningful coupling between: •gas and electricity systems; •distribution and transmission levels. The first topic is covered by questions related to P2G. The second topic requires close cooperation when defining the most efficient way to connect renewable gas production. It means lowering the cost of gas injection into the network taking into account long term potential. The different tools are direct connection to DSO or TSO grids, raw biogas networks with centralized upgrade to biomethane and DSO to TSO backhaul facilities. Allowing for socialisation of part of the grid development costs required to develop renewables gases and a close to zero injection tariff could help foster the development of this nascent market without significant impact on the transmission tariff. When becoming more mature, the development of decentralized gas production will certainly require the development of a new cost-allocation methodology as part of the Tariff network code process.

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?

Regarding long term capacity contract expiration, there is no certainty about the impact on spreads (e.g. the end of such contracts in Germany have not raised major issues) and the network code update process is sufficient should a problem arise. Only the set-up of an Inter TSO Compensation mechanism would require a new regulation. CEER appropriately points out the challenge of putting in place such a mechanism at the scale of the EU gas market (40 times higher than the electricity ITC for a smaller total revenue).

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

n/a

Other question

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

Carbon dioxide
The current focus of the gas sector is very much on biomethane and even more hydrogen. It is very positive but this framework should be complemented with CCS/U. Considering carbon dioxide as a commodity would leverage energy sector efforts towards carbon neutrality:
• on the short term, CCS/U will help to save EU carbon budget;
• CCS/U may be an opportunity to decarbonize industry at a cheaper cost than electrification or conversion to hydrogen, thus mitigating the risk of delocalisation;
• CCS paves the way to negative emissions necessary to ensure a resilient carbon neutrality;
• Methanation process helps to make better use of carbon dioxide including anthropic carbon dioxide on the short/medium term.
As the main CO2 sources are spread across Europe, there is merit in considering the potential value of regional carbon dioxide networks. Such networks would connect numerous CO2 sources with some valorisation facilities and exits towards carbon sequestration. Gas TSOs/DSOs are relevant future operators of such facilities given the operational similarity, the need of third party access and the likely neighbouring with methane networks (e.g. an industrial facility burning natural gas).

Regulatory sandbox
The present document mentions the concept of “regulatory sandbox”. The aim is to provide NRAs with a consistent and flexible EU framework enabling experimentation at national level. As a result, NRAs could authorize regulated investments in not yet mature technologies taking into account the national context. Such decisions should include a consultation process with relevant stakeholders.

Survey response 30

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Gas Networks Ireland

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
To enable the energy transition, TSOs and DSOs are well placed to progress activities that deliver decarbonisation and promote sector coupling. Gas Networks Ireland (GNI) believes that the assessment should consider activities such as, but not limited to, biomethane grid injection facilities, Compressed Natural Gas (CNG) for transport, Power-to-Gas (P2G) facilities, Hydrogen Storage, Hydrogen for transport, Carbon Capture and Storage (CCS), Carbon Capture and Utilisation (CCU) technologies and Carbon Dioxide pipelines. When TSOs and DSOs invest in decarbonisation activities on either a regulated or fully commercial basis, they can support the development and scaling-up of these markets. TSOs and DSOs can have a positive impact on enabling the integration of renewable and decarbonised gases, especially where there are no existing investors. If TSOs and DSOs own, operate and maintain such facilities and sell services to network users, they will do so in compliance with unbundling rules. Regarding Power-to-Gas facilities, it is necessary to consider all available technologies. By building an overarching energy system, integrating electricity and gas, it is more cost-efficient, more secure and a quicker way to achieve decarbonisation targets. There is a need to review the regulatory framework and, where necessary, to amend it to ensure the development of Power-to-Gas along with other decarbonisation technologies. Power-to-Gas is an enabling technology for renewable electricity generation, as it can provide cost effective long term energy storage for periods when there is high electricity demand and low renewable electricity generation. This is particularly true in Ireland where there is a prohibition on nuclear power and very little hydropower, so the options for low carbon dispatchable electricity are limited. Power-to-Gas facilities should not be classified as gas production plants. Power-to-Gas may be provided as a conversion service that transforms electricity from a renewable source, or any other electricity source, into gas (such as hydrogen or synthetic methane) for further use in the energy system. Therefore, there should be no obstacles for TSOs or DSOs to be the owners and operators of a Power-to-Gas facility from an unbundling point of view. Also regarding biomethane grid injection facilities, TSOs and DSOs should invest in facilities which enable the injection of other renewable gases such as biomethane (which is upgraded from biogas) and synthetic methane into the gas grid. In this situation, the TSO or DSO would have no direct involvement in the commodity side of the value chain, and simply offers an injection service to producers. In terms of regulatory and commercial considerations, gas TSOs and DSOs should have the opportunity to invest in any type of facility which enables decarbonisation and sector coupling. The question should not be which activities are considered relevant for potential TSO or DSO involvement, but which activities need additional regulation to facilitate their wider deployment. TSOs and DSOs would welcome opportunities to invest on a regulated or commercial basis, depending on market developments. Investing on a commercial basis, in competition with commercial investors, TSOs or DSOs should not have any specific commercial advantage or disadvantage. They should be in compliance with unbundling rules and a transparent separation between regulated and non-regulated activities established, which is supervised by the relevant NRA. Since private investment in decarbonisation activities may not materialise, consideration should be given to the development of these technologies by system operators. For some activities, where there is limited commercial development in new facilities or if the assets are essential facilities (natural monopolies), it may be necessary to establish a regulatory framework to ensure that the underlying technologies reach the required scale and maturity, by which time they will become essential for the operational integrity of the energy system. A regulated business allows for low-risk and cost-efficient development of relevant economic activities and energy transition facilities, creating new services open to all market participants in a non-discriminatory way and under the NRA’s oversight. The TSO or DSO would provide open and transparent 3rd party access to the facilities for all market participants. The appropriate framework could be left to the National Regulatory Authority in each Member State, depending on their particular circumstances. Objective criteria could be implemented by Member States to evaluate market appetite for investments in new decarbonisation facilities. As some of these activities are still in development, TSOs and DSOs should be have the opportunity to engage in research and development to help bring these technologies forward. The provision of an innovation fund by NRAs is an important tool for TSOs and DSOs to test and pilot new technologies before deciding whether to further develop the technologies. Additional types of support complementing the regulatory frameworks exist, such as subsidies and funding for the most promising technologies, which decrease their costs and increase their uptake. Support provided in the electricity sector for decarbonisation activities should be replicated in the gas sector, both in extent and duration. There should be a level playing field for all decarbonisation technologies.

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.
As recognised by CEER, there are different possible approaches towards hydrogen integration: blending hydrogen with methane (natural gas in the transition phase and biomethane and/or synthetic methane in the long-term) and hydrogen-only networks. While there is evidence that gas applications could be able to integrate different fractions of hydrogen, the optimal choice and pathway will be determined by national or even local conditions. Gas quality will be more and more diverse in the future and hence there is a clear need to increase the system's resilience, including infrastructure and end use, to handle it. A level playing field should be established to develop the different technologies that support the various pathways to a gas system which is carbon neutral. It is necessary to keep in mind (particularly in the earlier years) that it is likely that different Member States will follow different pathways and focus on a range of decarbonisation mechanisms. These issues should be tackled early on, so that the integrity of the internal gas market is not effected. Member States should be free to choose the pathway(s) they want to follow and relevant timelines. The use of hydrogen, either in combination with natural gas or in pure form, will require at least an assessment and possibly an adaptation or substitution of gas infrastructure elements and end use applications. Providing technical clarity at an EU and local level on the different pathways is necessary to identify which technological developments and investments are needed. It may also be appropriate to consider setting thresholds or limits for the blending of decarbonised gases in general, rather than hydrogen specifically. This would take into consideration the local availability or potential for decarbonised gases. For instance, Ireland has the highest biomethane potential in Europe [https://ec.europa.eu/energy/sites/ener/files/documents/ce_delft_3g84_biogas_beyond_2020_final_report.pdf] but does not have geology suited to inter-seasonal hydrogen storage. Before taking any decision, proper impact analysis should be carried out. This analysis should include the financial effects and any potential tariff implications of the foreseen changes, including the cost of the infrastructure upgrades, the cost of end-user appliances and implications on end consumers' bills. Regulators should play an important role in the transition of the European gas market into a carbon neutral system, particularly with regard to the recognition of certain costs as eligible in regulated sectors. In the short-term, there is an urgent requirement to remove technical and legal barriers that could hinder the further development of hydrogen systems, including blends. In the medium and longer-term, natural gas end-use equipment and appliance standards should increase their readiness for hydrogen blends. Gas equipment and appliances should also be provided with the necessary controls to withstand the foreseeable variability in hydrogen blends. An EU roadmap setting out the hydrogen readiness of new appliances would be beneficial.

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.

The use of hydrogen as an energy carrier has significant potential as part of the energy transition and it is envisaged that its use will increase in the coming years. To ensure hydrogen reaches its full potential, there is a need to make sure that there are no barriers to its development.

Hydrogen networks, connecting diverse production and demand centres, could be considered as natural monopolies since building parallel network structures would not be efficient. As mentioned in CEER's FROG study, it is likely that such new (or converted) large scale hydrogen pipelines will have similar economic characteristics to the existing natural gas networks. This premise aligns with GNI's view that it will be necessary to allow for non-discriminatory third-party access to support and further develop the Internal European Energy Market, and therefore such hydrogen networks could be operated by TSOs.

The scope of the gas directive should be expanded to include hydrogen. Hydrogen networks do not have to be under the same regulatory framework as natural gas networks; some nuances may be required. The level of regulation may depend on the level of maturity of the market, the national circumstances and the requirements of the regulator. New regulations should be carefully assessed and backed up by detailed technical and economic analysis, including potential impacts on final customers.

Regardless of the extent of regulation, benefits related to TSOs building and managing hydrogen pipelines include:
• Expertise and demonstration of prolonged operation of gas networks in a safe and efficient manner.
• Infrastructure optimisation and cost savings, as a result of coordinated planning reflecting the development needs of the sector.

• Development costs can be reduced using existing infrastructure by adjusting or converting some parts of the existing network into hydrogen networks and integrating existing hydrogen pipelines.
• Guaranteeing non-discriminatory third-party access, so that all interested market players can benefit from access to the hydrogen network, maximising the potential of sector coupling.
• Guaranteeing the viability of pipelines in the development stage, as the load factor progressively increases.
• Enabling the potential integration of hydrogen and biomethane markets. This integration would prevent market fragmentation as hydrogen usage develops alongside biomethane gas usage.

Blending hydrogen into the existing gas network will require the removal of technical barriers to cross-border trade. The regulated framework already in place for gas infrastructure should be used and possibly adjusted in order to facilitate and incentivise their evolution towards future-proofing assets.

As the use of hydrogen increases in the future, development costs can be reduced using the existing infrastructure, by adjusting or converting some parts of the existing gas network into a hydrogen ready network, or blended hydrogen/methane network. Conversion from methane to hydrogen will take time, and require R&D and investments for future-proofing existing infrastructure. These investments will have to be taken into consideration by NRAs and appropriately incentivised within the regulatory framework.

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.

GNI believes that 'cost efficiency' is a legitimate reason for pro-active market intervention by policymakers/regulators, where sustainability is the main driving force of the energy transition. A focus on Security of Supply (SoS) and affordability must also be maintained. 'Technology neutrality' is needed for the efficient development of a decarbonised energy market and its associated regulation. Support schemes should not favour one technology over another e.g. biogas support mechanisms for the production of electricity but not for injection into the gas system. There is a need for a 'whole of energy system' approach to such supports.

Besides cost efficiency, other criteria like SoS of the whole energy system, diversification of sources, peak demand, societal and environmental impacts (externalities) and future potential of the technology should be considered to promote activities including biomethane and CNG/LNG for the transport sector, Power-to-Gas, hydrogen networks and CCUS. In addition, any decision that will impact the future of gas and gas infrastructure, like a shift from a methane network to a pure hydrogen one, should be carefully assessed taking into account long-term cost efficiency.

There are supports and an adequate regulatory framework in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of supports, ensuring a level playing field between all technologies and energy carriers.

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

Power-to-Gas is a technology that will further enable sector coupling, fully enabling the development of a hybrid energy system that can provide, affordable, sustainable and secure energy. A Power-to-Gas facility should not be treated as a gas production facility, but instead as a conversion facility which transports energy from the electricity system to the gas system and if required back to the electricity system, if renewable electricity generation is low and demand is high.

Power-to-Gas has a number of benefits:
• It would facilitate sector coupling, thereby maximising the potential of the overall energy system, enabling optimal planning and development of gas and electricity networks in a complementary manner.
• It facilitates the maximisation of renewable electricity production by converting renewable electricity to renewable gas which can be injected into the existing gas network and used as a raw material by industry.
• It will contribute to better functioning of the energy market by reducing the occurrence of negative/very low prices on the power wholesale market and enabling the development of additional market-based renewable electricity generation whilst providing a renewable source of gaseous energy.
• It will ease the balancing of the power grid by providing both upward and downwards operational reserve and will contribute towards the reduction in electricity grid congestion.
• It will enable storage of large quantities of grid scale energy derived from renewable electricity over long periods in the gas system.
• It will improve SoS in both electricity and gas sectors.
• It will facilitate the development of renewable energy projects in remote areas with high wind availability, where the electricity grid is constrained.

Furthermore, TSOs are ideally suited to contribute to the ramp-up of Power-to-Gas infrastructure as they have the knowledge, experience and resources to develop this type of infrastructure. TSOs who wish to invest in Power-to-Gas as a conversion service should have the opportunity to commence doing so now, in order to ensure the technology reaches the required scale and maturity.

The development of blue hydrogen should be considered in the context of enabling greater alignment between demand and supply and ensuring SoS in the development phase. The development of blue hydrogen in the medium term would ensure the availability of retrofitted and converted infrastructure and enable the ramp up of Power-to-Gas facilities and the transition to fully green hydrogen in the medium-long term.

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?

Electricity and gas tariff systems could potentially create distortions to the efficient deployment and use of Power-to-Gas technologies. Consequently, electricity and gas TSOs should be able to propose a discount on the electricity and gas network tariffs justified by the benefits that Power-to-Gas facilities delivery to the overall energy system, in terms of positive externalities (SoS, supply diversification, balancing of the grids, support to renewable energy sources and decarbonisation etc.).

GNI believes that there should not be a differentiation between whether the gas produced is used to generate electricity or used for a different purpose.

Concerning the issue of tariffs and potential double charging when it comes to Power-to-Gas-to-Power (P2G2P), any unwarranted fees should be avoided as this could limit the development of hydrogen and act as a barrier to sector coupling. An example of this is that storage and conversion of one form of energy into another (which can be classified as an end-user in the electricity sector) should be treated as a separate conversion process, exempt from end-user taxes and levies, similar to storage under the Tariff Network Code.

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

The current legislative and regulatory frameworks were designed prior to the development of Power-to-Gas infrastructure, and therefore do not take into account its potential and possibilities. A review and amendment of the legislative and regulatory frameworks are needed to ensure their adequacy for the development of Power-to-Gas infrastructure.

The Gas Directive should be reviewed. In particular, it may be beneficial to consider the following changes:

- Inclusion of a definition of Power-to-Gas in the context of sector coupling, to enable the transition to a decarbonised energy system. Indeed, with a clear distinction between the facility operator and the facility user, it would be easier for TSOs to operate such a facility.
- A supportive framework is needed to enable the roll-out of Power-to-Gas. Regulation and/or the possibility to apply for EU investment funding should be taken into account.
- There should be no barriers to agreements for renewable and non-renewable low carbon gases traversing borders and sectors. However initially, careful consideration is required in terms of the blending of Hydrogen, in particular given that Member States may be at different stages of readiness.
- Furthermore, TSOs should be able to transport hydrogen and other gases to enable the scale-up of renewable hydrogen production from Power-to-Gas facilities.
- Both electricity and gas sectors should work together to evaluate the efficient development of infrastructure.

The Regulatory Framework enables infrastructure development in a cost effective way, and ensures that all costs are efficiently incurred. In the context of Power-to-Gas technologies, regulated investments are an effective mechanism of ensuring lower costs relative to the cost of any potential support schemes, such as explicit subsidies. Additionally, the efficiently incurred costs linked to regulated activities are under the supervision of the NRA. CEER indicates in the consultation that “subsidising technologies, which is not the responsibility of regulators but of policymakers, should be done using specific policies”. However, during the last Madrid Forum, the Commission clearly indicated that there will not be new specific subsidy schemes. Bearing this in mind, appropriate incentive-based regulation may be used as a mechanism to facilitate the development of Power-to-Gas.

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

GNI is of the opinion that the cross-border trade of Guarantees of Origin (GOs) for renewable gas should be supported by ensuring ‘interoperability’ of GOs across all Member States. Standardisation, interoperability and harmonisation of GOs across all Member States will enable efficient cross-border trading of the sustainability characteristics of renewable gas produced in the EU. The ‘European Renewable Gas Registry’ (ERGaR) has been established for this purpose and aims to incorporate all national renewable gas registries into the ERGaR system. The ERGaR project also aims to establish a European hub for GOs and, in doing so, to allow for mass balancing at a European level. Regulatory support will increase the chances of the successful implementation of the ERGaR system.

GNI also supports the establishment of GOs for energy from ‘non-renewable’ energy sources that have a positive impact on the reduction of Green House Gas (GHG) emissions (e.g. decarbonised/low-carbon gas), as in the terminology of the recast Renewable Energy Directive (RED II), which allows Member States to put this option in place.

Interoperability of GOs for different energy carriers (e.g. for renewable gas, hydrogen and electricity) from different issuing bodies is also a requirement to be established. Interoperability would manifest itself by way of the following two mechanisms:

- All GOs need to be convertible from one energy carrier into another when such conversion is physically taking place.
- The national issuing bodies for different energy carriers are encouraged to work towards setting-up clear and recognisable schemes for all GOs based on widely accepted rules. This would then ensure interoperability in terms of facilitating cross-border trading of GOs. These cross-border GO schemes should include criteria and processes for recognition by every issuing body of GOs supplied by every other issuing body, in order to enable the transfer of GOs. Any double support for the same MWh produced must be avoided. Additionally, a European-wide solution for the above-mentioned cooperation could be established.

A key requirement is fully functional audit or certification capabilities at Member State level. These audit functions should follow a standard audit methodology to validate the green credentials of gas produced in each Member State and certify compliance with RED II on a consistent basis. This is necessary as variability of production processes/inputs at facilities can result in different sustainability properties for the biomethane produced.

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?
Lessons learnt from the electricity sector include the necessity of a common understanding of data that should be included in the GO and certificate. All GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements. To that end, a common understanding of concepts and corresponding terminology is needed. Additionally, when designing common data requirements for all GOs, it is important to pay attention to operational aspects, such as data format, data fields and data protection. Lessons learnt from renewable electricity also underline the importance of avoiding any double support between an EU-wide GO system and Member State support schemes. The EU-wide GO system for renewable gas should be set-up ensuring that double counting of renewable gas volumes is avoided. Successful implementation of the ERGaR system (described in response to Q8), with mass balancing, will ensure that volumes are only counted once.

Infrastructure Investments and Regulation

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?
Current regulations establish an important role for ACER (and NRAs) in providing opinions on the ENTSOG Draft TYNDPs and CBA Methodologies. The recommendations provided to ENTSOG are published in the final version of the ENTSOG TYNDP as well as an explanation on how those were taken into account. Furthermore the CBA Methodology includes a dedicated document where ACER's opinions, as well as other stakeholders' feedback are published. In addition, this document indicates how this feedback has been taken into account in the final CBA methodology. These provisions have been successful in terms of developing a fair and transparent process for evaluating key infrastructure projects. It is GNI's view that the current role of ACER (and NRAs) should remain as is, in order to provide important recommendations to improve the TYNDP process, thereby facilitating a transparent and non-discriminatory process for all stakeholders. In terms of the development of TYNDP scenarios, gas and electricity TSOs are uniquely positioned to provide quantitative European focused scenarios on the impact of the energy transition on the development of European electricity and gas infrastructure in the long-term. These scenarios represent the first step in any network development exercise, and they provide a view on many elements, including energy demand and the development of renewable and decarbonised technologies. GNI notes that such scenarios are now developed jointly by ENTSOG and ENTSO-E. These scenarios have been developed by taking a holistic view of the energy system in order to ensure consistency and capture all interactions between energy sectors. Workshops and stakeholder public consultations have endeavoured to improve both the scenario development process itself and the associated publications. This process allows for the development of a robust, realistic and balanced view on the development of energy infrastructure in Europe.

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)?
GNI notes that sustainability is one of the key criteria for the evaluation of projects of Common interest as described in Regulation (EU) 347/2013. GNI welcomes the fact that there is now a focus on renewable and decarbonised gas projects, which will help ensure the transition to a decarbonised gas grid across Europe. GNI welcomes the fact that these projects will be assessed as part of the TYNDP 2020 process. In general terms, GNI is of the view that there is no ‘one size fits all’ solution for decarbonising gas infrastructure across Member States. As such, a wide range of projects and technologies should be supported through the PCI framework, including but not limited to, biomethane grid injection, Power-to-Gas (including the broader concept of sector coupling), hydrogen blending, dedicated hydrogen networks and CCS. With regard to the possibility of cross-references between the infrastructure regulation 347/2013 and the CAM NC, it is important to underline that Regulation (EU) 347/2013 and CAM NC have different aims. The aim of the PCI selection process is to identify projects which can have a positive impact for Europe in terms of sustainability, security of supply, competition and market integration. The CAM NC has a more specific focus which is to guarantee a non-discriminatory and harmonised third-party access to the gas networks across Europe. Incremental Capacity is a process to determine whether an investment is market-based, while PCI projects may be market-driven or equally based on security of supply or sustainability benefits. GNI believes that PCIs should continue to be evaluated in terms of the requirements set out in Regulation (EU) 347/2013 with a particular focus on sustainability going forward, given the challenge of decarbonising the energy system. Elements of the CAM NC may be of use in facilitating the connection of renewable gas projects to the grid, in particular the incremental capacity process, but should not create barriers in terms of the rollout of renewable gas projects.

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?
It is GNI's view that gas will remain a prominent feature in the future energy mix in the coming decades and beyond. Gas transmission networks will play a key role in providing affordable energy, maintaining security of supply, whilst becoming increasingly sustainable over time with the deployment of renewable and decarbonised gases. Due to the strong role gas will play in Europe's future energy system as other more carbon intensive fuels are phased out of the energy mix, GNI is of the view that it is premature and counterproductive to focus on the issue of stranded assets. At a European level, several studies point to a strong role for gas infrastructure in the long term and envisage stable or increased gas demand. These studies include the European Commission's study (published in 2018) on the role of trans-European gas infrastructure in 2050, the EC ASSET study on Sectorial Integration, and the Pöyry study on decarbonising Europe's energy system by 2050. In addition, peak-demand levels and higher flexibility needs are likely to increase in coming decades. While annual gas demand may decrease in some cases, peak demand may not reduce and may even increase in at least some Member States, due to changing demand patterns. Failure to account for this may lead to problems in terms of security of supply in some instances. Establishing the long-term decarbonisation potential of gas infrastructure justifies investments in decarbonisation innovations and technology. The opportunity to convert gas infrastructure to be a carrier for renewable gases (e.g. hydrogen) guarantees that these assets will not be stranded. In the case of Ireland, the European Commission's study on the role of trans-European gas infrastructure in 2050 recognises that "the risk for stranded gas assets is in Ireland limited" and that "the transmission network would continue to be used for increasing volumes of renewable gas". According to GNI's own demand forecasts (Draft Network Development Plan 2018 – median demand scenario) gas demand will continue to grow, increasing by 23% by 2027. A lot of this demand growth will be driven by the phasing out of more carbon intensive fuels in line with the government policy. The Irish Government's draft National Energy & Climate Plan (NECP) 2021-2030, published in December 2018, commits to "not burning coal and peat for power generation past 2025 and 2030 respectively". Furthermore The NECP also recognises the role of gas power generation with CCS "as a potential bridging technology that could support the transition to a low carbon energy future". GNI also has ambitious plans for the development of renewable gases. In particular, GNI is targeting circa 11 TWh of biomethane grid injection by 2030 (20% of current demand). In 2018, GNI was shortlisted for €8.5 million of funding for the GRAZE project under the Irish Government's Climate Action Fund – this will involve the construction of the first Central Grid Injection Facility for renewable gas in Ireland. GNI is also looking to the transport sector and Compressed Natural Gas (CNG) for heavy goods vehicles in particular as part of its decarbonisation strategy. In 2016, GNI was approved for €6.5 million of funding from the CEF Transport Fund for the Causeway Study. This will involve the construction of a pilot network of 14 CNG Stations. In the longer term, GNI is proposing to develop a national CNG station network, co-located in existing forecourts, on major routes and/or close to urban centres. This CNG network will be made-up of both public and private CNG fast fill refuelling stations.

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?
The assessment of any asset decommissioning needs very careful consideration as set out in the consultation document. There are significant benefits provided by network assets, and full consideration of all these benefits is needed prior to any further discussion on the development of a decommissioning CBA. The benefits to security of supply, market integration and diversification, optionality in managing uncertain future energy requirements, impacts on neighboring markets (and beyond) all need to be considered prior to any formal process and initiation of a decommissioning CBA. Given the key role of gas in the energy mix, it is premature to introduce discussions on the development of a formal decommissioning framework. On the contrary, efforts should be made to maximize the efficient use of the gas infrastructure to ensure that investments in the overall energy system occur in a balanced manner. In particular, optimal and integrated planning of gas and electricity infrastructure should be a key focus to ensure that the least cost pathway is taken to achieve the energy transition.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
GNI wishes to affirm its support for the advances that have taken place with regard to integration of the EU Gas Market and Third Package implementation. The current gas legislation provides a sound basis for ongoing development of an integrated gas market. Implementation of the regulations is almost complete and the impact on market development is already providing significant benefits, e.g. with better price convergence on many hubs, improved market liquidity and prevention of congestions and their management. The implementation of the current legislation has already had a clear positive effect in many market areas, resulting in liquid and functional market places. The incorporation of decarbonised gases (e.g. biomethane, synthetic methane & hydrogen) into the current market should also be fully considered, including the determination as to whether the current arrangements are fit for purpose and whether additional measures might be needed. In addition, the management of hydrogen within the current market arrangements might need to be considered, especially in determining whether there is a need to create a separate hydrogen market or incorporate hydrogen into the current gas market.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
GNI believes that future changes in the gas sector can have an impact on the dynamics of the gas market with the need to update it. Increasing injection of renewable gases at the distribution level can lead to market needs that are not a current reality. Excess of local renewable gas production that would not be consumed on the DSO network may require injection into the TSO network using reverse flow infrastructure to supply the demand of other locations or to be stored. Investments should be carefully assessed so that capacity allocation mechanisms, tariffs, quality assurance and operations will have the necessary regulatory framework for transparent, non-discriminatory and secure use. Additionally, the interchangeability of local renewable gases production at national and even cross-border levels should be facilitated in so far as is possible, since a local market may undervalue them, with possible negative effects on their production potential. A Guarantee of Origin Scheme is important as it gives market value for renewable gases such as biomethane, synthetic methane and hydrogen. Concerning the development of hydrogen, it will be necessary to determine whether or not there is a need to create a separate market for hydrogen, in the case of dedicated 100% hydrogen networks. More broadly, when considering the development of a decarbonised society, a one-size-fits-all solution is not ideal for a diverse pan-European energy market, with so many different requirements, political drivers, and stages of maturity and geographical distribution of resources. The main concern will then be how to connect all available solutions without hampering the integration of the European energy market already achieved.

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?
GNI considers it premature to evaluate the current tariff regime. GNI is in the process of implementing the TAR NC for October 2019. There are still a number of market benefits to be gained that are associated with the full development of the entry-exit model; most significantly, the creation of liquid markets with beneficial effects for final customers. We are aware of the debate on the potential need for tariff reform, as proposed by CEER's FROG report. However, prior to considering potential changes to the tariff arrangements we need to see the full effect of the implementation of the TAR NC first. GNI understands ENTSOG recognises that an excessively high cross-border tariff can become a 'de facto' barrier to gas trade, the 'pancaking' effect (i.e. the cumulative Interconnection Point (IP) costs for a shipper along a gas route) is a feature of the current EU gas market design and it should be considered as a normal effect provided that IPs tariffs are correctly determined. Changing the tariff regime providing less weight to cost-reflectivity would create winners and losers among network users. It is too early to assess the impact of the TAR NC, which is not yet fully implemented. Once Member States have implemented the TAR NC provisions, especially with the application of the new tariff methodology principles and transparency requirements, it will be relevant to reassess the TSO tariff regime. At this stage, reform proposals can be premature and might disrupt the ongoing implementation of the TAR NC.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
To assess the impact of cross-border tariffs on cross-border trade, ongoing monitoring of the markets is needed. As tariffs develop, the impact on cross-border trade needs to be assessed. While there is merit in identifying any general trends that may suggest a deterioration in cross-border trade, it may be equally important that any assessment done should allow due consideration to the characteristics of individual jurisdictions and acknowledge the potentially varied challenges that individual transmission networks face in this area, prior to any decisions or actions being taken.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
To realise the creation of a decarbonised society, TSOs, amongst other players, should have the opportunity to progressively invest in activities, such as biomethane facilities, CNG/LNG, CCS and CCU technologies, hydrogen networks, digitalisation, and related R&D and pilot project expenses. NRAs would be asked to take such costs into account as necessary infrastructure investments to be incentivised. Regulatory sandboxes could play an important role to encourage R&D and pilot projects by TSOs to test and roll-out required new technologies. The Regulatory Sandbox approach would allow testing of innovations under regulatory oversight. It can be used for experimentation with new technologies or new business models. Depending of the specifics of a project, it can be time-bound or include an innovation fund to allow an entity carry out R&D and pilot projects with new technologies. A sandbox creates a conducive and contained space where experimentation with innovations at the edge or even outside existing regulatory framework can be carried out (United Nations, Briefing on Regulatory Sandboxes).

Survey response 31

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Galp Gas Natural Distribuicao

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The strict separation of essential infrastructure activities (especially TSO and DSO) from supply and trade is fundamental in the gas market design established by the European energy regulation in place. DSOs and TSOs have a key role as market enablers to ensure fair and effective competition. As such, they are regulated monopolies focused on (i) the performance of their core activities and (ii) neutral facilitators to develop the market in the interest of end-users. The objective of decarbonising the economy requires an energy transition which involves the creation of new business models and a deep evolution of the energy markets. The way these changes will occur is still uncertain. Therefore, there are significant regulatory challenges to achieve a fully sustainable gas sector, especially concerning the potential contributory roles of DSOs and TSOs in facilitating the transition through new activities and necessary changes in the relationships between DSOs and TSOs. 1) New activities to foster renewable gas development Network operators must be fully dedicated to their core activities: design, develop, operate and maintain their assets and organise their use in a transparent and non-discriminatory manner. In addition to this, the specific position in the value chain of the network operators gives them a key position as neutral market facilitator. The current involvement of some European DSOs and TSOs to support the development of renewable gas such as biomethane injection or sustainable mobility show their potential as a market enabler for nascent activities conducted by third parties (biomethane or hydrogen producers for instance). That is why regulation should give sufficient flexibility to allow DSOs and TSOs to leverage their unique knowledge of the market as well as being initiators through, for instance, pilots and demonstrators in new activities while the market is not mature enough to develop them. Such new activity, approved by the regulation authority, should be allowed under specific conditions and especially with the objective of supporting competition and benefitting end-users. We would like to highlight that in the energy sector and across Member States, diverse examples of activities developed by different stakeholders subject to different regulatory frameworks can be found, such as gas storage, LNG plants, interconnection projects or supported renewable energy sources. Depending on the Member State, the activity and the state of the development, these activities were developed or not by TSO/DSOs. The shift to a fully decarbonised gas industry will require support for initiatives which are currently in the innovation phase of development to bring these to the point of commercial viability. DSOs and TSOs are well positioned to promote decarbonisation of the gas sector, but they need a flexible and appropriate regulatory framework to allow them to invest in new businesses such as decentralised management of a dynamic network, blending of natural gas with renewable gases, large scale experimentation of CO2 and/or H2 grid management. Furthermore, a way to solve the question of supply-demand balance on distribution grids raised by major injection of renewable gases in local networks could be to develop the demand according to a circular and local economy. Regulated entities like DSOs should be authorised to contribute to the investment in infrastructure for gas mobility such as gas refueling stations or bioLNG storage in the case that the market is not mature enough to propose it spontaneously and that such development brings value by avoiding network investments. Power-to-Gas facilities should not be classified as gas production plants. Power-to-Gas may be provided as a conversion service that transforms electricity from a renewable source, or any other electricity network user, into gas (such as hydrogen or synthetic methane) for storage and further use in the energy system. A clear definition of the role of Power-to-Gas technology is required in the regulation to enable sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner. Finally, the possible involvement of DSOs in building or managing biomethane/Power-to-Gas plants if the market is not ready to do so should be considered in the assessment. 2) Reinforce cooperation between DSOs and TSOs to support renewable gas penetration Considering the decarbonisation, decentralisation and digitalisation of the gas sector in the coming years, the role of DSOs ad TSOs will evolve. It will require operators to work closely together. The development of renewable gas is a priority. It is crucial to make the right move today to reach a decarbonised gas market in 2050. As production could take place in areas with a lower gas demand than production levels (particularly the case of biomethane production in rural areas) it could be necessary to send the renewable gas to other areas capable of consuming or to storing the excess gas locally. To do this, several means are possible including a reverse flow installation (consisting mainly of a compression unit enabling the movement of the gas from the distribution to the transmission grids) which is not the current network design. Therefore, DSOs and TSOs need to cooperate when it comes to renewable gas development – including Power-to-Gas plants - to plan together the required infrastructure, depending on the location and the characteristics of the injection points, and to ensure the adequacy of their operations. Local storage units are another means to balance supply and demand over the year and to avoid grid congestion. Such installation also needs to be planned between DSOs and TSOs as they participate in the development of renewable gases. This alternative should be compared to the reverse flow installation and other options like virtual pipelines. Cost/benefits analyses should be performed for each of the options to find the best solution for the gas system as a whole. At a European level, the right channel to facilitate the work between DSOs and TSOs should be through the potential EU gas DSO Entity and ENTSO-G: - DSOs are ready to actively participate in the TYNDP with regards to renewable gas plants, reverse flow pipes and network operations having an impact on the distribution network, - DSOs and TSOs should exchange data and best practices on their respective networks and work on cyber-security issues. GGND is willing to actively participate and contribute to the progress of renewable gases at a European level and would welcome taking part in joint discussions concerning elaboration of the rules for such evolution of the industry.

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.
In our opinion, the allowed percentage of hydrogen being injected in the gas grid should be harmonised at a European level. The level of this percentage should be defined within the discussion on norms such as CEN/TC 234 and EN16726. A harmonisation of hydrogen levels will facilitate the exchange of gas with hydrogen potentially flowing between countries, therefore contributing to security of supply. The question of the maximum percentage blend of hydrogen in the gas grid is a technical subject. Indeed, it depends mainly on the grid's characteristics (material and components), which vary significantly among Member States, and of the appliances used by the end-user. We fear that a definition of a harmonised hydrogen percentage would reflect the worst-case scenario leading to a relatively low value as the reference. However, Member States should be free to choose the pathway(s) they want to follow and relevant timelines. The use of hydrogen, either in combination with natural gas or in pure form, will require at least an assessment and possibly an adaptation or substitution of gas infrastructure elements and end use applications. Providing technical clarity at the EU and local level on the different pathways is necessary to identify which technological developments and investments are needed. In the short-term, there is an urgent requirement to remove technical and legal barriers that could hinder further development of hydrogen systems, including blends. In the medium and longer-term, natural gas end-use applications standards should increase their readiness for hydrogen blends. Gas applications should also be provided with the necessary controls to withstand the foreseeable variability in hydrogen blends. An EU roadmap setting out the hydrogen readiness of new appliances would be beneficial. It seems too early to fix a threshold for hydrogen injection in the gas grid in the present situation. Further studies and experimentation to establish what is the desirable/maximum percentage of hydrogen injectable without affecting security are underway, especially by Marcogaz. The issue of the measurement of the calorific values of blended gases still needs further examination.

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.
The use of hydrogen as an energy carrier has significant potential as part of the energy transition and its use is envisaged that this will increase in the coming years. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its development. The reason for the regulation of the natural gas network in Europe is that it constitutes essential facilities and as such, without regulation, competition in such activity would not be possible or would be negatively impacted for the industry as a whole. Such regulation was possible because most of the infrastructure was already build under a completely different framework based on long term supply contracts and global supply routes including transit, shipping, and storage. Assuming the development of a network dedicated to hydrogen transport and distribution, separate from current natural gas grids, such networks would constitute natural monopolies in the same manner as the gas networks. Therefore, there is no reason to treat them differently. Hydrogen networks should therefore be regulated in a similar way, taking into account the peculiarity of a developing network, a reduced number of connections to redelivery points in the early stage and capex likely to be higher than that of the gas network. We believe that the regulatory authorities should allow, depending on the relative maturity of the activity and its situation in terms of competition, the possibility for a regulated entity such as DSOs and TSOs to invest in hydrogen networks. This is the optimal way to develop a hydrogen industry at scale and ensure third party access and enable the safe and cost-effective development of hydrogen networks.

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.
The "technology neutral" approach should be the common rule and should be preserved as far as a holistic methodology is respected. For instance, the biomethane industry has been disappointed by the way zero emission has been considered in the transport regulation while considering a "tank to wheel" rather than a "well to wheel" approach. We remain convinced that life cycle analysis should always be promoted in the impact assessments. However, markets also require some policy or regulatory signals to deliver expected objectives in time. This is why, in the light of EU energy and climate strategy, some kind of intervention would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades: Decarbonisation gas targets, support schemes, definition of regulated activities and planning, etc are possible instruments that deserve further examination. In the case that market practices such as tender are not able to sufficiently account for both positive and negative externalities, specific rules should apply to allow the best investment decisions. For example, the development of renewable gas makes even more sense while considering the numerous positive externalities in terms of emission reduction of the agriculture and waste management, the promotion of agricultural sustainable practices and the creation of local jobs. Therefore the "cost efficiency" principle should be used to bring decisions in effective system optimisations and achievement of the long-term strategy of full decarbonisation by 2050. In particular, exemption of the "technology neutral" approach could be necessary to support nascent activities for which positive externalities are significant such as biomethane production and injection in the gas networks. There are supports and an adequate regulatory framework in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of supports, assuring a level playing field between all technologies and energy carriers.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas is a promising technology allowing the production of two different renewable gases that could be injected in the existing gas networks: • renewable hydrogen produced through electrolysis of water with renewable electricity, • synthetic methane via the process of methanation of the hydrogen with CO2 captured from the air, industrial processes or from a biomethane plant. Power-to-Gas could bring flexibility to the electricity grid as the gas network has the ability to enable large scale energy storage in an efficient way. Power-to-Gas allows the conversion of renewable electricity into a form of energy that could be consumed later, either directly or used to generate electricity. As such, Power-to-Gas is a new link between power and gas systems contributing to better integration through sector coupling. In other words, Power-to-Gas may offer the flexibility in time and space needed by non-dispatchable renewable sources at a marginal cost. This will help to keep the gas network functioning properly while natural gas consumption may decrease. The existence of a back-up in case, for instance, of a major disruption in the electricity sector will help the resilience of the energy sector as a whole. Power-to-Gas infrastructures is expected to strongly contribute to the decarbonisation of the gas sector and the question of ownership and management of this infrastructure is important. DSOs who wish to invest in Power-to-Gas as a conversion service should be allowed to start now, in order to ensure the technology reaches the required scale and maturity. Particularly where there is a lack of interest from the market, DSOs could be involved in these activities while respecting the unbundling regulation. Regarding the process to produce synthetic methane, it will be necessary to move CO2 from the producer (biomethane plant for instance) to the Power-to-Gas infrastructure. We are favorable to regulatory changes allowing under certain conditions DSOs to distribute CO2.

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?
Power-to-Gas technology could be considered as a pure consumer of electricity and apply the same rules as the other consumers. Nevertheless, considering such activity as a service for the energy system as a whole and the difficulty to develop business cases today, specific tariff should be envisaged for this activity as a storage, energy conversion, or a congestion management plant for instance. Considering that in the long-run, the power system would be mainly supplied by intermittent sources, the value of Power-to-Gas plants to provide flexibility and dispatchable energy should be related to security of supply concerns. Therefore, the regulation should be flexible enough to allow the development of various business models and avoid double charging in the tariff looking at effective synergies for both power and gas systems. Concerning the issue of tariffs and potential double charging when it comes to Power-to-Gas-to-Power (P2G2P), any unwarranted fees should be avoided as this could limit the development of hydrogen and act as a barrier to sector coupling. An example of this is that storage and conversion of one form of energy into another (which can be classified as an end-user in the electricity sector) should be treated as a separate conversion process, exempt from end-user taxes and levies.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legislative and regulatory frameworks were designed prior to the development of Power-to-Gas infrastructure, and therefore does not take into account its potential and possibilities. A review and amendment of the legislative and regulatory frameworks are needed to ensure their adequacy for the development of Power-to-Gas infrastructure.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Guarantees of Origin (GO) allow transparency for relevant parties (including end consumers), as they certify the conditions of production of the energy. Guarantees of Origin should be based on similar technological thresholds and the system should be overseen by a competent authority, in charge and able to collect reliable production data, to run appropriate control systems and – if needed – to impose appropriate sanctions in case of any Guarantees of Origin misuse. In addition, Guarantees of Origin give useful information on the development of renewable gas supply and alignment with demand. Regarding the development of a cross-border trading of renewable gas GOs, the following should be considered: - this scheme must be based on “mass balancing” and not on “book and claim”. It is necessary to keep the link between the GO and the molecule to ensure transparency for the end-user. - the system must include the sustainability criteria defined into RED II regarding biomethane. Cross-border trade of GOs for renewable gas should be supported by ensuring ‘interoperability’ of GOs across all Member States. Standardisation, interoperability and harmonisation of GOs across all Member States will allow for the efficient cross-border trading of the sustainability characteristics of renewable gas produced in the EU. The ‘European Renewable Gas Registry’ (ERGaR) has been established for this purpose and aims to incorporate all national renewable gas registries into the ERGaR system. The ERGaR project also aims to establish a European hub for GOs and, in doing so, to allow for mass balancing at a European level. Regulatory support will increase the chances of the successful implementation of the ERGaR system.

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?
One lesson to learn from the renewable electricity GO scheme is that it should not be based on a “book and claim” system, rather than a “mass balancing” system: it has more value to sell the green electricity to the person who receives the GO. Another lesson to be learnt from renewable electricity is the importance of avoiding any double support between an EU-wide GO system and Member State support schemes. The EU-wide GO system for renewable gas should be set-up ensuring that double counting of renewable gas volumes is avoided. Successful implementation of an EU wide scheme with mass balancing, will ensure that volumes are only counted once.

Infrastructure Investments and Regulation

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?
The regulatory authorities should make sure that DSOs’ contributions are effectively taken into consideration in the elaboration of the development plans such as TYNDP. Transparency is essential in the elaboration of the TYNDP and in the assumptions. ACER should have the power to establish the rules for the approval of the TYNDPs that individual NRAs must adopt. The system should work in a similar way in all countries, even though being sufficiently flexible to take into account the different structures of the gas systems amongst them, the gas penetration rate among consumers and the specific objectives connected to the decarbonisation and energy efficiency path established in the National Energy and Climate Plan (NECP) for each Member State, approved by the EU.

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)?
Sustainability is one of the key criteria for the evaluation of PCIs as described in Regulation (EU) 347/2013. GGND welcomes the fact that there is now a focus on renewable and decarbonised gas projects by the industry, which will help ensure the transition to a decarbonised gas grid across Europe. To reduce the risk of over-investments, and in the light of market needs and regulatory and energy policy objectives, new infrastructure investments should be based on the results of the application of validated CBA methodologies and appropriate market tests. The use of F factor stating the minimum amount of costs to be recovered from capacity bookings is paramount, to avoid selecting PCIs without a minimum market interest behind them. As mentioned by CEER, we support the extension of the PCIs’ selection scope to projects regarding the connection of decentralised and local gas generation, including renewable and decarbonised gas, as well as to gas-electricity integration in the context of Power-to-Gas and sector coupling as well as for the conversion/adaption of gas grids to new gaseous carriers. A wide range of projects and technologies should be supported through the PCI framework, including biomethane injection.

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?
We do not see a risk of stranded assets in terms of our DSO activity. Furthermore, based on existing and projected gas demand we do not see a risk for stranded assets, at the very least in the next 10 years. This is in line with CEER’s observations, as well as the EC’s 2050 scenarios and draft National Energy and Climate Plans 2020-2030 recently published, among others. A risk for stranded assets may arise in the case of a decline in natural gas consumption beyond 2030, if this is not accompanied by its substitution with renewable and decarbonised gases such as biomethane, green hydrogen or blue hydrogen injected into the grids. Alternative uses for potential stranded assets in the longer term should be considered by regulatory mechanisms to favor investments that are already made in essential facilities. A possible regulatory tool could be a financial incentive for the production of electricity converted into gas in the case of reduced electricity demand for a given plant, in order to avoid the formation of negative prices for the renewable electricity producer and indirectly support the production of gas from power. Due to its geographical location, Portugal has great potential for producing energy from renewable sources. In fact, more than half the electricity consumed in 2018 came from renewable sources (53.1%). Portugal is the European country with the third highest share of wind in its electricity mix. In 2018, wind provided 12.7 TWh, being the second largest energy source for electricity production, with a 22.4% share, only surpassed by hydroelectricity, with less than a 2 p.p. difference. In 2018, national wind power capacity increased to 5,4 GW, due to the installation of 26 wind turbines, with an average power rating of 2.6 MW. According to the National Energy and Climate Plan 2030, this capacity will reach between 8.8 and 9.2 GW, since wind energy will be heavily promoted, not only due to on shore wind farm enhancement, but also from off-shore facilities which will contribute to electricity production. This increase in power capacity means that by 2030 wind will probably be the largest source of electricity in Portugal. Solar capacity will also significantly increase, achieving between 7.8 and 9.3 GW, in 2030. Despite this increase in the installed power capacity, there may be periods when the energy produced by these sources is not consumed, causing curtailment conditions. In our opinion, when this surplus energy is not used for injection into the grid, there will be a great advantage in its use for injection into the gas grid, through technologies such as Power-to-Gas. In this way, it takes advantage of the installed capacity, storing the surplus energy and avoiding the stranded assets.

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?
In our opinion, the strengths of the natural gas infrastructure system include the numbers of interconnections, its extensive network across the EU and its access to energy sources located in different countries and arriving in Europe through different routes. These are the characteristics that allowed Europe to enjoy a long-lasting and secure energy supply, able to satisfy demand even through critical moments, of a political nature or linked to natural factors, which have affected specific producing countries and / or supply routes. It is because of these characteristics that the natural gas system can support the energy transition path towards an increasingly decarbonised economy. For this reason, the choices concerning the decommissioning of significant portions of natural gas infrastructures should be evaluated not only with regard to its effects on the country in which they are physically allocated, but also for the cascading effects on neighboring countries. Any development of a formal decommissioning framework should ensure efforts are made to maximise the efficient use of the gas infrastructure to ensure that investments in the overall energy system occur in a balanced manner. In particular, optimal and integrated planning of gas and electricity infrastructure should be a key focus to ensure that the least cost pathway is taken to achieve the energy transition.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The fast and wide development of renewable gases (biomethane, synthetic methane, green hydrogen) is critical. All the energy mix scenarios, including those of the electricity sector, show that we could not go above 60% electrification in Europe. Therefore, gas will continue to play an important role in the European energy mix. However, considering the Paris agreement, it is necessary to decarbonise this sector to meet the climate objectives. Therefore, it is important that gas market design further examines the topic of renewable gas development. The development of renewable gas will increase the level of energy decentralisation. Therefore, it is necessary to ensure an appropriate regulatory framework to enable DSOs to become key actors of this evolution, while respecting the unbundling rules. Since 2009 and the last revision of the gas market design, the economy has become more digitalised. Therefore, the new gas market design should reflect this evolution.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Some kind of policy or regulatory signals will be required to deliver expected ambitious decarbonisation and transformation: Decarbonisation gas targets, support schemes, definition of regulated activities and planning are possible instruments that deserve further examination. Some of these instruments are likely to be needed to enable necessary transformation of the gas sector in the coming decades. To this extent it's pertinent to look at the transformation occurred in the electricity sector in the last 20 years, as well as to the many lessons learned from it. We see a strong need to update the gas market design to develop renewable gases. Several regulatory changes are required to ensure the take-off of renewable gases production. First, it is necessary to define precisely renewable gases. It is fundamental to have a definition including the main technologies allowing us to have more visibility on the sector. "Gas produced from renewable sources": Gas produced - with respect of the rules listed in article 7, 25 and 26 of the RED II directive on the use of energy produced from renewable sources, either via anaerobic digestion, gasification of biomass, Power-to-Gas or via any of the technologies using renewable energy sources". "Anaerobic digestion": Biological conversion of biodegradable materials by micro-organisms in the absence of oxygen creating two main products: biogas and digestate. Once purified, biogas results in the production of biomethane. "Gasification": Thermochemical process at high temperature (> 700 °c), producing gases composed mainly of carbon monoxide and hydrogen, usually followed by a methylene stage for conversion to biomethane. "Power-to-Gas": Conversion process allowing the transformation of renewable electric energy into a gas vector produced from renewable sources: hydrogen by electrolyse of water or synthetic methane by electrolyse and methanation. "Biogas": Gas produced by anaerobic digestion of organic matter, gasification or even Power-to-Gas, before purification stage. Therefore, these definitions will allow investors greater clarify on the renewable gases production technologies. Several other regulatory changes would also contribute in this objective, such as the introduction of renewable gas targets. On this point, RED II objectives should be defined in the gas sector. Thus, we could have three different renewable gas objectives at the European level: - A general objective by 2030 of renewable gases injected in the grid, mandatory at the European level and indicative at Member States level, - An objective by 2030 of renewable gases in total final consumption of gas in the transport sector, - An objective of an increase of renewable gas per year in the total final consumption of gas in the heating and cooling sectors. The development of renewable gases must be sustainable. Therefore, it is key to make sure that the next gas market design refers to the sustainability criteria defined in the RED II directive. In addition, the next gas market design should include a principle of priority access to the gas network for renewable gases while ensuring the respect of unbundling and the security of the network. This priority right will allow us to harmonise the existing European practices. The producers will have the certainty that their projects will have priority over natural gas. The future gas market design should also require Member States to oblige operators to socialise all or part of the costs for the development of renewable gas production sites (connection costs, reinforcement of network). To conclude, this new role of DSOs will require an update of the definition of "distribution" and of "distribution system operators" in the gas directive to include the fact that they distribute today natural gas and gas produced from renewable sources.

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

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
1) An EU gas DSO Entity We would like consideration to be given to the tasks and form of the EU DSO Entity. In our opinion, the EU gas DSO entity should be different from the EU electricity DSO entity as there are several issues which are specific to the gas sector. Besides, the above-mentioned role of the entity when it comes to cooperation with the TSOs, the EU gas DSO entity will be responsible for facilitating the exchange of best practices on energy efficiency, digitalisation, demand side management, data protection and cyber-security. DSOs should also have a contributing role in the development of renewable gases, storage capacity and gas mobility. 2) The digitalisation of the network Smart meters are currently being rolled out in several EU countries. The next gas market design should support this development. Smart meters allow for the reduction of energy consumption, therefore participating in the energy efficiency objective defined in the EED directive. Moreover, they bring social benefits to consumers who are better informed about their energy consumption. Similarly, more DSOs are installing sensors on their network at pressure reduction stations and at biomethane injection plants. This evolution allows for optimised management of the network and better integration of renewable energies into the grid.

Survey response 32

Contact details and treatment of confidential responses

Contact details: [Organisation][]
VERBUND AG

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
From a VERBUND perspective, it is mainly P2G which should be considered in the assessment. Similar to the debate on storage in the electricity directive, VERBUND is of the opinion that P2G technologies should in principle be organised as a market activity. The transfer of P2G technologies into the regulated asset base of grid operators would lead to market distortions on the electricity markets and entail negative effects on other flexibility options available on the market. The current debate on P2G ownership mirrors the debate on storage in the electricity sector while at the same time adding a further layer of complexity, namely by adding the gas sector into the debate when talking about sector coupling. In particular from an electricity sector perspective, the adverse impact of P2G as a regulated asset on other flexibility options, such as hydro pumped storage, batteries and also demand side management could be severe: Large scale P2G will decrease the price spreads for other flexibility options, thus making these less attractive. This is problematic, if P2G is financed by regulated tariffs while other storage and flexibility options have to cover their costs on the market (no level playing field). Eventually this would distort market price signals both in the electricity and in the gas market. However, there is currently no business case for market based P2G investments. Therefore, as a first step, measures supporting a regulatory framework conducive to the economic viability of P2G installations should be implemented, e.g. introduction of CO2 pricing, certification, tariffication reform etc. If these measures fail to trigger a gradual market uptake and if the electricity and/or gas systems at that point in time demonstrate the actual need of absorbing excess electricity (in particular to allow for seasonal storage), only then alternative models of market introduction may be considered, i.e. by introducing dedicated support schemes for P2G installations or – as a means of last resort - a temporary and limited set-up of P2G pilot demonstration projects in the regulated sector (and as a consequence financed by regulated tariffs). These pilot projects should be limited in size and serve the sole purpose of gaining technical and operational insights, both on installation level as well as from a systemic point of view. In general, before such a step is taken, NRAs will need to decide which of the network operators (electricity or gas or both) will retain the right to build P2G installations. However, the potential detrimental effects of a transfer of P2G assets into the regulated sector, such as dampening price signals by transferring the cost of P2G into network fees and distortions on flexibility and hydrogen markets need to be carefully assessed against the potential benefits of such a measure. If the future policy framework eventually contains a compromise approach with regard to the regulatory set-up of P2G installations similar to the one laid out in the consultation document on p. 15, the critical element would be the mentioned “special justification and cost/benefit analysis”. The consultation document remains very vague on this part. The framework lacks guidance on which justification would be sufficient for the NRA to allow the activity or not. Similarly, there are no clear guidelines for the cost-benefit analysis. This raises the risk of arbitrary national decisions and a heterogeneous application of the framework in the European Union. A common set of rules on EU level is needed to be implemented by the NRAs. The elements sketched out in the previous paragraph (regulatory measures & still no market uptake, market based support scheme and only as a last resort the integration into the regulated asset base) could constitute a guiding principle on how to come to a decision on the role of P2G in the regulatory context. Furthermore, a regular market test similar to the one laid out in Art. 36 and 54 of the revised electricity market directive needs to be carried out. The time interval should be at least 3 years. If the market test comes to the conclusion that market based investment in P2G installations would take place, grid operator activities should be gradually phased out and compensated.

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.
In principle, the thresholds for the injection of hydrogen into the gas grid should be raised to the maximum level of technical feasibility in order to accommodate the long-term objective of storing excess renewable electricity via P2G in the gas grid (or in gas storage facilities). Ideally, there should be an EU-wide standard for the injection of hydrogen into the gas grid, in order to prevent barriers to cross border trade.

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.
Currently, as outlined in the consultation paper, there seems to be no necessity to regulate private hydrogen pipelines. In a medium to long term scenario, however, with a stronger uptake of hydrogen production, there could be competition issues, such as refusal of third party access. This development should be closely monitored and regulatory action should be taken, if necessary, then mirroring the regulatory principles for natural gas networks. Taking into account the ambitious development scenarios for hydrogen, legislators may consider to develop specific regulation now and define thresholds for the application of said regulation in order to create long-term security for investments.

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.
Pro-active market interventions should be a measure of last-resort if there is an inherent flaw in the functioning of the market. Before, Member States should strive to improve market functioning, for example introduce appropriate certification and remuneration mechanisms for the deployment and use of renewable hydrogen/gases.

Q5 Which role do you see for power-to-gas infrastructures?
Both scenarios mentioned in the consultation document (i.e. P2G with subsequent reconversion of H2 into electricity as well as P2G and subsequent injection of H2 into the gas grid) are possible in principle. The first case (P2G with subsequent reconversion into electricity), however, comes with high conversion losses, making a business case very unlikely. Therefore, the injection of hydrogen (depending on the maximum injection rate) into the gas grid seems to be more likely. (By methanation, the maximum injection rate for hydrogen can be avoided, however, this additional process deteriorates the business case even further) Not mentioned in the consultation paper, but essential for the decarbonisation of energy intensive industries (e.g. steel industry) are electrolysers producing renewable hydrogen on site (or in proximity to industrial sites with a direct line between producer and industrial consumer). In this case, renewable hydrogen will not be injected into the gas grid, but used directly in industrial processes (sectorial integration). In order to maintain a level playing field between hydrogen production injected into the grid and on-site consumption, this category should not be forgotten when designing the regulatory framework (i.e. in terms of tariffication of input electricity, certificates for renewable hydrogen etc.). VERBUND believes that electrolysers should generally be viewed as a conversion technology, allowing the conversion of one energy carrier into another. However, because hydrogen or other hydrogen-based energy carriers (ammonia, synthetic natural gas) can be stored, electrolysers can be considered part of a storage process, if there is a temporary deferral in end-use. Since P2G offers the possibility for different end-use cases, it will be important to apply tariffication accordingly.

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?
Yes, partially they do, for example in the case of double charging when P2G is used to convert electricity into a gaseous energy carrier.

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?
Pls. refer to answers to Q 9 .

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?
•Establish a system that allows for the development of a liquid European market for GOs for gases. VERBUND supports a full disclosure approach for gases, both renewable and non-renewable. For this purpose a unified gas classification scheme should be developed, which allows to compare different kinds of renewable, low-carbon or decarbonised gases based on their carbon footprint (e.g. CertifHy). •Ensure that Member States develop their certification systems on the basis of a common European set of rules and minimum standards in order to encourage cross border trade •Allow for a separate trade of the underlying energy carrier and the GO (also cross border) •Set up systems to avoid double-counting of the green/renewable property of the renewable gas •Need to address sectorial integration in the GO system: Renewable gases can have a strong decarbonisation impact in several sectors (i.e. green hydrogen in industry, in the refining sector, in transport etc.) These off-grid applications (where green hydrogen is not injected into the gas grid) should also generate GOs to be traded with other market players in order to provide incentives for these hard-to-decarbonise industries (while avoiding double counting of the renewable property). •Set up of an inter-registry communications hub (such as the AIB Hub for electricity GO) and make electronic transfers mandatory

Infrastructure Investments and Regulation

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?
Sector coupling will over time increase the competition between electricity and gas infrastructure. Therefore it will be important to have a framework that compares infrastructure development plans based on a unified framework that aims at system-efficiency.

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?

Adapting the Gas Market Design

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?

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
If renewable or CO_2-targets for the gas sector were to be introduced, it is important to take into account their impact across the entire value-chain and to analyse their effects within the context of the already existing support framework, in order to avoid negative side-effects.

Survey response 33

Contact details and treatment of confidential responses

Contact details: [Organisation][]

Netbeheer Nederland

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

The Dutch association of grid operators (from now on: Netbeheer Nederland) represents all the grid operators (DSOs and TSOs) in the Netherlands. In the Netherlands the grid operators are fully (legally and ownership) unbundled. Netbeheer Nederland welcomes the possibility to react on the CEER consultation on regulatory challenges for a sustainable gas sector and support CER doing so in the future.
In the changing energy sector, DSOs and TSOs have an important role as neutral market facilitators. With its natural position between production, trade and supply and the end users, DSOs and TSOs can play a significant role to achieve policy goals, also considering the climate targets resulting from the Paris Agreement. We would like to make a few suggestions:
1) DSOs and TSOs should have enough legal freedom to experiment (sandbox-rights) or to be able to kick-start new technologies if commercial parties are failing, for example regarding to sector coupling technologies such as power-to-gas as well all power-to-heat.
2) Further optimization of the DSO and TSO infrastructure is important for future and continuing system integration. This doesn't only exist of power-to-heat but also of stimulating the end users to use the most efficient energy carrier for his or her specific situation.
3) Netbeheer Nederland stresses that it is necessary to clarify the role of DSOs and TSOs in this system integration and what the policy goals are. So it is for instance possible to argue that the optimization of infrastructure is important (i.e. low infrastructural costs) or policy should support the maximum added value (economically and socially, i.e. energy and climate goals).
4) With the emergence of local biogas production, small biogas networks come to existence. There is a role for the DSO to operate these networks and upgrade the raw biogas to bio methane for injection in the natural gas grid.

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.

CEER addresses two different scenarios: blending (an increased amount of) hydrogen with natural gas use and the transport of pure hydrogen instead of or in addition to natural gas. Netbeheer Nederland thinks that it is not opportune to make a choice between the different scenario's. We prefer a cost-reflective approach and, in first instance, the possibility to experiment with both options.
On blending, we need a common European standard instead of different norms. In a more interconnected energy system, a coherent approach toward hydrogen blending is necessary. Especially because hydrogen might become the key gas regarding sector coupling and increasing synergies between electricity and gas sectors. Rules (standards?) should come at an earlier stage in order to support the development of hydrogen in both scenarios. Regarding the timing element, Netbeheer Nederland recommend to start innovative experiment right away. It is interesting to see whether it is possible to start with blending on a local scale in the distribution grids, to secure the TSO grids and interconnections are not hindered. For blending at local scale, it might prove necessary to allow DSO the legal rights to be responsible for the blending itself.
On hydrogen networks, it is of major importance that regulators and policy makers define which networks are of public interest and therefore should be regulated. This method might prevent that private initiative need to comply with new regulation in a later stage.

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.

The regulation of hydrogen (and biogas) shouldn't differ from the basic principles of the natural gas regulation today. These gasses might replace natural gas and thus have the same importance for society and economy.

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.
When addressing infrastructure use and planning, a cost efficient approach is (amongst others like speed and support) key in order to avoid unnecessary additional costs for users. However, as stated before, at the moment it is unclear which technology will be the most cost efficient. For that reason, experiments are key to develop these technologies to a more mature level. Regulatory sand boxes (also in European legislation) may be required for DSOs to participate in this experiments.

Q5 Which role do you see for power-to-gas infrastructures?
In a high-renewable future, the system balancing and the required flexibility will be provided by competing sources from both within and outside the power sector. On an European level traditional sources include conventional firm generation capacity such as hydro and nuclear power. In addition, we will see a much larger role played by demand side response from dispatch of new electric end-uses as well as storage and flexible production of electric fuels such as hydrogen and power-to-gas, and power-to-heat. In an integrated system this might lead to P2G and P2H technologies that are both needed by market-participants and TSO/DSO the last one for redispaching capacity across the different 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?
Regulation should adhere to these different technologies in a neutral way. A point of attention is that power-to-gas and power-to-heat are about a more shorter time and marginal coast, whereas network tariffs reflect the longer term and integral costs. ACER should give Member States guidance how to handle with this situation when adopting basic principles or best practises.

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?

Infrastructure Investments and Regulation

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?
In the Netherlands the government decided to phase out the so-called ‘Groningen-gas’ and to forbid in principle all new gas connections to the distribution grids. This means there will be stranded assets in the sense of grids that will be used less or shorter as expected. The significance of the impact depends on the future usage of the gas grids for other gasses, like hydrogen and biogas. The European principle that efficient costs will be remunerated, is applied in the Netherlands in a way that the tariffs also bear the costs of stranded assets. We strongly support this approach, however we are faced with the discussion how to handle the ascending costs for the end users that stay connected to the gas grid for the longest time. Together with the Dutch regulator, the DSOs and TSO are currently discussing this topic in the so-called MORGAN-project. An identified solution may be that the method for depreciation is altered or that a fund is created to bear future costs. The consultation document states on page 22 that “operators are responsible for the good management of their assets”. This statement is only true to a limited extent asthe regulator defines depreciation periods, while at the same time local governments by local policy decisions may decide whether a gas grid should be removed or not. As a consequence there will appear a difference between the regulatory depreciation period and the economic life cycle observed in practice. It is key that a firm and clear regulatory framework will address this situation since grid operators still have to invest in gas grids the coming years to secure the safety of their grids.

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?

Adapting the Gas Market Design

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?

Other question

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

Survey response 34

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Czech Gas Association

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
•To enable and foster the energy transition and the ongoing change to low emission energy system beyond 2050, TSOs/DSOs are well placed to be involved in activities that enable decarbonisation and promote future sector coupling. •The Czech Gas Association believes that the assessment should, among others, consider activities focused on production of renewable and decarbonized gases (e. g. biomethane), as well as on alternative gas facilities (e.g. Power to Gas facilities). By allowing TSOs/DSOs to invest in either a fully commercial way or to apply for financing through an open regulatory support scheme, they can support the development and scaling-up of the market. •Investing by TSOs/DSOs in alternative gas facilities should be possible in a commercial way if it is possible in given market– in competition with commercial investors. •If the commercial investments are not possible due to the market condition the Czech Gas Association believes that it would be beneficial to establish regulatory scheme open for any investor for ensuring that the underlying technologies can reach required scale and fully unlock its potential. A regulatory scheme should be under oversight of national NRAs. •The final decision on the possible implementation of regulatory scheme should be done by member states and should be based on market conditions. •TSOs/DSOs ownership and operation of alternative gasfacilities and offering conversion services to network users can comply with unbundling rules. Moreover, flexibility of alternative gas facilities can be offered as balancing service to electricity grid operators.

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.
•At first there should be no minimum threshold for hydrogen injection into the current gas grids. The maximum limit should be based on CEN and other expert institutions discussion and it should respond to realistic perception of current technical and legislative potential of transmission system operators. •Having in mind different stage of technical preparedness of infrastructure for hydrogen injection within the EU and still missing legislation covering hydrogen issue in several member states, it is difficult to set up common European threshold. Nevertheless, maximum threshold for hydrogen shouldn’t exceed 2 %, at minimum from the short-term perspective. However, impact of even 2 % hydrogen injection into gas grids and for CNG cars has to be further analyzed. •Further development and common agreement on standards for gas quality is needed in order to enable blending of hydrogen in gas networks reaching limits of 3 % - 5 % and more. •Regulation covering conditions for connection of points which could influence gas quality in the grids, including liabilities related to potential differences in gas quality stability and gas quality itself, should be considered on European or at minimum on national level. •The Czech Gas Association supports further analytical work of ENTSOG and CEN on possible hydrogen scenarios for 2050. Scenarios for concentration of hydrogen in the gas grids as well as in the whole gas chain on the level of 2%, 20% and 50% - 100% in 2050 should be developed and further analyzed in order to reach implementation of carbon neutral technologies. •Transition period will be needed in order to accommodate new requirements in this field. •Operators should be allowed to include in the RAB the cost of replacing depreciated assets by ones that are ready to integrate at least the hydrogen fraction indicated by threshold with the possibility to go beyond. Storage system operators should have access to climate-focused national or EU funds or financial support schemes to ensure that storage as an important part of the gas infrastructure is ready for future needs of the energy markets.

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.

• The use of hydrogen as an energy carrier may have a huge potential as part of the energy transition. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its growth.
• Hydrogen networks need to be regarded as natural monopolies as building parallel network structures would not be efficient mainly because of the large investment costs needed for building such network. It is likely that large scale hydrogen pipelines will have to have similar economic characteristics as the existing natural gas networks. The Czech Gas Association thinks that it will be necessary to allow TPA and further develop the EU Internal Energy Market to ensure pipelines full utilization. We believe it will be most efficient if the hydrogen networks will be managed by operators as a regulated business.
• The Czech Gas Association believes that the benefits of applying regulatory regime and TSO/DSO management over future hydrogen pipelines are following:
o Infrastructure optimization and cost savings as a result of coordinated planning that reflects the future development of the sector
o Guaranteeing non-discriminatory third-party access, so that all interested market players can benefit from gaining access to the hydrogen network and allowing its maximal possible utilization
o Guaranteeing the viability of pipelines in the development stage, as the load factor progressively increases.
o Allows a potential integration of hydrogen and (bio)methane markets to deliver one price signal for gaseous energy. This integration will prevent market fragmentation as hydrogen usage develops EU wide alongside gas usage.
• Conversion of parts of current natural gas grid to hydrogen pipeline can reduce the total investments that would be need for hydrogen pipeline construction. Such pipeline conversion still requires additional R&D, capital and time. These investments will have to be taken into consideration by NRAs and appropriately incentivised.

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.

• The Czech Gas Association believes that 'cost efficiency' is a legitimate reason for pro-active market / policymakers and/or regulators intervention where sustainability is the main driving force of the energy transition, but a focus on security of supply (SoS) and affordability must also be maintained.
• 'Technology neutrality' is needed for the efficient development of a decarbonised energy market and its associated regulation. Support schemes should not favour one technology over another e.g. biogas support mechanism for the production of electricity but not for injection into in the gas system.
• Besides cost efficiency, other criteria like SoS of the whole energy system, diversification of sources, peak demand, societal and environmental impacts (externalities) and future potential of the technology should be considered to promote activities like Power-to-Gas and hydrogen networks. In addition, any decision that will impact the future of gas and gas infrastructure, like a shift from a methane network to a pure hydrogen one, should be carefully assessed taking into account long-term cost efficiency.
• Nowadays, there are support schemes and an adequate regulatory framework in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of treatment assuring a level playing field between all technologies and all energy carriers.

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

The Czech Gas Association believes that power-to-gas as a technology will enable sector coupling which is essential for affordable, sustainable and secure energy transition. The role of alternative gas facilities should be to convert surplus of RES electricity to gaseous fuels - it should be treated as a conversions device.
The Czech Gas Association believes that usage of Power-to-gas has a number of benefits:
• It would facilitate sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner.
• It allows the maximisation of the renewable electricity production by converting renewable electricity to renewable gas which can be injected into the existing gas network and used among others as a raw material by industry.
• It will contribute to better functioning of the energy market by reducing the occurrence of negative/very low prices on the power wholesale market and enabling the development of additional market-based renewable electricity generation whilst providing a renewable source of gaseous energy.
• It will ease the balancing of the power grid by providing both up and downwards operational reserve and will contribute towards the reduction in electricity grid congestion.
• It allows to store gas in large quantities of energy derived from renewable electricity over long periods in gas storage facilities.
• It improves SoS in both electricity and gas sector.

Unfortunately, it is not economically sustainable to operate alternative gas facilities under current market conditions and therefore additional support may be needed. Regulation could have a role to play, as it is an efficient way to develop infrastructure and provide viable framework for potential investors. The Czech Gas Association proposes regulation as a mechanism that could be used to incentivise the development of alternative gas facilities.

Furthermore, the Czech Gas Association believes that TSOs in cooperation with DSOs and storage system operators are ideally suited to contribute to the ramp-up of power-to-gas infrastructure as they have the knowledge, experience and resources to develop this type of infrastructure.

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?
• The current electricity and gas tariff system is not designed to support efficient deployment and use of power-to-gas technologies. • Tariffs as well as other payments such as taxes and market operators fees shall be adjusted or avoided for power-to-gas station to avoid double payment for energy consumption (once at the power-to-gas station, for the second time with the final consumption of the converted energy) and also to provide a level of regulatory support for power-to-gas technology.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
• The current legislative and regulatory frameworks were developed prior to the development of power-to-gas infrastructure, therefore not taking into account its potential and possibilities. The current market conditions are not supportive for alternative gas facilities operation therefore a review and amendments of the regulatory framework is needed to ensure development of power-to-gas infrastructure. The Czech Gas Association suggests to make the following changes: • A definition of Power-to-Gas in the context of sector coupling should be included, with a clear distinction between the facility operator and the facility user. • A supportive framework is needed to enable the roll-out of Power-to-Gas. The possibility to apply for European investment funding (e.g. CEF) should be taken into account. • There should be no barriers to renewable and low-carbon gases to cross borders and sectors. EU-wide transparent guarantees of origin or certification scheme needs to be flexible enough to allow the cross-border transfer of energy and support cross-border trade of all kind of gases. • Furthermore, TSOs, DSOs a SSOs should be allowed to transport and store hydrogen and other gases to enable the scale-up of renewable hydrogen production from Power to Gas facilities.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
The Czech Gas Association believes that the cross-border trade of GOs for renewable gas is supported by ensuring ‘interoperability’ of different GOs. In this sense, ‘different GOs’ stand for different energy carrier (e.g. gas, electricity) and different issuing bodies. Therefore, compatibility should be ensured by the following measures: • Ability to convert the GO of one energy carrier to another when such is physically taking place • Cooperation of national issuing bodies and possibility of a EU-wide solution: National issuing bodies are encouraged to work towards setting up interoperable scheme for all GOs. This scheme includes recognition by every issuing body of GOs issued by every other issuing body – to allow the transfer of GOs. Additionally, a European-wide solution for the abovementioned cooperation could be established. The Czech Gas Association also supports the establishment of GOs for energy from “non-renewable” energy sources, in the terminology of the recast Renewable Energy Directive (RED II), that have a positive impact on the Green House Gas (GHG) emission reduction (e.g. decarbonised/low-carbon gas). This directive allows Member States to put in place that option.

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?
• Instead of copying the solutions from the renewable electricity to renewable gas, we should work towards being able to convert GO from one carrier to the other carrier. • Lessons learnt from the electricity sector include the necessity of common understanding of the data that should be included in the GO and certificate. All GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements. To that end, the common understanding of concepts and corresponding terminology is needed.

Infrastructure Investments and Regulation

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?
• Existing regulation provides an important role to ACER (and NRAs) in providing opinions to ENTSOs Draft TYNDPs and CBA Methodologies. o The recommendations provided to ENTSOG are published in the final version of the ENTSOG TYNDP as well as an explanation on how those where taken into account. o Also the CBA Methodology includes a dedicated document where ACER opinion, as well as other stakeholders feedback, are published together with the way those feedback have been taken into account. • Such ACER (and NRAs) role should be kept as it is foreseen today in order to provide important recommendation to improve TYNDPs/CBA Methodology while still preserving an open, transparent and non-discriminatory process towards all stakeholders. • Taking account the existing important roles for ACER/NRAs the Czech Gas Association does not see a need for extending them.

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)?
• It is important to underline that Regulation (EU) 347/2013 and CAM NC (2017/459) have different targets. • The Incremental Capacity process was designed for market-based investments, whereas PCI projects may be market-driven, but are important also for other reasons like security of supply or supply source diversity. This does not mean that those two Regulations are in conflict to each other. • The Czech Gas Association does not see a need for addition of cross-references between Regulation 347/2013 and 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?
• On one hand, we do see the risk of stranded assets on the side of DSO not only in the RES transition, but also in further use of (cheap) fossil fuels for economic reasons. Risk of stranded assets is also relevant for storage system operators. On the other hand, we assume a very low probability of this risk on the side of TSO. • In the very long view there is some uncertainty of the future of gas and it is difficult to assess the development of the gas sector, which will be influenced by many factors. Possible regulatory tools could include introducing risk premiums as a compensation for this risk, adjusting the depreciation periods and the applying front-loading depreciation methods. With regards to storage operators operating in highly competitive environment, a right market design should be set in a way that allows to maximise usage of storage facilities, for example by setting a discount up to 100% on transmission tariffs to/from storage facilities. Also, storage operators should be allowed to offer tailor-made products and services within the scope of legal boundaries without a need of additional regulatory approval. Especially with a view of the upcoming major shift in the energy sector, there is and will continue to be a demand for flexible adaptation to ever changing market conditions. • To reduce the potential future risks of underutilized or possibly stranded assets and their impact on investors regulators should appropriately balance the pace of old and new assets depreciation together with setting the adequate risk premia via WACC. • As the gas sector being in increasing competition with the electricity sector in future, regulators and gas regulated companies can e.g. try to define some measurable sector-to-sector indicators as a tool/proxy for the assessment of the above mentioned risks, which could drive the future regulated depreciation strategies for gas assets (e.g. such indicators might be deployment of electricity heating pumps, volume of electricity produced from gas, alternative gas facilities development and utilization, development of regulated electricity prices, etc.).

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?
• Given the clear indications on the key role of gas in the energy mix, it is premature to introduce discussions on the development of a formal decommissioning framework. • Before decommissioning of any asset, there needs to be thorough analysis including the assessment of the monetary and non-monetary benefits (e.g. security of supply, diversification of routes, impact of other markers). • We do not see any need for EU framework for decommissioning the infrastructure with a cross-border impact since the cross-border infrastructure is key in the fulfilment and preservation of integrated EU gas market.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
• The current gas legislation provides a sound basis for ongoing development of an integrated gas market. Implementation of the current legislation is almost complete and the impact on market development is already providing significant benefits, e.g. with better price convergence on many hubs, and improved market liquidity. • The implementation of the current legislation has already had a clear positive effect in many market areas, resulting in liquid and functional market places, as indicated in ACER's Market Monitoring Report in 2018. There are a number of EU gas markets that are mature. Where gas markets have not fully developed and are illiquid and still not fully functional, targeted measures that address the specific market needs should be considered. • EU-wide measures should only be considered where there is strong evidence of an EU-wide problem. • The focus should be on fully implementing the current legislation and where issues or problems are identified, additional measures could be considered.

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

• The Czech Gas Association believes that future changes in the gas sector can have an impact on the dynamics of the gas market with the need to update it.
• When considering the development of a low-emission society, a one-size-fits-all solution is not ideal for a national energy markets in the EU with so many different requirements, political drivers, stages of maturity and geographical distribution of resources. The main concern would then be how to streamline all available solutions without hampering the integration of the European energy market already achieved.
• The incorporation of renewable and low-carbon gases into the current gas market arrangements shall be done however we do not see a need for a substantial EU gas market model update/reform.

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?

• The Czech Gas Association believes that an appropriate transmission tariff regime and the efficient integration of the EU gas markets is supported by the ongoing implementation of the TAR NC (Regulation (EU) 2017/460).
• Before suggesting any changes, the Czech Gas Association supports the idea:
• To finalize the implementation of all the requirements of the European legislation,
• To monitor and assess the development of gas markets,
• To continue with regional initiatives in less developed markets.
• The situation in the Czech Republic has been constantly improving. For example, EFET Gas Hub Benchmarking Study from November 2018 considers the Czech VTP among the biggest risers in maturity and in liquidity. This is also confirmed by ACER Market Monitoring report 2017 which shows that there is very strong price convergence between German NCG and Czech VOB hub, and also by the fact that the estimated gas sourcing cost compared to the TTF hub has lowered from >3 euro/MWh in 2012 to

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

Please refer to our answer to Q16.

Other question

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

Survey response 36

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Ervia

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
TSO’s could be involved more in the transition to a sustainable gas sector Ervia believe that TSO’s are well placed to be involved in a number of activities that enable complete decarbonisation of the gas grid and other sectors. Ervia believes that the assessment should consider activities such as, but not limited to, Biomethane injection facilities, Compressed Natural Gas (CNG) for transport, Power-to-Gas facilities, Hydrogen Storage, Hydrogen for transport, Carbon Capture and Storage (CCS), Carbon Capture and Utilization (CCU) technologies and Carbon Dioxide (CO2) pipelines. As some of these activities are still in development, TSOs should be allowed to engage in research and development to help bring these technologies forward. These sustainable gas industries are at very early stages of development. It is therefore not appropriate to apply mature market rules to them. To do so may greatly restrict their development. Natural gas was developed initially by state owned monopolies as these were best placed to take long-term national strategic decisions on investment and development. Hydrogen and biomethane now again need state-owned bodies to take that long-term view and create the necessary infrastructure, on a vertically integrated basis if necessary, and with low risk costs of capital to ensure it is done at least-cost to consumers.

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.
Targets could be set for carbon neutral gas blends Targets could be set for the % of sustainable gas to be transported through gas networks in Europe. This could be similar to the current biofuel obligation where suppliers would be mandated to source x% of sustainable gas for their customers by a certain year. E.g. 10% sustainable gas transported by 2025, 20% by 2030 etc. Ervia feel it would not be wise to set separate targets for biomethane and hydrogen as some countries have different local availability of resources. For example Ireland has the highest potential per capita for biomethane.

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.
Cost of sustainable gas technologies must be compared on an equal basis, when compared to established renewable technologies When comparing emerging zero and low emission gas related technologies financial assessment and comparisons to other existing renewable and low emission technologies should only be done on a long run marginal cost basis to ensure that all costs imposed by technologies onto the system and onto consumers is adequately captured. Comparing technologies on a short run marginal cost basis is totally inappropriate when comparing intermittent renewable technologies such as wind and solar with firm renewable technologies such as hydrogen, biomethane and CCS with CCGT. Intermittent technologies impose many other costs onto consumers such as upgrades to electricity networks, batteries, deep retrofits to homes to facilitate heat pumps etc. but which are not captured in the technologies support costs and therefore fair comparisons are not made. Technology neutral auctions favour previously supported and developed technologies When renewable electricity technologies were first introduced 20 – 25 years ago a technology neutral approach was not taken. Individual technologies were given the supports necessary to ensure they were successfully developed and deployed across Europe. It is only in the last few years that technology neutral type auctions have been rolled out to secure more competitive prices, now that those technologies are sufficiently mature that the investment community are comfortable to take the necessary risks associated with more open market arrangements for their remuneration. Hydrogen, biomethane, CCS and other low and zero emission gas technologies should therefore be treated the same as renewable electricity technologies were when they started many years ago. Specific gas related technologies should be given the supports necessary now to ensure they are successfully developed and deployed and can therefore play a key role in decarbonising Europe in the future.

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?

Infrastructure Investments and Regulation

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?

Adapting the Gas Market Design

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?

Other question

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

Survey response 37

Contact details and treatment of confidential responses

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Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
1. CHARGING POINTS FOR GAS VEHICLES In general, the private initiative is already developing charging gas infrastructure for road and maritime transport (bunkering). It is expected that these actions are reinforced once higher emissions requirements for transport are in place. Therefore, it's expected that the private initiative can provide commercial solutions. Having said that, if the development of certain charging infrastructure is deemed crucial by regulatory authorities (e.g. for sustainability reasons, to trigger the demand of vehicles using alternative fuel), and if there isn't sufficient market interest or initiative for the deployment of these stations, then the MS should be enabled to make this investments happen. Otherwise, the inaction would endanger the fulfilment of the national decarbonisation strategies. Anyway, these double condition should be met, and verified by NRAs in order to decide the involvement of TSO/DSO).. In other words, the provisions agreed in the electricity Directive for the development of charging points for EV's seem rather appropriate. 2. POWER TO GAS (P2G) First of all, we would like to mention that we would have preferred questioning if there is room to consider this activity as a regulated activity or rather a pure commercial activity. In the gas sector we find examples of activities such as storage, LNG plants or interconnections that are developed and owned by different stakeholders subject to different regulatory frameworks. 2.1. POWER TO GAS IS NOT ELECTRICITY STORAGE. From an operational point of view in the electricity sector, P2G is basically a final use of electricity, managing (excess of) renewable production. Most volumes of gas are going to be consumed in gaseous form rather than being reconverted in electricity. Thus, although it cushions the storage challenge of the electricity sector, power-to-gas isn't an electricity storage technology, in the same manner than gas-to-power is not a gas storage technology but final gas consumption. Therefore, the legal and regulatory framework cannot be the same than for batteries or pumped hydro. Only those P2G devices which are potentially electricity-sector-oriented (P2G2P, like fuel cells acting like batteries) should ask to be treated under the regime of other electricity storage, but this likely unusual exception cannot make the rule. To this extent, the definition of the Directive on common rules for the internal market in electricity should be amended or clarified that it can only cover devices mainly designed to meet electricity demand only. 2.2 EXTREME MARKET CONDITIONS REQUIRED TO TRIGGER P2G BUSINESS CASE FOR INDIVIDUAL PLAYERS. In an uncertain context regarding technology evolution, covering not only P2G but also other technologies (renewable gas, batteries, DSR, CCS/CCU), ACER's own analysis depicted in the consultation document leads to think that market conditions will hardly lead to the development of P2G capacity. however, as for the challenges for a sustainable gas sector, CEER should have an holistic view, not limited to the challenges of the power and gas sector separately. To this extent, the existence of P2G capacity could potentially help to integrate more e-RES production that cannot be accommodated in the electricity sector as well as to facilitate the necessary entry of renewable gas. In the long term, and considering the stringent ambition to decarbonize the EU economy, we will see large amounts of dedicated renewable production to generate hydrogen (as Eurelectric's own 2050 study also highlights). In the absence of P2G capacity, we hardly foresee these dedicated investments in e-RES generation to happen (those leading to generation levels well above the demand of electricity sector which would be unable to absorb it). In other words, linking P2G use to renewable-spillovers-only would set a narrow perspective disconnected from the ambitious long term European scenarios and which could hamper the decarbonization of the gas sector. 2.3 THE LEGAL FRAMEWORK SHOULD NOT DISCARD THE CONSIDERATION OF POWER TO GAS AS A REGULATED ACTIVITY, ENABLING THE DEFINITION OF LEGALLY BINDING STANDARDS ON THIRD PARTY ACCESS SERVICES AND TRANSPARENCY. As mentioned during the last CEER workshop in May, NRAs should examine the positive externalities that couldn't be internalized by investors if P2G were to be developed as a purely commercial activity and thus leading to a suboptimal development and thus to a welfare loss. Due to the high upfront costs of P2G facilities, the socialization of infrastructure costs between all gas (and eventually electricity) consumers would reduce the high investment risks associated to this technology, favoring economies of scale and reaching potentially to all users. TPA would facilitate access for new market entrants and of gas from renewable energy sources. Current legislation establishes the implementation of a system of third party access to the transmission and distribution system, and LNG facilities based on public tariffs and applied objectively and without discrimination between system users (Art. 32). Regulated TPA is also considered for gas storage activities. As a consequence: •Member States should be enabled to decide on the regulatory regime for power-to-gas activities. A cost-benefit analysis made by the pertinent regulatory authorities should assess the options and impacts of the different alternatives and their relation to the fulfillment of climate and energy targets. •The revision of the EU Directive should also assess the application of a system of third party access for P2G capacity connected to the gas network.

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.
•An appropriate regulatory framework enabling hydrogen should be developed in a cost-efficient manner, considering the benefits for both the integration of RES generation –potentially avoiding electricity infrastructure-, taking advantage of the existing gas infrastructure and the contribution to the decarbonisation of gas sector. •Anyway, and for the moment being, we should be aware of that national gas infrastructure systems differ a lot (pressures, materials of pipelines and equipment, age, gas quality spec range, etc) and hydrogen volumes are rather small to foresee important cross-border transfers with gas of different qualities. A common European threshold should rather set the minimum threshold which all MS should accept to be injected. MS should be entitled to increase the threshold for the blending. To this extent, the minimum blending level should pay attention to the different materials composing the grid, to avoid that “the worse existing material” could set a too low threshold. For instance, polyethylene or PVC pipelines would be able to accommodate larger amounts of hydrogen. •As for the definition of dedicated regulation of transport, distribution and use of pure hydrogen, we believe that we are still very far for important volumes of hydrogen production. Blending is very likely to be the first and shortest way to distribute hydrogen in MS. Therefore, if regulatory actions are considered necessary at European level, they should address blending at a first stage.

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.
•The term “gas”, as an energy carrier, doesn’t refer to conventional natural gas anymore. In the same manner than electricity sector integrates electricity from diverse sources of origin, the gas sector will have to accommodate gases from different technologies (conventional natural gas, shale gas, renewable gas and decarbonised gases, including hydrogen). Thus the EU regulatory gas framework should be rather the same in most of relevant topics (retail and consumer protection, competition and State Aid, third party access, market operation, etc…). An inclusive regulatory framework covering different technologies seems more appropriate than separate pieces. •In general we hardly believe that the full conversion of existing gas networks to hydrogen will happen in most countries. This could be an opportunity for old local gas systems, fully amortised, with low ranges of gas quality accepted. In other words, it could represent an opportunity for systems planning a thorough refurbishment and/or replacement of their pipelines. In modern gas systems (e.g. Spain and Portugal) it wouldn’t make sense. As an exception, some specific hydrogen provisions for dedicated hydrogen-only infrastructure (e.g. in industrial sites) might make sense, similar to the provisions of direct lines in electricity. As a consequence, considering the limited number and concentration of dedicated hydrogen projects in Europe, these provisions could be included in the revision of the Gas Market Directive and Regulation as an option subject to the criteria of Member States based on the existence of dedicated pipelines at national level.

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.
•First of all, and as it was mentioned during CEER’s workshop by diverse industry members (EFET, Eurelectric, Eurogas, ENTSOs), markets are cost efficient instruments but which don’t necessarily deliver the expected results in the time required. Markets will likely require some kind of policy or regulatory signals to deliver expected ambitious decarbonisation and transformation. Decarbonisation gas targets, support schemes, definition of regulated activities and planning, etc are possible instruments that deserve further examination. In the light of EU energy and climate strategy, some kind of intervention would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades. To this extent it’s pertinent to look at the transformation occurred in the electricity sector in the last 20 years, as well as to the many lessons learned from it. •When addressing infrastructure use and planning, a cost efficient approach is key in order to avoid unnecessary additional costs for users. •As a minimum, the regulatory framework should also facilitate investments in R+D and pilot projects, like power-to-gas activities, where energy network companies may play a role. For instance, Naturgy’s subsidiary gas DSO Nedgia, is carrying out a hydrogen methanisation pilot project with potential injection into the gas grid. This kind of initiatives should be facilitated and properly rewarded.

Q5 Which role do you see for power-to-gas infrastructures?
•Power-to-gas as well as other renewable and decarbonised gases will have a clear role to play in the decarbonisation of the gas sector. Electricity alone cannot deliver full decarbonisation, as the EC’s 2050 scenarios highlight. Even the most optimistic scenario of Eurelectric’s Decarbonisation Pathways study, carried by McKinsey, sets that a maximum of 60% of direct electrification could be achieved. On top of this, Eurelectric foresees that important volumes of renewable generation would be developed to meet indirect electricity demand. In other words, dedicated e-RES could be developed and converted into hydrogen as a cost-efficient decarbonisation technology. oIn the transition towards an ambitious transformation of the gas sector, power-to-gas would facilitate sector coupling and the integration of e-RES. oIn the long term, we consider this capacity is going to be crucial to meet 2050 decarbonization targets. Considering that the electricity sector wouldn’t be able to absorb all the electricity production, the existence of power-to-gas capacity could be required to make the business case of dedicated RES generators to produce volumes of decarbonised gas.

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?
•It’s difficult to decide on the appropriate tariff regime for this type of infrastructure. As a general rule, same services should have the same treatment, therefore, depending to the service they provide, the tariff should be set accordingly. •In the gas sector, at an initial phase of development and below a certain capacity (in MW) specific gas injection tariffs could be considered. This could facilitate the initial deployment of renewable & decarbonised gas technologies, facilitating its cost reduction. •As for the electricity tariffs, a differentiation could be envisaged for electricity oriented P2G2P devices (similar to storage technologies) being less justifiable for mere electricity consumption in P2G installations. In the same manner, and similarly to the provisions for natural consumed to generate electricity, power consumed in P2G devices could be exempted from final special taxes (to avoid double imposition).

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
•As mentioned before (mainly Q1, but also Q4 and Q5), the consideration of this activity as a regulated activity, subject to standards on third party access and transparency requirements should be explored. There could be positive externalities for the deployment of P2G capacity. If they aren’t properly taken into account it could lead to suboptimal deployment of this technology. MS should be entitled to opt for this option as a way to contribute to the decarbonisation of the gas sector, especially considering the ambitious decarbonised scenarios proposed by the EC.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
•The implementation of a trading system for renewable guarantee of origin can be a pivotal instrument for the development of renewable gases & decarbonised gases. Member States are already required to issue GOs for renewable gas, as required by the Directive 2018/2001. They should also be asked to issue GOs for decarbonised gas, specifying the energy source from which the gas has been produced. •In the absence of a conversion system of GOs from one energy carrier to other, MS should be enabled to take into account the average renewable energy production to generate GOs. This requirement would be similar to the one included in the RES II Directive 2018/2001: “Where electricity is used for the production of renewable liquid and gaseous transport fuels of non-biological origin, either directly or for the production of intermediate products, the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy”. The average share of electricity from decarbonised sources (e.g. nuclear) shall be used to determine the share of decarbonised GOs. •Cooperation of national issuing bodies for different energy carriers should be encouraged to facilitate the interoperability of EU GO scheme.

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?

Infrastructure Investments and Regulation

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?
•PCI monitoring should look for the consistency of proposed PCIs aligned with market needs and regulatory and energy policy objectives. In fact, most interconnection points currently do not show signs of congestion, so prudence should be introduced regarding more investments in infrastructure, in particular new large projects. New infrastructure investments should be based on the results of the application of validated CBA methodologies and appropriate market tests to reduce the risk of over-investments. In other words, the regulation and scrutiny of PCIs should be clarified and unified, in combination with the incremental capacity procedure included in the network code on capacity allocation mechanisms. The use of F factor stating the minimum amount of costs to be recovered from capacity bookings is paramount, to avoid PCIs with no/insufficient market interest behind them

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)?

• As mentioned in Q10, and in particular for large infrastructure projects, the process should pay more attention to more concrete factual criteria, such as market opportunities/needs. Similarly, and in the light of the EU long-term energy strategy, the selection of PCIs should pay duly attention to the relevance and progress of projects over longer period of time.
• The use of existing LNG terminals, storage and pipelines and other gas infrastructure should be optimised. Before making financial investment decision, any gas PCI project (as for any power PCI project) should be subject to a sound, comprehensive, fair and unbiased cost-benefit analysis; this should be considered as a prerequisite to prevent any further risk of stranded assets.
• As mentioned by CEER, we support the extension of the PCIs selection scope to projects regarding the connection of decentralised and local gas generation -renewable and decarbonised gas, including gas-electricity integration via power-to-gas- as well as for the conversion/adaption of gas grids to new gaseous carriers. This is similar to the inclusion of smart grid projects in the PCIs of the electricity sector.
• As mentioned in Q10, the addition of cross-references between infrastructure regulation and the CAM NC (2017/459) will be paramount, especially for large infrastructure projects.

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?

• Based on existing and projected gas demand we don't see a risk for stranded assets at least in the next 10 years. This is in line with CEER's observations, as well as on the EC's 2050 scenarios and draft National Energy and Climate Plans 2020-2030 recently published, among others.
• Moreover, beyond the uncertain future levels of demand, it should be noticed that the gas system is dimensioned to cover important seasonal and daily variations of demand. In other words, it's dimensioned to meet peaks and throughputs. This will likely be exacerbated by a more volatile demand in the electricity sector. On the other hand, the likely fall of the conventional natural gas in the long term will not exclude the repurposing of these gas infrastructure including their reconversion to accommodate new gas sources. Even in the case of decommissioning, it would be likely needed to reserve and to maintain some capacity subject to compensation.
• Transmission infrastructure in Spain are being amortised at a proper pace, so we exclude any revision of the depreciation methodology. On the contrary, any acceleration in the depreciation of assets, as proposed in the FROG study, could have undesirable unintended consequences in the gas market that should be thoroughly assessed.

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?

See Q12. Considering the relative importance of overall demand, which is likely to remain at current levels for the next decade, and considering the potential of renewable and decarbonised gas, we believe that this shouldn't be a topic in the EU Agenda. Its consideration in the regulatory framework would only add uncertainty to the investments in the gas sector which, on the contrary, will likely needed for its sustainable transformation.

Adapting the Gas Market Design

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

• The gas market design should support gas to become progressively carbon neutral in order to play a role in a carbon neutral economy, taking into account of the increasing decentralization through new gas sources deployed at local level. An appropriate investment framework and clear energy policy guidance are therefore needed.
• The creation of an EU gas DSO entity with tasks and responsibilities –when applicable with shared responsibilities with ENTSOG-, for instance regarding the development of network codes related to decentralised production, gas quality and blending issues, etc
• Synergies and positive externalities with other sectors should be analysed.

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

• As mentioned in Q4, markets are cost efficient instruments but don't necessarily deliver the expected results in the time required. Some kind of policy or regulatory signals will be required to deliver expected ambitious decarbonisation and transformation of the gas sector: Decarbonisation gas targets, support schemes, role of market/regulated parties and energy planning, etc are possible instruments that deserve further examination. Some of these instruments would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades. To this extent it's pertinent to look at the transformation occurred in the electricity sector in the last 20 years -as well as to the many lessons learned from it to avoid committing mistakes-.

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?
•As a general rule, EU regulation to access infrastructure and transmission regime should not rely on ad hoc solutions developed at national level, as it would only add market distortions between Member States. In fact, this is not needed in the light of current situation and market perspective. Considering gas transmission infrastructure as the backbone of the internal gas market, we highly discourage CEER to promote this as a potential solution to be explored. •The increase of short term capacity availability should be linked to the availability of new capacity. •Capacity release programmes can raise a recovery issue and we don't see the benefits of their implementation as the CMP network code already addresses situations of contractual congestions. •Similarly, if commodity releases are studied at regional level, they should address demonstrated structural constraints to competition and liquidity only. •Last but not least, CEER mentions the Quo Vadis Tariff Reform Scenario, setting cross-border tariffs to zero Setting cross-border tariffs to zero: oimplies a socialization that hampers some peripheral countries, ie. Spain. These countries will assume higher entry costs (access tariffs) without getting any benefit as their supply costs will not change. oimpacts supply sources as it socializes transport routes and therefore the associated supply routes. This reform changes the current balance benefiting those which have lower costs when reaching the EU border, hampering diversification of origins. oGives and advantage to those companies that have transmission capacity at interconnections, as it would allow that they keep the right (capacity) at no cost (IP tariff = 0) and it will hamper those companies that have entry capacity in the EU (ie. Spanish shippers). Therefore, this model will distort the market affecting both supply sources and the competitive position of players. CEER is recommended to explore the benefits of Trading Zone Merger (Regional Market Merger) and Conditional market merger rather than the Tariff Reform.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
•See Q16

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Definitions of renewable and decarbonised gas. We would appreciate if definitions are broad enough to cover different technologies, proven that they meet the quality of "energy from renewable energy sources" and "gas whose production process and use reduces significantly carbon emissions compared to the use of conventional natural gas".

Survey response 38

Contact details and treatment of confidential responses

Contact details: [Organisation][]
UPRIGAZ

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
UPRIGAZ considers that the main challenges for TSO/DSO involvement towards renewable and decarbonized gases are fostering compliance on the quality of injected gas, the reliability of as flows and the delivery pressure. UPRIGAZ reminds that the unbundling of activities between production and supply as crucial for the development of a competitive market, and in particular to avoid any cross-subsidization between networks operators and its affiliates. In this regard, the involvement of TSO and DSO in supporting pilot projects related to renewable and decarbonized gases shall comply with the provisions foreseen in the 2019 revised Electricity Directive that is to say they would only be allowed to own, develop, manage or operate recharging points if no other entity has expressed interest in an open tendering procedure, and subject to approval from the regulator. In addition, it is crucial to minimize the network costs for customers and so such projects for renewable and decarbonized gases should be developed only if they provide an economic benefit to the collectivity.

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.
UPRIGAZ considers that this is too early to define minimum thresholds in Europe which could block the development of hydrogen projects (lots of local specificities and constraints). In first instance, UPRIGAZ suggests local/ regional solutions delegating to the TSOs the responsibility for optimizing interoperability, including regional balancing of blended gas quality. This flexible approach will allow to develop urgent solutions mostly at local level for the next years. In the long-term, once the technologies are commercially mature, UPRIGAZ considers that a network code should fix common rules for the blending of hydrogen in gas transportation networks. It is essential that the gas subject to cross border exchanges should comply with common EU quality standards and ensure interoperability of the EU gas infrastructure. Such targets should also apply to all decarbonized/sustainable/green gases.

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.
It is obvious that when hydrogen is blended with natural gas in any network, all the regulation applicable to transportation and distribution should apply. However, in the event a specific hydrogen distribution network is created, the situation should be considered on a case by case basis, in particular when the dedicated hydrogen network is connected to a small number of captive users and not connected to transportation or distribution networks.

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.
UPRIGAZ is adamant to the principle of a regulation avoiding all cross subsidies. Therefore, keeping a technology neutral approach should remain as an overriding rule for DSOs and TSOs. All pro-active market intervention should be decided by the regulators and applied in such a way that it does not contravene to the above mentioned principle or create a market distortion. However, technology neutrality is justified if the market signals are perfectly incorporating all externalities and costs of different technologies, which is not necessarily the case today. As a consequence, in case of non-commercial mature technologies, a technology specific approach should be justified if it brings a benefit for the collectivity.

Q5 Which role do you see for power-to-gas infrastructures?
UPRIGAZ considers that power to gas facilities should be intrinsically profitable taking into account the additional cost of infrastructure necessary for the connection to the gas grid. UPRIGAZ wishes to avoid cross-subsidies between power to gas and naturel gas that would disturb the principles of a sound regulation. Indeed, P2G will mostly provide flexibility to the electric network given increasing power demand and penetration of renewables, as well as plans to electrify additional sectors. As a consequence, power-to-gas infrastructure would serve the balancing of the power grid. Therefore, the related costs should be allocated to the power sector and not to the gas sector as the latter provides flexibility services to the power sector.

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?
The emergence of power to gas facilities results in a number of new situations which justify a case by case analysis. Notwithstanding our response to Q5, UPRIGAZ considers the regulation of electricity and gas aspects for such projects should pursue a joint approach to ensure an economic optimum for the end users.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The evolution of rules are necessary to ensure appropriate economic signals to value dispatchability value of H2 and Synthetic methane delivered through P2G. Interoperability and standardization are also needed to facilitate cross-border trade of GOs and create a more liquid market. For that purpose, a work is already ongoing by ERGAR (gas), CertifHy (H2) and AIB (electricity) and a new official CEN standard EN 16 325 is under development. These initiatives should be properly coordinated among each other. UPRIGAZ also recommends that national registries must be interoperable, both within one country (there might be different registries for electricity, gas and hydrogen) and between countries. One common standard GO for gas could be developed. It is important though that this standard is compliant with the minimum information requirements specified in Art. 19.7 RED II (energy source, identity, location, type and capacity of the installation, commissioning date, support mechanism if applicable, etc.). However, it should be possible to add additional information that allows to create products which address more specific customer needs.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
UPRIGAZ considers important that an EU wide GOs market for renewable and decarbonized gases should be established in the short term in order to facilitate the exchange of GOs across European countries and valorize renewable gas production at EU level and not just within a country. This system is also essential to allow the circulation of GOs at the interconnections. See also answer to Q7. However, UPRIGAZ considers as important to set up harmonized principles for the establishment of such GO EU wide market.

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?
UPRIGAZ is in favor of a parallel and timely development of an EU wide GO system and market for renewable electricity and renewable and decarbonized gases.

Infrastructure Investments and Regulation

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?
UPRIGAZ considers that for the sake of an efficient EU wide electricity and gas markets, ACER should be responsible for the approval of the TYNDPs and their implementation by national network operators under the control of NRAs. In this process the involvement of stakeholders should be maintain in the elaboration of the TYNDPs. In this process, the scenarios should be debated, with a view to harmonizing the CBA criteria and methodology. UPRIGAZ also considers that scenarios shall include critical periods of low e-res production and high heating needs. The costs of excessive electrification consequences should be taken into consideration in models. Moreover TYNDP shall include contribution to decarbonation of other sectors and gives a holistic view. The transparency should be reinforced for the following information : -Physical results in terms of curtailment for e.g. "dunkleflaute" periods, -Identification of the main bottlenecks of the EU transport network, -Sensitivity scenarios showing the effect of the change of one given major hypothesis (e.g. electrification of heating, of transport), -All investment costs, -Add the results of power modelling sensibility if generation investment is not occurring.

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)?

UPRIGAZ is attached to the principles stated in infrastructure regulation 347/203 and the CAM NC (2017/459). UPRIGAZ is favorable to the inclusion of a process of consultation of the market actors so as to secure the use of a new infrastructure and avoid the risk of stranded costs without avoiding key principles of market integration and security of supply.

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?

Given scenarios highlight a stabilization of gas demand and decrease in long term, UPRIGAZ analysis a risk of stranded assets only in long term. The risk will mainly if renewable and decarbonized gases development is not enough. This situation raises at least three discussion topics :
1.The optimization of existing capacities,
2.The valorization of potential national over-capacities in neighboring countries. The regulation framework should be suitable to face this new risk over long term,
3.The development of new infrastructure capacities should be allowed only if market actors get involved in the long term.

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?

In the view of UPRIGAZ, the issue of decommissioning infrastructure is of the utmost importance if it doesn’t serve anymore the security of supply and should be part of the responsibility of ACER. Actually, a decision of decommissioning taken by one EU Member state may affect other EU Member States, even if the decommissioning doesn't directly concern a cross-border infrastructure. Therefore, UPRIGAZ is in favor of a new set of regulation for the decommissioning of large capacity infrastructures, in particular cross-border pipelines with market tests similar to new pipeline investments.

Adapting the Gas Market Design

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

Main principal points to be addressed:

-Except GO system, UPRIGAZ sees no reason to modify the gas market design to accommodate the decarbonized gases such as biomethane or green/blue hydrogen. However the emergence of power to gas facilities may create some interference between the electricity and gas networks and markets. ACER should address these issues and implement a suitable regulatory framework to avoid or limit cross subsidies,
-As far as the EU natural gas market is concerned, considering the current trend in transport capacity bookings and the end of long term contracts, a limited revision of the market design could be necessary,
-Uncertainties on demand trajectory which should be considered in the assessment of infrastructure investments needs.

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

An EU-wide GO system for renewable and decarbonized gases should be implemented. There is an urgent need to update the gas market design in order to allow urgent large scale development and integration of different renewable and decarbonized gases into the system. Please refer also to answer of Q8.

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?

UPRIGAZ considers that maintaining a sufficient volume of activity for the EU wide gas system is of the utmost importance to guarantee the safety of supply and the satisfaction of consumers. This target should be part of the roadmap for the EU energy transition process, mainly by substituting natural gas to renewable and decarbonized gas so as to maintain a minimum volume of activity for the industry across the board.

The need for focused updates of the current market design and proposes : As far as the EU natural gas market is concerned, considering the current trend in transport capacity bookings and the end of long term contracts, a limited revision of the market design could be necessary.

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

See reply to Q16

Other question

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

No.

General comments from UPRIGAZ :

UPRIGAZ draws attention on the main regulatory challenges for fostering the well-functioning of the gas internal market while developing renewable and decarbonized gases :

- A clear definition of news gases is needed : CEER should not only focus on renewable gases but also include decarbonized gases. It should also refer to new gases group : Renewable gas / decarbonised gas / low-carbon gas / natural gas,
- Regulators need to take into account the uncertainties on the evolution of the gas demand in the future and be very careful on the assessment of the needs for infrastructure investment in order to avoid any stranded assets,
- With the development of renewable and decarbonized gases, the network operators shall continue to act as neutral market facilitators. The role of network operators in the management of renewable and decarbonized gases projects should be limited to the conditions foreseen by the electricity Directive.
- The development of renewable and decarbonized gases should be technologically neutral and a cost-effective analysis should be positive. In case of non-commercial mature technologies, a technology specific approach is justified if it brings benefits for the energy system and the customers.

Survey response 39

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Eni SpA

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The definition of the relevant activities for potential TSO/DSO involvement to be considered in the assessment proposed, in a decarbonized gas sector perspective and through the development of sector coupling are, in our view, strictly linked to what CEER itself call “policy” choices and, in principle, excluded from the scope of the consultation. Moreover we don’t see a distinction between market operators and network operators but between regulated approach and market approach. From this point of view the definition of “sufficiently developed market” itself is key in the described process: the level of market development should take into account the ability of the market to fulfill the decarbonisation targets. Decisions on technology(ies) to be developed (for instance whether the market select the most efficient technology or support with subsidies or other policies, the development of the most promising ones) have an impact on the regulatory solutions to be designed and implemented to allow not economically sustainable activities (or which the market is not “mature” yet). More specifically, the role foreseen for power-to-gas plant/activities impacts the regulatory approach. Moreover, concerning the “hybrid” category of activities identified as “activity allowed under conditions”, that should identify activities that could be operated by TSOs/DSOs due to the insufficient market development, we consider that such “hybrid” activities could (and should) be carried out under a regulated regime by market operators different from network operators, ensuring competition. The “competition for the market” procedures (typically tenders) for the assignment of the activity that, due to the level of competition in the market or the nature of the activity itself, would be regulated, would grant the development of the potential competition and the efficiency. It is therefore necessary to create and define all possible conditions (i.e. volumes, reserve price etc. for tenders) to trigger market conditions for the relevant activities. Network operators should not be admitted to the tenders in order to avoid cross-subsidies between “monopolistic” activities (such network operation) and potentially contestable ones and undue competitive advantages due to the abuse of their position as a regulated operator. In case network operators would be admitted to the tenders, a very strict regulation should be put in place in order to allocate cost correctly and segregate the activities and to prevent discriminations (separate accounts etc.).

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.
Eni shares CEER view on the need to adapt the European legislation (namely NC Interoperability) in order to foresee the evolution of the role of renewable gases and hydrogen and avoid negative impacts on the European market integration. It is necessary to avoid the risk of physical separation between national/regional markets due to different characteristics of the gas transported by the gas networks taking into account the apparent differences among European gas networks, in terms of maximum level of hydrogen they can sustain (interoperability issues). Nevertheless it is necessary not to align the threshold downwards due to certain local constraints in order to avoid the risk of limiting the cross-border gas trading.

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.
From a regulatory point of view, the logic leading the decision whether regulate or not hydrogen networks should be the same adopted for any other transmission network. Vertical integration among commercial and monopolistic activities – like typically the transmission activity- should be avoided, non-discriminatory access to third parties (TPA) should be granted, through appropriate unbundling rules. This should apply both to network transporting gas blended with hydrogen and to 100% hydrogen networks in a centralized transmission/distribution network system. Another approach could apply to isolated network (as, for instance, transmission network within industrial facilities) or in case of a distributed/decentralized development of the hydrogen (production and transmission) market. As for "how" hydrogen should be regulated, we deem that D-Gas (decarbonized gas), and more in general hydrogen, should be included in the scope of natural gas (transport) regulation, namely on the TPA and tariff aspects. More importantly, D-Gas and hydrogen should be considered in the same framework as the regulation about renewable gases (in case, for example, of the definition of European/national targets for injection/consumption etc): an hydrogen specific regulation could imply the risk of unnecessary complication of the energy regulatory framework. Finally, the variability of the quantities of hydrogen injected to the grid, should be considered also in light of the potential implications in terms of storage/methanization needs due to the congestion" (i.e. the saturation of the H2 treshold)

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.
In our view any regulatory approach, especially in a long term view, should include in its decisions, an opportune assessment of the externalities linked to each technological solution.

Q5 Which role do you see for power-to-gas infrastructures?
The possible roles we see for power-to-gas infrastructures are: -Storage of energy (power temporary stored as hydrogen, no injection of gas into the gas network), giving flexibility and support for power grid balancing; -Production/Transformation of gas (hydrogen/other synthetic gas) from power providing flexibility and support for balancing to both power and gas sectors and networks, additional source for gas industry. Moreover, from another angle, power-to-gas facilities could operate in a competitive market or be identified as service providers necessary for the industry (to develop an adequate level of sector coupling) in order to achieve the decarbonization targets (see Q1).

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?
How to regulate power-to-gas infrastructure, taking into account their contribution to both sectors and to both network balancing but, at the same time, that they are are increasing the complexity of the network management and balancing, depends mainly on the role that will be defined for them. If a market, with an adequate level of competition, will emerge, an adequate and efficient allocation of the infrastructure costs to all the users, included power-to-gas facilities, should be granted, taking into account on one hand their use of the network and on the other hand their contribution in terms of flexibility and balancing of the system. Potential distortion could emerge from the tariff system and how costs are charged to users depending on the role of power-to-gas in both industries (if treated as power end users/ transformers of electricity into gas / power storage facility/ gas network users etc.), leading to the need of clear borders between the different potential roles/activities. From a general point of view, we consider that the approach to avoid distortions and to actually set a level playing field for the P2G facilities is reached via an appropriate cost allocation to the different categories of network users (on this also see answer to Q17). In this perspective, we suggest, as a general approach, to consider power and gas networks as an integrated system in which P2G contribute to the "coupling", being they energy transformers (from electricity to gas). In this integrated vision, gas fired power plants (G2P) should be considered having a similar role, as they are energy transformers as well (from gas to electricity) enabling already a sector coupling. In other words, a "bidirectional" and integrated efficiency should be the overall target. Based on the described approach, we consider that in order to avoid the risk of distortions on the destination market and of not efficient double charging, some of the charges paid by final energy users should not apply to P2G and G2P facilities. Moreover, when it comes to the cost allocation process, transmission tariff settings, both for power and for gas networks, should take into account the specific role of P2G and G2P facilities and their contribution in terms of integration, flexibility and balancing of the two systems. In other words, the regulation framework and the application of transmission tariffs and other charges (taxes and levies) should avoid to unduly applying charges in one system with the result of inducing distortions in the other one, negatively affecting, as a consequence, the P2G and G2P ability to compete in the destination market.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
If the gas network is used like a buffer to balance the electrical grid thanks to the production of hydrogen/green gas produced by electrolysis/methganation, it will be necessary to set a structured communication protocol among TSO/DSO/Gas Network Operator/H2 producer and the relevant services fees.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
GOs certificates need to be standardized enable to cross border trade at European level. Tradability issues can arise when the measures for transition will be managed locally. Countries should set up clear criteria for the recognition of imported GOs. It’s required to overcome the barrier for cross-border trade (2009 RES Directive does not include requirements for cross-border coordination and transfer of GOss between countries). It’s needed to eliminate the policy redundancy, particularly when certificates are traded internationally, the corresponding production risk to receive both production support (e.g. a feed-in tariff) and end-use support (e.g. a consumer tax exemption). An essential condition for cross border trading is that the given product is recognized in the GOs system of the receiving country. For each trade the latter needs to issue the corresponding certificates and the same amount of certificates needs to be cancelled in the registry of the exporting country. In order to grant the harmonization, countries should organize national registries using the same data structures and the same procedures for internal certification. Having a clear split between the factual part (i.e. information on the origin of the product) and a qualitative part, that deals with the way the given product meets certain qualifications (i.e. RES 2009, etc) could allow more easy and efficient management of possible future developments in policy over time, In order to grant the efficiency for the system it should be considered to centrally manage the issuing and operation of the GOs system, regardless for the energy vector (power, gas, biogas, H2...), also taking into account the complexity deriving from the possibility to convert energy vectors from one to another.

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?
The Guarantee of Origin of the renewable gas should clearly highlight the mix of the production sources in order to define an ecological ranking (i.e. Blue H2, Green H2).

Infrastructure Investments and Regulation

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?
ACER and NRAs responsibility should focus on strengthening the coordination at national and regional level coherently with an integrated view of the European infrastructural needs, taking into account national peculiarities in terms of needs and gas (+renewable gases) demand scenarios. Moreover, CBA methodology should be standardized and oriented to a clear assessment of the cross-border benefits of new “national” infrastructure, in order to proceed to an actually correct cross-border cost allocation.

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)?
The existence of parallel regulation on investments, based on different criteria, without a clear view on the interactions between the two is an obstacle to transparency in the identification of the actual infrastructure needs. More clarity on the interactions between the Incremental Capacity mechanism (NC CAM) and the TEN-E Regulation seems necessary to increase transparency and predictability in the European infrastructure development. Moreover, we would suggest a deeper integration (not only in terms of scenarios) in the development of the infrastructure plans in the gas and power industries.

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?
Nowadays the electrical market is facing for example non remunerative prices (negative CSS) that obliges to find alternative opportunities and take into account regulatory tools possibly considering also positive externalities

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?
Eni shares CEER concerns about the mechanisms leading to decommission decision, In a progressively integrated European market, decommissioning decision need to take adequately into account of the cross-border impacts of such decision when infrastructure are relevant for more than one Member State. In our view, the decisions on decommissioning should be based on the following general rules: 1)Decommissioning should only be discussed about infrastructures that showed not to be useful anymore and not about under-utilized infrastructurespotentially still useful for the system (for SoS purposes, for instance); 2)Decision on decommissioning of an infrastructure might be decided in accordance toa neighboring country potentially negatively impacted by the decision; in other words, the cross-border (potential) relevance of each infrastructure need to be correctly identified in order to assess the opportunity of decommissioning; 3)Infrastructural costs should be allocated to the impacted countries based on the cross-border relevance of each infrastructure (both in case of decision for or against decommissioning); Such mechanisms should be integrated in a more general vision on the evolution of infrastructure tariff regulation, in order to take into account the cross-border relevance of each infrastructure, allocating cross-border their costs to the relevant beneficiaries (see answer to Q17).

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
See cumulative answer to Q14, Q15,Q16,Q17

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
See cumulative answer to Q14, Q15,Q16,Q17

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?
See cumulative answer to Q14, Q15,Q16,Q17

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
[Answer to Q14, Q15,Q16,Q17] We share both CEER view on the level of achievement of the Gas Target Model objectives (not totally achieved and not homogeneously across Europe) and the analysis of the risks implied by the foreseen evolutions of the gas industry and the need to adapt the current market design to prevent those risks. In our view, to support an efficient gas market in the short and medium term is a condition for a healthy gas industry in the long term; at the same time, the review of the current regulatory framework should take into account the view for the industry in the long term. Now, as far as the long-term view is concerned, more and more studies and scenarios are envisaging for gas, in combination with renewable gases, a relevant role in a decarbonized energy sector, thus implying the need for healthy and efficient gas infrastructure, that should be even able in the future to underpin an interlinking with the power grids (for instance to allow sector coupling). In order to properly address the need for healthy and efficient gas infrastructure, there are some relevant pieces of the regulatory design that would need a review in the short-medium term: such as the current tariff regulatory framework. It is necessary, indeed, to attribute the right value and role to gas infrastructure both in the (already started) process of decarbonization and in a long-term vision of decarbonized energy industry. In an integrated view, considering the increasing role of flexibility, the value of gas infrastructure needs to be less dependent on the current market environment than it is now and the regulatory framework must be properly corrected. In fact, in the current regulatory design the setting of tariffs level is based on long term capacity bookings or on the actual use of short-term capacities: this risks creating distortive impacts on the efficient use of infrastructure, when it comes to lower revenues due to long term contracts expiry or lower utilization of routes, which in turn trigger a spiraling tariff effect. Instead, a new framework should properly take into consideration the risk that distortive impacts could lead to underestimate the value of infrastructure which are not sufficiently utilized but still necessary, for the European system, also in a long term vision. In the consultation CEER indicates a possible ad hoc solution at regional level working on IP tariffs with reference to Quo Vadis tariff scenario. With reference to it, we would instead welcome a EU entry/exit system instead of ad hoc solutions that: -sets to 0 the reserve prices at IPs connecting liquid and competitive markets (where competition – and possibly congestions - for the interconnection capacity may fully arise and the market players can really express the correct market value of such capacity); -and, in order to ensure the TSOs revenues' neutrality - splits the costs between i) IPs connecting EU with non-liquid or oligopolistic markets and ii) domestic exit points. The split should be performed in order to maintain, on one hand, the attractiveness of the European market and, on the other hand, to allocate the costs to network users based on the elasticity of their demand (the higher the elasticity, the lower the transmission tariff). Finally, with reference to cost allocation in tariff setting, we welcome CEER suggestion to "consider a cost allocation methodology that includes all the benefits provided by the gas infrastructures and tries to allocate costs to beneficiaries". In our view, in order to ensure the principles for market competitiveness and, at the same time, efficiency in the use of transportation infrastructures, the TSOs allowed revenues should be split and allocated based on the nature of the corresponding costs to be covered. In other words, TSOs costs included in the allowed revenues should be distinguished among the following cost categories: A."Transportation and transit costs": Costs related to infrastructures dedicated to the transportation of gas in the domestic system (to be covered through tariffs paid by network users supplying domestic final customers and/or by domestic final customers) or to transit gas to other countries (to be paid by shippers using infrastructures to supply downstream countries); B."Costs for internal security of supply (and market competitiveness)": Costs linked to infrastructures aimed at granting the domestic security of supply (to be covered by the tariffs paid directly by the final customers that benefit from security of supply) and; C."Costs for security of supply (and market competitiveness) of other EU countries": Costs linked to new investments (PCI) and to existing infrastructures with limited value for the system in which they are located but still useful for the security of other countries and for the related competition upsides. Such cost, with cross-border relevance, should be covered through cross-border cost allocation mechanisms by the end users benefitting from the infrastructure. Once the above splitting in the three categories of the allowed revenues of each TSO is done, the network costs at each TSO level can already be allocated more efficiently than today, by charging each category of cost to the specific network users that benefit from the associated infrastructures.

Other question

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

Survey response 42

Contact details and treatment of confidential responses

Contact details: [Organisation][]
OMV Gas Marketing&Trading GmbH

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
All activities as mentioned in the consultation paper in chapter 4.1, namely (CNG/LNG) refueling and fueling infrastructure, power to gas facilities and hydrogen networks) should allow the involvement of TSO/DSOs for the technical development and operation of such facility under competitive conditions. We believe that this would be beneficial for the development of these new kinds of energy infrastructure by lifting synergies in the operation and strategic planning, furthermore it provides a broader range of potential providers and hence competition. The future regulation however need to be adapted and needs to provide a framework that clearly distinguish between “core” activities of a TSO/DSO as we know it today and auxiliary services in the future. Such distinction is important to ensure a cost-reflective and cost-efficient development and operation of an extended energy infrastructure with CNG/LNG refueling and fueling infrastructure and power to gas facilities.

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.
We leave it up to the technical experts to which extend a common European threshold is feasible and reasonable. Important for OGMT as a supplier and trader of natural gas is, that the blending of hydrogen does not lead to any technical issue in the wide range of applications of gas and that it does not distort cross-border trading within the internal European gas market.

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.
Assuming that hydrogen production will develop, the geographical scope of dedicated H2 networks and the extent of transport demand will evolve it seems obvious that this development requires a particular H2 network regulation. Such regulation of hydrogen networks have to fulfill the principals of grid-bounded energy networks, amongst other, the non-discriminatory access for network users and harmonized access rules, a high degree of supply security and important items to facilitate cross-border transport and trading. Where existing natural gas infrastructure is used for the purpose of H2 blending, the same regulatory rules for gas transport shall apply and only amended where necessary to ensure for example the technical compatibility or cost-reflectiveness related to the injection and transport of H2 in existing gas pipelines.

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.
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Q5 Which role do you see for power-to-gas infrastructures?
From today’s perspective, we also see the two realistic scenarios for applications of P2G facilities as outlined in chapter 4.3. The use of the gas network for injecting either H2 or synthetic gas following methanation may play a more important role than the use of locally re-generated electricity for reasons attributable to higher losses of a re-generation into electricity. However, it remains to be seen whether the development and operation of such facilities becomes economically viable and if so, in which geographical areas these can be realized best, depending on the availability of wind and solar.

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?
If the same rules for the connection and use of natural gas or electricity networks apply to P2G facilities with other injection or production facilities (off course in due consideration of its specific characteristics), we believe that possible distortion can be avoided, which include potential double-counting effects

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
To ensure a high degree of cost-reflectiveness. A strict distinction in terms of tariffing for Entry points from conventional natural gas production and renewable gas production including power-to-gas is necessary and should be clearly reflected in the future regulation.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
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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?
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Infrastructure Investments and Regulation

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)?
OGMT agrees with the position of CEER, that new investment decisions in gas infrastructure should be carefully assessed. Different to CEERs' view we do not see uncertainties in the future demand for gas/the evolution of the gas sector in the long run, but rather see the uncertainties in the future gas flows as a result of decreasing indigenous production and increasing diversification of supply sources (e.g.LNG) across Europe. A common framework for new investments in gas infrastructure by means of a better coordination between the CAM NC incremental capacity approach (based on market tests) and the PCI selection process (based on CBA) would be useful to ensure the coordinated economic and strategic assessments.

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?
We do not see a risk of stranded assets in our country, but as a European wide natural gas player, we see the risk in certain areas in other countries as well as in certain interconnection pipelines. We therefore support the idea of a possible decommissioning of gas infrastructures where reasonable. A coordinated framework for the decommissioning of cross-border assets is needed to ensure cost efficient operations of the transmission network also in the future but at the same time this framework should ensure sufficient cross-border capacity to avoid undesired effects, such as distortion of competition in the internal gas market.

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?
A coordinated framework for the decommissioning of cross-border assets is needed to ensure cost efficient operations of the transmission network also in the future but at the same time this framework should ensure sufficient cross-border capacity to avoid undesired effects, such as distortion of competition in the internal gas market.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
We share the view of CEER that the risk of an accelerating upwards trend (price spiral) in transmission tariffs is immanent because of expiring long-term contracts. We are of the opinion that this is an urgent matter for the gas market design to avoid detrimental effects to the internal gas market. With reference to our answer in Q16 we'd like to provide for a potential solution.

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?
Yes, as already outlines in question 11, we share the view of CEER that the risk of an accelerating upwards trend (price spiral) in transmission tariffs is immanent because of expiring long-term contracts. We are of the opinion that this is an urgent matter for which the current regulation does not provide a solution. Therefore a new regulation or an amendmet is required that gives TSOs more room to provide flexibility to existing long-term shippers in using their contacts (e.g. with providing the right to shift an existing Entry/Exit usage right from one point to another point) or allowing them to terminate their contracts at a certain due date (Principle of the “Sunset Clause”). At the same time the regulation should be amended in a way that the undesired effects of increasing hub spreads or increasing tariffs on domestic Exit points (as outlined in chapter 6.1 in the consultation document) are mitigated or even eliminated. The new EC policy development in the gas sector should consider this with the new Energy Package.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
The subsequent costs allocation methodologies very much depend on the way how to deal with the issue of expiring contracts and the detrimental effect that comes along. One way could be the review of an optimal market zone size.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
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Survey response 45

Contact details and treatment of confidential responses

Contact details: [Organisation][]
CEDEC

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Flexibility is becoming a key topic with the increase of renewable electricity, namely wind and solar generation. Gas networks must play a key role in flexibility as they can absorb volatile electricity production and store it for a long period or transport it to demand centres. DSOs must be able to use this flexibility to ensure efficient network development and operation but also to contribute to the transition towards a more and more decarbonised and sustainable European energy sector. With the recent developments in sector coupling, technologies such as power-to-gas provide new activity domains and flexibility tools for DSOs. Taking into account their know-how on the characteristics, development potential and needs of the grids, DSOs should be stimulated to be involved in research and development and allowed to operate power-to-gas plants, at least until a competitive market has developed. As a general rule, new technologies should not be overregulated while they are still in the development phase, as this could potentially be counterproductive to further development.

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.
It is necessary that there are common rules for blending of hydrogen. Market actors need transparency and planning security. These rules should be set up in such a way that they allow the market of hydrogen to continue to develop. Nevertheless, we believe that the threshold should be defined at national/local level and based on technical and financial feasibility – there should be a gradual increase of the amount of hydrogen allowed in the gas grid defined in close cooperation with the local DSO. To contribute to the uptake of hydrogen, manufacturer of end-products (gas appliances) should be obliged to produce devices that are able to support a higher percentage of hydrogen.

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.
In general, CEDEC encourages the use of existing gas networks upgraded to accept a maximum amount of hydrogen, rather than creating costly parallel hydrogen networks. Synergies should be used where possible. If a former gas network becomes a mixed gas-hydrogen or hydrogen network, this must be regulated and follow the same rules and obligations as the gas networks. Existing hydrogen networks that are purely private networks for industrial purposes should not be subject to the same regulation.

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.
Yes. Both long term cost efficiency and the effectiveness of the energy transition are valid grounds for “pro-active market intervention” (meaning intervening in the normal market functioning). When addressing the planning and use of energy infrastructures, a cost-efficiency approach is key in order to avoid unnecessary additional costs for users. When considering long term cost-efficiency, the issue of stranded assets (ending the use of existing gas networks before their economic lifetime) should be taken into account. However, it should be noted that “market intervention” is not possible when there is no (mature) market yet. A technology neutral approach in markets can hinder the development and market entrance of new technologies and limit the optimal exploitation of local renewable resources. As both effectiveness of the energy transition and long term cost efficiency are valid grounds for “pro-active market intervention”, regulated actors like grid operators should equally be allowed to invest in and operate processes based on innovative technologies that can serve the optimal management of their grids, including through sector coupling. Research & development projects are key to develop these technologies to a more mature level. What is important for the development of future technologies, is that they do not face overregulation when in the development phase.

Q5 Which role do you see for power-to-gas infrastructures?
CEDEC believes that P2G will play an important role in the future energy system. P2G technology is key for the development of sector coupling, in order to balance integrated energy systems. P2G technology perfectly complements a decentralised energy system, with its unique ability to ensure storage for surplus of renewable electricity in form of renewable hydrogen or synthetic gas in existing gas infrastructure, also for longer periods – capable of ensuring seasonal storage. With the P2G technology, the existing natural gas infrastructure can contribute to the decarbonisation of the whole energy sector. P2G technology is not yet economically viable and the current installations are mainly pilot projects. Since the market does not fully deliver on decarbonisation, and to maximise the injection of RES gases into the DSO grids and to facilitate the uptake of P2G, DSOs should have the right to own and operate P2G installations. P2G technology not only increases coupling between electricity and gas but the renewable hydrogen or synthetic gas obtained through P2G can also be used for industrial purposes or for mobility and be transported via trailers.

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?
At the DSO level, targeting tariffs for a power-to-gas technology might be useful - especially for a limited time in an introductory phase - so that it can become a sustainable technology. However, targeting tariffs only might not be sufficient for the development of the technology as shown by the German example. In Germany, there are certain obstacles to the further development of P2G technologies such as taxes and levies. However, the government and the sector are working on a proposal to enhance the efficient deployment and use of P2G. In Germany, it is not seen as an efficient solution to reduce only grid tariffs for P2G. A whole set of new measures will be needed to integrate P2G successfully in the current tax/levy/regulation system.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
As mentioned in Q6, a whole set of measures will be needed for the development of P2G technology. Since P2G installations are currently not economically viable, and large-scale market uptake can currently not be expected, it is key that the legislation allows DSO to own and operate P2G installations if this allows an optimal energy system management.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
First of all, CEDEC welcomes the introduction of GOs for renewable gases in RED II. To facilitate efficient cross-border trading of renewable gas GOs, uniform standards are necessary. CEDEC is in favour of the possibility to issue GOs not only for renewable gases but also for decarbonised and low-carbon gases. GO schemes must be interoperable.

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?
No answer.

Infrastructure Investments and Regulation

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?
Given the decentralisation of the energy systems, it is important to give the adequate consideration to the evolving situations on the distribution grids and to the role of DSOs to contribute to a high quality of the TYNDP. With the increasing levels of renewable energy sources, the energy system is evolving and so is the role of DSOs. Whereas traditional generators tend to be connected to the TSO, 90% of renewable energy producers are connected to the DSO. With the ongoing increase of production of renewable gas, gas DSOs also face the challenge of managing a network with increasing generation at the distribution level. This evolution must be taken into account and DSOs must be structurally involved in the elaboration of the TYNDP.

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)?
There should be a better coordination between NC CAM and PCI selection process. Since the adoption of the regulation, the picture has changed substantially: the political priority and citizens' consensus has moved from an energy policy focused on large infrastructures to more decentralised energy networks allowing customer empowerment and integration of large amounts of renewables. The TEN-E Regulation neither reflects this new situation in the European energy system nor supports reaching the Union's climate and energy goals as put forward in the Clean Energy for All Europeans Package and the Paris Agreement. The DSOs have become ever more important in the energy system. This is particularly the case with regards to customer participation and integration of RES. However, to date, only four DSO smart grid projects have been selected as PCI to be implemented under the TEN-E Framework, out of 170+. The selection scope must be extended also to renewable/ decarbonised/low-carbon gases, to sector coupling and the development of promising technologies such as P2G.

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?
In Germany, although DSOs believe that gas is going to play a very important role as part of Germany's energy mix, there is also a risk of stranded asset. The possible decommissioning of gas networks must be financially feasible and shall not lead to further or additional costs for the consumers nor shall it endanger long term security of investments for the DSOs. To reduce decommissioning risk, some tools could be used such as a shorter economic lifetime for the networks, a higher calculated return on capital or the recognition of asset disposal. In the Netherlands the government decided to phase out the so-called 'Groningen-gas' and to forbid in principle all new gas connections to the distribution networks. This means there will be stranded assets in the sense of networks being used less or for a shorter period than expected. The significance of the impact also depends on the usage of the gas networks for other gases, such as hydrogen and biogas. The European principle that efficient costs will be remunerated, is applied in the Netherlands in a way that the tariffs also bear the costs of stranded assets. This approach led to thorough discussions on how to handle the ascending costs for the end users that stay connected to the gas networks for the longest time. Together with the Dutch regulator, the DSOs and TSO are discussing this topic in the MORGAN-project. An identified solution may be that the method for amortizations is altered or that a fund is created to bear future costs. Adjustment of accounting rules may not be a good solution, since the regulator plays a leading role in the definition of depreciation periods, but local governments can decide whether to remove a gas network. It is essential that a strong and clear regulatory framework will address this situation as network operators still have to invest in gas grids the coming years to ensure the security of their networks.

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?
The decommissioning of network assessments could take place at different pressure levels. It should be clear that decommissioning in one country must not endanger security of supply in another Member State or create financial burdens for adjacent Member States

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Gas legislation must to a certain extent be complementary to the electricity legislation, as many DSOs are active in both electricity and gas and need to have compatible business processes. CEDEC believes that some key issues must be tackled in the future gas market design. •Legislation must encourage the uptake of renewable/decarbonised/low-carbon gases. To do so, the legislation must be updated to allow injection of various gases in the network. Furthermore, manufacturers of end-products must also be obliged to produce devices that can accept these new gases. •Legislation must leave flexibility on tariff design e.g. to allow DSOs to invest in hydrogen ready networks or in networks that can accept fluctuating gas qualities. •Legislation must promote cooperation with other sectors through sector coupling at local level. The future gas market will need to be able to respond to the increased level of interaction as it is necessary to meet the climate change targets. •DSO should be allowed to build/operate P2G installations and storage to maximise injection of RES/ decarbonised/low carbon gases into the DSO grids. The Clean Energy Package puts a brake for DSOs on capital-intensive investments in new technologies such as storage or EV charging infrastructure. The same mistake should be avoided in the gas market design and instead of focusing on making sure that DSO/TSO do not foreclose competition in the future, the legislation should ensure that TSO/DSO actively support technological innovation. In general, DSOs should have the right to be involved in the development of promising innovations/technologies that are not yet economically viable, as long as markets are not fully competitive. •For Network Codes impacting DSOs such as balancing and interoperability (e.g. gas quality), there should be a joint responsibility TSO/DSO in the drafting of the network codes. To trigger this joint responsibility, CEDEC believes that an EU DSO Entity for gas should be established, or – even better to avoid continued and structural silo-thinking – an integrated electricity & gas Entity.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The production of renewable hydrogen from surplus RES electricity can avoid the installation of additional fossil/renewable generation capacity and replace electricity network expansion. These avoided costs need to be monetised and hydrogen producers shall be financially rewarded accordingly. P2G producers should be recognised as flexibility providers. Biomethane producers shall be rewarded for all positive externalities. Support schemes shall be developed taking into account all the positive externalities: contribution to energy flexibility, decarbonisation of agriculture, waste treatment… Gas prosumers using smart gas flexible solutions such as micro-CHP shall be incentivised.

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?
No answer.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
No answer.

Other question

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

Regarding the “Framework for allowing TSOs/DSOs to participate in an activity” (page 15), CEDEC would like to recall comments already made in the CEER consultation on “The future role of DSOs”.
The proposed framework is one-dimensional as it is only focused on competition potential and customer short term interests, and is not taking into account distribution system needs.

Fundamentally, for all types of activity a choice has to be made, new or not, between 3 categories: “core regulated”, “regulated - under conditions” and “competition”. The question should then be formulated – for every activity - as follows : “Is competition the best solution to guarantee an essential service in the interest of all consumers ?”

An “essential service” (cf. CEER Principle 3 in report “The future role of DSOs”) should respond to 3 requirements :
1)Offering infrastructure and/or supply services to all consumers
2)Covering the whole territory
3)Taking into account short and long term “public interest” (cf. CEER Principle 3 in report "The future role of DSOs") objectives, such as security, privacy, sustainability, innovation.

Even if the answer on the competition question is in principle yes, the second question “Is there a justification for DSOs to carry out (part of) the activity?” remains valid: if the answer is yes, the activity remains in the regulated domain, albeit under conditions. It is rightly stated that a justification should also consider an integrated view for the electricity and gas sectors.

Some remarks concerning text on page 15:
-The word “special” in “special justification” can be deleted.
-Some new activities are currently under-developed, not “relatively”. delete relatively.
-It is not clear what “limited participation” exactly means and implies. delete limited ?

Justifications here might be the lack of geographical coverage of energy-related infrastructures, disturbing influence on grid operation, the higher overall societal cost if left to competition, or tackling the risk of vendor lock-in behaviour by commercial actors on the market. The overall societal cost may be reduced amongst others if closely related tasks can be executed by one regulated party, creating possible effects of synergy and scale.

The conditions set should not only focus on potential competition in the future, but even more on the role DSOs/TSOs can play to help develop technological innovation.

Another element that should be taken into account is how much regulation is needed.

Survey response 46

Contact details and treatment of confidential responses

Contact details: [Organisation][]
ENGIE

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Engie considers that 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. DSOs and TSOs play a crucial role in facilitating the development of a competitive market. Grid operators should act as market facilitators for the rapid development of renewable and decarbonized gases. The definition of standards, under NRA supervision and following transparent and participative procedures, also represents an important task within the perimeter of grid operators. As far as P2G activities are concerned, they are in principle market activities. As a consequence, the development and operation of P2G should be carried out by market operators benefiting of an enabling regulatory framework to be put into place. Notwithstanding to that, as already done in the “Clean energy for all Europeans” package, we expect the EU Institutions to identify efficient solutions to possible market failures or limits.

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.
ENGIE considers it too early to define a EU-wide maximum threshold for the blending of hydrogen in the gas network. There are local specificities and constraints which can differ significantly from one network to the other, therefore a common threshold is not adequate. Moreover agreeing on such thresholds takes time and risks to result in the “smallest common denominator”, thus limiting hydrogen development and injection below its potential, in particular in more advanced/ambitious regions. In terms of timing we considered a 2 step-approach: •It is most urgent to find solutions to ensure a maximum of hydrogen injection at local and regional level, this must happen in the next years. •In the medium term, TSOs must be obliged to cooperate to find solutions that allow to maximize the interoperability of networks with different hydrogen injection levels, including regional balancing of blended gas quality.

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.
For new hydrogen networks, ENGIE supports the application of the same principles as for natural gas networks: Pipelines should be regulated, including Third Party Access, regulated network tariffs and access conditions. Direct lines linking dedicated H2 production facilities and consumption sites could be exempted from these rules, similar to closed distribution systems. Existing pipelines should normally not be subject to these rules in line with the non-retroactivity principle.

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.
As the development of a sustainable gas sector is still at an early stage with lots of uncertainty regarding future evolutions and since technology options have different maturity levels, the approach should remain as open as possible and avoid to exclude certain solutions and pathways at an early stage. This however is exactly the risk when applying a technology-neutral approach too early. A technology-neutral approach can lead to cost-efficient results when mature technologies compete with each other on a level playing field. This however requires that all positive and negative externalities are properly internalized which is far from being the case for green gases. Moreover market signals don’t reflect the necessary long-term perspective that is needed if we want to achieve decarbonization targets. Thus a technology-neutral approach might be cost-efficient in the short-term (privileging the cheapest solutions today) but might compromise cost-efficiency in the long-term when certain options reach their limits and promising alternatives have not been developed. We therefore support a technology-specific approach for the development of different sustainable gas solutions (including biomethane, synthetic gas, renewable hydrogen, decarbonized gas and hydrogen etc.).

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

P2G plays a key role for sector coupling between electricity and gas (H2 or synthetic gas produced from electrolysis is injected in the gas network and is used in typical gas end use appliances such as heating) and sector integration (H2 or synthetic gas produced from electrolysis, is injected or not in the gas network and is used in other sectors like mobility or industry, thereby replacing other energy carriers like petrol, fossil hydrogen etc.). P2G based on renewable electricity allows thus to decarbonize the gas and other sectors and as additional benefit transform whether-dependent, variable energy (from wind, solar) into schedulable energy that is available when needed.

Another important function of P2G is that of a storage facility, when variable renewable electricity is converted to hydrogen or synthetic gas during times when it is available abundantly and reconverted to electricity (through CCGTs, fuel cells, etc.) at moments where there is a lack. A crucial advantage of P2G compared to other storage options like batteries is its capability to function as longer-term / seasonal storage.
Moreover P2G can serve as efficient way to transport over long distances energy, avoiding unnecessary and inefficient investments in electricity grids.

Mostly obviously in the storage case, but also in cases where it is not reconverted to electricity, P2G can bring necessary flexibility to electricity system which is needed to integrate variable renewable electricity production. It competes in this case with other flexibility options like batteries, demand response or investments to reinforce electricity networks.

In some cases P2G also can be used to satisfy specific demand needs (e.g. industrial districts linked to dedicated production sites).

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?

The storage and flexibility function of P2G and G2P should be taken into account and could translate into a discount on network tariffs:
• G2P in form of CCGTs or fuel cells can help to deal with peak demand in the electricity system. Today gas storage benefits from a discount on gas network charges, the same principle could apply for G2P with regard to power network charges.
• On the other hand, P2G can help to stabilize the power system by using network capacities during times of low demand (and high infeed of renewables). This service could be incentivized through a discount on network tariffs for P2G.

A complementary option is to remunerate the services that P2G and G2P bring to the power system through relevant market mechanisms (flexibility/reserve/capacity markets, congestion management etc.) provided such mechanisms exist and provide a level playing field for all participants.

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

In addition to our answer to question 1, there is a clear need for unambiguous definitions, an EU blueprint for guarantees of origins, appropriate rules for the injection of green gases into the grid, simplification of permitting, identification of appropriate economic signals to value dispatchability value of H2 and synthetic methane delivered through P2G.

Moreover, as general principle, costs associated to the development of P2G shall be borne by the beneficiaries of P2G (e.g. avoided electricity grid costs, avoided curtailment of intermittent e-RES).

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
ENGIE agrees that interoperability and standardization are needed to facilitate cross-border trade of GOs and create a more liquid market. We would like to recall that work is already ongoing by ERGAR (gas), CertifHy (H2) and AIB (electricity) and a new official CEN standard EN 16 325 is under development. These initiatives should be properly coordinated among each other. National registries must be interoperable, both within one country (there might be different registries for electricity, gas and hydrogen) and between countries. One common standard GO for gas could be developed. It is important though that this standard is compliant with the minimum information requirements specified in Art. 19.7 RED II (energy source, identity, location, type and capacity of the installation, commissioning date, support mechanism if applicable, etc.). However, it should be possible to add additional information that allows to create products which address more specific customer needs. Buyers of GOs can be very different including utilities, large enterprises, municipalities etc. A municipality may place big importance on GOs from a renewable source in their geographical proximity while this might be of less relevance for an industrial consumer that simply wants to reduce his carbon footprint. ENGIE is in favor of issuing GOs also for non-renewable, decarbonized gases (such as natural gas with CCS/CCU or fossil hydrogen with CCS/CCU) but it must be possible to clearly distinguish between renewable and non-renewable gases. We consider that this distinction is in principle possible if the minimum information required by the RED II on the energy source and type of installation is included, as mentioned above. In this context, we would like to stress the importance that definitions and criteria for renewable and non-renewable but decarbonized gases are aligned across countries to avoid confusion and contribute to a more level playing field. The standard should include also a common methodology on how to issue, register, transfer and cancel GOs, as well as how to convert them from one energy carriers to another – all this in a proper way to avoid any double counting of the same volumes. Conversion e.g. of electricity GOs into hydrogen GOs in principle means that electricity GOs are cancelled and a corresponding amount of hydrogen GOs is issued (taking into account losses). However we would like to stress that such a conversion can only happen if a physical conversion (e.g. from electricity to hydrogen or from hydrogen to synthetic gas) takes place as well. Without physical conversion, it should not be possible to convert or use GOs in another sector (e.g. using electricity GOs to green the gas sector or vice versa). Last but not least we would like to emphasize that the creation of a liquid national and international market for gas GOs will allow green gas producers to generate additional income, the value of which is driven by consumer demand. However this is most likely not sufficient to fully trigger investment in green gas production that is needed to comply with climate targets: Power GOs are trading at a very low price, and gas GO price will likely be in a similar order of magnitude. Additional policies that directly and indirectly incentivize the uptake of green gas production will be key. Moreover it is important to note that there is a link between incentive mechanisms/regulatory framework and the price at which the GOs will be sold. Larger discrepancies between countries will create distortions on the GO markets.

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?
In addition to the elements provided under answer to Q8, in order to establish liquid markets, it is essential that the commodity can be traded regardless of its origin. It should therefore be possible to trade guarantees of origin for gas independently from the commodity, as is the case for electricity GOs and required by the RED II.

Infrastructure Investments and Regulation

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?

It seems that in some European countries (e.g. France), policy choices in favor of electrification of demand are taken without proper impact assessment, thus putting at risk the important economic contribution, security of supply, quality and environmental benefits that gas (natural, renewable and decarbonized) can provide to citizens and industry. Considering the interconnected nature of the European energy system, these inefficient choices, even if taken at national level, can negatively affect neighboring countries' security of supply, energy system costs and trigger inefficient additional investment needs. The EU should identify the necessary measures to avoid the above mentioned risks and inefficiencies, in the interest of EU citizens and industry.
As far as the TYNDPs are concerned, they shall pursue cost efficient energy transition as guiding target. In particular, the costs of excessive electrification and the importance of gas in heating shall be taken into consideration in the models. In that respect, scenarios shall include critical periods of low e-res production and high heating needs, as well as all necessary variables that could impact the stability of the network. Moreover TYNDPs shall include the contribution to decarbonation of other sectors (mobility for instance).

In that respect, transparency is a key factor and shall begin with what is already produced :
-Physical results in terms of demand curtailment e.g. in "Dunkelflaute" periods
-Identification of the main bottlenecks of the EU transport network
-Sensitivity scenarios showing the effect of the change of one given major hypothesis (e.g. electrification of heating, of transport) to allow some form of marginal cost estimation (not possible today to isolate such effect with three main scenarios mixing many different issues),
-All investment costs should be published, including FID
-In the power modeling, generation is automatically adjusted and optimized to answer demand with no sensibility on what is happening if generation investment is not occurring e.g. in the best possible locations
-It must be disclosed which extreme climatic scenarios the network should be resilient to. European citizens must be aware of what is happening in case of the "worst Dunkelflaute" occurring every x years.

Considering the increasing complexity induced by sector coupling, and the growing sensitivity of citizens and governments regarding the bill of the energy transition, it is important to ensure that methodological orientations and scenario building are not influenced by the sole interest of TSOs.

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)?

Green Gas development projects, hydrogen/methane blending projects, P2G, P2G2Methane projects and biogas upgrading (into biomethane) projects shall be eligible as Projects of Common Interest and externalities shall be fully included into modeling, including sector integration benefits.
For cross-border transport investment, CAM NC is defining an effective way to assess market willingness to pay for the project. Therefore, the market test of CAM should be the driving factor to determine the economic added value of the pipe.
Hence, the addition of cross-references between the infrastructure regulation 347/2013 and the CAM NC (2017/459) is positive.

Moreover, there should be more transparency given to the market on the advancement of projects and on the evolution of technical capacities. TSOs should make regular updates on the projects, be transparent on the nature of the difficulties encountered, and give as soon as possible the most detailed information on the future offer of capacity (in terms of capacity, of firmness, of conditionality).
When different commercial capacity offers are possible to take into account network constraints (e.g. capacity can be offered in competition on several points, or several forms of conditional capacities), thorough consultation of the market should be made, based on transparent technical information : where are the bottlenecks, what are the most constraining flow patterns...
Similarly, for interruptible or partially firm capacities, maximum information should be given on the market on the technical criteria retained for deciding an interruption : what is the constraining flow pattern, where are the physical congestion within the network...

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?
Gas assets are key in the energy transition : Their long-term storage capacity is unique and much needed, gas is the leading option for long-haul mobility, biogases are a key part to integrate efficiently energy and agriculture sectors, and generally, gas solutions are delivering the most affordable energy transition to a decarbonized system. So if correct planning is done, if distortions or hidden costs are revealed, there should not be a major stranding of gas infrastructure in the foreseeable future. Though, locally, there will be some assets that will become stranded, e.g. following the decrease of local production in Europe. For France as well as for other European Countries, the risk is not seen in the short term and medium term. In the long term it will depend on green gas development, and on the forward-looking and integrated approach to gas and power network planning. Where and when such stranding could occur, spiraling of gas network tariff should be avoided. Most of these assets are regulated, may not be fully amortized yet, so related guaranteed revenues will have to be paid anyway. So the risk of tariff spiraling is real, especially if compounded by other factors (cf. questions 14 and 16). Spiraling of tariffs should be avoided to protect final customers from increasing bills that would generate distortive and non-efficient behaviors, further putting at risk the stability of the system. Two kinds of tools could be used to avoid such spiraling : First, considering the wide role of the gas system, some socialization of costs beyond the gas industry should be considered. Secondly, within the gas system, a Quo Vadis/Tarif Reform solution, potentially on a regional level, should be considered, as specified in question 14. Another aspect to limit the risk of stranded assets is to carefully evaluate the inclusion of new cross-border pipeline projects as PCI. Apart from very limited exceptions, mostly in Eastern countries, new projects should be underwritten by engagements from market participants.

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?
Yes, because gas systems are integrated, decisions on decommissioning / mothballing (mothballing has a value option that can in some cases be more attractive than a full decommissioning) should be assessed with methodologies similar to those used for investing in new cross-border infrastructures. An EU framework for decommissioning / mothballing infrastructure with a cross-border impact shall also be implemented. In particular the adequacy assessment shall be carried out following standardized methodologies defined at EU level including all relevant stakeholders.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
First, measures allowing an efficient development of renewable and decarbonized gases (as described in the answer to the next question). Secondly, cross-border transport tariffs are a major issue for the gas market. Two considerations are adding up to make this subject more important in the next few years : -Some major cross-border tariffs, e.g. in Germany, have increased very significantly in the last years. -With the now rapidly decreasing long-term bookings in the hands of European actors, tariff pancaking will become a major issue. Important spreads, costing the European customers billions of €, are already present in the South and Eastern Europe. This issue remains valid whatever the LNG context : -During periods when the LNG is expensive with fewer emissions in Europe, pancaking could create massive spreads all across Europe; -Even if the LNG is massively unloaded in Europe, many areas have to cross several borders to access to a significant LNG price signal. A Quo Vadis Tarif Reform solution, allowing to push tariffs away from cross-border points and to create a more liquid and integrated European gas market, should therefore be considered. Concentration of the booking of transport capacities in the hands of a few actors, which is an expected result of the current market design, is also creating issues and risks. Capacity releases are an efficient tool to address this issue. Beyond tariffs, access to firm capacities could be an issue. For instance, the German merger is creating massive uncertainties regarding the firm capacities that will be proposed, and little clarity on when and why interruptible capacities will effectively be interrupted. Indeed, it is not clear how the German gas grid will be physically optimized : There are no obvious incentives for the many German TSOs to cooperate to search for the most efficient flow patterns within Germany... Another very important aspect of the gas market design is its enforceability : There are still many measures in place, hampering the development of a competitive European gas market, that are not respecting the spirit of the letter of the current gas package.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Just as renewables in the electricity sector, biogas and biomethane, renewable hydrogen and renewable synthetic gas will need dedicated policies and support mechanisms to kick off and – through large-scale employment – realize cost reductions. As proven in the electricity sector, a binding renewable gas target on EU and/or national level (% of renewable and decarbonized gas in final gas demand) can be a strong driver and provide the necessary visibility to investors (and lenders). An efficient objective setting shall be cost-efficient, market-based and competitive support mechanisms will help to achieve this target. However in order to keep support cost under control and reduce the need for direct financial support as much as possible, a broader enabling framework has to be put in place, which should include at least the following elements: •A functioning GO system that allows to track green gas also across border and clearly differentiates between renewable and non-renewable gases. This is needed to create transparency towards final customers and enable suppliers to offer green products corresponding to customers' needs. •Enable renewable gas operators to maximize their energy market revenues, not only from selling renewable gas but also from participating to other markets such as reserve/flexibility/ancillary service markets (P2G and G2P). •Internalization of positive externalities •Proper recognition of CO2 savings through the use of renewable gas via a well-to-wheel methodology in relevant EU legislation. This will also put renewable gas on an equal footing with other solutions, e.g. in the mobility sector were currently only tailpipe emissions are considered. •Removal of entry barriers, e.g. undue technical requirements/restrictions to the injection of renewable gas in the network •Dedicated R&D support •Next to financial support on the production side, incentives to stimulate demand for green gas, including through tax advantages, blending obligations •Simplified permitting and administrative procedures •Measures outside the gas sector such as possibility to properly valorize side-products (e.g. digestate from production of biomethane), review "distortive" support mechanism in electricity that privilege biogas use for onsite electricity production, aligning the agricultural sector with climate goals, etc. •CO2 pricing: While cost-efficient support mechanisms will be important to kick-start large scale development of green gas in the short run, ENGIE supports in the medium term a transition towards a more CO2-based taxation in the non-ETS sector (taxation of heating and transport fuels). To avoid distortions on the EU's internal market, such a transition must be promoted on a cross-regional or even European level. It could be implemented by reviewing the minimum taxation levels determined in the energy taxation Directive which are currently calculated on the basis of the energy content not taking into account the impact on climate change. Such a review would also allow to better align CO2 price signals to decarbonize different parts of the economy and between the EU ETS and the non ETS sectors. •ETS installations using green gas with GO's should not have to submit CO2 allowances

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?
Yes, as described in question 14, this is a major concern, already costing billions of € to European gas consumers. Decrease of gas consumption would of course make the issue even more problematic, and reinforce the urgent need for an ambitious solution. Article 5 of regulation 2017/460 has been designed with the relevant objective of limiting cross-subsidies between intra-system and cross-system network use. The formulas proposed in this article are often leading to a result in contradiction with this objective. Current tariff network code is solely focused on internal gas infrastructure issues. The code is not considering as an objective the role of gas in the energy transition. More particularly, it does not contain any reference to specific treatment of renewable or decarbonized gases, and to the flexibility services offered to the power grid, mainly through Gas to Power and Power to Gas installations or gas heating.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
As general principle, grid costs associated to the development of P2G shall be borne by beneficiaries (e.g. avoided electricity grid costs, avoided curtailment of intermittent e-RES).

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Please refer to the answer to question 15.

Survey response 47

Contact details and treatment of confidential responses

Contact details: [Organisation][]
BDEW e.V.

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The energy system transition will have a substantial impact on the gas sector. As the role of renewable energy grows, the contribution of the gas sector to facilitate this overall system transition becomes more important. BDEW is currently working on guidelines and recommen-dations and will give them as input in the further discussion at EU level.

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.
In general, BDEW regards the increasing infeed of hydrogen into the gas networks as a signif-icant contribution to the integration of renewable and decarbonised gases. The absorption ca-pacity of the gas network is primarily in the remit of each grid operator and will depend on the ability of the gas appliances connected to absorb hydrogen. This will change in the course of time with the development of new appliances. Already today appliances exist that can take up to 100 % hydrogen, and further ones are in the design phase. The physical properties of hy-drogen are different in regards to density, the Wobbe index, calorific value and flame speed. This aspect has to be taken into account. Furthermore, the possible level of hydrogen infeed depends on the characteristics of the natu-ral gas already in the grid, as the Wobbe index and the calorific value between different kinds of H-gases differs. Moreover, as the development of hydrogen should be driven by the market, the infeed of hy-drogen most likely will not develop at the same time to the same extent, but differently across regions and/or sectors. With a view to the corresponding development of hydrogen demand and increase of blends, a close and frequent cooperation between the TSO and DSO regard-ing gas quality data as well as R&D for sensors should be taken into consideration. This also applies to smart gas grids that would allow the DSO and the TSO to define the gas mixtures in the grid and therefore optimise the injection of all renewable and decarbonised gases. Ultimately, the possibility of methanisation in certain parts of the grid or of sequestration of hydrogen with membranes for sensitive consumers connected to certain parts of the grid (e.g. CNG filling stations, quality sensitive industrial customers or turbines) offer all opportunities. However, it is important to get a holistic view from the production of renewable and decarbonised gases to the enduser appliances. In conclusion, when considering a common European threshold, criteria such as costs, re-gional characteristics and a sensible timeline should be taken into account, e.g. in the frame-work of a roadmap. While a mandatory European-wide threshold of high level does not seem recommendable at this point in time, an indicative low threshold which takes into account all relevant technical and legal conditions/restrictions and which is accepted by the stakeholders could be an approach to give some directions for the developing market. One reason for this is that the increasing infeed of hydrogen will require extensive cooperation across Member States to prevent barriers to the cross-border tradability of gas. The issue should be discussed at the next Madrid Forum in June 2019. Nevertheless, the maximum hydrogen concentration based on the technical development and the hydrogen compatibility of the end consumer should be increased gradually in the national technical rules and standards.

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.
Hydrogen networks should fall under the same regulatory rules as gas networks if the hydrogen is used as an energy carrier in the public energy supply for households, industry, commercial consumers and power plants, as defined in the 3rd Energy Package. In principal, the establishment of an extensive parallel new infrastructure should be avoided, if cheaper blending options are available to ensure economic efficiency. However, many grids may develop from blends to pure hydrogen in the course of time. Per definition, these grids would always be part of the regulation. The reuse of existing networks will require the replacement of certain network components. This should be taken into consideration by the regulatory authorities. At the same time, hydrogen pipelines for specific consumers already exist today, e.g. in Germany and other European countries. These are mostly point-to-point industrial hydrogen pipelines dedicated for a specific hydrogen production and delivery to one or few large industrial consumers. Generally, these pipelines are oriented to the industrial needs and are not accessible for other consumers due to technical reasons. When shaping a regulatory framework for future hydrogen networks, the coexistence of these already existing pipelines and public grids for all consumers has to be taken into account. In general, the development of an infrastrucure dedicated for 100% hydrogen transport has to be in line with the demand. With respect to network access, inefficient grid connection for hydrogen should be avoided. A costbenefit analysis or minimum requirements depending on the existing infrastructure could be a solution in those cases.

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.
Market-driven and technology-open solutions should be prioritised in order to make an economically efficient contribution to the energy system. This approach should be supported by measures to ensure non-discriminatory market participation by all competing technologies. The current regulatory conditions, however, do not fully provide this level playing field. Distortive conditions will lead to unnecessary cost inefficiencies in the long term. Therefore, “cost efficiency” is a principle which should be considered when assessing the optimal and reasonable pathways for reaching the climate targets on a technology neutral basis. However, the “cost efficiency” criterion should not only be applied regarding short-term effects but should also consider the long-term development of new technologies. The reason for this is, in particular, that the high upfront investment costs are often necessary for the benefit of a long-term cost-efficient solution. Proactive market interventions may be required to enable the advancement of new technologies and to reach long-term cost efficiency.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas is a key technology for the necessary coupling of electricity and gas networks. It is currently the only technology that can be used to interconnect all sectors (electricity, industry, heating and transport) while ensuring energy supply and seasonal storage. The technology converts renewable electricity into renewable gases, which can be further processed in the value chain of all sectors to support the achievement of the climate targets. Hence, a Power-to-Gas infrastructure should be planned taking into account the needs of the electricity, gas, heating and transport sectors. By doing so, power-to-gas can play an important role for reducing the curtailment of renewable electricity and help reducing the need for grid expansion. Power-to-gas and its products have to particularly be seen from the user perspective. Accordingly, its grid and system relevant function is a potential and important use. Its main purpose and potentially the biggest area of application is the decarbonisation by means of enabling the use of renewables and decarbonised gases in the different sectors. The storage of renewable gas in gas storage facilities can also ensure seasonal storage. For this purpose, it is important to secure the outlook of valuable infrastructure (gas networks and storage facilities) to be able to continue to use them in the future. In this regard, BDEW also sees the need of a joint approach for the planning of electricity and gas infrastructures at the European, national and regional level in order to reap the benefits of creating synergies be-tween both planning regimes. BDEW supports the existing coordination in the scenario building process for the European gas and electricity TYNDPs. In addition, NRAs should assess whether NDP processes at national level can be optimised, also taking into account the grid development at the DSO level. To optimise the use of power-to-gas plants and a coupling of electricity and gas grids, a joint planning of gas and electricity grids at DSO level should be considered. In order to reach the climate targets, a considerable share of power-to-gas infrastructures for the production of decarbonized gas will be necessary by 2030, with growing shares until 2050 (1). Therefore, timely investments in power-to-gas facilities are important to mature the technology and to reach the required scale by the time it could play an essential role for reach-ing the climate targets. (1) See for example: Agentur für Erneuerbare Energien, Metaanalyse: Die Rolle erneuerbarer Gase in der Ener-giewende, 2018, S. 22. / BCG, prognos, Klimapfade für Deutschland, 2018, S. 243. / dena, Leitstudie Integrierte Energiewende, 2018, Ergebnisbericht, S. 25 ff. / Netzentwicklungsplan Strom 2030, Version 2019, 1. Entwurf, Zahlen – Daten – Fakten, 2019, S. 5. / Agora Energiewende, European Energy Transition: The Big Picture, S. 78.)

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?
In Germany, sector coupling technologies like power-to-gas are generally classified as "end consumers" in the electricity sector and are therefore charged with all associated taxes and levies. However, power-to-gas facilities provide valuable flexibility to the electricity system for example by reducing the load in the electricity system during periods of extensive renewable energy production and hence allow for the seasonal storage of energy. Partial exemptions, some of which are in place today, are often complicated, of temporary nature, or specific for certain technologies. Storage and conversion of one form of energy into another should be treated as a separate process, exempted in particular from end consumer taxes and levies. Moreover, the goal should be a technology-open level-playing field with a CO_2 pricing in all sectors. With a view to energy efficiency and cost efficiency for investments in renewables the injection of excess renewable electricity into power-to-gas facilities should be endeavoured instead of curtailment.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
It should be noted that the regulatory framework currently in place was set up in a time when the possibilities of sector coupling via power-to-gas were not yet envisaged. Hence, any new regulatory overhaul should clarify the roles of stakeholders in the development of power-to-gas facilities and shall recognise the system value of conversion realised by those facilities in a coupled energy system. A constant demand for renewable and/or decarbonised gases is essential to create sustainable business cases for power-to-gas plants as well as other incentives and reliable business models. Therefore, the contribution of renewable and decarbonised gases to achieve the 2030 and 2050 GHG objectives in all sectors needs to be considered in the regulatory framework (e.g. renewable quotas, public tenders). Furthermore, the national regulatory authorities should clarify the handling with feed-in requests for sector coupling technologies and the connected technical grid adaption to ensure a safe, cost efficient and sustainable grid operation. Nevertheless, non-discrimination of technologies need to be respected. Consistent energy and climate policy in terms of European coordination as well as energy levies replacement by CO_2 pricing could be an option. New energy products with a consumer premium for lower CO_2 emissions already work and should gain a bigger role in the gas market. In order to create demand for renewable and decarbonised gases, adequate incentives have to be put in place across different sectors. For the mobility sector, it should be possible for vehicle manufacturers to meet the CO_2 emission standards for cars and light duty as well as heavy duty vehicles by using renewable and decarbonised gases. Aside from this, the uptake of renewable and decarbonised gases in the heating sectors has to be supported by the energy efficiency legislation. As long as those gases delivered via the grid are not acknowledged in the energy efficiency calculation of buildings, the interest of custom-ers will be very low. Renewable and decarbonised gases can play a crucial role in the faster decarbonisation of the heating sector.

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

To enable EU-wide trade with renewable and decarbonised gas a transparent and consistent mechanism is needed. When establishing a European Mechanism the focus should be set on a standardisation of the renewable and decarbonised gas characteristics to allow comparability of sustainability certificates. Efficient cross border trading needs flexible mechanisms to adjust the system depending on the potentials of generation and import of renewable and decarbonised energy. Therefore, the focus should not be solely on European mechanism for cross border trading but also beyond.
A European mechanism should not increase the administrative effort for all trading partners to ensure acceptance.
A mechanism should be based on existing operating experiences such as EUAs or gas certifi-cate mechanisms.
Germany has several gas certificates mechanisms that enable the verification of the sustaina-bility character of the renewable gas.
Main mechanism:
“dena Biogasregister”
• The Biogasregister is a commercial mass balancing system that is organised by the state-owned energy agency dena
• It was established to enable the verification and trade of biomethane in order to be eligible to receive compensation under the Renewable Energy Sources Act (EEG) or to veri-fy the renewable gas quality
• The purpose of the demonstration is to ensure transparent traceability with regard to the origin, quantity and characteristics of the biomethane
• Inclusion of other gases (e.g. hydrogen) is possible, focusses on gas transport via pipe-lines
• Follows “input-output-principle”: by injecting biomethane into the gas pipelines, it blends with fossil natural gas, therefore it is not possible to transport pure biomethane physical-ly. Instead, this is done via the so-called gas exchange: when gas from the gas network is consumed, it is assumed that it is biomethane if an equivalent amount of biomethane was fed into it at another location in Germany
• Mechanism records the exact quantity produced and the production location and period. In the course of further delivery, the trading partners register along the retail chain in the mass balance system. When supplying, for example, a CHP plant, a traceability via the mass balance system is then possible

“Nabisy”
• federal web application “Sustainable Biomass Systems” (“Nabisy”) of the German Federal Agency for Agriculture and Food (BLE) is another mass balancing system and provides evidence of the sustainability of liquid and gaseous biomass according to EU Directive 2009/28 / EC
• Distributors of liquefied or gaseous biomass in Germany can only allow their quota obligation to be credited to them or receive tax relief if they can prove that the liquid or gaseous biomass meets the sustainability criteria resulting from the EU Directive 2009/28 / EC
• the sustainability criteria for liquid biomass for power generation must be met if economic operators want to receive compensation under the EEG

Besides those two mechanisms, other certificates do exist, e.g. it is possible to engage an eternal assessor and to verify the renewable and decarbonised gas quality/characteristic direct-ly to the buyer.
However, none of the above-mentioned certificate systems currently allows a tradability sepa-rated from the commodity as it is the case with the GOs for electricity. In addition, the large number of certification systems hinders the establishment of a liquid market.
Besides these German gas certificate mechanisms there are also good examples for Europe-an-wide certificate systems such as ERGaR for renewable gas and certifHy for hydrogen.
Plant-specific GOs are not a prerequisite to enable trade since it should not matter whether a certificate originates from Denmark or Hungary if both can be trusted to carry the same re-newable and decarbonised gas quality. The certificate (as a guarantee of origin) should therefore be tradable independently from the commodity gas (Book&Claim). The guarantee of origin must also be transferable into products and differ between natural gas on one side and renewable and decarbonised gas on the other. Another important aspect is that the GO should recognise/show the decarbonisation attribute of the product. Therefore, it will be transparent for all market participants which contribution of decarbonisation the product implies.

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?

In order to establish liquid markets, it is essential that the commodity can be traded regardless of its origin. Therefore, as mentioned above, a certificate system for gas, similar to that for electricity, should be structured in such a way that a certificate can be traded independently of the commodity. This ensures, for example, that the commodity can be produced in Germany, transported and consumed in France, but that the GO is sold and cancelled in Belgium. This would also allow to trade certificates from different countries at the same trading hub. Synthet-ic gases produced with renewable energies as well as gas from biogenic origin should be part of that system.

Infrastructure Investments and Regulation

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?
ACER and the NRAs should be responsible for managing a continuous development of European integrated TYNDPs, which are focused on sector coupling. The existing framework and the TYNDP processes based on Regulation 715/2009 have proven to be very transparent and well accepted by stakeholders. Regulators as well as the European Commission have played an important and active role in this process so far. Taking into account that the TYNDP remains a non-binding network planning tool, additional administrative burden does not appear reasonable from BDEW's perspective. On the contrary, additional requirements and approval processes might make the TYNDP process even more lengthy and complex. The level of the involvement of the NRAs and ACER is already described in detail in European Regulations (347/2013 and 715/2009) and has proven to work very well. It is more important to join national grid development plans for gas and electricity during their development process and to ensure appropriate DSO and stakeholder involvement in the scenario building process. At European level, gas and electricity TSOs already develop joint scenarios and an interlinked model. Sector coupling and sector integration and the cost efficient use of existing infrastruc-ture should be the key principles. Realistic assumptions building on recent experiences should be taken into account, e.g. the current scenarios for the next TYNDP 2020 in electricity and gas built on a future reference grid of 2025.

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)?
Incremental Capacity is a process to prove, whether an investment is market-base, whereas PCI projects may be market-driven, but are important mainly for other reasons like security of supply or diversification of supply sources. BDEW does not see a contradiction of both frameworks. In fact, the current framework with the Incremental Capacity and the PCI process is complementary. A market-based invest-ment, supported by a positive economic test, can get the PCI-status in case the conditions are met. BDEW sees the need to clarify that the incremental procedure, 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.

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?
BDEW continues to see high demand for the gas network in the future energy system. Furthermore, against the background of the German political decision to phase out coal-fired power plants there will be an increasing importance of gas-fired power plants and thus of the gas infrastructure in Germany in the upcoming years as well as in the long run as the gas in-frastructure will play an essential role for the decarbonisation of the energy sector. This applies also to the cross-border gas infrastructure in order to provide flexibility of supply sources and to ensure security of supply and the mutual support of neighbouring countries at all times. The increase of the hydrogen absorption capacity might necessitate the replacement of net components before their calculated economic lifetime has ended. This should be taken into consideration in the regulatory framework.

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?
If the development of gas flows shows that certain parts of the existing gas infrastructure will no longer be needed for the transport of natural gas or methane from other sources, primarily a repurposing instead of decommissioning must be analysed (e.g. for the transport of hydrogen to help building a hydrogen infrastructure or for the transport of CO2 to support CCS). In any case, when considering the decommissioning of infrastructure, potential effects on securi-ty of supply, also in other Member States, and on market functioning have to be taken into account. Security of supply has to remain the top priority and must not be compromised. With regard to decommissioning, BDEW does not see the need for the establishment of an EU framework.

Adapting the Gas Market Design

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

BDEW agrees that the gas market integration has improved over the last years. Especially in the NW-Region the liquidity is high, hubs are highly functioning and the prices continued to converge. It is, therefore, important to allow the full implementation of the current regulation (in particular the Gas Network Codes) to be achieved before considering alternative or additional measures.

The development of renewable and decarbonised gases addressed in the consultation paper must be discussed in a more specific manner. From our point of view the current market de-sign is sufficient to integrate an increasing percentage of biomethane.

For a higher percentage of hydrogen the discussion has to start right now. The existing policy framework has been designed around natural gas. There are regulatory barriers and gaps for the integration of higher shares of renewable or decarbonised gases into the EU energy systems. Among others, a Guarantee of Origin framework and their accounting to the European Climate targets is critical. Parts of the hydrogen value chain, such as production, storage, distribution and other uses (such as for heating and power generation) continue to face (mostly unintended) regulatory and administrative barriers.

There is no specific legal provision that allows for, or regulates, hydrogen injection into the gas grid at either a Distribution level or Transmission level across the EU. The regulatory frame-work does not carry over well or appropriately covers network access for hydrogen injection.
This has caused barriers in the following areas:
• First, the process chain for power-to-gas is complex and there is no clear and unequiv-ocal legal position for power-to-gas. Gas grid network safety and operational proce-dures are managed at the national level leading to differing approaches to recognition of power-to-gas plants and hydrogen injection at legally acceptable levels. ‘Acceptable’ procedures for hydrogen injection/blending diverge considerably across MS and networks. Clear procedures should ensure standard conditions for grid access.
• Second, legally mandated national limits apply for hydrogen concentration in the gas grid. These vary from a ‘minimal’ level (reflecting the typical background concentration of hydrogen in natural gas) of 0.1%vol to 0.5%vol; a ‘low’ level of 1%vol to 4%vol; and a mid to high concentration of 6%vol to 10%vol. Where maximum hydrogen concen-trations are not legally mandated, the hydrogen concentration limits are based on accepted (national) safety norms for natural gas and which would limit hydrogen to (con-siderably) less than 10%vol. Nevertheless, the maximum hydrogen concentration based on the technical development and the hydrogen compatibility of the end consumer should be increased gradually in the national technical rules and standards. See also answer to question no. 2 above.

Besides, the following aspects should be considered in a review of the gas market design:
• As already today, each TSO and DSO should remain responsible to control the gas quality of the gas distributed to the users connected to their grids within the EU and na-tional gas quality standards. To do this the DSO needs timely information from the TSO, thus a sound information process between TSOs and DSOs has to be implemented. The NC on Interoperability has foreseen this, but at the time of its elaboration there was not yet the need for detailed processes in each country. Since the grid structures differ between countries, the detailed information processes should be designed at national level.
• With the NC on Gas Balancing the daily balancing system has been implemented. When starting with hydrogen injections from Power-to-Gas (e.g. based on renewable electricity), the long time experiences with biomethane injections in Germany should be used.
• The use of linepack is very important to be able to take up renewable and decarbonised gas in summer. In the past regulators have not seen the importance of this flexibil-ity and did not acknowledge the (re)investment at DSO level. This has to be changed.
• Several amendments in the Renewable Energies Directive resulting from the revision in 2018 (“RED II”) lead to unclear rules or are even harmful for the use of hydrogen produced on the basis of renewable or decarbonised sources (e.g. integration of hydrogen besides for use in transport also in other sectors like heating). Therefore, the review of the gas market design should also include checking and, if necessary, adapting the Renewable Energies Directive.

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

See previous answer.

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?

The full implementation of Regulation (EU) 2017/460 (TAR NC) will be realized in the forthcoming years. The current rules concerning transparency, consultation obligations and the determination of tariffs ensure cost-reflectiveness and will foster market integration. ACER and ENTSOG will monitor the effects of these rules. Before new rules may be developed, a sound analysis of the possible impact on the gas sector would be needed. Changes that may result in a less liquid and more fragmented European market should be avoided and it needs to be assessed if and where specific actions are appropriate and needed. It should be self-evident that infrastructure is paid by all its users. Otherwise, there would be an imminent risk of cross-subsidisation.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
A possible necessity for amending the NC TAR can only be identified after monitoring the effects of this NC which has only only been adopted in 2017. The NC foresees a monitoring process conducted by ACER and ENTSOG. Only after an appropriate monitoring has taken place, an amendment should be considered. In the long run, gas consumption patterns will evolve, new appliances as well as new locations with gas sources will play a more important role. This will probably lead to other transportation and distribution needs than today, affecting also the allocation of grid costs. The possible effects on different grid user groups have to be analysed properly Possible recommendations on adjustments of the cost allocation methodologies can only be derived, once such an analysis has taken place.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
There is a general growing awareness that, for reaching the European climate targets, imports of renewable as well as of decarbonised gases might be needed. Thus, considering a technology neutral approach, BDEW proposes to expand the focus of this CEER document also to decarbonised gases and to analyse potential regulatory measures regarding the facilitation of imports of renewable and decarbonised gases. More research and development is needed in the field of variable gas conditions, their potential effects on gas appliances and possible measures to cope with them. The same applies for the blending of hydrogen in gas networks.

Survey response 48

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GRDF

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The strict separation of essential infrastructure activities (especially TSO and DSO) from supply and trade is fundamental in the gas market design established by the European energy regulation in place. DSOs and TSOs have a key role of market enablers to ensure fair and effective competition. As such they are regulated monopolies focused in (i) the performance of their core activities and (ii) neutral facilitators to develop the market in the interest of the consumers. The objective of decarbonizing the economy supposes an energy transition which involves the creation of new business models and a deep evolution of the energy markets. The way these changes will occur is still uncertain today. That is why there are significant regulatory challenges to achieve a fully sustainable gas sector, especially concerning the potential contribution of DSOs and TSOs to accompany the transition through new activities and necessary changes in the relationships between DSOs and TSOs. 1) New activities of the infrastructures to foster renewable gas development Network operators must be fully dedicated to their core activities: design, develop, operate and maintain their assets and organize their usage in a transparent and non-discriminatory manner. In addition to this, the specific position in the value chain of the network operators give them a key position as neutral market facilitator. The current involvement of DSOs and TSOs to support the development of renewable gas such as biomethane injection or sustainable mobility show their potential of market enabler for nascent activities conducted by third parties (biomethane or hydrogen producers for instance). That is why regulation should give sufficient agility to allow DSOs and TSOs to leverage their unique knowledge of the market as well as initiators through, for instance, pilots and demonstrators in new activities as soon as the market is not mature enough to develop them. Such new activity, approved by the regulation authority, should be allowed under specific conditions and especially with the concern of supporting competition and end-users' benefits. The shift to a fully decarbonized gas industry supposes to proof on the short term what is still today new activities and turn them into effective commercial standards. DSOs and TSOs are well positioned to promote decarbonization of the gas sector, but it supposes to find agility and adequate regulatory framework to authorize them to spend time and money (OPEX and/or CAPEX) in R&D&I, new activities such as decentralized management of a dynamic network, blending of natural gas with renewable gases, large scale experimentation of CO2 or H2 grid management. Furthermore, a way to solve the question of supply-demand balance on distribution grid raised by major injection of renewable gases in local network could be to develop the demand according to a circular and local economy. Regulated entities like DSOs should be authorized to contribute to the investment in infrastructure for gas mobility such as gas refueling stations or bioLNG storage in the case that the market is not mature enough to propose it spontaneously and that such development brings value by avoiding network investments. 2) Reinforce cooperation between DSOs and TSOs to support renewable gas penetration Considering the decarbonisation, decentralization and digitalization of the gas sector in the coming years, the role of DSOs ad TSOs will evolve. It will require operators to closely work together. The development of renewable gas is a priority. It is crucial to launch the right move today to reach a decarbonized gas market in 2050. As the production could occur in areas with a gas demand lower than the production level - this is particularly the case of rural areas for biomethane - it could be necessary to send the renewable gas to another area able to consume or to store this local excess of gas. To do that, several means are possible including a reverse flow installation (consisting mainly in a compression unit enabling to move the gas from the distribution to the transmission grids) which is not the current network design. For example, in France the project called "West Grid Synergy" aims at reaching a 100% renewable gas distribution network and foresees to build a reverse flow installation between the network of GRDF and GRTgaz. Therefore, DSOs and TSOs need to cooperate when it comes to renewable gas development – including Power-to-Gas plants - to plan together the required infrastructure, depending on the location and the characteristics of the injection points, and to adequate their operations. Local storage units are another mean to adequate supply and demand over the year and to avoid grid congestion. Such installation also needs to be planned between DSOs and TSOs as they participate in the development of renewable gases. This alternative should be compared to the reverse flow installation and other options like virtual pipelines. Cost/benefits analysis should be made among the alternatives to find the best solution for the gas system as a whole. At the European level, the right channel to facilitate the work between DSOs and TSOs should be through the potential EU gas DSO Entity and ENTSO-G: - DSOs will actively participate in the TYNDP with regards to renewable gas plants, reverse flow pipes and network operations having an impact on the distribution network, - DSOs and TSOs will exchange data and best practices on their respective networks and work on cybersecurity issues.

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.
In our opinion, the allowed percentage of hydrogen being injected in the gas grid should be harmonized at the European level. The level of this percentage should be defined within the discussion on norms such as CEN/TC 234 and EN16726. A harmonization of hydrogen level will facilitate the exchange of gas with hydrogen incorporation between countries, therefore contributing to security of supply. A harmonization will also push the actors and investors to develop R&D projects to test the economic viability of hydrogen. It will also bring visibility to DSOs regarding their investment on the network. The question of the maximum level of content of hydrogen in the gas grid is both a technical and an economical subject. Indeed, it depends mainly on the characteristics of the grid (material and components) and of the appliances used by the end consumers. According to current studies and experiment, incorporating hydrogen up to 10% in the gas infrastructure would not require major investments. Considering these limited investments, it is important to promote the use of the existing gas infrastructure when relevant. To do so, it is necessary to support a coordinated R&D roadmap for gas infrastructure and gas appliances at European level and to define a timeline with increasing level of hydrogen content accordingly. We fear that a definition of a harmonized hydrogen percentage could bring to a relatively low value as the worst cases could make the reference. That's why, it should be accompany by other measures such as timeline of increasing level of hydrogen content and the principle that system operators must accept the highest incorporation as possible considering the local characteristics of the grid and its clients provided that the investment to adapt the infrastructure remain affordable. However, it seems too early to fix a threshold for hydrogen injection in the gas grids in the present situation. Further studies and experimentation to establish what is the desirable/maximum percentage of hydrogen injectable without affecting security are underway, especially by Marcogaz. The issue of the measurement of the calorific power of blended gases still needs to be solved. It will also largely depend on the ability of customers' appliances to use H2 and on the development of H2 production. In a decentralized production system, mainly on the distribution grid, the threshold could be quite different from one area to the other if you don't need to organize flows between different areas. On the opposite, with very large production platforms directly connected to the transmission grid, the need of a common threshold is more obvious to allow gas exchange between different countries.

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.
The reason of the regulation of the natural gas network in Europe was that they constitute essential facilities and that competition in such activity would not be possible or would be negative for the industry as a whole. Such regulation was possible because most of the infrastructure was already constructed under a completely different framework based on long term supply contracts and global supply routes including transit, shipping, storage. It is difficult today to imagine how hydrogen networks will develop and in which proportion they will use the existing gas infrastructure or not. In the assumption of the development of a network dedicated to hydrogen transport and distribution, different from current natural gas grids, such networks would constitute a natural monopoly in the same manner as the gas networks. We believe that the regulation authorities should be allowed to assess on a case by case basis, integrating the relative maturity of the activity as well and its situation in terms of competition, the possibility for a regulated entity such as DSOs and TSOs to invest and/or operate hydrogen networks. It should be a way to ensure third party access and an optimized and safe development of hydrogen networks. Furthermore, the new activity should be separated of the current activities and the regulated entity will report in transparency about it to the regulator and to the market, supporting the awareness and interest of potential shippers, suppliers or investors to commit into the hydrogen industry. As a consequence, considering the limited number and concentration of dedicated hydrogen projects in Europe, these provisions could be included in the revision of the Gas Market Directive and Regulation as an option subject to the criteria of Member States based on the existence of dedicated pipelines at national level.

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.
The "technology neutral" approach should be the common rule and should be preserved as far as a holistic methodology is respected. For instance, the biomethane industry has been disappointed by the way zero emission has been considered in the transport regulation while considering a "tank to wheel" rather than a "well to wheel" approach. We remain convinced that life cycle analysis should be always promoted in the impact assessments. However, markets also require some policy or regulatory signals to deliver expected objectives in time. This is why, in the light of EU energy and climate strategy, some kind of intervention would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades: Decarbonisation gas targets, support schemes, definition of regulated activities and planning are possible instruments that deserve further examination. In the case that market practices such as tender are not able to valorize sufficiently both positive and negative externalities, specific rules should apply to allow the best investment decisions. For example, the development of renewable gas makes even more sense while considering the numerous positive externalities in terms of emission reduction of the agriculture and waste management, the promotion of agricultural sustainable practices and the creation of local jobs. Therefore the "cost efficiency" principle should be used to bring decisions in effective system optimizations and achievement of the long-term strategy of full decarbonization by 2050. Especially, exemption of the "technology neutral" approach could be necessary to support nascent activities for which positive externalities are significant such as biomethane production and injection in the gas networks.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas is a promising technology allowing the production of two different renewable gases that could be injected in the existing gas networks: • renewable hydrogen produced through electrolyze of water with renewable electricity, • synthetic methane via the process of methanation of the hydrogen with CO_2 captured from the air, industrial processes or from a biomethane plant. Power-to-Gas could bring flexibility to the electricity grid as gas system is able to store energy in an efficient and massive way. Therefore, Power-to-Gas allow the conversion of renewable electricity into a form of energy, gas, that could be consumed later directly or used to generate electricity. As such, Power-to-Gas is a new link between power and gas systems contributing to the better integration through sector coupling. Therefore, Power-to-Gas infrastructures is expected to strongly contribute to the decarbonisation of the gas sector and the question of ownership and management of these infrastructures is important. Regarding the infrastructure per se – the electrolyzes – it should be a contestable activity. However, in the conditions already described in Q1 and Q3 and for instance in case of a lack of interest from the market, DSOs and TSOs could be involved in this business under strict conditions to respect the unbundling regulation. Regarding the process to produce synthetic methane, it will be necessary to move CO_2 from the producer (biomethane plant for instance) to the Power-to-Gas infrastructure. We are favourable to regulatory changes allowing under certain conditions DSOs to distribute CO_2.

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?
Power-to-Gas technology could be considered as a pure consumer of electricity and apply the same rules as the other consumers. Nevertheless, considering such activity as a service for the energy system as a whole and the difficulty to develop business cases today, specific tariff should be envisaged for this activity as a storage or a congestion management plant for instance. Considering that on the long-run, the power system would be mainly supplied by intermittent sources, the value of Power-to-Gas plants to provide flexibility and dispatchable energy should be related to security of supply concerns. Therefore, the regulation should be flexible enough to allow the development of various business models and avoid double charging in the tariff looking at effective synergies for both power and gas systems.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
No answer

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Guarantees of Origin (GO) allow transparency for consumers as it certifies the conditions of production of the energy. They are necessary to prove the sustainability of the commodity and permit customers to orientate their preferences for renewable gas. Guarantee of Origin should be emitted on similar technological thresholds and the system should be overseen by a competent authority, in charge and able to collect reliable production data, to run appropriate control systems and – if needed – to impose appropriate sanctions in case of Guarantee of Origin misuse. In addition, Guarantees of Origin give useful information of the development of renewable gas supply and the balance with demand. Regarding the development of a cross-border trading of renewable gas GOs, two important elements must be considered: - this scheme must be based on “mass balancing” as it is currently done in France for instance, and not on “book and claim”. It is necessary to keep the link between the GO and the molecule for more transparency towards the customer. - the system must include the sustainability criteria defined into RED II regarding biomethane.

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?
One lesson to learn from the renewable electricity GO scheme is that it should not be based on a “book and claim” system. France has a “book and claim” system for electricity GOs. However, it has more value to sell the green electricity to the person who receives the GO. Therefore, a provision equivalent to “mass balancing” was later introduced into the scheme. Another lesson to be learnt from renewable electricity is the importance of avoiding any double support between an EU-wide GO system and Member State support schemes. The EU-wide GO system for renewable gas should be set-up ensuring that double counting of renewable gas volumes is avoided. Successful implementation of an EU wide scheme with mass balancing, will ensure that volumes are only counted once.

Infrastructure Investments and Regulation

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?
The regulation authorities should make sure that the contribution of the DSOs is effectively taken into consideration in the elaboration of the development plans such as TYNDP. ACER and NRAs should make the sure that the CBA methodologies takes into account the positive externalities of developing technologies such as biomethane injection. Last but not least transparency is essential in the elaboration of the TYNDP and in the assumptions. ACER and NRAs responsibility should also include the coherence between the TYNDPs of gas and power sectors.

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)?
As mentioned by CEER, we support the extension of the PCIs selection scope to projects regarding the connection of decentralized and local renewable gas generation, as well as to gas-electricity integration in the context of power-to-gas and sector coupling as well as for the conversion/adaption of gas grids to new gaseous carriers. A wide range of projects and technologies should be supported through the PCI framework, including biomethane injection.

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?
We do not see a risk of stranded assets in the perimeter of our DSO activity. Furthermore, based on existing and projected gas demand we don't see a risk for stranded assets in the next 10 years. This is in line with CEER's observations, as well as on the EC's 2050 scenarios and draft National Energy and Climate Plans 2020-2030 recently published, among others. A risk for stranded assets may arise in case of a sharp decline in natural gas consumption beyond 2030, not accompanied by its substitution with renewable gas, green hydrogen and/or blue hydrogen injected in to the grids. The risk potentially involves present Natural Gas chain, from LNG terminals to storage, transport and distribution networks, to a higher or lesser extent depending on the final mix of those three energy vectors in satisfying primary energy demand. It also could be caused for instance by a lack of appreciation of the level of the demand during the lifespan of the assets or by "incentive" for consumers to exit from the network ultimately reaching a point where it is no longer economically feasible to maintain the operation. Stranded assets in a regulated network activity could be caused for instance by a miss appreciation of the level of the demand during the lifespan of the assets or by "incentive" for consumers to exit from the network until reaching a point where it makes uneconomical to maintain the operation. The appreciation of the level of the demand requires, in the context of the energy transition, a clear political strategy on the ambition in terms of energy efficiency and energy mix. Infrastructure supposes significant capital expenditure and long return on investment period. As such enough visibility is essential for investors in their risk assessment. The design of the tariff is essential to give the right signal in terms of economic value of a network service. Furthermore, the market design, the long-term planning and the investment decisions in infrastructure should integrate for gas and power, the role of each energy and its relative contribution to the decarbonization of the economy. Alternative usage of potential stranded assets should be considered by regulatory tools to valorize investments realized in essential facilities.

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?
No answer

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The fast and wide development of renewable gases (biomethane, synthetic methane, green hydrogen) is one critical point. All the energy mix scenarios – including those of the electricity sector - show we could not go above a 60% electrification in Europe. Therefore, gas will continue to play an important role in the European economy. Moreover, considering the Paris agreement, it is necessary to decarbonize this sector to meet the climate objectives. Therefore, it is of the greatest importance that the gas market design looks at the topic of renewable gas development. The development of renewable gas will increase the level of energy decentralization. Therefore, it is necessary to get the right regulation to allow DSOs to become actors of this evolution while respecting the unbundling rules. Finally, since 2009 and the last revision of the gas market design, the economy is being more and more digitalized. Therefore, the new gas market design should consider this evolution. These three critical points are further detailed in the other questions of the consultation.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
We see a strong need to update the gas market design to develop renewable gases. Several regulatory changes are needed for a takeoff of the renewable gases production. First, it is necessary to define precisely renewable gases. It is fundamental to have a definition including the main technologies allowing us to have more visibility on the sector. “Gas produced from renewable sources”: Gas produced - with respect of the rules listed in article 7, 25 and 26 of the RED II directive on the use of energy produced from renewable sources, either via anaerobic digestion, gasification of biomass, power-to-gas or via any of the technologies using renewable energy sources”. “Anaerobic digestion”: Biological conversion of biodegradable materials by micro-organisms in the absence of oxygen creating two main products: biogas and digestate. Once purified, biogas results in the production of biomethane. “Gasification”: Thermochemical process at high temperature (> 700 °c), producing gases composed mainly of carbon monoxide and hydrogen, usually followed by a methylene stage for conversion to biomethane. “Power-to-Gas”: Conversion chain allowing the transformation of renewable electric energy into a gas vector produced from renewable sources: hydrogen by electrolyse of water or synthetic methane by electrolyse and methanation. “Biogas”: Gas produced by anaerobic digestion of organic matter, gasification or even power-to-gas, before purification stage. Therefore, this definition will allow investors to get visibility on the renewable gases production technologies. Several other regulatory changes would also contribute in this objective, such as the introduction of renewables gases targets. On this point, RED II objectives should be declined in the gas sector. Thus, we could have three different renewable gases objectives at the European level: - A general objective by 2030 of renewable gases injected in the grid, mandatory at the European level and indicative at Member States level, - An objective by 2030 of renewable gases in total final consumption of gas in the transport sector, - An objective of an increase of renewable gas per year in the total final consumption of gas in the heating and cooling sectors. Considering the discussion period of the objectives and their implementation, a post-2030 horizon could be considered as soon as the industry receives the right signal. The development of renewable gases must be sustainable. Therefore, it is key to make sure that the next gas market design refers to the sustainability criteria defined in the RED II directive. Besides, the next gas market design should include a principle of priority access to the gas network for renewable gases while ensuring the respect of unbundling and the security of the network. This priority right will allow us to harmonize the existing European practices. The producers will have the certitude that their projects will have priority over fossil gas. The future gas market design should also require from Member States to oblige operators to socialize all or part of the costs for the development of renewable gases production sites (connection costs, reinforcement of network). To conclude, this new role of DSOs will require an update of the definition of “distribution” and of “distribution system operators” in the gas directive to include the fact that they distribute today natural gas and gas produced from renewable sources.

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?
No answer

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
No answer

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
1)An EU gas DSO Entity We would like to detail a bit more the tasks and form of the EU DSO Entity. In our opinion, the EU gas DSO entity should be different from the EU electricity DSO entity as there are a numerous issue which are specific to the gas sector. Besides, the above-mentioned role of the entity when it comes to cooperation with the TSOs, the EU gas DSO entity will be responsible to facilitate the exchange of best practices on energy efficiency, digitalization, demand side management, data protection and cybersecurity. It should also contribute in the development of renewable gases, storage capacity and gas mobility. 2)The digitalization of the network Smart meters are currently being rolled out in several EU countries. The next gas market design should support this development. Smart meters allow to reduce the energy consumption, therefore participating in the energy efficiency objective defined in the EED directive. Moreover, it brings social benefits to consumers who are better informed about their energy consumption. Therefore, we would suggest several proposals: - Require the revision every 5 years of the negative technical and economic study regarding the roll-out of smart gas meters, - Make optional the ON/OFF distance switching technology on smart meters for security and economic reasons. In terms of data management, we would support the following: - Let the determination of eligible parties having access to data at the Member States level. DSOs as regulated entities are key to manage the data of the consumers, - Allow DSOs to socialize the cost of data management in their tariff, - Enact a principle of interoperability of data.

Survey response 50

Contact details and treatment of confidential responses

Contact details: [Organisation][]
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Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
DSO should be involved in establishing local thresholds for hydrogen blending in gas networks (see Q2). TSO should assume responsibility for the availability of gas quality within the legal thresholds. Currently, there is no party legally assumed responsible for delivering a compliant gas composition to the final consumers. TSOs/DSOs should not be allowed to operate power-to-gas-plants, since this conflicts with the principles of unbundling. If there is no interest in the market to invest in and to operate such facilities, TSOs/DSOs might be allowed to jump in as a matter of last resort. But such exemptions must only be possible for a limited period of time ("regulatory holidays") and only to create economies of scale.

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.
Operation, safety and efficiency of certain industrial processes can already be corrupted by hydrogen contents as low as 1.5%. Such sensitive consumption units may not be ubiquitous, but nevertheless, the hydrogen content in a given grid area needs to take into account the specifications of the most sensitive consumer. Apart from industrial processes using gas as feedstock, also gas turbines can be very sensitive with regard to the hydrogen content. This calls for a very careful approach to hydrogen injection. Besides static thresholds, gradients of concentration changes in time are to be limited, as fluctuation can be as problematic as too high static concentrations. On the other hand too narrow gas specifications can hamper the liquidity of the European gas markets. As a consequence strict mandatory thresholds are inevitably required in grid areas where sensitive consumption units are located. A comprehensive threshold all over Europe is of secondary importance. Timing is of significant importance in sensitive grid areas. Therefore, in such areas hydrogen contents and other parameters should be analysed and made publicly available near real time.

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.
It should be very thoroughly analysed whether pure hydrogen grids are natural monopolies. I.e., how much competitive pressure can be executed by other means of transport (e.g. by truck). Alongside a European natural gas infrastructure dedicated local and regional hydrogen infrastructure exists for decades already, used by commercial market parties. If hydrogen grids are deemed to be natural monopolies and when the quantity of producers and consumers connected to the grid reach a level of competitive relevance, they should in principle be regulated in the same way as gas or electricity grids (regulated tariffs, fair third party access etc.). A threshold for competitive relevance has yet to be discussed.

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.
A technology neutral approach for a given low carbon investment or a given flexibility service (i.e. for a given timeframe) is essential as the transition pathway to an overall low carbon energy supply ist not clear. Transition challenge: We are looking at decarbonisation over a 30 year horizon. It is not clear whether further deployment of renewables only will be the most effective or the most efficient way to achieve GHG reduction, especially with intermittent renewables for electricity generation and the necessary back-up to cope with periods of over- and undersupply. There may be different possible routes to achieve GHG reduction: •The further deployment of low carbon energy sources, with existing (demand response, flexible generation units, storage) as well as new sources of flexibility (power-to-X, new types of storage: hydrogen, ammonia) for providing the necessary back-up capacity for coping with intermittency; •Investments in geothermal energy; -Investments in nuclear technology (extensions of existing plants as well as 3rd and 4th generation reactors, Small Modular Reactors, nuclear fusion); •Development of CCS and CCU. Regulatory support and barrier removal needed: a.Looking at all existing technologies is a must, as well as underlining the importance of stimulating R&D into new technologies; b.Interference of the energy sector with the heat and transport sectors can also be part of the solution, as electrification might be one of the ways to decarbonise these sectors too.

Q5 Which role do you see for power-to-gas infrastructures?
1.To act as a flexibility option for the electricity supply system, characterised by an increasing amount of volatile generation; 2.Enabling supply of certain energy sectors such as heat and mobility with renewable energy; 3.Enabling a liquid gas market by granting a non-discriminating grid access to gas producers, shippers and consumers; 4.Enabling a secure supply of electricity and gas to consumers.

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?
Significantly high surcharges on electricity, e.g. the "EEG-Umlage" in Germany, result in artificially high electricity costs and, in turn, compromise the competitiveness of Power-to-X technologies. Special electricity tariffs, e.g. atypical consumer tariff regimes pricing individual grid usage according to the state of the grid at the time of usage, contribute to support Power-to-X technologies. In general, tariffs and other administrative surcharges should be low in situations, where deployment of Power-to-X is desirable (e.g. high renewable electricity production whilst the consumption is low). Otherwise significant market penetration of Power-to-X technologies will fail.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The regulatory framework should enable the compatibility of the natural gas grid to be oriented to industrial plants that are sensitive to natural gas inflow containing certain levels of hydrogen. Furthermore research and development of sector coupling technologies and relevant pilot projects should be driven forward. Here, it is particularly important to exempt pilot projects from administrative burdens such as levies and charges. The General Block Exemption Regulation (GBER) limits funding to € 15 million per application. Such a ceiling does not adequately reflect the technological complexity of pilots on an industrial scale. Therefore, applicants for pilot projects in the field of sector coupling should be exempted from it.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
There should be a unique standard. GOs should be independent of local origin and energy carrier (gas, electricity) and similar systems for gas and electricity.

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?
Guarantees of origin should be restricted to certify the produced green gas and create green certificates. The GOs in itself must not lead to a subsidization system.

Infrastructure Investments and Regulation

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?
ACER and NRAs should target on maintaining the existing level of security of supply at the most efficient costs. High network development costs will reflect in high tariffs. As mentioned in Q6 administrative surcharges hamper the market penetration of Power-to-X technologies. This should be considered when choosing the 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)?
To support cross-sector integration we need to a proper energy infrastructure for the changing energy system, including adequate infrastructure capacities. Transition challenges are: •Infrastructural adaption is needed for energy conversion (hydrogen) and CCS and because of (de)centralizing of energy generation, resulting in locational challenges. •Consumers that have to make long term technology innovations to reduce GHG (e.g. Power-to-Heat, hydrogen) need a sound and sufficient infrastructure network to reduce investment risks.

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?
The risks for stranded assets can be reduced by a stable regulatory framework enabling long term projections for investors. Furthermore the regulatory framework should respect technology neutrality. Regulatory preference of certain technological pathways may enhance the risk of stranded investments as alternative developments can be more cost efficient. Investments in pre-selected technologies can lead to investments in eventually non-competitive solutions.

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?
Further studies are necessary in this respect. It should not be the default that stranded assets resulting from decommissioning are passed on to grid users, the consumers. The grid operators also are being at risk and hence should bear costs regarding stranded assets.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Enhancement of competition of the European gas market: this can be achieved by an increase of suppliers and supply routes, e.g. enabling investments in sufficient LNG capacities, while the degree of capacity utilisation of the existing facilities is rising. However: Any regulation disturbing competition should be avoided. For example, in Germany 90% of the costs for connecting LNG facilities to the grid can be shifted into the grid tariffs, instead of being borne by the operator of the LNG facility. Such cost allocation schemes distort the competition between locations and lead to higher i.e. inefficient system costs.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The gas market design and the regulatory framework in general should be optimised by reducing regulatory obstacles for green gases. Some of them have been addressed in Q6, 7. Market penetration of green gas should be incentivised rather than regulated. Limitations of sensitive facilities such as industrial processes and existing gas turbines with respect to hydrogen are to be considered by the regulatory framework.

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?
A suitable and substantiated answer to this question cannot be given without investigating the possible consequences of scenario’s.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
see Q16

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
No Answer.

Survey response 51

Contact details and treatment of confidential responses

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Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Equinor welcomes CEER’s decision to launch a public consultation on regulatory challenges for a sustainable gas sector. We wish to start our submission with some more general comments regarding the consultation’s scope. The consultation paper uses different terms to set the scope, such as sustainable, decarbonised, low-carbon or renewable gases. We suggest that for CEER’s work on regulatory challenges for a sustainable gas sector, the scope of included gases other than natural gas should be as large as reasonably possible. The challenge to decarbonise the gas sector is significant. Therefore, all possible options should be included at this stage, and allowed to compete on a level-playing field, true to the principle of technology neutrality. Reducing the scope to renewable gases (as for instance the headline of chapter 4 of the consultation document suggests) would be detrimental to CEER’s objective of “decarbonisation at least cost”. The full potential of renewable and fossil-based, decarbonised gases will be needed to get Europe to its decarbonisation targets. When it comes to the future involvement of TSOs and DSOs, the guiding principle remains that only activities that constitute a natural monopoly should be regulated and only assets related to such activities should be part of the regulated asset base. We broadly agree with the assessment done in the consultation paper; besides the examples listed, the production of hydrogen from natural gas through methane reformation with carbon capture and storage (CCS) should be assessed in this context as well. If there is a wish to “kick start” the introduction of a new technology, the main tool to achieve this should be incentives for market participants (CAPEX subsidies, feed-in tariffs, contracts for difference, tax exemptions, etc.) rather than an inclusion of such technologies in the regulated asset base. Only if there are obvious socio-economic advantages of investment and operation by regulated entities (e.g. significantly lower cost for society), TSOs and DSOs should be allowed to enter these markets. An example of such socio-economic advantage in favour of regulation might exist when the gas grid for public supply is converted to 100% hydrogen: the cost for society might be significantly lower if the needed conversion facilities like steam methane or autothermal reformers are considered part of the regulated network. These facilities have very high capital cost; therefore, the lower expected rates of returns and longer repayment periods of regulated assets can significantly reduce cost. Given the early stage of development of power-to-gas and gas reformation solutions for the purpose of decarbonising the gas grid, it seems premature to fully define the most appropriate regulatory solutions. Due to the important differences of currently suggested projects, we believe that exemptions from general regulatory principles should be handled case-by-case. However, one rule should already now be defined: the capacity of power-to-gas plants and methane reformers should, when these facilities are owned by a TSO or DSO, be fully offered to market participants. If power-to-gas plants are mostly used to absorb “excess power” from wind and solar installations, then the related costs must be covered by the power sector (e.g. added to power grid fees). The main purpose of such power-to-gas plants would be to solve electricity system issues. Hence, the gas sector and gas consumers should not bear costs related to this.

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.
There will be different ways towards a decarbonised world. Blending of hydrogen in gas networks can constitute a first step towards decarbonisation of the gas network. Increased blending can prepare for a full switch at a later stage. With full decarbonisation being the ultimate goal, any measures taken to support increased blending of hydrogen should not hinder a switch to 100% hydrogen later. Another approach could consist in the immediate full switch to 100% hydrogen of isolated (distribution) grid areas, while surrounding areas remain supplied with methane, leading to the coexistence of hydrogen and methane networks at least during a transitional period. The technical possibilities and implications of blending and full conversion are complex. Some parts of the European gas network are ready for increased blending, while others are not. End-consumers (residential and industry) are affected to different degrees, and their interests need to be considered. A broad dialogue with all concerned parties is necessary before amending the rules for blending; such dialogue should start with open communication by network operators regarding the technical possibilities of their networks. Introducing a common European threshold seems currently premature, but the cross-border implications of increased blending need to be addressed from the outset, through cooperation and communication among affected parties.

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.
If hydrogen networks will be used for broader energy supply in the future, in the same way as most natural gas networks are used today, then they should be regulated. This could be the case e.g. when a (regulated) gas network is converted to hydrogen. There seem to be good reasons to regulate hydrogen networks in the same way as gas networks. Existing legislation could be adopted by broadening its scope, so that hydrogen and potentially other gases are included. Hydrogen storage might be assessed in a similar way. There are clear parallels with gas market regulation. Regulation of hydrogen storage might be appropriate if there is no competition between storage operators (e.g. when there is only one operator active in the hydrogen storage market).

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.
In general, a technology neutral approach based on market mechanisms is the best way to achieve cost efficiency. There should be a level-playing field for all decarbonisation technologies. If market intervention is seen as necessary, e.g. in order to facilitate the introduction of a new technology, then different decarbonisation technologies should be treated equally.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-gas is an evolving technology that has the potential to make a major contribution to sector coupling. Its future role should be determined by its competitiveness: like all new technologies, power-to-gas infrastructures will need to show their added value in competition with other options that allow to reach the same objectives. Power-to-gas can serve different purposes, like the improved integration of variable renewables and the decarbonisation of the gas grid. For each purpose, power-to-gas needs to prove its advantages compared to other options, like power network reinforcements and electricity storage (batteries) for the integration of renewables, or biomethane and “blue hydrogen” for the decarbonisation of the gas grid. The competitiveness and future role of power-to-gas will to a large extent depend on developments in the power sector, especially the availability of “renewable electrons” at low cost. Power-to-gas facilities will have to compete for such “renewable electrons” with other electricity consumers. Equinor assumes that most electrons from renewable sources will be consumed as electrons, given plans to electrify additional demand sectors, decisions to phase out coal and nuclear power generation, and expectations of overall increasing power demand.

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?
There might be distortions when specific, favourable rules exist for certain clean hydrogen production technologies, but not for others. Following the principle of technology neutrality, such advantages should be granted to all renewable and decarbonized gases, without discrimination. This is not always the case. In Germany, for instance, hydrogen from electrolysis is exempted from the entry tariff, while “blue hydrogen” from gas reformation with CCS is not exempted. There needs to be fair competition between decarbonisation solutions; only this will lead to efficient cost levels for end consumers.

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?
When considering the question of guarantees of origin in the gas sector, Equinor advocates for an approach in line with CertifHy, the guarantee of origin scheme for hydrogen: any such system should include both renewable and decarbonised gases. In the spirit of “decarbonisation at least cost”, the different options available to decarbonise should be adequately reflected in any GO system. If the above condition is fulfilled, Equinor supports a European-wide system that replaces national GO systems. This would ease cross-border trading. As long as long as national systems exist, they should, to the extent possible, be based on common standards and definitions. In any such system, the percentage of decarbonisation needs to be reflected in the GO: a higher decarbonisation rate should deliver a more valuable GO.

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?

Infrastructure Investments and Regulation

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?
In line with statements by CEER, Equinor believes that the decommissioning of gas infrastructures will not be a major theme in the near future. There does not seem to be any specific urgency to make decisions about appropriate regulatory solutions (yet). The market should be involved in any decommissioning decisions that affect available capacities. Before TSO or DSO take a decision to decommission, a mechanism should apply that allows market participants to indicate their interest in future use of the capacity in question. Such mechanism could indeed be similar to mechanisms used for decisions about investment in new cross-border infrastructures. Defining these rules at EU level might be appropriate given the cross-border aspect of decommissioning decisions.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Generally, the European gas market design is appropriate for today's gas market. It will, however, remain important to continue the implementation of the Network Codes. European regulators should enforce implementation in all EU member states.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Yes. In line with the situations described in questions 1 to 9, there is a need to include the production of decarbonised and renewable gases in the market design. The gas market design needs to be adapted to allow for an efficient management of the transition towards a decarbonised gas system.

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?
In Equinor's experience, the current transmission tariff regime generally works well. However, due to the implementation of the Network Code Tariff, some gas infrastructures might be less used in the future. Members States have chosen different approaches to implement NC TAR in their markets. In some cases, the post stamp methodology increases the tariffs at the interconnection points significantly. Consequently, transit flows will be de-incentivized. This could lead to a vicious circle of increasing gas transport tariffs and declining volumes. We advise against taking the decrease of European gas consumption for granted; over the last few years, European gas demand increased. Future gas networks and gas market design should be developed in a way that they are compatible with different scenarios regarding future European gas consumption. Adaptations should only be made if a clear trend indicating decreasing gas demand occurs. The share of long-term capacity contracts has already much decreased over the last years. In combination with the fact that an increasing share of the gas infrastructure is depreciated, we do not foresee a need to adapt the transmission tariff regime due to a lower share of long-term capacity bookings. If in the future there will be indications that some of the negative developments described in the consultation document occur, adaptations to the tariff regime could be considered.

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

Other question

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

Survey response 53

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Enel

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Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
P2G plants should not be operated by regulated entities, like TSOs or DSOs. GAS Production activity, such as P2G, shall operate on market basis to avoid distortion into the market and certainly should never be recognized in RAB. The operation of P2G plant, as GAS production, by regulated entities bears the risk of preferential treatment, at the same time could bring a competition distortive effect and hamper the development of other flexibility resources that shall compete on the market. The position of "limited participation by the TSOs and DSOs might help "kick start" the development of these technologies" is questionable, in fact (i) if the appropriate policies are established, the development can be done in the market (ii) once the infrastructural operators have acquired the skills the other operators are likely to be displaced. In general, in a coupling scenario, a mirroring between the two regulations should be pursued. As highlighted by the consultation, currently there is an asymmetry between the electricity sector and the gas sector as regards unbundling: lighter for the gas sector with less restriction. This asymmetry should be overcome mirroring what was established in the electricity sector also for gas sector.

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.
Gas quality harmonization, including a common European threshold for the blending of hydrogen in gas networks, between countries is paramount in order to allow the development of Hydrogen application and sector coupling. Blending concentrations strongly depend on the characteristics of the existing network, natural gas composition and end use applications. A timely progressive increase of blending concentration of hydrogen shall be considered in order to allow the network and end uses application to adapt in reasonable time manner. Starting from now, it could be also useful that TSO and DSO evaluates and communicates the actual and expected threshold of Hydrogen that could be injected in blending on the network with a report at European level.

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.
At this moment it is premature to know if a dedicated hydrogen network will be needed and the convenience to regulate it or not. It will depend on the market needs and it should be carefully assessed. In case a hydrogen network is needed, the priority shall be given to reuse the existing gas grid in order to accommodate the hydrogen as well. A brand new infrastructure with a sufficient capillarity is costly and increase the risk of strained asset of the existing natural gas grid, considering also that the stranded assets risk will be greater in the future and the infrastructure remuneration will no longer be based on the existence of long-term contracts. In general terms, the networks should be as interconnected and interoperable as possible and in this case the regulation should symmetrically follow the same rules for all the networks whether they are natural gas or hydrogen.

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.
The EU shall rely on the market as the most efficient means to meet customers' energy needs. In this sense also sector integration and sector coupling should be achieved via market-based solutions. A combination of well-designed markets ensures non-discriminatory market participation by all competing technologies and gives the right economic signals, taking into account the positive or negative externalities. Like other flexibility solutions such as battery storage and demand response, Power-to-Gas shall be developed by market operators to avoid distortions and inefficient market outcomes.

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

The coupling of electricity, gas networks through Power-to-gas is a potential missing link in the transition to a deeply decarbonized economy, where needed to complement direct electrification in “harder to abate” sectors. Despite Power-to-X technologies are not mature yet, in the future they could help channeling large amounts of renewable electricity into end-energy use sectors for which the direct electrification option could be not feasible or less cost-effective (e.g. industrial sector requiring hydrogen as feedstock, or high-grade heat, some segments of heavy transport). The coupling of electricity and gas sector through Power-to-X could also have a complementary role in providing firm and flexible capacity to the power sector of the future featured by a high share of renewables.

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?

Harmonized and efficient rules on network tariffs for energy storage and power-to-gas are needed. Inefficient electricity network tariffs methodologies may lead to pay double as both consumer (of electricity during P2G) and producer (during G2P) could represent a financial barrier and create distortions for the deployment of power-to-gas technologies. In this analysis to avoid financial barriers and distortions should be the taken into account the effect of levies/charges and taxes affecting the energy storage and power-to-gas technologies.

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

1. Establish a taxonomy and clear definitions of sustainable gases and other gases (beyond the hydrogen case e.g. synthetic methane as well) based on CO2 emission production pathways.

2. Establish a Guarantees of Origin system based on CO2 production pathway (including both electricity, CO2 source) at EU level. Furthermore, looking at the rules on guarantees of origin as proposed under the Recast Renewable Energy Directive, the proposed shortened lifespan of guarantees of origins needs to be reconsidered as this may disincentive the long-term storage of renewable energy.

3. Given the significant uncertainties on the evolution of the demand for gas in the long run and due to the still incipient phase of sector coupling technologies new investment decisions on gas infrastructure should be carefully assessed. A stronger oversight by ACER and NRAs will be necessary and the increasing importance of links between gas and electricity infrastructure shall be reflected in a new requirement for joint grid planning activities, at both European and national levels.

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

To facilitate the development and use of renewable gases, the implementation of a trading system for renewable guarantee of origin can be a pivotal instrument.
A harmonized system enables transparent and trustworthy trading across borders. This required:

1. Standardize a European definition of renewable gas
2. Standardize the different types of renewable gas GOs at European level
3. Standardize the compliance deadlines at European level
4. Integrate the market in the standard trading platforms (as for EUAs)

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?

Guarantees of origin should be:
(i) extended to all forms of unconventional gas
(ii) tradable
(iii) contain a minimum information set
(iv) even if there are national registers then there should be a European exchange point.

It should be recognized that the purpose of GOs is “disclosure” and not “support”. To avoid confusion, it should therefore be preferable to clearly distinguish support mechanisms and GOs. Moreover, renewables gases are only one of the vectors within the matrix of the renewable energies. Renewable energy targets should be fulfilled in a “cost efficient” way so the introduction of mandatory objectives or quotas for renewable gas penetration shall be avoided.

Infrastructure Investments and Regulation

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?
Due to the growing interdependencies between gas and electricity systems in Europe, a stronger oversight by ACER and NRAs will be necessary. The increasing importance of links between gas and electricity infrastructure shall be reflected in a new requirement for joint grid planning and scenarios, at both European and national levels. ACER and NRAs should play an important role ensuring that these scenarios and grid planning take into account the European decarbonization objectives and maturity of different technologies, such as power-to-gas.

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?
Although natural gas and gas infrastructures will play an important role in the short and medium term, they have a limited lifetime in the transition to a decarbonized system in order to meet the long-term climate goals. This can lead to stranded assets as the remaining economic lifetime for parts of the existing infrastructure may be longer than the lifetime these parts may be used to serve customers. The potential developing of hydrogen in the future can contribute to extend the lifetime of the gas infrastructure, thus reducing the volume of stranded assets. Existing gas infrastructure could be used for the transport and distribution of hydrogen and renewable gases, after technical feasibility & safety considerations have been addressed. If power-to-gas technologies mature and become competitive and commercially available, gas networks will be necessary in the long term and the risk of stranded assets could be completely eliminated. What is crucial is to ensure that gas regulation schemes do not incentivize building more gas infrastructure if not necessary. Gas regulation schemes should prevent unnecessary investments in gas infrastructures where possible if they do not comply with the goals towards a decarbonized system. To do so, gas regulation schemes should be subject to a continuous monitoring of the maturity and competitiveness of hydrogen and power to gas technologies and be based on gas demand forecasts that are compliant with the Paris agreement and in line with the most recent analysis.

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?
Potential decommissioning of gas assets should be subject beforehand to a transparent and robust cross-border assessment with the adjacent Member States which may be impacted (in terms of security of supply, market functioning); in this sense, an EU framework set of rules valid for all established at European level could be appropriate.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The priority should be given to the full implementation of the different EU Network Codes, including the Network Code on Harmonized Transmission Tariff Structures (TAR NC) for gas.

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?
The current transmission tariff regime can be made more efficient by abandoning the concept of capacity "Use It Or Loose It", and by adopting a regime "Use It Or Sell It". In this way, the physical flows at a cross border point would reflect in a better way the market values of the spread between countries. In a scenario where long term contracts expire, it would be very important to simplify the logistic chain to buy spot cross-border capacities. This could be done by increasing the number of cross-border point at which an operator can buy a "bundled capacity". The integration of the gas infrastructures in a common European gas capacity trading platform could deliver a more efficient system (e.g. integration of the FluxSwiss pipeline in the European capacity market (PRISMA))

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
Overcoming the entry exit system is the condition that could guarantee greater liquidity to the markets, thus facilitating flows exchange within the European Union. In a longer-term scenario, for an economic sustainability of the gas sector as well, new solutions could be considered to overcome the national entry/exit areas. In particular, it will be increasingly important to think about solutions that exceed the current set-up, in a scenario of reduced consumption and therefore a certain increase in tariffs (reducing booked capacities also for LT contracts terminations). What was said a fortiori that expiring LT can lead to increase of prices if will be incorporating the full transportation cost. A future solution could be consider a different cost allocation methodology, not as it is today only for shippers, based on the identification of the benefits of the service and the beneficiaries. Enel believes that it is preferable to identify the benefits and beneficiaries and the cost should weigh more heavily on the customers for whom the infrastructure is sized: customers with more thermal consumption profiles. In any case, the regulated costs of the gas network should be covered through the gas network tariffs paid by gas users.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
See answer Q7

Survey response 54

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Klaipedos nafta

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Regulatory Challenges for Renewable Gases

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.
Common European threshold would be useful in order to foster cross-border trade without the limitation of differences in gas specifications in different countries. However the threshold should be set only after careful consideration of the gas consumers' needs in each specific country.

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?
The regulatory framework could allow flexibility and incentives such as tariff discounts in the DSO/TSO systems in order to allow the faster development and investment to the power-to-gas facilities when a certain level of the efficiency of technology is reached.

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?

Infrastructure Investments and Regulation

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
There could be additional guidance regarding the market mergers and market integration measures. The market integration could be more achievable if there were approved or recommended principles on ITC mechanisms, also the principles of assessing costs and benefits of potential market mergers.

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?
The guidance on cross-border ITC mechanisms, and the framework to facilitate the market mergers would help to reach decisions more effectively. The TAR NC provisions on making discounts on cross-border points could be more flexible.

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

Other question

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

Survey response 55

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Enagas S.A.

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
To foster the energy transition, gas infrastructure operators, including TSOs, are well placed to be involved in activities that enable the decarbonisation of the energy system and promote sector coupling. Enagás believes that the assessment should consider activities such as, but not limited to, power-to-gas facilities, synthetic gas plants, biomethane plants (upgrading biogas), CCU and CCS (Carbon Capture and Use – Carbon Capture and Storage) technologies and CNG/LNG refuelling infrastructures for the transport sector. By allowing TSOs to invest either on a regulated or fully commercial way, they can support the development and scaling-up of these activities. Gas TSOs can have a positive impact on enabling the integration of renewable and decarbonised gases (hydrogen, biomethane, synthetic gas, etc.), especially where there are no other existing investors willing to invest. Gas TSOs should be allowed to own, operate and maintain such facilities, selling the conversion/production capacity services to network users, on a non-discriminatory way, in order to fully comply with the unbundling rules. POWER-TO-GAS FACILITIES: By effectively integrating electricity and gas, it is more cost-efficient, more reliable and quicker to achieve the EU's decarbonisation targets. There is a need to review the regulatory framework and, where necessary, to amend it to ensure the development of power-to-gas alongside other decarbonisation technologies. In the context of sector coupling, Power-to-gas plants should not be classified as gas production plants, but as a conversion service which transforms (renewable) electricity into gas, such as hydrogen or synthetic methane, for further use in the energy system or, alternatively, for use as feedstock or fuel for transport. TSOs could own, operate and maintain these facilities, offering the conversion service to third parties on a non-discriminatory and regulated way. On this way, TSOs would respect the unbundling rules since the electrons and molecules entering and exiting the facility would belong to network users, and not to the TSO. Power-to-gas plants (together with the biomethane plants) should be part of every National Energy and Climate Plan in order to have a clear evidence about the expected penetration targets and decarbonisation levels to be achieved with these gases. REGULATED vs. COMMERCIAL INVESTMENTS: Gas TSOs should be allowed to invest in any facility enabling the decarbonisation of the energy/transport sector and the sector coupling, such as power-to-gas, biomethane plants, CNG/LNG filling stations, etc.. The question is not which activities are to be allowed for potential TSO/DSO involvement, but which activities need additional enabling regulation to facilitate their wide deployment, and how to make sure those activities are widely deployed on a quick manner. TSOs would then like to be able to invest either in a regulated or in a commercial way. Investing in a commercial way, in competition with commercial investors, TSOs should not have any specific commercial advantage or disadvantage. They should be in compliance with unbundling rules and a transparent separation between regulated and non-regulated activities set up, supervised by the relevant NRA. If the market players are not willing to invest on a fully commercial and competitive manner, the authorities should ensure that the decarbonising technologies reach the required scale and maturity, according to the timelines foreseen. To achieve this, two options can be envisaged: - set up an investment regulatory framework which triggers commercial investments from market players. In this case, TSOs should be able to invest like any other market player. - allow TSOs to invest on a regulated manner, by adding the new decarbonising facilities to their RAB. In all cases, the TSO would offer the conversion service to all market participants on a transparent and non-discriminatory way, respecting the unbundling rules. The regulated environment would be maintained until the market reaches enough level of maturity and development which allows for a commercial/competitive investments to take place without significant regulatory support. Objective criteria could be put in place by Member States to evaluate market appetite for investments in new decarbonisation facilities, such as a market test. The appropriate framework could be left to the authorities in the Member States, depending on their particular circumstances, however, the options should not be limited to regulated investments. As some of these activities are still in development, TSOs should be allowed to engage in research and development to help bring these technologies forward.

Additional types of support complementing the regulatory frameworks exist, such as temporal subsidies and funding for the most promising technologies to favour their evolutions and cost decrease. Support provided in the electricity sector for decarbonisation activities should be replicated in the gas sector. There should be a level playing field for all decarbonisation technologies.

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.

As already recognised by CEER, there are different possible approaches towards hydrogen integration: blending hydrogen methane (natural gas at a transition phase and biomethane and/or synthetic methane in the long-term) and hydrogen-only networks. While there is evidence that gas applications could be able to integrate different fractions of hydrogen, the optimal choice and pathway will be determined by national or even local conditions.

With the increasing amounts of renewable/decarbonised gases being injected into the gas grid, gas quality will be more and more diverse in the future and hence there is a clear need to increase the system's resilience -including infrastructure and end use- to handle it.

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.

The use of hydrogen either in combination with natural gas or in pure form will require an assessment and possibly an adaptation or substitution of gas infrastructure elements or end use applications beyond certain levels of concentration. As CEER has correctly identified, providing technical clarity at EU and local level on the different pathways is necessary to identify which technological developments and investments are needed.

When it comes to acceptable admixtures of hydrogen into the gas network, Enagás would like to note the following:
a. Hydrogen admixtures up to a stable 4% should not require any kind of special permission, from the perspective of network integrity, safety, utilization and energy transport capacity in both transmission and distribution networks.
b. Hydrogen admixtures in the natural gas grid until reaching a stable 10%, is feasible, according to the standards UNE-EN-16726 and UNE-EN-16723 part.1 and part.2, although it will be necessary evaluate, by the owner of the infrastructure (including all infrastructure segments, e.g. CNG/LNG fuelling stations), the end users, to verify that there are no incompatibilities with tertiary uses.
c. Hydrogen admixtures in the natural gas grid until reaching a stable 18.5%, although it continues to meet the gas exchangeability criteria of the 2nd family (for the resulting product), according to the Delburg diagram, requires an exhaustive analysis of said product quality, depending on the type of admixture and the Wobbe Index, besides requiring analysis of integrity of the gas infrastructure, uses in which said mixture is applied, and adaptations of appliances, turbines and burners, to avoid backfire processes, mismatches in combustion and possible unforeseen detonations.
d. Consequently, based on the above previous points, a), b) and c), it is recommended, following what has been collected in projects such as NATURALHY, works by MARCOGAZ, ENTSOG and the CEN Committee, to currently limit the percentage of hydrogen injection into the gas grid to 10% maximum.

In the short-term, it is important to remove technical and legal barriers that could hinder further development of hydrogen -including blends- systems. For example:
Short-term legal barriers
a. National legislation and bilateral interconnection agreements need to be revised to allow the flow of hydrogen admixtures gases at Interconnection Points.
b. A favourable fiscal regime for electricity aimed at producing hydrogen, essential to back up non-manageable renewable energy (such as wind and solar power plants), should be introduced, ensuring a level-playing field for such electricity. This should be backed by a proper GOs system for hydrogen.
Short-term technical barriers
c. In order to unlock the current 2% limitation in hydrogen/methane blends, it is key to test the ability of UGS facilities and CNG mobility application to use higher fractions.
d. The current relative density requirement in the CEN standard EN16726 (from 0.555 to 0.7) should be revised in the context of current CEN harmonisation work as the lower value hinders the development of hydrogen. It is worth mentioning that test gases in the standard EN437 already foresees the testing of H-gas appliances with up to 23% hydrogen.
e. In any case, EN16726 should recognise the different hydrogen tolerance of end use applications and infrastructure elements. Rather than settling for the common least denominator (e.g. 2% for CNG), hydrogen injection requests should be assessed by the relevant operators on a flexible case by case approach with the oversight of the competent authorities. Otherwise, the development of business cases for renewable and decarbonised gases in the short term could be hindered.

The evaluation of the current system and implication of future changes are the following ones:
f. From the technical point of view, the realisation has to be started with a proper feasibility study of the existing system from production (hydrogen/biogas), storage, transport to consumption, in order to handle the aimed renewable and low carbon targets. The technical evaluation should suggest what modifications have to be done to achieve the targets (modify existing installation, design criteria for new installation, new separate hydrogen system for transport/storage). Through an iterative process, the most economic path should be evaluated between utilization of existing systems, rebuilding separate H2 infrastructure or H2 conversion in synthetic methane.
g. Before taking any decision, a proper impact analysis should be carried out, including on the financial effects and impact on tariffs by the foreseen changes – costs of the infrastructure upgrades, costs of end-user appliances, and implications to the

consumer bill. Regulators shall play important role in transition of the European gas market into carbon neutral system, especially by accepting these costs as eligible in regulated sectors.

In the medium and longer-term, natural gas end-use applications standards should increase their readiness for higher hydrogen fractions. It is also important that gas applications and infrastructure are provided with the necessary controls to withstand the foreseeable variability in the hydrogen fraction.

In order to enable a smooth transition, an EU roadmap setting minimum hydrogen readiness targets for gas infrastructure and new appliances 2030, 2040 and 2050 would be beneficial, without prejudice for Member States to extend these limits nationally or locally if desired. Based on the roadmap the analysis of costs and benefits of such a transformation should be performed.

The implications of this roadmap would be:
a.All new domestic and commercial applications -including CNG- should be able to withstand a variable concentration of hydrogen up to the established threshold.
b.TSOs should be allowed to include in the RAB the cost of new assets, as well as the replacement of depreciated assets by new ones that are ready to integrate at least the hydrogen fraction indicated by the given threshold, with the possibility to go beyond.
c.For industrial and power generation customers, a specific case by case assessment should be done locally where hydrogen injection is foreseen. NRA's may need to be involved to decide on possible mechanisms for socialising costs where needed.
d.Member States should cooperate in order to ensure the safe and reliable cross-border flow of gas, and gas-hydrogen mixtures, and coordinate their readiness to transport and use certain hydrogen fraction. Minimum thresholds for gas networks should be set on national levels.

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.
Hydrogen networks, using public domain land, and connecting diverse production and demand centres, should be considered as natural monopolies since building parallel/competing network structures would not be efficient from a socio-economic point of view. 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. This idea is fully aligned with Enagás view. It will be necessary to allow for a regulated non-discriminatory third-party access to hydrogen networks to support and further develop a European internal energy market. Therefore hydrogen networks could be efficiently managed by gas TSOs. The level of regulation would depend on the level of maturity of the market, objectives the regulator is trying to achieve and national circumstances. Based on the above, it would make sense to enlarge the scope of the EU gas directive (2009/73/EC) to include hydrogen infrastructure. It should not be obligatory that hydrogen networks and hydrogen storage have exactly the same regulatory framework than natural gas infrastructure. Some adaptions would be most likely needed to reflect the hydrogen business particularities. Independently from being fully / partially regulated or not, the benefits of having the TSO building and managing hydrogen pipelines would be: a. TSOs are better placed to manage system operations also across sectors ("sector coupling perspective"), for balancing, for network development plans and technical issues such as compression and gas quality. b. Infrastructure optimisation and cost savings as a result of coordinated planning reflecting the development needs of the sector (e.g. blending and/or dedicated pipelines; full/partial conversion to hydrogen of existing pipelines, etc.). c. Development costs can be reduced by using existing infrastructure and converting some parts of the existing gas network into hydrogen networks, as well as via the integration of existing hydrogen pipelines. d. Guaranteeing non-discriminatory third-party access, so that all interested market players can benefit from gaining access to the hydrogen networks, maximizing the potential for sector coupling. e. Guaranteeing the viability of hydrogen pipelines in the development stage, as the load factor progressively increases. f. Allows a potential integration of hydrogen and (bio)methane markets to deliver one price signal for gaseous energy, in a similar manner as H gas and L gas are integrated in some EU markets. This integration will prevent market fragmentation as hydrogen usage develops alongside gas usage. Blending hydrogen into the existing gas network will also require the removal of technical barriers for cross border trade. The regulated framework already in place for gas infrastructure should be used and possibly adjusted in order to facilitate and incentivise their evolution towards future-proofing assets. As the use of hydrogen increases in the future, development costs can be reduced using the existing infrastructure, by adjusting or converting some parts of the existing gas network into a hydrogen ready network, or blended hydrogen / methane network with higher concentration of hydrogen. Conversion from methane to hydrogen will take time, R&D and investments for future proofing existing infrastructure will need to be carried out. These investments will have to be taken into consideration by NRAs and appropriately incentivised.

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.

Enagás believes that “cost efficiency” is a legitimate reason for a pro-active market intervention where sustainability is the main driving force of the energy transition, but keeping in mind the other two pillars of the energy policy: competitiveness/affordability and security of supply.

The “cost efficiency” principle will ensure that the energy transition is as affordable as possible, ensuring a just transition, socially acceptable. This idea is fully in line with the European Commission´s “Strategic long-term vision for a prosperous, modern, competitive and climate neutral economy” released in November 2018.

Enagás would like to underline that the gas infrastructure system allows for a massive transmission and storage capacity of energy. Due to is enormous capacities, the gas system is able to transport and store energy during short, medium and long-term periods, and in a much more cost-effective and cheaper way than electricity. This feature makes the gas system the perfect partner for integrating growing amounts of renewable energy, and places the gas TSOs in an ideal situation to manage the transport and storage of hydrogen via the existing gas infrastructure (or through dedicated hydrogen pipelines).

On the other side, apart from of “cost-efficiency”, “technology neutrality” should be respected as much as possible for the efficient development of a decarbonised energy market and regulation. Support schemes should not favour one technology over another, e.g. biogas support mechanism for the production of electricity but not for the injection in the gas system.

Besides cost efficiency, other criteria like security of supply of the whole energy system, diversification of sources, peak demand, societal and environmental impacts (externalities) and future potential of the technology should be considered to promote activities like power- to- gas, hydrogen networks, CCS/CCU, biomethane and CNG/LNG refuelling stations for the transport sector.

In addition, any main decision that will structure the future of gas and gas infrastructure, such as the shift from a methane network to a pure hydrogen one, should be assessed taking into account long-term cost efficiency.

Nowadays, there are several supporting schemes and regulatory frameworks in place to promote the production of renewable electricity. All technologies, including those which enable renewable and decarbonised gases, that contribute to the decarbonisation of the energy system should benefit from the same kind of treatment, assuring a level playing field between all technologies and all energy carriers.

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

Power-to-gas is a technology that will further enable sector coupling, fully enabling the development of a hybrid energy system that can provide, affordable, sustainable and secure energy. A power-to-gas facility should not be treated as a gas production facility but, instead, as a conversion facility which transports energy from the electricity system into the gas system.

Power-to-gas has a number of benefits:

a. It would facilitate sector coupling, thereby maximising the potential of the overall energy system, allowing for optimal planning and development of gas and electricity networks in a complementary manner
b. It allows the maximisation of the renewable electricity production (RES production) by converting renewable electricity to renewable gas/ renewable hydrogen which can be injected into the existing gas network and used, among others, as a feedstock by the industry.
c. It will contribute to better functioning of the energy market by reducing the occurrence of curtailment and the associated negative/very low prices in the power wholesale markets; this enables the development of additional market-based renewable electricity generation whilst providing a renewable source of gaseous energy.
d. It will ease the balancing of the power grid by providing both up and downwards operational reserve and will contribute towards the reduction in electricity grid congestion
e. It allows storage of large quantities of renewable electricity over long periods in the gas system (unlike battery energy storage systems, which are discharged rapidly)
f. It improves security of supply in both the electricity and gas sector

Gas TSOs are ideally suited to contribute to the ramp-up of power-to-gas infrastructure as they have the knowledge, experience and resources to develop this type of infrastructure.

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?

Electricity and gas tariff systems, including taxes and levies issues, could create distortions to the efficient deployment and use of power-to-gas technologies.

Electricity and gas TSOs should be allowed to propose a discount on the electricity and gas network tariffs justified by the benefits that power-to-gas plants generate to the overall energy system in terms of positive externalities such as security of supply, supply diversification, balancing of the grids, support to renewables integration, decarbonisation, etc.

Enagás believes that there shouldn't be a differentiation between whether the gas produced via power-to-gas is either used to generate electricity or used for a different purpose.

It would be difficult and counterproductive to restrict the use of renewable gas as described in the first case of section 4.3 within CEER document. That's why the discount similar to the one described in the second case (i.e. "special provisions for high-intense consumers") could be a workable solution.

In addition, power-to-gas facilities should be classified as a "conversion service". So, power-to-gas users will not bear tax and levies associated with their electricity consumption.

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

The current legislative and regulatory frameworks were developed prior to the development of power-to-gas infrastructure, therefore not taking into account its potential and possibilities. A review and amendment of the current legislative and regulatory frameworks are needed to ensure their adequacy to the development of power-to-gas infrastructure.

The Gas Directive, among others, should be reviewed. It would be beneficial to introduce the following changes:

a. A definition of power-to-gas in the context of sector coupling should be included to enable the transition to a decarbonised energy system. Indeed, a clear distinction between the facility operator and the facility operator and the facility user, it would be easier for TSOs to operate such a facility.
b. A supportive framework is needed to enable the roll-out of power-to-gas. The possibility to apply for European investment funding should be also taken into account.
c. There should be no barriers to renewable and non-renewable low carbon gases crossing borders and sectors.
d. Furthermore, TSOs should be allowed to transport and storage hydrogen, and other gases, to enable the scale-up of renewable hydrogen production from power-to-gas facilities.
e. Both electricity and gas sectors should work together to evaluate and identify the efficient development of power-to-gas infrastructure.

Regarding the supportive framework to enable power to gas, regulation could have a role to play, since it is an efficient way to develop infrastructure, allowing for financial benefits. Regulated investments are a mechanism that is likely to have a lower cost than the cost of supporting schemes such as explicit subsidies. Additionally, the costs linked to regulated activity are under the recurrent scrutiny of NRAs. CEER indicates in the consultation document that "subsidising technologies, which is not the responsibility of regulators but of policymakers, should be done using specific policies". However, during last Madrid Forum, the European Commission clearly indicated that that there will not be new specific subsidy schemes. In the absence of subsidy schemes, regulated investments could be used to incentivise the development of power-to-gas facilities.

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

Cross-border trade of GOs for renewable gas should be supported by ensuring "interoperability" of different GOs. In this sense, "different GOs" stand for different energy carriers (e.g. gas, electricity) and different issuing bodies. Interoperability would manifest itself by way of the following two mechanisms:
a. All GOs need to be convertible from one energy carrier into another when such conversion is physically taking place.
b. The national issuing bodies for different energy carriers are encouraged to work towards setting up clear and recognisable schemes for all GOs. These schemes can then be interoperable since they are based on the same widely accepted rules. These schemes include criteria and processes for recognition by every issuing body of GOs issued by every other issuing body – to allow the transfer of GOs. Any double support for the same MWh produced must be avoided. Additionally, a European-wide solution for the above-mentioned cooperation could be established.

Enagás also supports the establishment of GOs for energy from "non-renewable" energy sources that have a positive impact on the Green House Gas (GHG) emission reduction (e.g. decarbonised/low-carbon gas), as in the terminology of the recast Renewable Energy Directive (RED II), which allows Member States to put this option in place.

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?
Enagás draws attention to our response to the previous question for interoperability of different GOs. That said, instead of copying the solutions from the renewable electricity to renewable gas, we should work towards being able to convert GO from one carrier to the other carrier. Lessons learnt from the electricity sector include the necessity of a common understanding of data that should be included in the GO and certificate. All GOs, regardless of the energy carrier for which they are issued and regardless of the issuing body, must comply with the same transparency requirements. To that end, the common understanding of concepts and corresponding terminology is needed. Additionally, when designing common data requirements for all GOs, it is important to pay attention to operational aspects, such as data format, data fields and data protection. Lessons learnt from renewable electricity also underline the importance of avoiding any double support between an EU-wide GO system and MS support schemes.

Infrastructure Investments and Regulation

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?
ACER (and NRAs) role should be kept as it is foreseen today in order to provide important recommendations to improve TYNDPs while still preserving an open, transparent and non-discriminatory process towards all stakeholders. The ENTSOs already assign a primary role to ACER and evaluates with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements. Regulation confers an important role to ACER (and NRAs) in providing opinions to ENTSOs Draft TYNDPs and CBA Methodologies. The recommendations provided to ENTSOG are published in the final version of the ENTSOG TYNDP as well as an explanation on how those where taken into account. Also the CBA Methodology includes a dedicated document where ACER opinion, as well as other stakeholders feedback, are published together with the way those feedback have been taken into account. Additionally, with regards to the ENTSOs CBA Methodologies and their possible update, art. 11 (6) of Regulation (EU) 347/2013 states that "the Agency, on its own initiative or upon a duly reasoned request by national regulatory authorities or stakeholders, and after formally consulting the organisations representing all relevant stakeholders and the Commission, may request such updates and improvements with due justification and timescales". While the process is rather comprehensive and has been enhanced with time, it does not always ensure that the national authorities in charge of planning participate to the process, e.g. in countries like Spain the authority in charge of planning (which for basic natural gas infrastructures is mandatory) is the Ministry. The process should ensure that the relevant authorities are directly consulted. In line with Regulation (EC) 715/2009, ENTSOs TYNDPs represent a non-binding Community-wide ten-year network development plan. Under the current legislative and regulatory frameworks, the TYNDP non-binding nature is an important feature to be preserved to avoid incompatibility with other more prescriptive and detailed planning tools, such as national plans. The ENTSOs are responsible for creating an open process for any project promoter meeting the relevant requisites to submit their project to the TYNDP (facilitating the collection of information). As a regulatory requirement, projects applying for the PCI label are required be part of TYNDP. Projects submission is regulated by the TYNDP Practical Implementation Document (implementing the European Commission Recommendation of 24 July 2018 "on Guidelines on equal treatment and transparency criteria to be applied by ENTSO-E and ENTSOG when developing their TYNDPs") that sets rules and criteria promoters and projects have to comply with in order to be part of their respective TYNDPs. In Enagás view, the Practical Implementation Document (PID) developed by ENTSOG, and other related documentation, are not sufficiently prescriptive to ensure that the goals set by the European Commission Recommendation of 24 July 2018 are met. In particular: a.There should be provisions to check at an earlier stage whether projects submitted to the TYNDP are of European relevance, as required by art- 1.2 of the Recommendation. Currently, promoters can use the TYNDP to publicise projects of non-European relevance, just by declaring, without providing evidence based on contacts with other affected operators, that projects increase capacity elsewhere affecting more than one Member State. If the lack of European relevance is proved, the project should be excluded from the TYNDP. b.The European relevance is only tested by ENTSOG after projects have been included in the modelling. Art. 4 of the Recommendation notes that the inclusion of inappropriate project applications affects the modelling of the electricity and gas networks, potentially putting at risk the timely adoption of the TYNDPs and the objective of transparency regarding the development of electricity and gas networks in the Union, and therefore asks ENTSOs to define in their PIDs criteria for the inclusion or exclusion of submitted projects. ENTSOG should be more active defining criteria for exclusion based on the non-European relevance, and requiring promoters to bring evidence on the capacities declared when the affect other infrastructure operators. The latter would allow to allow for the assessment of its European relevance by ENTSOG at an earlier stage. Ensuring the fulfilment of the European Commission Recommendation of 24 July 2018 is of particular relevance given the role that ENTSOG's TYNDP plays as a starting point in the PCI section process. ACER and NRAs could be granted a greater role as regards confirming the European relevance of projects. ENTSOG assesses and tests the infrastructure against the possible future scenarios, jointly developed with ENTSO-E. To that end, a proper selection of projects, ensuring their European relevance, should be done in advance, in order to discourage inappropriate project applications and avoid unnecessary complexity in the process and distortions in the results. It should also be ensured that the assessment of ENTSOG is conducted on a transparent manner and establishing a level-playing field. However, the relatively limited tools at disposition of ENTSOG for simulation (e.g., ENTSOG cannot perform hydraulic simulations and is not conducting simulations of national systems, but only between them) implies that ENTSOG must rely on TSOs in order to confirm the impact of promoters' projects on national systems, in particular on capacities at IPs. The data provided by TSOs on their systems should be the reference for any simulation, since there are in a unique position to provide this data, and ENTSOG should not aim at replicating, with limited tools, national simulations. Given the limited role of ENTSOG as regards the modelling of balancing zones, requisites could be placed on TSOs to ensure that such calculations are properly conducted if required to ensure transparency and non-discrimination. This would ensure a balance

between promoters and impacted TSOs rights. If this was not sufficient and internal balancing zones had to be simulated by third parties in the future, maybe a new architecture would be required in order to ensure technical capacity and objectivity, granting a role to third-parties under the umbrella of the European Commission, such as JRC.

Though the selection of projects could be enhanced, submitted projects are nevertheless analysed based on the methodology approved by the European Commission. The 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements to measure the level of completion of the pillars of the EU Energy Policy from an infrastructure perspective. It is then the role of the Regional Groups (including EC, Member States, ACER and the NRAs) to propose and review Projects of Common Interests. For the first time, ENTSOG TYNDP 2018 publishes the results of the project-specific assessments carried out.

Gas and electricity TSOs are in a unique position to provide quantitative European focused scenarios on the impact of the energy transition on the European electricity and gas infrastructure needs and challenges. The scenarios represent the first step in any network development exercise, and they provide a view on many elements e.g. energy demand, prices, technology developments, etc. The demand scenarios are built jointly between ENTSOG and ENTSO-E with an objective approach, guided by the need for the infrastructure assessment to look at the range of possible futures. They are built taking a holistic approach to the energy system in order to ensure consistency and capturing all the interactions between all energy sectors. Stakeholder workshops and public consultations have endeavoured to improve both the scenarios themselves and the supporting publications. The ENTSOs in fact consults stakeholders in different step of the Scenarios Development ensuring transparency and impartial treatment of all stakeholder feedback. As already said, in this context, the ENTSOs already assigns to ACER a primary role and evaluates with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements.

It should be noted that there is a decreasing trend and narrower range with each scenario development exercise. When the gas demand scenarios in previous ENTSOG TYNDPs (since TYNDP 15) are compared with actual gas demand figures, the results show that over-estimation does not occur, and that the predicted data falls within the observable range of results. For example, TYNDP 2017 scenarios show a lower demand for 2017 than that which was observed. In the range of TYNDP 2015 scenarios for 2015 – 2017, the actual demand fit well within the range. In addition, in TYNDP 2018 scenarios, 2020 yearly demand start with a lower demand than any of the TYNDP 2017 scenarios. In TYNDP 2018 all scenarios go beyond the 2030 target and on track with 2040. When compared to other Institutions' scenarios (like IEA World Energy Outlook) ENTSOG TYNDP 2018 scenarios are in the range.

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)?
First of all, Enagás shares the auspice to extend the PCI selection scope to projects dedicated to renewable and decarbonised gases (hydrogen, biomethane, synthetic gas, etc.). Enagás shares the understanding that decision making processes regarding new infrastructures should run consistently, using the same data set to the extent possible. Nevertheless, as mentioned in the consultation document, there is a significant difference between the use of the same data and having the market test provided by the CAM NC as a standard market testing procedure to be included in the CBAs carried out by project promoters. It is important to underline that Regulation (EU) 347/2013 and CAM NC have different targets. In order to be considered potentially eligible for the PCI label, only projects having reached a sufficient degree of maturity have to provide also a project-cost benefit analysis based on the ENTSOs CBA Methodologies. Also “non-mature-enough projects” can apply and be considered eligible for PCI label (even without a project-specific CBA analysis). The aim of the PCI selection process should be in fact to identify which projects can have positive impact for Europe, regardless of their commercial viability. The incremental process included in CAM NC aims, on the other hand, to the harmonization of market test across the EU, and it should be the default procedure used to carry out market tests. Indeed, Regulation 347/2013 envisages the possibility that positive externalities may justify some investments even if market demand is not sufficient to support them. The role of the project-specific cost-benefit analysis carried out by promoters consistently (but not necessarily exactly the same) with the ENTSOs CBA Methodologies is to identify whether the project brings social positive benefits (also in terms of positive externalities) but not whether the project is commercially viable or not. In addition to the application of the CBA methodology, Regulation 347/2013 introduces a second analysis on the commercial viability that should always be carried out by the promoter itself. This second analysis should for the sake of consistency, be aligned to the market test defined by CAM NC. The results of market testing become relevant in order to be eligible for Union financial assistance in the form of grants for works. For that purpose, the project has also to be non-commercially viable according to the business plan and other assessments carried out (art. 12 of Regulation 347/2013). Stating that “project promoters submitting an investment request shall accompany the cross-border cost allocation by a project-specific cost-benefit analysis (consistent with ENTSOs CBA Methodologies) and a business plan evaluating the financial viability of the project including the results of market testing”, art. 14 of Regulation 347/2013 properly reflects the fact that such market testing should not be considered part of the project-specific assessment but, as a complementary analysis looking into a different aspect. Additionally, Enagás notes that in its Opinion on the Draft 2nd ENTSOG Cost-Benefit Analysis Methodology , ACER has asked ENTSOG to remove any reference to investment request (including CBCA) originally included in the Draft version of the 2nd CBA Methodology. Given the role of its CBA Methodology, there is no need for the inclusion of market testing in the 2nd CBA Methodology itself and in the PCI selection process where, as already said, benefits stemming from a project realisation should be considered regardless the commercial viability of the project. However, this does not prevent that, as proposed in the CEER consultation paper, the incremental procedure provided by the CAM NC should be used as a standard market testing procedure to accompany the cost-benefit analysis in the phase of submitting an investment request or applying for grants of works, as it would favour the consistency of the processes.

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?
Enagás welcomes CEER's view on a really cautious and prudent approach with relation to decommission choices and agrees that there are no reasons to act in the near future. There is strong evidence that gas, be it natural gas or renewable/decarbonised gas (biomethane, hydrogen, synthetic gas, etc.), will remain prominent in the future energy mix in the upcoming decades and beyond. The gas infrastructure system will play a key role in providing affordable energy, maintaining security of supply (SoS) whilst becoming increasingly sustainable. Due to the strong role gases will play in the European energy system as other fuels are phased out of the energy mix, there is significant uncertainty in the future gas demand. Therefore it is premature and counterproductive to introduce an issue about stranded assets. For example, several some scenarios in the EC study in 2018 on the role of trans-European gas infrastructure by 2050, in the EC ASSET study on Sectorial Integration, or the Pöyry study for 2050 envisage quite stable or increased gas demand levels. In addition, peak-demand levels and higher flexibility needs are likely to increase in coming decades. By considering general demand reduction over the year, CEER overlooks the fact that peak demand may not reduce and may even increase, due to changing demand patterns and security of supply requirements. Especially in the case of hydrogen (with 1/3 calorific power compared to natural gas), more capacity and compression power will be needed to transport and store the same amount of energy. So, the current gas infrastructure system could be fit for that purpose. Calling for their dismantling could increase the need for future investments. The gas infrastructure will be one of the two pillars in sector coupling and the transport of renewable and low carbon gases. Due to the current and future integration of the energy system, a holistic approach to the energy sector is required to assess the value of infrastructure. Therefore, no regret options (i.e. keep the assets until proved actually superfluous) and careful evaluations should be preferred to hasty choices. There should be regulatory tools to reduce the risk that assets are wrongly considered as stranded and get decommissioned. It should primarily consist of measures incentivizing TSOs to keep existing assets in operations so that they could increase the pace of the energy transition. Enagás believes that, instead of working on potential decommissioning, efforts should focus on how to maximize and ensure an efficient use of the gas infrastructure during the energy transition and beyond.

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?
As already expressed in the answer to question 12, the assessment of any asset for decommissioning is premature and needs very careful consideration. There are significant benefits provided by gas infrastructure assets, and full consideration of all these benefits are needed prior to any further discussion on the development of a decommissioning CBA. The benefits in terms of security of supply, market integration, price convergence, diversification, optionality in managing uncertain future energy requirements, impact on neighbouring markets (and beyond) need to be considered prior to a formal process and initiation of a decommissioning CBA. Given the current clear indications on the key role of gas (natural gas, biomethane, hydrogen, synthetic gas, etc.) in the energy mix, it is premature to introduce discussions on the development of a formal decommissioning framework. On the contrary, efforts should be made on how to maximize and ensure an efficient use of the gas infrastructure during the energy transition and beyond. Should in the future decommissioning needs becomes increasingly clear, decommissioning processes, especially when cross-border capacity is at stake, should be addressed in a transparent and balanced way in full coordination with all relevant authorities (Member States and NRAs) and TSOs of the impacted systems.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The current gas legislation provides a sound basis for ongoing development of an integrated gas market. Implementation of the existing legislation/regulations is still not completed and the impact on market development is already providing significant benefits, e.g. with better price convergence on many hubs, improved market liquidity and prevention of congestions and their management. The implementation of the current legislation has already had a clear positive effect in some market areas, resulting in liquid and functional market places, as indicated in ACER’s Market Monitoring Report (MMR) released in 2018. Within the EU there are a number of EU gas markets which are mature. However, there are other markets a.�not fully integrated lacking price convergence with the more mature markets or b.�not fully developed, illiquid and/or still not fully functional In these cases, targeted measures that address the specific market needs should be considered. The focus should be on fully implementing the current legislation and, where issues or problems are identified, additional measures could be considered. EU-wide measures should only be considered where there is strong evidence of an EU-wide problem. The incorporation of decarbonised gases into the current market should also be fully considered. ENVIRONMENTAL TAX FRAMEWORK It is necessary to promote an efficiently environmental tax reform, internalizing the cost of the existing externalities, under the principle of technology neutrality. Only in this way the market will provide a cost-efficient solution, avoiding sending distorting price signals that might lead to inefficient consumption of each one of the different energy vectors. In this sense, a tax reform of these characteristics should be implemented based on the "polluter pays" principle in a broad manner, ensuring a clear CO2 price path (through the ETS) as economic signal, both in the short-term, to encourage the entry of less polluting and more efficient technologies, and in the long-term, facilitating the investment in renewable and clean technologies, thus enabling the achievement of climate objectives in the most cost-efficient way. The environmental taxation in sectors such as industry, residential or transport, is usually a non-cost-effective measure due to the lack of substitute clean energy products and the low elasticity of the demand. In those sectors, the implemented measures target should be to ensure the emissions reduction, favoring innovation and the development of the most efficient technologies and solutions. Therefore, applying the polluter pays principle widely is needed. For this aim, other mechanisms such as the introduction of new, more stringent emission standards or tax exemptions and support frameworks for investments in clean solutions (i.e. energy efficiency, replacement of less efficient or obsolete equipment, innovation and development of non-electric renewables, information policies…), which allow the consumer to modify those behaviors that are less respectful with the environment. Moreover, any reform must take into account that the industry competes in a global market in which the inputs’ costs is a key factor of their production chain and competitiveness. The measures introduced should prevent from the relocation of industry outside Europe, to avoid not only the associated economic loss but also the "export" of climate damage to another region with a less stringent environmental regulation.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
First of all, it would be necessary that all biomethane and hydrogen projects are included in the National Energy and Climate Plans in order to have a clear evidence about the expected penetration targets and decarbonisation levels to be achieved with these gases. Moreover, it would be necessary to consider as “public interest/use” the new infrastructure projects associated to the decarbonisation plants (power-to-gas, biomethane, etc.) and guarantee the access to the gas and electricity networks. Furthermore, and in order to promote renewables gases and provide regulatory stability and certainty for investors willing to invest in these technologies, specific regulation should be designed at national level, containing specific production objectives from renewable gases. The future gas market design should also take into account the impact of the changes in the gas sector. Increasing injections of renewable/decarbonised gases in the gas network can lead to new market needs. Excess of local renewable gas production that won’t be consumed at DSO level may need to be injected into the TSO network, using reverse flow infrastructure, either to cover the demand in other places or to be stored. The investments should be assessed and facilitated, where really needed. With the wide development of biogas plants, the new framework should incentivise the upgrade of biogas into biomethane, and the injection of renewable gases (biomethane and hydrogen) into the gas network. With this approach, the market could take advantage of the existing gas infrastructure to transport and store renewable energy on a cost-efficient manner. When it comes to capacity allocation mechanisms, tariffs, quality assurance and operations will need a proper regulatory framework for a transparent, non-discriminatory and secure use. Additionally, it should be facilitated as much as possible the interchangeability of local renewable gases productions at national and even cross-border levels, since a local market can undervalue them, with possible negative effects on their production potentials. The production of renewable hydrogen in power-to-gas units in a decentralised way, and the ability to inject it into the gas grid, will also face challenges. One possible challenge could be the need for the creation of a separate market for hydrogen that will necessarily have a different value from natural gas. Guarantees of origin is the way to give market value in this case for the renewable hydrogen. When considering the development of a decarbonised society, a one-size-fits-all solution is not ideal for a pan-European energy market so diverse, with so many different requirements, political drivers, stages of maturity and geographical distribution of resources. The main concern will then be how to connect all available solutions without hampering the integration of the European energy market already achieved.

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?

Enagás is in favour of evaluating the current tariff regime once the TAR NC is supposed to be implemented in all Member States, which should happen in 2019. The TAR NC provides in principle a balance of the key aims of Regulation (EC) No. 715/2009. While the TAR NC might have gaps to ensure these aims, it is not clear why these aims should change (i.e. removal of cost-reflectivity or moving away minimising cross-subsidisation). There are a number of market benefits associated with the introduction of the entry-exit system i.e. liquid markets.

In any case, Enagás would like to underline that:
a.⍰excessively high cross-border tariffs become "de facto" barriers to gas trade. They should be addressed as a matter of urgency.
b.⍰NRAs have the statutory right to minimise costs for national consumers and therefore have an incentive to overcharge at exit points at IPs to minimise the cost allocated to national consumers.
c.⍰while the proper application of the TAR NC should in principle remedy unduly high tariffs, it should be highlighted that under the current TAR NC there are no sufficient guarantees that NRAs will follow the TAR NC principles and in particular ACER recommendations. Action should be taken to ensure in the short-term that NRAs do not deviate from the requirements established in the TAR NC. In particular, according to Art. 27 of the TAR NC (Commission Regulation (EU) 2017/460 of 16 March 2017) NRAs shall forward the documents of the final consultation established in art. 26 to ACER, which shall publish and send to the NRA (or TSO) and the Commission, the conclusion of its analysis. The NRA shall then, within five months, take and publish a motivated decision on all items set out in Article 26(1). Upon publication, the NRA shall send to ACER and the Commission its decision, but it is not foreseen for ACER to publish immediately after an analysis on whether this final decision is compliant with the TAR NC. This allows NRAs to deviate from the TAR NC, and therefore unduly high tariffs at IPs might remain. A possible example of this effect is the decision by BNetzA which has been criticised by ARERA and the CRE.

In light of the above, Enagás proposes to amend the TAR NC and/or Regulation 713/2009 to ensure that in case of discrepancy between NRAs during the consultation period, ACER has the final say when it comes to confirm that NRA decisions on national tariffs fulfil the TAR NC, at least regarding issues of cross-border relevance.

CEER quotes the Quo Vadis (QV) study and FROG studies to solve issues arising from the end of long-term (LT) bookings and the decarbonisation of gas. Enagás acknowledges such issues.
a.⍰On LT contracts, these studies point at potentially useful solutions and Enagás view is that lowering or eliminating tariffs at IPs is a measure that should be studied. It must be noted that some of the QV and FROG proposals have certain drawbacks. The studies overlook or do not fully take into account that, as regards decarbonisation, that gas will have a future to 2050 and beyond, as new gasses will complement renewable electricity. TSOs should be able to offer additional products adapted to decarbonised gas.

Enagás view is that CEER's first suggested solution of eliminating (or at least limiting) IP tariffs is an option which should be explored and analysed in further detail. The creation of a truly European internal gas market would imply that all gas consumers can have access to gas supplies on a level playing field. Removing IP tariffs would lead to further price convergence across the EU for the benefit of all EU consumers. This option should be well designed in order to avoid losers, and to minimise the need for inter-TSO compensation monetary flows (e.g. by properly adjusting the domestic exit tariffs).

In addition to the QV and FROG studies, it is also important to bear in mind the study performed by the Florence School of Regulation called: "Towards an efficient and sustainable tariff methodology for the European gas transmission network". The paper analyses alternative tariff methodologies that would address the drawbacks of the current system. The first approach meets the transmission revenue requirement by charging only the transmission network's exit points to distribution networks and to directly connected end-customers. The second approach does not charge entry and exit intra-EU boundaries, and offsets the missed revenues via charges at the points of entry of foreign gas supply into the EU transmission system. The paper concludes that the first approach is superior in terms of efficiency; further, it may be implemented in a way that broadly replicates the current sharing of the overall network cost among the European citizens. A move to this model entails material increases of domestic transmission tariffs, which, under plausible assumptions on the wholesale gas price formation mechanism, would be more than offset by commodity price reductions.

There are particular cases where a tariff decrease in an IP could have a very clear net positive impact. For example: a decrease in IP tariffs might have impact on the whole gas price of an importing market, in particular if the IP where the tariff decrease is produced is one of the main sources for importing gas. In this case the benefit of lowering tariffs is bigger than the drop of revenues that may occur in the point. If the revenue recovery can be moved to other points (national exits), then the cost recovery of the TSO would remain the same while the whole market would benefit from lower gas prices. An example of this is the above-cited case of BNetzA and ARERA, where ARERA claims that the increase on IP tariffs (0,387 €/MWh) has an effect on the marginal price of gas in Italy, resulting on an impact of 300 million €/year.

To conclude, while it is too early to assess the impact of the TAR NC, which is not yet fully implemented, it should be fully implemented soon. Once MSs should have implemented the TAR NC provisions, especially with the application of the new tariff methodology principles and transparency requirements, it will be relevant to reassess the TSO tariff regime. That can be done as early as in the second half of 2020. The reduction of excessively high IP tariffs should be a first step, followed by a careful and detailed assessment of benefits associated to the elimination of all intra-EU tariffs. In the meantime, regional initiatives for voluntary market integration should continue.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
To assess the impact of cross-border tariffs on cross-border trade, assessment of the historical data and ongoing monitoring of the markets is needed. As tariffs develop, the impact on cross-border trade needs to be assessed. If there are general trends that suggest a deterioration in cross-border trade, then consideration on how best to address the change should be considered. The reduction of excessively high IP tariffs should be a first step, followed by a careful and detailed assessment of costs and benefits associated to the elimination of all intra-EU IP tariffs. A sound solution should be found to eliminate IP tariffs with a positive cost-benefit analysis, enabling EU-wide price convergence among all wholesale gas market across the EU for the benefit of all the EU consumers. The cross-border impact of IP tariffs implies that NRAs, whose statutory obligation is to minimise costs for national consumers, are not ideally placed to take decisions on cost allocation to IPs, and indeed have an incentive to overcharge exits (i.e. to move costs to other adjacent systems). ACER should be granted a much more relevant role as regards IP tariffs, being able to adopt a final, binding decision in case there are discrepancies between the NRA of the Member State and NRAs from adjacent systems.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
To realise the creation of a decarbonised society, TSOs, amongst other players, will have to progressively invest in future proof technologies such as power to gas, hydrogen networks, CCS/CCU, biomethane facilities, CNG/LNG for transport, digitalisation, and related R&D and pilot project expenses. Some regulatory challenges for a sustainable gas sector not addressed in the document could be: a.Regulatory sandboxes: they can play an important role to encourage, as a first step, R&D and pilot projects by gas infrastructure operators to test and roll out the required new technologies. NRAs would be asked to take such costs into account as necessary infrastructure investments. b.Carbon Capture and Storage (CCS) and Carbon Capture and Utilization (CCU): these technologies should be considered as a permanent characteristic for a secure, reliable and affordable energy system. c.Methane Emissions: Enagás supports the development of efficient policy and regulatory frameworks that incentivise early action, drive performance improvements, facilitate proper enforcement and stimulate innovation. Policies and regulations to manage methane emissions across the gas value chain should enable the role of gas/gases in the future energy mix by: i.helping governments achieve their climate goals ii.instilling stakeholder confidence with respect to gas’ environmental value iii.providing long-term predictability that allow industrial planning and investment.

Survey response 56

Contact details and treatment of confidential responses

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Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The strict separation of essential infrastructure activities (especially TSO and DSO) from supply and trade is fundamental in the gas market design established by the European energy regulation in place. DSOs and TSOs have a key role of market enablers to ensure fair and effective competition. As such, they are regulated monopolies focused on (i) the performance of their core activities (design, develop, operate and maintain their assets and organize their use in a transparent and non-discriminatory manner) and (ii) neutral facilitators to develop the market in the interest of the consumers. The objective of decarbonising the economy supposes an energy transition which involves the creation of new business models and a deep evolution of the energy markets. The way these changes will occur is still uncertain. The definition of the relevant activities for potential TSO/DSO involvement to be considered in the assessment proposed, in a decarbonized gas sector perspective and through the development of sector coupling are, in our view, strictly linked to what CEER itself call “policy” choices and it is also a matter of opportunity TSO/DSO should focus on infrastructural solutions aimed at facilitating innovative uses of the grids (transmission or distribution) and the maximisation of green gas injection also beyond, as for distribution grids, the current limits due to the local grids’ absorption capacity constraints. In fact, where gas grids are widespread, efficient and represent a strategic investment subject to stranded cost - if underused - their utilisation should be maximised. TSO/DSO should work on ensuring the grids inter-functionality, since this would allow a reverse flow (from distribution to transmission grids) and consequently to inject green gas into the grids where it is more efficient (transmission or distribution grid, according to a CBA approach). In such a way green gas injection into the distribution grids would be feasible even when the downstream consumption is not sufficient to absorb the whole green gas production, allowing to divert the surplus into the transmission grid (which has a broader linepack and is also connected to storage sites). Given this, we don’t see a distinction between market operators and network operators but between regulated approach and market approach. From this point of view the definition of “sufficiently developed market” itself is key in the described process: the level of market development should take into account the ability of the market to fulfill the decarbonisation targets. Decisions on technology(ies) to be developed (for instance whether the market select the most efficient technology or support with subsidies or other policies, the development of the most promising ones) have an impact on the regulatory solutions to be designed and implemented to allow not economically sustainable activities (or which the market is not “mature” yet). More specifically, the role foreseen for power-to-gas plant/activities impacts the regulatory approach. Moreover, concerning the “hybrid” category of activities identified as “activity allowed under condition”, that should identify activities that could be operated by TSOs/DSOs due to the insufficient market development, we consider that such “hybrid” activities could (and should) be carried out under a regulated regime by market operators in the first place, ensuring competition through regulated procedures (typically tenders) for the assignment of the activity in order to develop the potential competition and the efficiency, defining all possible conditions (i.e. volumes, reserve price etc. for tenders). Alternatively, if no market operator was able to implement (pilot) projects, network operators under specific conditions should have the possibility to do so; in this case, in order to be admitted to the tenders, network operators should avoid, according to specific rules (i.e. unbundling regulation and similar), any cross-subsidies between “monopolistic” activities (such network operation) and potentially contestable ones, and any undue competitive advantages resulting from the abuse of their position as regulated entities. All in order to allocate cost correctly and segregate the activities and to prevent discriminations (separate accounts etc.). However, If market failures occurs, it would be desirable to remove the causes.

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.
We share CEER view on the need to adapt the European legislation (namely NC Interoperability) in order to foresee the evolution of the role of hydrogen and renewable gases (which do not need blending) and avoid negative impacts on the European market integration. It is necessary to avoid the risk of physical separation between national/regional markets due to different characteristics of the gas transported by the gas networks taking into account the apparent differences among European gas networks, in terms of maximum level of hydrogen they can sustain (interoperability issues). An European coordinated renewable gas guarantees of origin system should be put in place in order to promote the hydrogen marketing across Europe. The question of the maximum level of content of hydrogen in the gas grid is a technical subject. Indeed, it depends mainly on the grid's characteristics (material and components), which vary significant among member states, and of the appliances used by the end consumers. We fear that a definition of a harmonised hydrogen percentage would reflect the worst-case scenario leading to a relatively low value as the reference. That's why, it should be accompanied by other measures such as a timeline of increasing levels of hydrogen content and the principle that system operators must accept the highest possible levels, taking into consideration the local characteristics of the grid and its clients. A common European threshold should rather set the minimum threshold which all MS should accept to be injected. MS should be entitled to increase the threshold for the blending in order to maximise the production of hydrogen. However, it seems too early to fix a threshold for hydrogen injection in the gas grids in the present situation. Further studies and experimentation to establish what is the desirable/maximum percentage of hydrogen injectable without affecting security are underway, especially by Marcogaz. The issue of the measurement of the calorific power of blended gases still needs to be solved.

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.
From a regulatory point of view, the logic leading the decision whether regulate or not hydrogen networks should be the same adopted for any other transmission network. Vertical integration among commercial and monopolistic activities – like typically the transmission activity- should be avoided, non-discriminatory access to third parties (TPA) should be granted, through appropriate unbundling rules. This should apply both to network transporting gas blended with hydrogen and to 100% hydrogen networks in a centralized transmission/distribution network system. Another approach could apply to isolated network (as, for instance, transmission network within industrial facilities) or in case of a distributed/decentralized development of the hydrogen (production and transmission) market. We think that the development of "fully hydrogen" networks is not desirable: we would instead support promoting blending of hydrogen in the existing gas networks for a most cost-effective solution. As for "how" hydrogen should be regulated, we deem that D-Gas (decarbonized gas), and more in general hydrogen, should be included in the scope of natural gas (transport) regulation, namely on the TPA and tariff aspects. More importantly, D-Gas and hydrogen should be considered in the same framework as the regulation about renewable gases (in case, for example, of the definition of European/national targets for injection/consumption etc): an hydrogen specific regulation could imply the risk of unnecessary complication of the energy regulatory framework. Even beyond the development of the production and distribution of hydrogen in the future, we highlight the need to implement a coordinated and harmonised energy regulation aimed at accompanying the efficient development of the energy system as a whole. Finally, the variability of the quantities of hydrogen injected to the grid, should be considered also in light of the potential implications in terms of storage/methanization needs due to the congestion" (i.e. the saturation of the H2 threshold).

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.
The "technology neutral" approach should be the common rule and should be preserved as far as a holistic methodology is respected. For instance, the biomethane industry has been disappointed by the way zero emission has been considered in the transport regulation while considering a "tank to wheel" rather than a "well to wheel" approach. We remain convinced that life cycle analysis should always be promoted in the impact assessments. However, markets also require some policy or regulatory signals to deliver expected objectives in time. This is why, in the light of EU energy and climate strategy, some kind of intervention would be likely needed to set the grounds for a significant transformation of the gas sector in the next decades. In the case that market practices such as tender are not able to valorise sufficiently both positive and negative externalities, specific rules should apply to allow the best investment decisions. For example, the development of renewable gas makes even more sense while considering the numerous positive externalities in terms of emission reduction of the agriculture and waste management, the promotion of agricultural sustainable practices and the creation of local jobs... Therefore the "cost efficiency" principle should be used to bring decisions in effective system optimizations and achievement of the long-term strategy of full decarbonisation by 2050. However, this should be done taking into account an opportune assessment of the externalities linked to each technological solution.

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

The possible roles we see for power-to-gas infrastructures are:
- Storage of energy (power temporary stored as hydrogen, no injection of gas into the gas network), giving flexibility and support for power grid balancing;
- Production/Transformation of gas (hydrogen/other synthetic gas) from power providing flexibility and support for balancing to both power and gas sectors and networks, additional source for gas industry.

Moreover, from another angle, power-to-gas facilities could operate in a competitive market or be identified as service providers necessary for the industry (to develop an adequate level of sector coupling) in order to achieve the decarbonization targets (see Q1).

Power-to-gas could bring flexibility to the electricity grid as the gas network has the ability to store local excess of energy in an efficient and massive way without significant investment. Therefore, Power-to-Gas allows the conversion of renewable electricity into a form of energy/gas that could be consumed later, directly or used to generate electricity. As such, power-to-gas is a new link between power and gas systems contributing to the better integration through sector coupling.

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?

How to regulate power-to-gas infrastructure - taking into account their contribution to both sectors and to both network balancing and the increasing complexity of the network management and balancing - depends mainly on the role that will be defined for them.

If a market, with an adequate level of competition, will emerge, an adequate allocation of the infrastructure costs to all the users, included power-to-gas facilities, should be granted, taking into account on one hand their use of the network and on the other hand their contribution in terms of flexibility and balancing of the system.

Potential distortion could emerge from the tariff system and how costs are charged to users depending on the role of power-to-gas in both industries (if treated as power end users/ electricity transformers/ storage facility/ network users etc.), leading to the need of clear borders between the different potential roles/activities.

However, an appropriate cost-benefit analyses should be carried out before defining the power-to-gas regulation to be implemented.

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

See answer to Q8

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

Guarantees of Origin (GO) allow transparency for consumers as they certify the conditions of production of the energy. They are necessary to prove the sustainability of the commodity and permit customers to orientate their preferences for renewable gas.

GO should be emitted on similar technological thresholds and according to CO2 production pathway the system should be overseen by a competent authority, in charge, able to collect reliable production data, to run appropriate control systems and – if needed – to impose appropriate sanctions in case of GO misuse.

GOs certificates need to be standardized enable to cross border trade at European level. Tradability issues can arise when the measures for transition will be managed locally.

Regarding the development of a cross-border trading of renewable gas GOs, we recommend:
- One standardised GO for “renewable”, “low-carbon” and “decarbonised” gases form the basis for developing the traded market for GOs. Such GO should be based on the minimum requirements of article 19 of RED II; and (2) upcoming CEN 16325 standard on renewable, low carbon and decarbonised gases.
- This upcoming CEN 16325 standard should be developed in cooperation with AIB, Certifhy, ERGaR and, if any, other issuing bodies. We encourage all parties to present a first draft as soon as possible, preferably by the next Madrid Forum in October 2019
- It should be possible to add additional information on top of the standardised GO and offer more sophisticated products to target specific customers
- Cancellation of allowances in other countries should be possible as it is currently possible for power GOs. This could be achieved through a model similar to the power GOs model:
  - o MS registers remain, but they coordinate through a EU body like AIB for power
  - o Requirements for acceptability of GOs in neighbouring countries
  - o Coordinated cancellation system to avoid double counting
- Support to compatibility between different GOs schemes. In the absence of a conversion system of GOs from one energy carrier to other, MS should be enabled to take into account the average renewable energy production to generate GOs, in line with the one included in the RES II Directive 2018/2001: “Where electricity is used for the production of renewable liquid and gaseous transport fuels of non-biological origin, either directly or for the production of intermediate products, the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy”. The average share of electricity from decarbonised sources (e.g. wind or solar) shall be used to determine the share of decarbonised GOs. Another yardstick for comparing GO's between different energy carriers could be using CO2 pathways registered for the production of (renewable) power and gas, in this way it could be possible to compare products of different origins (eg. blue hydrogen and green hydrogen).

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?
In order to establish liquid markets, it is essential that the commodity can be traded regardless of its origin. Therefore, a certificate system for gas, similar to that for electricity, should be structured in such a way that a certificate can be traded independently of the commodity. This ensures, for example, that the commodity can be produced in Germany, transported and consumed in France, but that the GO is sold and cancelled in Belgium. This would also allow to trade certificates from different countries at the same trading hub. Another lesson to be learnt from renewable electricity is the importance of avoiding any double support between an EU-wide GO system and Member State support schemes. The EU-wide GO system for renewable gas should be set-up ensuring that double counting of renewable gas volumes is avoided. Successful implementation of an EU wide scheme with mass balancing, will ensure that volumes are only counted once.

Infrastructure Investments and Regulation

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?
ACER and NRAs responsibility should focus on strengthening the coordination at national and regional level coherently with an integrated view of the European infrastructural needs, taking into account national peculiarities in terms of needs and gas (+renewable gases) demand scenarios. The increasing importance of links between gas and electricity infrastructure shall be reflected in a new requirement for joint grid planning activities, at both European and national levels. Moreover, CBA methodology should be standardized and oriented to a clear assessment of the cross-border benefits of new "national" infrastructure, in order to proceed to an actually correct cross-border cost allocation.

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)?
The existence of parallel regulation on investments, based on different criteria, without a clear view on the interactions between the two is an obstacle to transparency in the identification of the actual infrastructure needs. More clarity on the interactions between the Incremental Capacity mechanism (NC CAM) and the TEN-E Regulation seems necessary to increase transparency and predictability in the European infrastructure development. Moreover, we would suggest a deeper integration (not only in terms of scenarios) in the development of the infrastructure plans in the gas and power industries.

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?
See answer to Q13

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?
Firstly we promote a regulation able to maximise the use of the existing infrastructures for a cost efficient gas sector and sustainable energy transition. We shares CEER concerns about the mechanisms leading to decommission decision. In a progressively integrated European market, decommissioning decision need to take adequately into account of the cross-border impacts of such decision when infrastructures are relevant for more than one Member State. In our view, the decisions on decommissioning should be based on the following general rules: •Decommissioning should only be discussed about infrastructures that showed not to be useful anymore and not about under-utilized infrastructures, but potentially still useful for the system (for SoS purposes, for instance); •Decision on decommissioning of an infrastructure might be stopped by a neighboring country negatively impacted by the decision; in other words, the cross-border (potential) relevance of each infrastructure need to be correctly identified in order to assess the opportunity of decommissioning; •Infrastructural costs should be allocated to the impacted countries based on the cross-border relevance of each infrastructure (both in case of decision for or against decommissioning); Such mechanisms should be integrated in a more general vision on the evolution of infrastructure tariff regulation, in order to take into account the cross-border relevance of each infrastructure, allocating cross-border their costs to the relevant beneficiaries (see answer to Q17). In any case it is equally important to ensure that gas regulation schemes do not incentivize building more gas infrastructure if not necessary.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
see answer to Q17

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
To achieve the expected results in terms of development of renewable gas, we expect a renewed gas market design to address at least the following points: -clear definition of what is “renewable gas” (biomethane, green hydrogen, blue hydrogen + CCSU); -clear definition of the technologies used for producing “renewable gas” (anaerobic digestion; Power-to-Gas); -possible review of the definition of “distribution” and of “distribution system operators”. Decarbonisation gas targets, support schemes, definition of regulated activities and planning would need further examination and should be supported by clear cost-benefits analyses. A key success factor for the market entrance of power-to-gas technologies is the acknowledgement in the target sectors mobility and heating.

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?
see answer to Q17

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
As highlighted by the last Market Monitoring Report, gas market integration has improved in Europe in recent years and gas wholesale prices have showed increasing levels of convergence in many hubs. But there is still to be done to achieve the Gas Target Model objectives (not totally achieved and not homogeneously across Europe). Moreover, new challenges are related to the forecasted decrease of gas consumption and the termination of long-term capacity contracts, which could bring back higher hub price differentials in the future, impacting the market liquidity. Thus would require to adapt the current market design to prevent those risks. From our point of view, the regulatory framework should support the efficient use of the existing gas infrastructure as a condition for a healthy gas industry. At the same time, the review of the current regulatory framework should take into account the view for the industry in the long term, envisaging gas in combination with renewable gases and underpinning an interlinking with the power grids (to allow sector coupling). It is necessary to attribute the right value and role to gas infrastructure both in the (already started) process of decarbonization and in a long-term vision of decarbonized energy industry. In an integrated view, considering the increasing role of flexibility, the value of gas infrastructure needs to be less dependent on the current market environment than it is now and the regulatory framework must be properly corrected. A new framework should properly take into consideration the risk that distortive impacts, linked to different levels of utilization of infrastructures, could lead to underestimate the value of infrastructure which are not sufficiently utilized but still necessary, for the European system, also in a long term vision. With reference to cost allocation in tariff setting, we welcome CEER suggestion to “consider a cost allocation methodology that includes all the benefits provided by the gas infrastructures and tries to allocate costs to beneficiaries”. About that, from our point of view, the TSOs allowed revenues should be split and allocated based on the nature of the corresponding costs to be covered, distinguished among the following cost categories: A.“Transportation and transit costs”: Costs related to infrastructures dedicated to the transportation of gas in the domestic system (to be covered through tariffs paid by network users supplying domestic final customers and/or by domestic final customers) or to transit gas to other countries (to be paid by shippers using infrastructures to supply downstream countries); B.“Costs for internal security of supply (and market competitiveness)”: Costs linked to infrastructures aimed at granting the domestic security of supply (to be covered by the tariffs paid directly by the final customers that benefit from security of supply) and; C.“Costs for security of supply (and market competitiveness) of other EU countries”: Costs linked to new investments (PCI) and to existing infrastructures with limited value for the system in which they are located but still useful for the security of other countries and for the related competition upsides. Such cost, with cross-border relevance, should be covered through cross-border cost allocation mechanisms by the end users benefitting from the infrastructure. We would therefore recommend to review all the Network Codes and the TAR Code firstly, in order to i) understand what is not functioning in their implementation, ii) define a more effective cost allocation methodology and iii) promote a real energy market integration. The review should be functional to better define the governance and empower ACER to monitor and assess the level of competition, and actively support the implementation of EU rules in each Member State (for example assessing the impact of each country’s transport tariff choice has on neighbouring countries). ACER has currently very limited ability to go beyond the reporting of formal compliance and to play a role in implementation processes.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
An EU gas DSO Entity - different from the EU electricity DSO entity – could be envisaged to foster cooperation with TSOs on the exchange of best practices on energy efficiency, digitalization, demand side management, data protection and cyber-security. This, obviously, always in a logic of an overall vision of the whole energy system. Also, from a regulatory point of view emphasis should be given to the digitalization of the networks. Apart from allowing for the reduction of energy consumption, and thus benefitting consumers via the smart meters roll-out, network digitalization will allows for optimized management of the network and better integration of renewable energies into the grid. GENERAL COMMENTS Firstly, Anigas draws the CEER's attention to the centrality of the natural gas in the European energy system: natural gas is indispensable to guarantee an energy transition path that is economically, environmentally and socially sustainable. Natural gas is the least polluting and certainly the most flexible fossil fuel, characteristics that make it essential to effectively support the development of renewable sources, guaranteeing electricity generation continuity and security of supply and offsetting intermittence and the non-programmability of renewables. Moreover, only the gas vector is currently able to grant flexibility in case of peak demand during winter. Even with respect to end uses, it is undeniable that, in the short and mid-terms, gas remains the reference energy carrier for some sectors of use. Nonetheless, it should be considered that many industrial production processes necessarily require the use of natural gas as there are currently no alternative feasible solutions (from a technological and economic point of view), also in the long-term. Also for the residential sector, the electrification of consumption, which could have spaces of penetration with respect to new buildings while compared to existing ones, seems possible only if supported by relevant infrastructural investments to be evaluated on the basis of a cost-benefit analysis (CBA) approach considering the already existing - widespread and efficient - gas infrastructures in order to avoid stranded costs for those ones. In addition, such a process will require a greater involvement of consumers, called to completely modify even their internal heating systems. Therefore, due to the costs related to such a massive fuel switch, it is reasonable to assume that natural gas will play a certain role also in the long-term. From this point of view, in order to guarantee the economic sustainability of a path of energy transition that is certainly challenging, it could be essential to review the current regulatory tariff design, promoting market integration and avoiding distortive effects. Given the growing integration between the electricity and gas sectors and hoping that energy regulation can guarantee a synergistic approach, we believe it is essential that the evolutionary hypotheses for natural gas have, as an objective, to promote an efficient use of existing infrastructures and a correct allocation of costs according to the beneficiaries of such infrastructures, as well as to support the interoperability of such networks. This in light of renewable gases (biomethane, hydrogen and synthesis gas as a storage of surplus energy produced by electric RESs) using the existing infrastructures supporting the cost-efficient decarbonisation. As a substantial part of renewable gases will likely be generated locally and therefore also injected directly into to the gas distribution networks, these networks will be important to maintain the benefits of the integral gas system. We believe that it is necessary to accumulate some experience on the available technologies and on their operational and technical aspects, before defining the relevant regulation and who does what. It is therefore considered very important, even beyond the role that the various storage technologies will play in terms of system flexibility and the impact on the decarbonisation of the energy sector, the need to implement a coordinated and harmonised energy regulation aimed at accompanying the efficient development of the energy system as a whole. From this point of view - and in coherence with the European and international context - each Member State (MS) will identify and develop balanced and coherent solutions in a cost-benefit logic, able to reconcile objectives in terms of environmental sustainability, economic sustainability and energy security.

Survey response 57

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Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Plants should compete within the market. Lack of cost-effectiveness is no reason for operation in the regulated area. Financing through network charges should be considered only for purely network-related use and with proof that this would be cheaper than network expansion.

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.
Common European threshold is meaningful to not affect cross-border trade.

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.
No! Market interventions lead to distortions in the competition of technologies among each other. This means, cost reduction potentials of other technologies could not be exploited in this approach. We are clearly in favour of a technology-neutral competitive framework.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas is a key technology for decarbonisation of heating and transport. Reconversion of “green gases” will be relevant only with very high renewables quotes.

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?
In particular, high taxes and levy burden within the entire process chain of the Power to Gas-process makes the linking of the sectors currently unattractive.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Danger of too early construction in the regulated area; Risk of plants not being used due to lack of economic incentives; Stranded Investments.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
An EU-wide definition of the product "green gas" is needed. This includes a clear descrip-tion of what “green gas” means and a clarification of the requirements on, for example, electricity used in PowerToGas-plants.

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?

Infrastructure Investments and Regulation

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?
PowerToGas-plants are currently not very profitable in Germany. This is due, on the one hand, to the high burden of levies and charges on the electricity side and, on the other hand, to the lack of pricing of CO2 in the heating and transport sector and the compara-tively low efficiencies of the technology. Barriers need to be dismantled to enable the link-ing of the sectors in perspective. If PowerTo gas-plants are not used for network related purposes only (see above), there is a risk that these plants won't be used at all or only for a few hours due to lacking eco-nomic attractivity. This includes plants which are financed from network charges only and offered to the market (eg in the form of a conversion fee).

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?

Adapting the Gas Market Design

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?

Other question

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

Survey response 58

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GAZ-SYSTEM S.A.

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Gas TSOs are well placed to be involved in activities that contribute towards EU long-term objectives in the area of energy and climate. TSO assets may well be used to build a sustainable energy system across the EU by: •enabling significant reduction of CO2 emissions, •mitigating air pollution, •accommodating the increasing uptake of renewable energy sources, •utilising synergies and enabling optimal use of the available potentials of different sectors and systems (coupling of gas grids with power, heating & cooling energy and transport infrastructure). Gas TSOs should be allowed to invest in any type of facility contributing to EU long-term commitments and sector coupling. The question should not be which activities are considered relevant for potential TSO involvement, but which activities need additional enabling regulation to facilitate their wide deployment. TSOs would then like to be able to invest in a regulated or in a commercial way. Investing in a commercial way, in competition with commercial investors, TSOs should not have any specific commercial advantage or disadvantage. They should be in compliance with unbundling rules and a transparent separation between regulated and non-regulated activities set up, supervised by the relevant NRA. As technologies related to renewable gases and hydrogen are still in development, TSOs should be allowed to engage in research and development to help bring these technologies forward. Power-to-Gas facilities should not be classified as gas production plants. Power-to-Gas may be provided as a conversion service that transforms electricity from a renewable producer, or any other electricity network user, into gas (such as hydrogen or synthetic methane) for further use in the energy system. Therefore, no obstacle for TSOs to be the owners and operators of a Power-to-Gas facility should arise from an unbundling point of view.

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.
As recognized by CEER, there are different possible approaches towards hydrogen integration: blending hydrogen with methane (natural gas at a transition phase and biomethane and/or synthetic methane in the long-term) and hydrogen-only networks. The feasibility of these options results from conditions prevailing at a local level. Therefore, Member States should be free to choose the pathway they want to follow and the relevant timeline. The use of hydrogen either in combination with natural gas or in pure form will require further assessments on the possibilities of adapting gas infrastructure elements and end use applications, and of developing dedicated networks. Therefore, the optimal choice and pathway will be determined by a supportive business environment and local conditions. Under the ongoing works on the gas package, the focus should be put on removing technical and legal barriers that could hinder further development of hydrogen systems. The EU regulatory framework should support the development of renewable gases under a bottom-up approach to foster R&D activities, to make new technologies commercially viable and finally to offer new services in a competitive manner, etc. In consequence, there is no need at this stage for a common European threshold for the blending of hydrogen in gas networks.

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.
The use of hydrogen as an energy carrier has significant potential as part of the energy transition and its use is envisaged to increase in the coming years. For the potential of hydrogen to be fully enabled there is a need to make sure that there are no barriers to its growth. Where hydrogen networks connect diverse supply and demand in a public manner, a similar regulatory frame as the one applied to gas should be introduced to ensure third party access in a non-discriminatory manner. The level of regulation would depend on the level of maturity of the market and national circumstances. In any case, new regulation should be carefully assessed subject to the detailed technical and economic analysis including the impact on the final customer.

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.
Cost efficiency and technology neutrality are key in the implementation of EU long-term objectives. In this context it should be noted that paths towards meeting the long-term climate objectives may vary across the EU countries depending on local circumstances. There are a number of factors that determine how climate objectives may be implemented by individual countries and regions. The current energy mix, political choices, potential of RES development, the role of natural gas in the energy mix, the state of gas infrastructure development, regional opportunities and challenges and competition with other energy carriers may be considered as the most important aspects. Moreover, it is worth noting that the EU Member States share the same climate and energy objectives in the long run. However, they do have different starting points in their paths towards the energy transition. In this context high-emission sources of energy represent a large share of the national energy mix in Central-Eastern Europe. In some countries, including Poland, these sources far exceed 50% of the energy mix. Similar conditions hold true for instance in the power generation and heating sectors. This shows that the implementation of long-term climate and energy objectives can be led through the promotion of natural gas and its infrastructure. Such policy will contribute significantly towards substantial emission reductions in the long-term perspective. To this end, the planned projects are foreseen to provide incremental volumes of natural gas as a low emission fuel to the power, heating sectors and other industries. Furthermore, the projects will help accommodate the increasing uptake of renewable energy sources. As a result, this will foster the energy transition in an efficient, affordable and sustainable manner. As a result, EU framework should allow the use of technologies and energy sources that are compatible with overarching EU long-term targets, considering local and national circumstances.

Q5 Which role do you see for power-to-gas infrastructures?
P2G infrastructures are going to have a greater role with the advancement and increasing accessibility and availability of technologies applicable in the various scales. In particular, these infrastructures may play an increasing role in the energy market while global power to gas transformation prices decrease and cost/efficiency ratio of applied technologies is more attainable for investors.

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?
Electricity grid charges have a substantial impact on the overall cost and profitability of P2G plants. By using energy conversion services and the underlying gas infrastructure, additional investments in the electricity grid might be avoided. This system value provided by the gas infrastructure to the future energy system needs to be reflected in the regulatory framework. Hence, the principle of cost reflectivity in setting grid charges should be extended to recognize the contribution of energy storage systems to avoid (i) electrical grid constraints and grid extension costs and (ii) curtailment of intermittent renewable electricity generation. In particular no additional levies and taxes should be applied to any energy unit transferred from one sector to another.

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?

Infrastructure Investments and Regulation

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?
ACER and the NRAs already play an important role in the TYNDP process. The framework and process for the TYNDP defined by regulation (EC) 715/2009 has proven to work very well and there is currently no need to adapt. The current framework under 715/2009 provides important recommendations to improve TYNDPs while still preserving an open, transparent and non-discriminatory process towards all stakeholders. The ENTSOs already assign a primary role to ACER and evaluates with the utmost attention the indications coming from the Agency, when possible implementing them through an exercise of progressive TYNDPs improvements.

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)?
The Incremental Capacity and PCI processes are supplementary. Whereas Incremental Capacity is a process to ensure market-based investments, PCI projects are important mainly for other reasons like security of supply or supply source diversification. Additionally, a market-based investment via the Incremental Capacity process, supported by a positive economic test, can receive PCI-status in case the conditions are met and the settlement of f-factor within the Incremental Capacity process can also incorporate external effects of PCI projects. There is no contradiction of both frameworks. In contrast, the actual frameworks of Incremental Capacity and PCI seem to be compatible and there is no need for major changes.

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?
As highlighted in the answer to Q4 there is no risk of stranded assets in Poland due to a constantly growing domestic demand for natural gas and a positive outlook for the future. GAZ-SYSTEM welcomes the CEER view on taking a very cautious and prudent approach with relation to decommissioning choices and agrees that there are no reasons to act in the near future. Instead of working on potential decommissioning, efforts should focus on how to maximize and ensure an efficient use of gas infrastructure during the energy transition and beyond.

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?
As already expressed in the answer to Q12, GAZ-SYSTEM sees no need for developing a dedicated methodology on decommissioning.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The current gas legislation provides a sound basis for ongoing development of an internal gas market. The EU regulatory set-up is still used to further develop gas markets in Central-Eastern Europe where sufficient maturity of markets has not been reached yet. In this case it is important that the existing frameworks are maintained to ensure timely implementation of necessary investments and creation of competitive gas markets across the EU (e.g. regional gas market in the CEE region). Introduction of EU regulatory measures related to renewable gases should have a complementary role on top of the existing framework, to exploit the potential of gas technologies and infrastructures in efficient implementation of EU objectives in the long-run.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Please refer to the answer to the question 14.

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?
It is too early to assess the impact of the TAR NC, which is not yet fully implemented. Once Member States have implemented the TAR NC provisions, especially with the application of the new tariff methodology principles and transparency requirements, it will be relevant to reassess the TSO tariff regime. At this stage, reform proposals can be premature and might disrupt the ongoing implementation of TAR NC.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
To assess the impact of cross-border tariffs on cross-border trade, ongoing monitoring of the markets is needed. As tariffs develop, the impact on cross-border trade needs to be assessed. If there are general trends that suggest a deterioration in cross-border trade, then an Impact Assessment according to the current process of revision of Framework Guideline and Network Codes process can be considered.

Other question

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

Survey response 59

Contact details and treatment of confidential responses

Contact details: [Organisation][]
International Association of Oil and Gas Producers (IOGP)

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Activities that should be included in the assessment for potential TSO/DSO involvement include the provision of gas-to-hydrogen reforming facilities if there is no appropriate commercial framework to support commercial development, and - in relation to CCUS - the transportation and storage of CO2. These activities are in addition to the activities mentioned in the CEER consultation document: i.e. provision of CNG/LNG refueling infrastructure and power-to-gas infrastructure and the operation of hydrogen networks. Additional areas TSOs could be involved in include: •Ensuring they provide connection of new facilities such as power to gas, managing gas quality and potentially blending services which could include operating facilities. •Have a role in investing to realign existing network assets for more general use, e.g. hydrogen, flowing gas with wider spec. In general, the role of TSOs/DSOs should be limited and clearly defined, and only where the market is not able to deliver.

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.
IOGP supports the various initiatives to explore the technical possibilities for blending hydrogen in the gas networks and also for converting (parts of the) gas network to transport 100% hydrogen. It can be expected that the maximum acceptable % of hydrogen in gas networks will depend on local conditions, including technical limitations, and will not be common across the EU. We do not share the view that there is a need to define common EU specifications on the % of hydrogen that can be blended into the gas networks either as a minimum or a maximum. The Interoperability Network Code and the CEN standard EN16726 currently do not explicitly limit the possible blending of hydrogen into gas networks and we see no need to revisit those for setting hydrogen limits. Blending of hydrogen with natural gas will affect the Wobbe Index and we support CEN's current work on this matter. It would be useful if connected Member States and TSOs could coordinate (and consult on) any changes to quality rules. Blending services could also be offered which could mean a mandatory threshold is not appropriate.

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.
Regulation of gas networks is defined in the Gas Directive 2009/73/EC in terms of transmission and distribution of natural gas. Under the Directives, regulation will also apply where hydrogen is blended into the gas networks. With respect to dedicated hydrogen pipelines, where these are (currently) owned and operated by commercial entities producing and/or consuming hydrogen there is no reason to regulate such networks retrospectively. However, in cases where a TSO or DSO would convert part of the gas network to hydrogen or construct a new hydrogen network regulation should be considered as an option but without making regulated access a requirement. Reasons for this regulation are to ensure there are no undue cross-subsidies between gas transmission and hydrogen transmission, and to protect end-consumers that would be switched from natural gas to hydrogen. Regulation may also help facilitate financing of new hydrogen networks. In such cases it would make sense that hydrogen networks should be regulated in the same way as gas networks. To the extent possible, the regulation should be generic for all gases that are transported by TSOs and DSOs: natural gas, biogas, synthetic methane and hydrogen. This would facilitate the possibility to trade natural gas and hydrogen as a single energy product, irrespective of how hydrogen is physically moved in the networks.

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.
IOGP is a firm supporter of a technology neutral approach to questions of sustainability. Hence we suggest a generic approach to the regulation of transport for all gases in the response to question 3. This would also contribute to cost efficiency by maximising the use of markets. We also support a cost-effective approach to meeting the EU climate targets, in which the production of hydrogen from natural gas with CCS can play a significant role in achieving reduction in carbon intensity for heat and transport in particular. This would also benefit from a technology neutral approach to EU and Member State support schemes for reaching the CO2 emission reduction targets.

Q5 Which role do you see for power-to-gas infrastructures?
We see a limited role for power-to-gas infrastructures in the near-/mid-term. Power-to-gas infrastructures could help in a scenario with systematically high and variable volumes of renewable power to ‘store’ the excess of electricity from renewable energy. Existing gas infrastructure, particularly distribution systems and gas storage facilities can be used for this purpose, while taking into account technical limitations. However such a situation is not likely to emerge in the short-medium term and development of the Hydrogen economy will initially come from methane reformation. With the current fuel-mix for power generation in the EU, increasing the share of natural gas in power generation would effectively reduce overall CO2 emissions, whereas power-to-gas would increase overall CO2 emissions.

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?
We do not see that the gas tariff system creates distortions for the use of power-to-gas technologies as such facilities would constitute production of gas being injected into the network rather than being part of the networks themselves. Just like gas fired power generators are gas consumers and need to pay exit tariffs for taking gas from the network. We support the comment in the consultation document that network tariffs should not be used as a way to subsidize technologies. We note that there could be additional costs placed on the gas network to accommodate power-to-gas facilities, which could increase tariffs.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
No

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
We refer to the work done by GIE and ENTSOG on GOs. IOGP supports the development of one standardised GO for renewable and low carbon gas in order to aggregate the trading of GOs and develop a meaningful market size. Without such a standard GO, the market for GOs will remain fragmented and national, preventing efficient trading of 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?
A more technology neutral approach should be taken that prioritises reduction in greenhouse gas emissions rather than favouring particular technologies such as “renewable gas”.

Infrastructure Investments and Regulation

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?
IOGP supports the continuous improvements by ENTSOG to enhance the TYNDP process including scenario building. We believe that the development of TYNDPs should be the responsibility of ENTSOG (and the TSOs), taking input from network users, as stipulated in the Gas Regulation 715/2009. We do not support the suggestion that the TYNDPs or their underlying scenarios should be subject to ACER approval, also taking into account that the TYNDPs are non-binding. On a national level the NRAs have monitoring and approval tasks with respect to the (binding) network development plans as laid down in Article 22 of the Gas Directive 2009/73.

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)?
We do not support the addition of cross-references between the infrastructure regulation 347/2013 (PCI regulation) and the CAM NC. PCIs are often initiated at an early stage in the project, prior to any market testing under the CAM NC, and this should be supported to get a broad overview of potential future investments. Also PCIs may deal with infrastructure that is not subject to the CAM NC, such as LNG terminals, gas storages and CO2 pipelines. In cases where the PCI regulation refers to the results of an assessment of market demand in generic terms (e.g. article 12, paragraph 2), it is clear that the results of a market testing under CAM/NC can be used where this has been completed, but other supporting evidence should not be excluded.

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?
We believe the term ‘stranded assets’ deserves further discussion. In an entry-exit system it is difficult to identify which assets no longer serve an economic purpose. Assets that still have a (book) value in the RAB will generate revenue for the TSO even when those assets have no physical use for the system. Alternatively, assets that have been depreciated do not generate revenue for the TSO but may still have a physical value in the system. In any case it is likely that the energy transition will require capability to be maintained in gas networks even while alternative energies are being developed. In order to maintain security of supply, consumers may need to contribute to assets that are used less intensively or less frequently.

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?
We agree that decisions on decommissioning of assets with a cross-border impact should be coordinated. This also applies when assets are put into a different service, for instance the conversion from L-gas to H-gas in Germany. Based on the experience to date we do not see the need for an EU framework for decommissioning infrastructure and this can be dealt with through existing structures for cooperation between regulators. In the case of decommissioning cross-border infrastructure which is no longer in use, the affected TSOs should be able to independently decide on when and how to decommission their part of the infrastructure. When assessing decommissioning, it should be recognised that some under-utilised infrastructure could still be useful to the system, for example for security of supply purposes. Decisions on decommissioning should consider any cross-border relevance of the infrastructure in question, with decommissioning costs allocated to the relevant Member States in accordance with the relative costs and benefits of removing the infrastructure.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
IOGP supports the gas market design based on the 3rd Package and described in ACER’s Gas target Model. This have proven to be very effective in developing liquid and competitive gas wholesale markets covering ~75% of the EU’s gas demand. Where problems exist, this is not because of failures in the gas market design but often due to missing interconnections and incomplete implementation of the market rules

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
In our view, the possible development of renewable gases would best be facilitated by allowing renewable gases and low carbon gases to be traded together with natural gas in a single gas market. In this manner the renewable gases would benefit from the established liquidity of the gas market. This does not require a revision of the gas market design but rather make the existing regulation generic for all gases. See also response to questions 3 and 8. In particular, regulators should avoid recreating in the gas market the distortions created by “priority dispatch” in the electricity market over the past 15 years.

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?
We believe that the potential issues with transmission tariffs in case the long-term contracts expire relate primarily to the balance between tariffs for short-term and long-term capacity products. There are different options available under the NC TAR for adjusting this balance and mitigate potential issues. With respect to the suggestion of a decreasing gas consumption we note that under many scenarios EU gas demand is expected to be relatively flat throughout 2030, and might increase in the near term when natural gas would replace coal in power generation or be more extensively used for heating and transport.

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

Other question

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

Survey response 60

Contact details and treatment of confidential responses

Contact details: [Organisation][]
BVES - German Energy Storage Association

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The “logical framework” presented in the consultation document (figure 1) can serve as a tool to categorise the possible activity range of network operators. However, the unbundling requirements must be respected under all circumstances. Energy production and trade is a task of market players.

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.
An overall low threshold should be mandatory in order to promote the feed in of H2 in the hole gas-network. Over time this minimum-threshold should be adapted upwards. Furthermore, where feasible the threshold should be set higher, according to the regional technical configuration and potential. New infrastructure and devices should be implemented with a maximum of possible H2-compatibility. However, the implementation of green-gases should be market driven. Therefore, higher thresholds serve as door opener.

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.
Hydrogen networks should fall under the same regulatory rules as gas networks. The transition from a H2-blended gas-network to a pure H2-networks or mixed green gas networks should be promoted.

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.
Technological development can’t be foreseen in any case. Therefore, market interventions should be limited to the needed minimum. More important is, to set a framework where price signals can drive the market development in the desired manner - e.g. throw CO2 prices - and to open up the market for all players to deal with those prices-signals.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-gas is a key technology for the coupling of sectors. Especially in regions with high curtailment, additional demand can make use of currently wasted electricity. Furthermore, it is crucial to make significant progress in the heat and mobility sector. Hence, power-to-gas infrastructure should be planed with regard to the electricity, gas and mobility infrastructure simultaneously. Top priority should be to implement curtailed electricity by allowing an economical feasible use of it. This could reduce costs for network expansion as well.

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?
The main burden for storages and power-to-gas devices in Germany is the classification as “end consumers”. With that, charges on the converted or stored electricity hinder the economical feasibility of those urgently needed sector-coupling-technologies. In addition, the current compensation measures for wind park operators provide no incentive for the efficient use of excess electricity, as described above. With a view to energy efficiency and cost efficiency for investments in renewables the injection of excess renewable electricity into power-to-gas facilities - instead of curtailment - is necessary.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Non-discrimination of technologies as well as unbundling requirements need to be respected. In order to drive the demand to renewable energy carriers introducing a price signal is crucial, either by extending the European emission trading system (ETS) into the heating and mobility sector or by introducing an CO2 pricing for final customers. Furthermore, to create business cases fo power-to-gas devices, the contribution of green gases to the decarbonisation of all sectors needs to be implemented in the regulatory framework. Meaning that the usage of already accounted carbon (e.g. ETS integrated carbon or carbon charged with a CO2 price) can be used for recycling (CCU) to produce synthetic gases. Those gases can be accounted as climate-neutral as no additional carbon-emissions are caused by its usage. Those synthetic gases must be classified as (near) carbon-neutral similar to gases from biogenic origin. Another option to create demand for renewable gases are adequate incentives across different sectors: In the mobility sector, the possibility for vehicle manufacturers to meet the CO2 emission standards by using green gases. In the heating sectors green gases have to be supported by the energy efficiency legislation. As long as renewable gases delivered via the grid is not acknowledged in the energy efficiency calculation of buildings there will be no significant demand.

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?
GOs should foster the installation of renewable capacity, hence drive the market integration. Therefore several options are considerable: a combination of investment incentives, tenders on capacity instead of the promotion sum and the possibility for all state-aided renewable installations to produce GO's (as notified in the RED II) would open up the market. Thereby setting up a market price with incentives to build additional renewable capacity. A rising price of GO's, due to increased demand, would lead to a faster installation rate of renewable capacity. Synthetic gases produced with renewable energies as well as gas from biogenic origin should be part of that trading-system.

Infrastructure Investments and Regulation

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?

Adapting the Gas Market Design

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?

Other question

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

Survey response 61

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Teréga

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Teréga supports GIE and ENTSOG positions highlighting that TSOs should be allowed to provide services in all activities facilitating the energy transition, such as Power-to-gas facilities, biomethane plants, energy storage, CCU and CCS (Carbon capture and Use - Carbon Capture and Storage) technologies (including CO2 infrastructures) and CNG/LNG facilities. Given their territorial anchorage, their expertise in the management of industrial projects and their experience in the dialogue and consultation with local stakeholders, the participation of the TSOs to the activities related to energy transition - as specified above - would bring a stronger financial credibility to the projects promoters. TSOs participation to these activities will also accelerate the development of green gas projects, realise higher economies of scale and reduce the production costs. The participation of TSOs to these activities should be possible in a regulated or fully commercial way. This evolution must be clarified at a European level in the Gas Directive. The appropriate framework and conditions could be further precised by Member States according to the local context, market conditions and the level of the commercial development of the green gas facilities.

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.
Teréga supports the position expressed by ENTSOG on hydrogen. In France, infrastructure gas operators are jointly working on the identification of all factors in play when considering injection of hydrogen in the gas infrastructures. Technical and economic scenarios are under development, associated to R&D actions. Several pilot projects in France (among them Jupiter 1000 the power-to-gas pilot demonstrator) and a national taskforce (with the participation of the French regulator and French ministry) are also helping to progress further in this direction. Teréga would like to underline that the optimisation of the necessary investments requires to build a global vision of the system (from production to usages): the combination of all technical solutions will enable to offer an adapted solution to each territory, taking into account local specificities. This is a key condition for a successful deployment of hydrogen in the gas infrastructures in Europe. Thus, Teréga considers that while a European roadmap on hydrogen should be developed, Member States should be free to develop their own pathway to inject hydrogen in the gas infrastructures, leaving the possibility for each country to adapt the pathway to local specificities. Of course, a coordination between Member States, in particular on cross border points, should be a prerequisite.

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.
NA

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.
As supported by ENTSOG and GIE, Teréga is in favour of a general “technology neutral” approach when it comes to the transition for the gas sector to a low-carbon energy demand scenario. However, while cost efficiency should be a key principle for energy transition, policy makers should also take into account market criteria, as well as criteria such as security of supply of the whole energy system, diversification of sources, peak demand, and economic, societal and environmental impacts (externalities). “Cost-efficiency” should also be considered in setting cost reflective power grid charges that recognize the contribution of gas storages in terms of overall system flexibility and avoiding additional investments in the electricity infrastructure. The current “silo” approach distinguishing analyses in the electricity sector and in the gas sector should be overcome, to move towards a “holistic” approach to optimize investment planning across the entire energy system.

Q5 Which role do you see for power-to-gas infrastructures?
If we want to achieve carbon neutrality in 2050, the energy system as a whole has to evolve towards a systemic multi-energy approach. This can only be achieved in a cost effective way by using the significant, reliable and flexible storage capacities of the gas infrastructure system. Power-to-gas is therefore an absolutely essential and central element of tomorrow's energy system. Power-to-gas facilities are the most adapted solution to long duration seasonal storage, bringing flexibility to the electricity system with the progressive deployment of intermittent renewable energy. Gas storage sites can store significant volumes of energy. For instance, in France, storage capacities represent 138 TWh, whereas the Pumped Storage Power Station (PSPS) capacities represent only 100 GWh. Power-to-gas installations will bring huge benefits to the energy system such as a massive absorption of excessive electricity production, and avoidance of local investments in the electricity network, while relying on the existing gas infrastructures and network strongly integrated at a European level. These installations accelerate also the decarbonisation of the mobility sector (with hydrogen or GNC). We also see a progressive interest in the P2G technology by some renewable electricity producers not able to inject their production in the electricity network in some congested areas. Power-to-gas is a key enabler of a successful energy transition optimising the functioning of the electricity and gas systems. Beyond the complementarity between electricity and gas sectors, the coupling of the heating sector with electricity and gas significantly increases energy efficiency and brings huge environmental and economic benefits to the system.

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?
Teréga is fully in line with ENTSOG and GIE proposals. In particular, we consider that power to gas facilities should be classified as a conversion service , so that no additional levies and taxes are applied to any energy unit transferred from one sector to another. Furthermore, electricity and gas network usage tariffs should be adapted to this sector coupling, reflecting the fact that electricity users are capturing the full value of gas infrastructures.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
Teréga contributed and fully supports the position of GIE and ENTSOG on this topic. Teréga was involved in the FTI-CL Energy study and in the drafting of the GIE recommendation paper. Given the magnitude and the nature of the upcoming challenges to address energy transition, a modernized and flexible regulatory framework will most definitely be needed to be able to tackle rising issues with all their complexity (e.g. economic, technical, sectorial, social and environmental), at the right organizational level (local, national, European).

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Teréga contributed and fully support the position of GIE and ENTSOG on this topic.

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?
NA

Infrastructure Investments and Regulation

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?
NA

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)?
Teréga contributed and fully supports the position of GIE and ENTSOG on this topic. We would like to emphasize that "infrastructures" have to be understood in its full meaning, including not only gas grid but also LNG terminals and storages, as they all contribute to reaching the outstanding flexibility and performance of the European gas system in delivering the necessary energy quantities in case of peak demand, in a timely manner.

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?
As acknowledged by CEER in the consultation document and in the conclusions of the Madrid Forum, 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. Several studies (in particular Gas for Climate) show that the large deployment of renewable gas (renewable methane or hydrogen) will enable to reach the COP21 objectives, while realising huge savings for the European consumer. This evolution can be made possible given the already existing gas infrastructures and the largely integrated network at an EU level. Renewable gas is thus a key solution for decarbonising the sectors of industry, transport, electricity and residential. In addition, the gas infrastructures (transport, distribution, storage...) bring the much needed flexibility for the electricity system and play a key role in satisfying winter peak demands, as highlighted above. Furthermore, the contribution of green gas generates also several positive externalities to the system, notably in the agriculture sector. It is also in line with a circular economy approach with the waste recycling, it reduces the GES emissions and favours the emergence of non fine-particular pollution in the mobility sector. For all these reasons, Teréga is convinced that the gas sector will play a key role in the European energy transition and that there should be no stranded assets in the future. Thus, we consider that the issue of stranded assets should be addressed by a very cautious and as wide as possible approach. Teréga is of the opinion that the regulation has to cover entirely and explicitly this kind of risk, while recognizing that there are no reasons to act rules in the near future.

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?
Teréga supports the views that any decisions on decommissioning of transmission networks or storages should be assessed with methodologies like relevant Cost Benefits Analysis. Having said that, Teréga joins the suggestion of ENTSOG to cooperate with CEER and work on finding the best framework, as soon as a need would be known.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Teréga contributed and supports the position of GIE and ENTSOG on this topic. Since November 2018, there has been a unique market place in France. Results show that the Trading Region France (TRF) is already providing significant benefits. On storage, the current French regulatory framework with the storage reform allows to capture the values created by gas storages for the gas system (optimized functioning, appropriate network scaling) and insurance (i.e. security of supply), in line with the approach developed by GIE. The future market design should also develop an approach to recognise the full value of gas infrastructures for the whole system (gas and electricity). We also see the injection of renewable gases in gas grids, whether at the transmission or distribution level, with a need to manage reverse flows and cross-border trading as one of the main issue to be addressed. A common European licensing approach could also benefit the well-functioning of the European gas market.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Teréga contributed and fully supports the position of GIE and ENTSOG on this topic. It is a priority to make sure the gas market design evolves to include decarbonized and renewable gases so as to fully integrate and recognize the market value of such gases, making sure that the relevant markets arise and cross-border trading is feasible.

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?
At this stage, reform proposals can be premature and might disrupt the ongoing implementation of TAR NC. Teréga recommends that regional initiatives for voluntary market integration also continue to being taken into consideration with regard to their potential effects on the overall European market integration. The future regulatory framework will need to take into consideration the new gas market conditions, based on short-term capacity bookings and the end of long-term contracts. In this context, several questions asked by ongoing European work and studies(Quo Vadis, FRoG) are to be addressed.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
As indicated previously, the optimization of capacity bookings incentivises market players to mostly book short-term. Although this trend must be confirmed with the end of long term capacity contracts, it could lead to a very significant tariff increase if the cost-reflectivity principle were to be applied without moderation, especially for transit infrastructures, potentially triggering a vicious circle leading to the uncoupling of national gas markets.

Other question

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

Survey response 62

Contact details and treatment of confidential responses

Contact details: [Organisation][]
innogy Gas Storage NWE GmbH

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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?

Infrastructure Investments and Regulation

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?
innogy Gas Storage NWE GmbH (further on iGSNWE) foresees that the natural gas infrastructure may play an important role in decarbonising the future energy supply especially with regard to the phase out of coal-fired power plants e.g. in Germany. But in addition to that it is also expected that on a long run the changes within the natural gas market e.g. reduction of the European natural gas production, national decisions to step out also from the usage of natural gas will lead in North West Europe to a reduced usage of natural gas - we see this in the Netherlands right now. At that moment the political discussion is mostly focusing on the supply of electricity and the development and extension of the electricity infrastructure. To achieve the Paris climate goals and reduce the CO2 emissions up to 95% iGSNWE sees not only the necessity to invest in new electricity infrastructure but also to exploit the full potential of the already existing infrastructure and a combination of the gas and electricity infrastructure. This infrastructure is already connecting European countries and could play an important role especially with regard to an European approach and the cross boarder delivery of an energy carrier and the storage of that carrier to get a decarbonised energy supply. For sure it has to be analysed to what extend the infrastructure could be used for green gases without further investment. If a positive economic future is foreseen by the infrastructure owners the gas infrastructure will not run a risk to become a stranded asset. Following this aspect iGSNWE sees the necessity of a faster political decision process of the European member states and the EU to improve sector coupling and the change from natural to green gas. Further regulation is basically not expected to be necessary. The necessity might only arise if national developments lead to negative impacts like barriers on the European market and the cross-border supply of gases and flexibility.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
The existing policy framework has been designed around natural gas. There are regulatory barriers and gaps for the integration of higher shares of renewable or decarbonised gases into the EU energy systems. From our point of view the current market design is sufficient to integrate an increasing percentage of Biomethan. For a higher percentage of hydrogen the discussion has to start right now.

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?

Other question

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

Survey response 63

Contact details and treatment of confidential responses

Contact details: [Organisation][]
GERMAN CHEMICAL INDUSTRY ASSOCIATION - VCI

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
DSO should be involved in establishing local thresholds for hydrogen blending in gas networks (see Q2). TSO should assume responsibility for the availability of gas quality within the legal thresholds. Currently, there is no party legally assumed responsible for delivering a compliant gas composition to the final consumers. TSOs/DSOs should not be allowed to operate power-to-gas-plants, since this conflicts with the principles of unbundling. If there is no interest in the market to invest in and to operate such facilities, TSOs/DSOs might be allowed to jump in as a matter of last resort. But such exemptions must only be possible for a limited period of time (“regulatory holidays”) and only to create economies of scale.

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.
Operation, safety and efficiency of certain industrial processes can already be corrupted by hydrogen contents as low as 1.5%. Such sensitive consumption units may not be ubiquitous, but nevertheless, the hydrogen content in a given grid area needs to take into account the specifications of the most sensitive consumer. Apart from industrial processes using gas as feedstock, also gas turbines can be very sensitive with regard to the hydrogen content. This calls for a very careful approach to hydrogen injection. Besides static thresholds, gradients of concentration changes in time are to be limited, because fluctuation can be as problematic as too high static concentrations. On the other hand too narrow gas specifications can hamper the liquidity of the European gas markets. As a consequence strict mandatory thresholds are inevitably required in grid areas where sensitive consumption units are located. A comprehensive threshold all over Europe is of secondary importance. Timing is of significant importance in sensitive grid areas. Therefore, in such areas hydrogen contents and other parameters should be analysed and made publicly available near real time.

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.
It should be very thoroughly analysed whether pure hydrogen grids are natural monopolies. I.e., how much competitive pressure can be executed by other means of transport (e.g. by truck). Alongside a European natural gas infrastructure dedicated local and regional hydrogen infrastructures exist for decades already, used by commercial market parties. If hydrogen grids are deemed to be natural monopolies and when the quantity of producers and consumers connected to the grid reach a level of competitive relevance, they should in principle be regulated in the same way as gas or electricity grids (regulated tariffs, fair third party access etc.). A threshold for competitive relevance has yet to be discussed.

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.
A technology neutral approach for a given low carbon investment or a given flexibility service (i.e. for a given timeframe) is essential as the transition pathway to an overall low carbon energy supply ist not clear. Transition challenge: We are looking at decarbonisation over a 30 year horizon. It is not clear whether further deployment of renewables only will be the most effective or the most efficient way to achieve GHG reduction, especially with intermittent renewables for electricity generation and the necessary back-up to cope with periods of over- and undersupply. There may be different possible routes to achieve GHG reduction: •The further deployment of low carbon energy sources, with existing (demand response, flexible generation units, storage) as well as new sources of flexibility (power-to-X, new types of storage: hydrogen, ammonia) for providing the necessary back-up capacity for coping with intermittency; •Investments in geothermal energy; •Development of CCS and CCU. Regulatory support and barrier removal needed: a.Looking at all existing technologies is a must, as well as underlining the importance of stimulating R&D into new technologies; b.Interference of the energy sector with the heat and transport sectors can also be part of the solution, as electrification might be one of the ways to decarbonise these sectors too.

Q5 Which role do you see for power-to-gas infrastructures?
1.To act as a flexibility option for the electricity supply system, characterised by an increasing amount of volatile generation; 2.Enabling supply of certain energy sectors such as heat and mobility with renewable energy; 3.Enabling a liquid gas market by granting a non-discriminating grid access to gas producers, shippers and consumers; 4.Enabling a secure supply of electricity and gas to consumers.

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?
Significantly high surcharges on electricity, e.g. the “EEG-Umlage” in Germany, result in artificially high electricity costs and, in turn, compromise the competitiveness of Power-to-X technologies. Special electricity tariffs, e.g. atypical consumer tariff regimes pricing individual grid usage according to the state of the grid at the time of usage, contribute to support Power-to-X technologies. In general, tariffs and other administrative surcharges should be low in situations, where deployment of Power-to-X is desirable (e.g. high renewable electricity production whilst the consumption is low). Otherwise significant market penetration of Power-to-X technologies will fail.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The regulatory framework should enable the compatibility of the natural gas grid to be oriented to industrial plants that are sensitive to natural gas inflow containing certain levels of hydrogen. Furthermore research and development of sector coupling technologies and relevant pilot projects should be driven forward. Here, it is particularly important to exempt pilot projects from administrative burdens such as levies and charges. The General Block Exemption Regulation (GBER) limits funding to € 15 million per application. Such a ceiling does not adequately reflect the technological complexity of pilots on an industrial scale. Therefore, applicants for pilot projects in the field of sector coupling should be exempted from it.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
There should be a unique standard. GOs should be independent of local origin and embedded in similar systems for gas and electricity.

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?
Guarantees of origin should be restricted to certify the produced green gas and create green certificates. The GOs in itself must not lead to a subsidization system.

Infrastructure Investments and Regulation

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?
ACER and NRAs should target on maintaining the existing level of security of supply at the most efficient costs. High network development costs will reflect in high tariffs. As mentioned in Q6 administrative surcharges hamper the market penetration of Power-to-X technologies. This should be considered when choosing the 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)?
To support cross-sector integration we need to a proper energy infrastructure for the changing energy system, including adequate infrastructure capacities. Transition challenges are: • Infrastructural adaption is needed for energy conversion (hydrogen) and CCS and because of (de)centralizing of energy generation, resulting in locational challenges. • Consumers that have to make long term technology innovations to reduce GHG (e.g. Power-to-Heat, hydrogen) need a sound and sufficient infrastructure network to reduce investment risks.

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?
The risks for stranded assets can be reduced by a stable regulatory framework enabling long term projections for investors. Furthermore the regulatory framework should respect technology neutrality. Regulatory preference of certain technological pathways may enhance the risk of stranded investments as alternative developments can be more cost efficient. Investments in pre-selected technologies can lead to investments in eventually non-competitive solutions.

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?
Further studies are necessary in this respect. It should not be the default that stranded assets resulting from decommissioning are passed on to grid users, the consumers. The grid operators also are being at risk and hence should bear costs regarding stranded assets.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Enhancement of competition of the European gas market: this can be achieved by an increase of suppliers and supply routes, e.g. enabling investments in sufficient LNG capacities, while the degree of capacity utilisation of the existing facilities is rising. However: any regulation disturbing competition should be avoided. For example, in Germany 90% of the costs for connecting LNG facilities to the grid can be shifted into the grid tariffs, instead of being borne by the operator of the LNG facility. Such cost allocation schemes distort the competition between locations and lead to higher i.e. inefficient system costs.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The gas market design and the regulatory framework in general should be optimised by reducing regulatory obstacles for green gases. Some of them have been addressed in Q6, 7. Market penetration of green gas should be incentivised rather than regulated. Limitations of sensitive facilities such as industrial processes and existing gas turbines with respect to hydrogen are to be considered by the regulatory framework.

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?
A suitable and substantiated answer to this question cannot be given without investigating the possible consequences of scenarios'.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
See Q 16

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
No answer.

Survey response 64

Contact details and treatment of confidential responses

Contact details: [Organisation][]
EDF

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
EDF would first like to recall CEER's conclusions in its recent conclusions paper on "New Services and DSO Involvement". Indeed, we consider that principles stated in this document that mainly focuses on electricity examples could, in the case at hand, also apply to gas: •TSOs and DSOs must act as neutral market facilitators and in the public interest, fostering cost efficient activities. As neutral market facilitators, TSOs and DSOs are vital to facilitate service markets – by performing their core activities related to the transmission and distribution system. •TSOs and DSOs should avoid creating undue distortion of activities open to competition by acting in a non-discriminatory manner towards all actors. •The boundary between the TSO/DSO's core activity and the provision of other services must therefore be drawn clearly. Where activities are open to competition, the TSO/DSO should not be allowed to be active in that area. This is due to the fact that TSO/DSO has part of its costs covered by regulated tariffs, and therefore carries a lower risk profile supported by its core monopoly activity. This places the TSO/DSO in an advantageous position over other market parties. •When the market cannot (yet) provide the activity, NRAs should be in the position to decide on exceptions. Such an exception should be based on a thorough market analysis and could be granted, under conditions, with explicit consent by the NRA. Conditions can include restrictions such as an application on a temporary basis, and, a monitoring of the performance of the activity and an assessment of relevant developments in the market when the NRA review the approval. EDF shares CEER's view that unbundling is a fundamental pillar of a well-functioning gas market. Any technical or/and commercial activities from the TSO/DSOs opened to competition should be separated from regulated activities and should be supervised. Moreover, the network tariff should not be used to subsidize non-mature activities. Therefore, EDF considers that the biogas production, the NGV sector or the hydrogen production are market activities. Extending TSO/DSO's missions to these activities would distort competition. So, if TSO/DSO would like to develop one of these activities, this must be done within a separate legal entity such as a subsidiary exposed to market mechanisms. The costs associated to these activities must not be covered by network tariff.

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.

First of all, EDF considers that renewable and/or low carbon hydrogen use should be fostered (i) where it is the most cost-effective for decarbonisation - i.e. primarily for industrial use and long haul mobility, which may be difficult to electrify - and (ii) where the switch to clean hydrogen may even be close to breakeven today (light industry). These uses do not require injection of hydrogen into the gas grid, for which the gap is harder to bridge:

- The technical feasibility of injection of large volumes in the existing transmission and distribution gas network is not yet established. Depending on the topology of the grids, on pipeline materials, on instrumentation, on end-user devices and appliances, on safety requirements, the cost of blending may be prohibitive. In particular, aquifer underground natural gas storages are not suited to store hydrogen. From EDF current understanding, in order to minimize the cost of existing networks conversion to hydrogen, a mix of different technical solutions should be implemented, even solutions including methanation of hydrogen for some part of the grids which are not suited for hydrogen.
- In case hydrogen is injected in the gas networks for electricity storage purposes, the low efficiency of the complete cycle (electricity to gas to electricity) induces a very high cost, which does not qualify this solution until a very high share of RES is reached in the electricity mix. Compared to these potentially high costs, the level of revenue would be dependent on natural gas price, which evolution is disconnected from hydrogen economics.

The priority today is scaling up renewable and/or low carbon hydrogen technologies and bringing costs down through mass-market effect. Given that the majority of H2 is currently consumed as a feedstock for industry, for non-energy uses, a lever to reach this goal in a short period of time could be to favour local ecosystemic approaches, addressing directly industrial sites demand and adding up local uses around it. If this approach is followed, it is likely that the issue of market power abuse, competition, and of cross border trade will not arise in the same way as they do for electricity and gas markets, and that common injection level in the gas network will not be the first nor the only way to ensure a sound competition.

Therefore, EDF does not believe that injection of hydrogen in the gas network is essential to spur the development of low carbon and renewable hydrogen market, and shares CEER observation that the need to align hydrogen blending levels throughout Europe is not immediate. Instead blending H2 into the gas network should be seen as an additional lever, an upside to optimize the economics of the projects already addressing industrial uses and mobility. More technico-economic studies addressing the impact both on existing gas infrastructure, and on the natural gas quality issues should be carried out before justifying a common injection threshold and revising existing regulation. Flexibility should be kept to allow Member States to choose the best conversion solution.

Eventually, an economic assessment of decarbonation cost through H2 injection in gas networks should duly encompass both costs of H2 generation and costs of gas networks adaptation.

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.

In order to minimize the cost of switching to low carbon and renewable hydrogen, EDF considers that transportation costs should be avoided whenever possible, and that production units should be installed as close as possible to end-users: electrolysers could be built on industrial sites for instance. As a consequence, as an initial approach, EDF does not support the construction of greenfield hydrogen pipelines.

As for the regulation of existing hydrogen pipeline networks, if competition distortion issues appear, third party access could be implemented to ensure a level playing field between new renewable and/or low carbon hydrogen stakeholders on one side, and historical producers and consumers on the other side. In any case, costly network extensions should be avoided. In case an existing gas regulated infrastructure is used, it is already regulated and this regulation should apply to hydrogen producers and end-users.

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.

The response is no. Indeed, the market should deliver the right economic signals, taking into account the positive or negative externalities. If a pro-active intervention by policymakers questioning the "technology neutral" principle is needed, it means that the market does not give the right economic signals. Therefore, EDF is favorable to the "cost efficiency" principle and the "technology neutral" approach, the market must provide the right signals to choose the right technology.

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

In case of a strong development of RES, Power to Gas could be an interesting tool to manage the RES surplus over the long term. However, different studies, notably a study from European Commission (METIS Study 2016 – The role and need of flexibility in 2030: focus on energy storage), highlighted that the RES surplus should remain low in the short and mid-term.

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?

EDF considers that electricity and gas tariff systems do not create distortion to the efficient deployment and use of Power-to-Gas technologies. For this reason, EDF does not support the implementation of specific electricity and gas tariff reductions or exemptions to support the development of power to gas production units, or to compensate for services they may supply to the grids:

• Tariff structures should be tailored so that each grid user pays a price covering the costs it induces on the grid;
• Flexibility services supplied through power to gas technologies should be offered on existing flexibility markets (demand response, capacity markets, reserve markets…).

Public support may be needed to prepare the deployment of power to gas technologies, to support future very high shares of RES in the electricity mix as the case may be. As a general principle, EDF considers this public support should be direct (direct subvention for instance) to ensure visibility and transparency, and avoid distortion between grid users, while being adapted to the maturity of relevant technologies.

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?

EDF considers that the following measures can foster efficient cross-border trading of GOs:

• Common definitions should be adopted for renewable and low carbon gases. EDF remarks that a lot of terms are currently used (green hydrogen, blue hydrogen, grey hydrogen, green gas….) which adds to confusion given that there are a lot of different technologies to reduce the CO2 footprint of gas and hydrogen.
• Any double counting of renewable and/or low carbon gas should be avoided to ensure the credibility of the system.
• Special attention should be paid to conversions between different energy carrier GOs, taking into account efficiency factors, for instance :
o between electricity GOs and hydrogen GOs in case a stakeholder wants to certify electrolytic hydrogen,
o between biogas GOs and hydrogen GOs in case a stakeholder wants to certifhy hydrogen produced with an SMR cracking biogas.
• Such GOs conversions should be limited to cases where a physical conversion occurs. A stakeholder producing hydrogen from natural gas with a SMR without CCS, and buying renewable gas GOs to "green" such natural gas should not be entitled to hydrogen GOs.
• Member States should be encouraged to issue GOs both for renewable and / or low carbon gas produced whether it is injected in the gas grid or not. This will kickstart the development of a market with enough volumes, and ensure a level playing field between producers and investors in different Member States.
• Renewable and/or low carbon gas GO national registries should be based on either a common interface or an interoperable one. In each Member State, the mandated organization in charge of operating the registry should use standard systems and procedures aimed at objectivity, non-discrimination, transparency, avoidance of double–counting and costs effectiveness.
• Member States should harmonise deadlines for issuance, cancellation, expiry of renewable/low carbon gas GOs to allow market players to have clarity, predictability and the ability to trade across the EU in a uniform manner.

We note that, according to RED II, Member States must recognize guarantees of origin issued by other Member States. In case of refusal, the European Commission should ensure openness and transparency in this area by publishing in a timely manner any notifications of refusal it receives, and its final rulings.

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?
In general, the current renewable electricity GO system appears to be a well-designed and suited tool, as it constitutes a guarantee of reliability, while also enabling “green offers” to develop for consumers having a willingness to pay a premium for it. It should be recognized that the purpose of GOs is “disclosure” and not “support”. To avoid confusion, it should therefore be preferable to clearly distinguish support mechanisms and GOs. RED II has not included the CO2 footprint among the minimum information that must be included in the GOs. However, EDF considers that as long as GOs do not carry the value of associated carbon emissions, a piece of the puzzle is missing, as consumers may not find it meaningful to purchase a renewable/low carbon gas product if the carbon content is not clearly mentioned and specific to that product. While GOs currently is the instrument that empowers customers to make active choices for the energy transition, the incentive would be much stronger if carbon was included in the picture. Such approach has been retained in the European project CertifHY, funded by EC FCH JU, whose aim is to design the 1st EU-wide Guarantee of Origin (GoO) pilot scheme for renewable and/or low carbon hydrogen. The introduction of a CO2 criteria in hydrogen GOs also allows: •To recognize the role of non-renewable but low carbon hydrogen to reduce EU GES emissions in a cost-effective way. Under CertiF’HY, hydrogen productions installations can be eligible to GOs if they display a carbon footprint lower than 131 gCO2eq/kWh, whether hydrogen is renewable or not. This is in line with RED II, which opens the possibility to establish GOs for non-renewable energy sources. •To make a clear difference between carbon neutral and renewable, and give value to the energy source with less CO2 content. Such displayed CO2 should be consistent with commonly agreed international standards/recommendations.

Infrastructure Investments and Regulation

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?
EDF considers that NRAs and ACER should be more involved over the TYNDP process, in particularly for the elaboration of scenarios. NRAs and ACER should monitor that at least one scenario takes into account the energy policies of each Members State.

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)?
EDF considers that the selection process for projects of common interest (PCI), and in particular the process for awarding financing, should be modified. It is clear that, today, many PCIs and associated financing decisions are not based on technical criteria and cost-benefit analysis results only. Projects should be reviewed when all data are available, with a robust cost-benefit analysis. A general scheme at European level would be necessary: •Projects selection, CBA when the project is at a sufficiently advanced stage, and proposal for sharing costs and congestion revenues; •The decision by each regulator approving the costs that would be covered by tariff; •Comparison by the European Commission of all the projects according to the ratio "amount of subsidy requested to balance the budget vs expected benefits of the projects". The lowest ratios should be prioritized in granting subsidies and any derogation should be duly justified. It should be possible to integrate preliminary projects in the list but only to benefit from the administrative facilities from the beginning, without prejudging the financing decisions, which would intervene later in the process when all the information is available for a sufficiently robust CBA. EDF also considers that the criterion of common interest should be made clearer. In addition, the perimeter of the PCI should be expanded to take into account the evolutions in the energy market, with a specific focus on storage or projects of digitalization and / or harmonization at European level that generate a benefit at the European level.

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?
In France, the revenue of storage operators who manage underground storages considered as necessary for security of supply, is now regulated. The perimeter of underground storages necessary for security of supply is set by the government. Based on its assessment of the situation, this perimeter is expected to be reduced from 2023 onwards. Therefore, there is a risk of stranded assets for underground storages. In order to reduce the risk of sunk costs, it is necessary to be more careful in investment decisions and the decision process described in the previous question could be used. We also believe that in the view of mitigating storage costs for the collectivity, it could be useful to take into account others sources of flexibility to the system, as LNG terminals, and subsequently adjust the perimeter of underground storages. LNG terminals can provide peak capacity at an optimized cost for collectivity. In the long term, the role of LNG terminals may evolve in an European context: more services like bunkering, truck loading, small scale LNG carriers loading, security of supply (peak capacity), less natural gas based LNG imports, possibly bio-LNG imports.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
EDF shares CEER's view that "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". Therefore, the gas market design should support gas to become progressively carbon neutral in order to play a role in a carbon neutral economy. The development of renewable gases should be achieved at the lowest cost (incl. potential re-organisation of the gas value chain).

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Generally speaking, the development of renewable gas (biomethane, power-to-gas) together with an expected decrease of natural gas consumption on the long term will change flow patterns in the network: development of reverse flow into some distribution networks and into some transmission networks, changing flow direction in transmission networks, lower aggregate load factors. It seems reasonable to say at this stage that it will be necessary to adjust the market design, for instance by reviewing the relationships between distribution and transmission networks. As hinted by the CEER public consultation paper, the relevance of the current system of entry-exit zones based on national networks may be questioned on the long term where we could be faced with more fragmented gas systems, less long term flows, more guarantees of origin prompting more "local" consumption, but still requiring to ensure sufficient flows between countries/regions.

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?
Over the long term, gas consumption is expected to decrease, which will necessarily lead to increase the unit cost of the transport network. The current network tariff methodology might not be sustainable and it is crucial that alternative approaches to network tariffs are carefully evaluated and discussed by stakeholders.

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

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
The definition, deployment and application of a CBA approach integrating long term effects is of utmost importance to ensure consistency in energy investments in the EU, preventing stranded costs. All decarbonisation EU scenarios show a substantial decrease in gas consumption, a decrease which should be accounted for in defining future regulatory measures.

Survey response 66

Contact details and treatment of confidential responses

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N.V. Nederlandse Gasunie

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Gasunie is a front runner in a range of activities which aim at facilitating and speeding-up the energy transition. Gasunie is ownership unbundled gas infrastructure company. We are the sole owner of two transmission system operators: Gasunie Transport Services (only TSO in the Netherlands) and Gasunie Deutschland (a leading TSO in Germany). Our activities with regard to speeding-up the energy transition - outside the scope of natural gas - are being pursued by different legal group entities (Gasunie New Energy, Vertogas, Gasunie Waterstof Services, Energystock, GATE LNG Terminal) which are not regulated/ only partly regulated. Infrastructure companies can play an important role in aggregating demand and fostering market liquidity. Gasunie has successfully deployed several asset-owner business models where the infrastructure company is the independent asset-owner of conversion (LNG, power-to-gas, biogas) and storage facilities where conversion service or tolling agreements are offered to the market on a non-discriminatory basis. Gasunie believes that the unbundling provisions of the third energy package, remain applicable for renewable and low-carbon gasses, notably that neither electrons or molecules are owned (i.e. produced, traded or supplied) by infrastructure company (or TSO's). We believe that this independent asset-owner model can accelerate the energy transition and should be a blueprint for the rest of Europe. Transport of hydrogen (H2) via (mainly) existing high pressure natural gas networks, which belong/belonged to a TSO such as GTS or GUD, has to be carefully assessed. To avoid the risk of abuse of market power or the refusal for third party access and depending on the development of the market and system users a degree of regulation of H2-transport seems desirable. Similarly, investments which facilitate the injection and blending of renewable and low carbon gases are especially important in a future integrated energy system. Those investments are often critical for a successful business case of renewable and low carbon gas producers. Therefore, some support / (regulatory) intervention in those cases could be envisaged. Hydrogen and green gas (biogas that meets the transmission grid standard) will be gradually replacing natural gas in the various demand sectors (low and high temperature heating and feedstock). In order to facilitate the green gas market, Vertogas expands its certification platform in order to allow flexible trade of GO between the European member states. Currently the production cost of green gas is not competitive with the production cost of natural gas and therefore highly dependent on public support mechanisms. In addition several regulatory hurdles limit possibilities to invest in production or conversion facilities that support the energy transition. It would be a consideration to allow the TSO's to facilitate these investments to enable this technology to mature and go through the different innovation phases.

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.

Gasunie agrees with the considerations set out in chapter 4.2 regarding the cost-efficiency of full conversion of natural gas networks towards hydrogen networks, as we believe that full conversion allows for a steeper decarbonization trajectory for end-use sectors. The attention is on the transition period towards a liquid H2 market where full conversion is feasible at scale. However, in such a transition period, to some extent blending an amount of hydrogen with natural gas can be feasible and should not be excluded at forehand. Commodity related targets cannot be imposed on the operators of gas infrastructure, given the unbundled nature of their activities. Therefore, we are not expressing support or opposition for a common (mandatory) threshold which would have to be imposed on users of our networks. We are however, sharing below some considerations:

1. The technical feasibility of increasing hydrogen percentages within our natural gas networks has been thoroughly assessed. One of the most recent assessments within CEN TC234 conclude that up to 100% H2 design pressure can be transported in existing pipelines within the Gasunie transmission system, without affecting the integrity of the pipeline during its lifetime. Adaptations are required for existing valves schemes and flanges as well as compressor units. We do not know if all end-use applications are suitable for blends. End-use applications and installations sometimes require specific gas qualities or varying hydrogen purity levels.
2. From a broader perspective, rather than a technical perspective, the challenge is a market-related one. End-users are confronted with considerable pressure to decarbonize their activities. They are faced with investment challenges while taking market developments into consideration.. This means that a public discussion about a blending threshold needs to include demand sectors, also regarding demand and supply measures.
3. A production-related incentive alone, like a blending threshold, will not help to create a market. Incentives are needed for transport, storage and consumption of renewable and low carbon gases to make sure we cross the innovation gap. Such incentives should be technology specific, while overall targets (e.g. on CO2 emission reduction) should be the overall investment trigger for decarbonization technologies.

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.

Hydrogen pipelines - with underlying long-term contracts - are currently mainly point-to-point connections between one H2-producer and one H2 consumer. It's questionable if regulation is required for such connections. This is the case for many existing hydrogen networks in Europe. As soon as the pipeline connects to a wider network, with multiple entry-, exit- and possible interconnection points (similar to the current natural gas network), enabling third party access is required. Therefore, a certain degree of regulation could be desirable, also depending on the system users (industry, consumers, etc.).
Gasunie has studied the establishment of an H2-economy and a national H2-infrastructure and concluded that connections between local production and (industrial) demand centres across regions, are required as of a certain volumetric threshold and provide for system integrity and balancing. Those connections and networks would typically be regulated to ensure for end-users and the wider economy the best value propositions. For the transition period towards a liquid hydrogen market (when it is mostly industrial demand that is connected) we believe that the way the gas storage market is currently regulated (non-exclusivity / negotiated and regulated TPA) could serve as a blueprint for regulation of the hydrogen market. We see the regulation of natural gas networks as a suitable blueprint for hydrogen networks when its development is comparable to the current state of the gas transmission market.

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.

Cost efficiency and pro-active intervention are in a direct relationship. Cost-efficiency for regulated entities serves market and societal interest. The same can be said for the cost-efficient transition towards a carbon neutral energy system. The EU Commission's Long-Term Vision 'A Clean Planet for all - A European strategic long-term vision' from 2018 stated that to deliver "on the transformation towards a net-zero greenhouse gas emissions economy thus requires early long-term planning, improving knowledge of the opportunities for transforming our entire economy and building trust within our society and all economic actors that this change is possible and opportune". Gasunie therefore believes it is a societal objective to deliver on the energy transition at lowest possible cost, which merits pro-active market intervention. Crucial for proactive market intervention is that technology neutrality is maintained. It is important to realize in this respect that hydrogen is not a technology but a energy carrier – like electricity. This means that different technologies to produce hydrogen should compete and the energy system development should be optimised to re-use existing infrastructure, especially when it can mitigate investments in other / new infrastructure or technologies. Favouring one technology over another leads to less cost-optimal decarbonization pathways. Against the backdrop of increasing intermittent renewable electricity production, we also need to balance the interests of society for decarbonization and cost-efficiency with the adequate robustness of the energy system.

The EU Commission recognizes that the challenge of the energy transition is for all players and the entire economy, not only for some market players. This includes also regulators, which should subscribe to the societal goal of delivering a cost-effective energy transition. Today, we can see that regulators are putting pressure on regulated entities to deliver cost-reflective and efficient services. While this principle is critical for regulated markets, it also must be brought into balance with societal interests regarding (the acceleration of) decarbonization, which in many cases require investments that are not the most cost-effective ones.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-gas infrastructures will be the linking pin required for the coupling of gas and electricity system. As a corner stone of a future integrated energy system, it enables the transport and storage of huge amounts of renewable electricity in the energy system (as molecules). Further, it will help to satisfy a major part of the energy demand and it provides the electricity system with the flexibility which is currently drawn from dispatchable fossil energy sources. This is of relevance with the continued electrification of gas-demand sectors such as residential heating and the decarbonization pressure on 'hard to electrify' sectors. For those industrial processes, but also for mobility applications, hydrogen is the only viable decarbonization option aside from the application of end-of-pipe carbon capture. While the potential of power-to-gas installations is significant, careful assessment is required by electricity and gas infrastructure operators, as such installations can optimise or worsen congestion in the electricity system if not adequately planned. Power-to-gas-installations should therefore typically be located near to the power production to prevent additional congestion in the electricity network. Currently power-to-gas installations require significant further development to achieve the capacities required for the future energy system. Similarly, to the development of offshore wind, support mechanisms are required to enable this technology to mature and go through the different innovation phases.

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?
In some EU Member States, power-to-gas-installations are considered as end-users of electricity and therefore subjected to several end-user charges, taxes and levies (often combined with the grid tariff invoice). This further complicates business cases for such installations. For example, a power-to-gas-plant in Germany would have to pay the renewable energy surcharge (EEG-umlage), because the installation is seen as a final electricity consumer. This surcharge is even higher as the average renewable energy generation cost. For the appropriate classification of power-to-gas-installations, we need to consider the system value in the total benefit they bring (see above). Power-to-gas-installations, coupling electricity and gas networks and enabling further transport and storage of renewable energy, should be classified as conversion installations. We believe that only the end-use of energy (and not the conversion) should be confronted with taxes and levies that are not related to grid use. In this context we believe taxation and regulatory hurdles should be taken away to achieve the scale-up of hydrogen as vital part of the decarbonised energy system.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
We believe that there is currently no need to regulate the hydrogen market or specific elements of the hydrogen value chain. There is a serious risk that regulatory intervention, without an understanding of the particularities of the hydrogen markets (also at the national and local level) might hamper the hydrogen economy from developing. The elaborate regulatory regimes which have been developed for natural gas markets and infrastructures were not developed from the outset but have organically grown as the market and corresponding regulatory requirements developed. We should take a similar approach to the hydrogen economy and its underlying technologies, given that the objectives of regulation in a non-existent market are not present. Given that the hydrogen economy still must be developed, we believe the preferred route towards a liquid European hydrogen market should be to allow all market players to develop viable business models, so that these can compete without regulatory or state aid intervention, to accelerate the energy transition. To trigger the hydrogen economy, the power-to-gas technology needs urgent upscaling which requires investments and support mechanisms. In addition,; llocation, capacity and operation of power-to-gas installations are decisive factors for optimal sector-coupling and system integration to be successful. Several market players (including infrastructure companies) are currently interested in investing in power-to-gas, in many cases with an uncertain economic outlook. In this phase of the energy transition this should be supported. Power-to-gas installations have no positive business case yet and this is especially the case when end-user taxes and levies are applied to electrolysers. Therefore, we foresee that in the short term specific (national) support is needed to kickstart the power-to-gas market.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
The cross-border trade in general requires supporting two EU goals under the RED II legislation by each member state. The first is the trading of GOs for disclosure purposes only servicing as proof for the general goal of 32% renewable in 2030 (RED II art. 3 and 7) and counted by each member state based on its local production. The second goal is related to biofuel obligations and for this specific use of renewable gas mass balance verification is required to proof physical offtake and usage in the member state where the renewable gas is off taken and delivered as a biofuel. Here the member state where it is used must count it towards the specific biofuel quota (RED2 art. 25 – 30) The cross-border trade of renewable gas GOs, for disclosure and biofuel purpose, based on these REDII requirements are a fundamental step towards the further integration of the renewable markets across Europe. National issuing bodies, such as Vertogas in the Netherlands that has been mandated by the Ministry of Economic Affairs for the issuance of GO's and supporting the mass balance regime for biofuels with additional GO information for the verification on biofuel deliveries , has already set up a RED(II) compliant interoperable scheme for GOs and mass balanced verified biofuel deliveries in the Netherlands together with the Dutch Emission authority (mandated for verification of achieving Dutch Biofuel quota). ERGaR, the European scheme for facilitating the international transfer of GO's for mass balanced biofuel deliveries and GO for end user disclosure is being set up to support the market between European IB's. This transfer scheme specifically for verification on biofuel deliveries will be approved by the European Commission under RED II making ERGaR the only RED II compliant transfer platform to support these specific biofuel obligations for member states. We believe that such further integration is required which allows for the trade of renewable hydrogen alongside biogases. Vertogas further supports the creation of a GO and Biofuel scheme for the trade of renewable and decarbonized energy carriers such as hydrogen based on the same REDII and ERGaR principles so help the development of emission reduction markets. The current RED II legislation allows such an introduction.

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?
In principle we believe regulation should always be tailor made. The Gas sector, including the trade of GO's is very distinct, both from its physical properties and the underlining market dynamics from the trade in renewable electricity. Supporting both systems, being GO's for disclosure about the origin and Mass Balanced GO's, must be supported correctly through platforms like ERGaR and Issuing Bodies like Vertogas. This framework of GO for different REDII criteria must enable member states to allocate their additions to these renewable goals correctly within its national boundaries but also when renewable gas (CH_4 & H_2) is traded internationally.

Infrastructure Investments and Regulation

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?
Already today NRAs/ACER have central roles in the development of TYNDP and CBA Methodologies. The recommendation from ACER are a central part of the process, unless duly justified. In principle the current TYNDP process is a very integrative process which allows for all stakeholders to contribute and comment. Any projects which are being submitted must follow the TYNDP Practical Implementation document which in turn is based on an EU Commission recommendation. In view of an increasingly prescriptive approach from the EU Commission with respect to the underlining scenarios used for the TYNDP, it could be questioned which objective an increased responsibility of the NRAs and ACER would have. This is the case as the expertise with regards to network planning and scenarios is with the TSOs and not a core competence of NRAs. An important responsibility that ACER and NRA's have is to ensure that a more holistic approach of the energy system is taken. Currently there is a separate process for indicative planning of gas and electricity network development plans. Without a more integrated view there might be a risk of inefficient investments. Given the long time to implement changes in asset-heavy networks, it is crucial that this planning is proactive and a holistic approach is used. Some countries have started this joint planning voluntarily, but more progress is needed.

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)?
No opinion

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?
As the EU Commission has outlined in its long-term decarbonization strategy, gas(eous energy carriers) and its infrastructure will play an important role in the energy system in the coming decades. In view of this, it can be expected that (peak) capacity demand is unlikely to reduce in the way the volume of natural gas is reduced. In addition, studies such as Gas for Climate (2019) provide a solid overview of the volumetric potential of renewable and decarbonized molecular energy carriers. Their volume patterns are also likely to be different. In this light, there might be a local, specific need to assess the future use of existing infrastructures. For example, Low-calorific gas (L-Gas) infrastructure might be available for refurbishment and reuse for hydrogen or could be decommissioned. We do not believe there is a need for regulatory rules to support the decommissioning of infrastructures.

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?
In view of the above (see answer to question 12), Gasunie believes it is premature to discuss the development of a formal decommissioning framework. However, in the Netherlands we are accelerating the phase out of L-Gas, resulting in the fact that gas networks will be shorter or less used than originally estimated by the NRA. The extent of this development will depend on the re-use of some networks with hydrogen. As the cost of decommissioning or amortization periods are socialized via tariffs, there is a possibility that those network users who stay connected must bear the costs of underutilized networks. An open discussion is currently taking place in the Netherlands to identify solutions.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
We continue to work on an integrated, open access, liquid gas market in the EU. While the North Western European Market is already deep, liquid and mature, other markets continue to lag behind (see to this end the CEER bridge to 2025 document and the gas target model). We would like to highlight that measures which aim at bringing further liquidity to the market and aim at addressing perceived tariff pancaking in some markets, should not risk the well-functioning of mature markets in North Western Europe. While in principle market mergers and the combining of balancing zones is possible, very little has happened in that respect. Gasunie believes that market mergers are beneficial for network users, which is why the viability of market mergers as well as the challenges, need to be further assessed. Biogas that has been locally produced by several initiatives usually needs upgrading towards TSO standard gas qualities. Collecting such unprocessed biogas and centralised upgrading facilities can be offered as service by the TSO. With regard to GO's for renewable gas, member states should mandate national issuing bodies to allow for the issuance of these GO's. This would facilitate the liquidity of the market with regard to the trade of renewable gas.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The European Union sees a considerable role for gaseous energy carriers during the energy transition. At this time the groundwork must be laid to create long-term viable markets for renewable and low carbon gases. A value chain approach is needed particularly in the context of sector coupling as the markets for renewable and low carbon gases still must grow, especially with respect to hydrogen and biogas. While to a certain extent an updated legal framework could create pull and push incentives, we believe that we should not over-regulate markets which are currently in development. We further believe that we need to carefully assess barriers to the deployment of renewable and low-carbon technologies. This includes end-user tariffs, charges and levies for power-to-gas installations, but also funding availabilities for the battery solutions which disregard the requirements of integrated energy systems. This means that the focus should be towards 2030 and further and from that position determine the needs for the market and 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?
No opinion

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
No opinion

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Gas and gas infrastructure are indispensable to achieve the transition to a fully renewable energy system. A major challenge is the establishment of new value chains, be it for heat, green gas, CO2 or hydrogen. While infrastructures can enable value chains, a holistic approach needs to be found which addresses the production of energy, transport and storage as well as demand. There is a need for a common approach at the European level, looking beyond the current regulatory gas framework. At the European level, clear and uniform definitions of renewable and low-carbon hydrogen, power-to-gas, power-to-hydrogen and energy storage should be formulated and adopted, based on existing European projects, when possible. Standardization is key element of establishing demand and can help to reduce costs and improve efficiency creating an effective and efficient system integration solution that has both business value as well as a societal value. The cross-border trade of renewable and low carbon gases should be incentivized by EU institutions.

Survey response 67

Contact details and treatment of confidential responses

Contact details: [Organisation][]
EUTurbines - European Association of Gas and Steam Turbine Manufacturers

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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.
From the viewpoint of gas-based power generation, to achieve the EU target of a carbon-neutral economy, the switch to renewable gas is essential. This will maximise the value of dispatchable, reliable and efficient power and heat, independently of weather conditions – complementing variable renewables such as wind and photovoltaics generation. In terms of amounts, hydrogen will have a predominant role among the renewable gases. The gas power plants technology is optimised for a specific gas composition. The injection of new, renewable gases in the gas network has an impact on that gas composition. In the case of hydrogen, today most gas turbines are capable of running with a share of 5% hydrogen in the gas mix. The gas turbines industry has committed itself to provide turbines that handle a share of 20% hydrogen by 2020 and provide solutions for customers requesting turbines operating with 100% hydrogen by 2030. This applies for new products. Regarding existing power plants, the sector is committed to offer retrofit solutions – the specific capabilities about hydrogen-blending are however to be examined on a case-by-case basis for the moment. An important aspect, when considering blending of different gases into the gas network, is the need to ensure a certain stability of the gas quality delivered to customers (i.e. at exit point). Limited variations can be handled by the technology without modifications. However, larger changes in the composition – not only related to hydrogen content – may need additional (soft- and/or hardware) adaptations. Short-term variations at the connection point to the power plant must be kept within a reasonable range and the speed of the variation (rate of change) needs to be controlled. For this reason, information on the expected changes need to be communicated by the grid operators in a structured way and well ahead. Should big variations in the amount of hydrogen in the gas pipeline become reality, it will need to be ensured that at the exit point to power plants the gas composition stays within reasonable ranges. Setting up targets to inject certain amounts of renewable gases into the gas pipeline could help accelerating the decarbonisation of the gas sector – as well as its users, such as gas power generation. The aspects mentioned above should be taken into consideration in the discussion.

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.
It is important that all potential customers have access to renewable gases. The relevance of using renewable gas in dispatchable power generation should not be underestimated: (renewable) gas power plants are needed in combination with variable renewables to ensure the stability of the electricity grid and provide enough power and heat, meeting seasonal peak demand. Securing the supply of renewable gas to the power sector is, in this sense, a new dimension of the term “security of supply”.

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.
It is not clear at what stage and for what purpose “cost efficiency” would be considered – for the customers, for the system, of a given technology…. Other aspects, such as the contribution to the well-functioning of the energy system needs to be also considered.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas infrastructures bring together the electricity and the gas sector and gas power plants can combine the gas, electricity and heat sector. Their combination ensures optimum sector coupling. In the same way, Power-to-Gas infrastructure will help integrating other sectors, such as transport. Ensuring sufficient hydrogen or synthetic fuels from Power-to-Gas is therefore key in the decarbonisation efforts. In this sense, a fast implementation of RED II, following a pragmatic implementation of "delegated acts" for renewable electricity can help achieving higher amounts of electricity that through sector coupling, would be converted in renewable gases.

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?
One challenge is created by the combination of both tariff systems. If hydrogen is sold to the application paying the highest prices, this is pure hydrogen for industrial customers and transport. Electricity prices do not allow to pay similar prices for hydrogen as input factor for gas power plants. Since, however, the electricity system needs gas plants to provide the residual load, which at the same time need to be decarbonised, there is a need to ensure the availability of renewable gas for power generation. This could be done e.g. via contracts for difference – but the renewable gas amounts need to be ensured.

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?

Infrastructure Investments and Regulation

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?
Looking at the whole gas infrastructure (i.e. beyond the gas grid), it should be noted that gas power plants, currently needed to accelerate the coal phase-out (and by this considerably reduce carbon emissions), can be already equipped or later retrofitted to operate with renewable gases, including different amounts of hydrogen. This ensures that they will not become stranded assets, providing valuable dispatchable renewable power – a capability needed in a system with high shares of variable electricity from wind and PV – as well as heat. However, to achieve this, the supply of renewable gas to gas power plants – central as well as increasingly decentral – is essential.

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?
It is often argued by supporters of a high level of electrification that costs could be saved by decommissioning large parts of the gas infrastructure, especially in the distribution grid. In an increasingly decentralised energy system, we will see a growing share of decentral dispatchable gas power plants, not only to provide electricity when wind and PV do not deliver, but also in cogeneration plants. These power plants need access to the gas grid to perform this key task.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Setting incentives for decarbonising the whole gas grid – not only by providing a parallel infrastructure for pure H2 for a limited customer group.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Yes. Targets need to be defined, also outlining a process to achieve them. This will ensure that investors feel confident in investing in the technology needed (avoiding the risk of investing in stranded assets).

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?

Other question

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

Survey response 70

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Vereniging Gasopslag Nederland (VGN)

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The Dutch association of Gas Storages (from now on: Vereniging Gasopslag Nederland - VGN) represents all the gas storage operators that are connected to the Dutch natural gas grid. VGN welcomes the possibility to react on the CEER consultation on regulatory challenges for a sustainable gas sector and support CEER doing so in the future. In the changing energy sector storage of (renewable and low carbon) gas has an important role in providing security of supply and flexibility. Above that, storage of energy in the form of molecules can play a significant role to achieve policy goals, also considering the climate targets resulting from the Paris Agreement.

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.
Market intervention by TSO's/ DSO's should only take place in case of market failure and should be temporary, until the market picks up. If those conditions are met, cost-efficiency could be a legitimate reason for market intervention by TSO's/DSO's and serves market and societal interest. The same can be said about the cost-efficient transition towards a carbon neutral energy system. To deliver on the transformation towards a net-zero greenhouse gas emissions economy thus requires a long-term view. VGN believes it is a societal objective to deliver on the energy transition at lowest possible costs, which potentially merits pro-active market intervention. Crucial for proactive market intervention is that technology neutrality is maintained. Favouring one technology over another leads to less cost-optimal decarbonization pathways. Against the backdrop of increasing intermittent renewable electricity production, we also need to balance the interests of society for decarbonization, cost-efficiency with the adequate robustness of the energy system.

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?

Infrastructure Investments and Regulation

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?
The EU Commission has outlined in its long-term decarbonization strategy, that gas(eous energy carriers) and its infrastructure will play an important role in the energy system in the coming decades. In view of this, it can be expected that (peak) capacity demand is unlikely to reduce in the way as the volume of natural gas is reduced. Above that, in the Netherlands the government decided to phase out the production of so-called low-calorific 'Groningen-gas'. This means there will a risk for stranded assets in the sense of grids that will be used less or shorter as expected. The significance of the impact depends on the future usage of the gas grids for other gasses, like hydrogen and biomethane. Together with the Dutch regulator, grid operators and market parties, VGN is currently discussing this topic in the so-called MORGAN-project. Potential solutions may be that the method for depreciation is altered, impairments are taken by the TSO/DSO's or that a fund is created to bear future costs. Within the Morgan project the alternatives (and their effects) within the regulatory scope are currently investigated by the regulator.

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?
There might be a local, specific need to assess the future use of existing infrastructures. For example Low-calorific gas (L-Gas) infrastructure might be available for refurbishment and reuse for hydrogen or could be decommissioned. Believes it is premature to discuss the development of a formal decommissioning framework.

Adapting the Gas Market Design

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?
The European Union sees a considerable role of gaseous energy carriers during the energy transition. The groundwork has to be done now to create long-term viable markets for renewable and low carbon gases. A value chain approach is needed particularly in the context of sector coupling and the role gas storages play in cross-sectoral flexibility markets.

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?

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Gas infrastructure and gas storages are indispensable to achieve the transition to a fully renewable energy system. Major challenges are the establishment of new value chains and maintaining security of supply. A holistic approach needs to be found which addresses the whole value chain of energy from production of energy, transport and storage (in the form of electrons and molecules) as well as demand. There is a need for a common approach at the European level, looking beyond the current regulatory gas framework.

Survey response 71

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Shell

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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

Shell considers that activities which have the potential to be developed on a commercial basis should remain in the market domain. The following regulatory design elements are key to enable the commercial development of new technologies:
- Unbundling of potentially contestable activities from core network activities to remain a key principle;
- Explicit and transparent support for new technology which have not yet reached commercial maturity (e.g. through innovation funds or supported pilot projects);
- Phase out of support as soon as technologies reach commercial maturity;
- Competitive ways to make funds supporting new technologies available (e.g. tenders for large projects enabling the deployment of technologies at scale);
- Removal of possible barriers to commercial development.

PtG and biomethane production are potentially contestable activities which the market can deliver. The development of the policy and regulatory framework to enable commercial development should therefore be the priority. For example, support may be needed at an initial stage of development to enable technological development and deployment at scale. However, the objective should be to phase out support over time and to enable deployment of these technologies on a fully commercial basis.
Therefore, we do not support TSO/DSO led development of either hydrogen production through PtG or biomethane production.
Instead, we consider that TSO/DSO have a key role in facilitating market development, for example by enabling the network to accommodate different forms of gases and ensuring third party access.
Should policy makers decide to allow TSO/DSO to carry out gas production activities such as PtG, we suggest considering the following mitigations to avoid foreclosing potentially contestable activities:
- TSO/DSO to operate PtG facilities on a temporary basis (e.g. only pilot projects to test the technology);
- TSO/DSO not to own, trade or sell either the power or the hydrogen produced, or the hydrogen itself;
- No inclusion in the network RAB of the inherent cost of the activities, i.e. users of the facility pay as opposed to the socialization the relevant costs among all network users;
- No preferential treatment on network transmission tariffs or using network tariffs to subsidize new technologies. However, we would support adjusting tariffs to remove double counting or possible distortions;
- Clear conditions for TSO/DSO exit so that facilities can return to the market when the market reaches sufficient level of maturity.

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.

Any decision should be primarily driven by technical considerations and it should take into account the specificities of local networks as it may be expected that these will determine maximum acceptable % of hydrogen. Common EU specification should be considered as a minimum and not prevent injecting additional volumes of low carbon gas.

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.

DSOs and TSOs play a crucial role in facilitating the development of competitive markets and unbundling rules guarantee that network operators can act in a non-discriminatory manner in undertaking their core functions.
Similar principles should apply for hydrogen networks.
In cases where a TSO or DSO would convert part of the gas network to hydrogen or construct a hydrogen network connecting multiple injection and withdrawal points, regulation should be considered to enable access to an essential facility, which could not economically be replicated.
The above should be applicable for all gases that are transported by TSOs and DSOs: natural gas, biogas, synthetic methane and hydrogen as this would facilitate the possibility to trade them as single energy product, irrespective of how they are singularly physically moved in the networks.

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.

As a general principle we consider that a technology neutral approach delivers the most efficient outcome to the benefit of consumers. Proactive market intervention should be limited to cases in which market failures prevent delivery of the most efficient outcome. The presence of negative externalities and the lack of coordination may justify regulatory intervention to ensure externalities are factored in and coordination is established to achieve a more efficient outcome.
We support the CEER's view that coordination at European level may contribute to achieving a cost-efficient network for hydrogen.

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

To foster the development of a sustainable gas sector, it will be important to maintain a technology neutral approach to avoid prematurely closing out potential solutions. Power to gas and both green and blue hydrogen with CCUS merit further development in decarbonising the gas sector and providing a cost-efficient means to utilise the existing gas infrastructure.
Power to gas and hydrogen can play an important role, not only in decarbonising the gas sector but also the transport sector, and in managing the increased need for flexibility linked to the growing penetration of intermittent generation.

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?

We do not see how electricity and gas tariffs could inherently create distortions if they are designed based on cost-reflectivity and to promote an efficient use of the network. To the extent that the use of power-to-gas facilities are considered as production plants which inject gas into the network and treated on equal footing with other gas producers, the risk of distortion will not materialise.
This said, it is important to note that tariffs should also be set as to ensure a technology neutral approach, leaving support to new technologies to explicit subsidies where these are deemed necessary. Equally tariffs should be set as to provide long-term signals: in the context of providing for a future role of any form of gas shortening of depreciation period of assets should be avoided.

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?

Increasing customer awareness for renewable, low carbon and decarbonised solutions help drive the energy transition by supporting the development of new technologies. In this context GOs are essential to demonstrate the renewable/low-carbon/decarbonised nature of gases injected into the system.
Consumers and consumers' demand for clean energy solutions should be put at the centre of the development of any market for GOs.
The existing market for GOs present the following challenges:
- Currently there exist a limited number of sellers and buyers;
- There is limited oversight of registries and of GOs and this may pose "trust" issues;
- GOs are "rare" and at the moment equivalent to c.ca 2 BCM only;
- Only fragmented national markets exist today which inter alia means limited price discovery.

Hence, to enable the development of a GOs market which put consumers' demand at its core would require:
- The development of one standardised GO for "renewable", "low-carbon" and "decarbonised". Such GO should be based on the minimum requirements of article 19 of RED II;
- The possibility to add information on the standardised GO to offer tailored product to consumers who require higher specifications to comply with regulatory sustainability requirements established for specific sectors (e.g. transport), or consumers who require more sophisticated clean energy solutions;
- Regulatory oversight of national registries/issuing bodies to avoid possible fraud and support market trust;
- Coordination and cooperation of national registries to achieve a mutual recognition of national GOs via a basic harmonised set of rules for the compatibility of national registries.

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?

Please see previous answered.

Infrastructure Investments and Regulation

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?
Whilst we maintain that TSOs should not own or operate power-to-gas facilities as this would be in breach of the unbundling rules, where exemptions have been allowed in specific markets, investment in such facilities should be ringfenced to ensure full transparency around the costs and revenues associated with a power-to-gas facility.

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)?
We believe that with respect to transmission infrastructure the CAM code provides a good starting point and a good way to avoid unnecessary investment, including for the development of complex infrastructure spamming across several countries.

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?
While TSOs should always be encouraged and incentivised to run systems in the most efficient way possible, the option to write off unutilised assets should be on the table, after all alternative uses and rationales for the maintenance of the relevant infrastructure have been considered, i.e. security of supply, possibility of conversion assets into hydrogen apt infrastructure, enhancement of cross-border trade. Transparent compensation schemes for decommissioning should be considered as they may contribute to lower transmission costs going forward. Should conventional supplies of gas decline in some countries, this could be replaced with more diverse sources of green gas and hydrogen. Where practicable, capacity availability and network flexibility should be maintained to ensure a degree of optionality for future sources of supply to utilise the gas network. Regulatory tools to manage the balance between maintaining optionality but avoiding inefficient network investment would likely form, if they don't already, the basis of network development plans and price controls to ensure the TSO's RAB adequately reflects the need for future investment. We would not support accelerated depreciation periods as this would increase tariffs for existing network users and could act as a barrier to entry with respect to future utilisation of the gas network. Discounting tariffs for green gas would resolve this but subsidising renewable energy through tariffs is not transparent, is not technology neutral and creates an unlevel playing field between different types of network users. Moreover, as the share of renewable energy connected to the network increases, these concerns are exacerbated and could artificially raise the price of gas, ultimately to the cost to consumers.

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?
In general, we believe that decommissioning should follow the same framework as commissioning, while mothballing should be regarded as an interim solution before decommissioning. However, in the case of decommissioning cross-border infrastructure, while coordination is desirable, the affected TSOs should be able to independently decide on when and how to decommission their part of the infrastructure.

Adapting the Gas Market Design

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

We continue to support the gas market design based on the 3rd Package and described in ACER's Gas target Model. They have proven very effective in developing liquid and competitive gas wholesale markets giving evidence that, where problems exist, this is not because of failures in the gas market design but because of missing interconnections and incomplete implementation of the market rules.
This said we recommend continued focus on improved transparency with respect to setting system operators' allowed revenues and relevant transmission tariffs.
In this regard we note that:
- ACER has been very effective in issuing detailed opinions on NRAs proposal:
- Views from market players have generally been taken onboard;
- The interaction with NRAs has in some case allowed further disclosure of information;
- The role of ACER in the process has legitimised the participation in national consultations of third countries industry associations.

However:
- Only in one case ACER has deemed the proposed methodology invalid and recommended to issue a new proposal;
- In several countries ACER has noted that the information provided did not allow a proper compliance assessment with limited consequences on NRAs' decision-making processes.

In conclusion we can say that:
- The TAR NC implementation process has generally increased the level of transparency, it has allowed network users to learn more about tariff setting rules, and it has allowed a European debate on the cost of transmission services;
- In some countries, changes have materially improved the situation, e.g. better conditions for cross-border trade, less cross-subsidies, restitution of TSOs' over-recoveries;
- Improvements have gone only as far as NRAs were willing to challenge national TSOs missing an automatic mechanism to enforce full compliance.

Therefore, going forward we recommend:
- Within the existing regulatory framework:

o More and early stage ACER's involvement in the TAR NC consultation processes;
o Enhancing the usability of ACER's monitoring activities and the standardization of the publication requirements;
o Clarifying the scope of the interactions between ACER and the Commission following the publication of ACER's opinions;

- Within a potential future regulatory framework:

o Increasing NRAs' accountability through the obligation to react to ACER's recommendations by adopting them or providing a rationale for taking a different decision;
o Giving ACER the mandate to publish reports following the preliminary consultation stage;
o Attributing ACER powers to address impact on cross-border trade and flows.

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

We are convinced that the development of renewable gases would best be facilitated by allowing renewable gases and low carbon gases to be traded together with natural gas in a single gas market. This does not require a revision of the gas market design but rather to make the existing regulation generic for all gases. Please also see answer to Q16.

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?

Please see answer to Q12 and Q14.
Also, we believe that gas, in its different forms, should play a significant role in the Energy Transition. While doing so, we support a growing role of renewable and decarbonised gases to meet climate objectives. In this context to avoid a vicious circle of spiralling tariffs in case of change of utilisation patterns in parts of the system we regard the following elements as key:
- Policy clarity on the future role of renewable gas and decarbonised gas;
- Coordinated decommissioning or mothballing of stranded infrastructure which is not critical for security of supply, with explicit compensation outside network tariffs;
- Forward-looking and integrated gas and power network planning;
- Recognizing the value of new infrastructures developed on a merchant basis;
- Avoiding accelerated depreciation of TSO infrastructure and on the contrary consider the introduction of longer transmission assets depreciation periods to reduce transmission cost in the short-term and send a strong signal to the market on the long-term availability of gas infrastructure.

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

- Please see previous answers.

Other question

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

Survey response 72

Contact details and treatment of confidential responses

Contact details: [Organisation][]
EUGINE - European Engine Power Plants Association

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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.
From the viewpoint of gas-based power generation, to achieve the target of a carbon-neutral economy, the switch to renewable gas is essential. This will maximise the value of dispatchable, reliable and efficient power and heat generation, independently of weather conditions – complementing variable renewables such as wind and photovoltaics generation. In terms of amounts, hydrogen and synthetic methane will probably have a predominant role among the renewable gases. The gas power plants technology is optimised for a specific gas composition. The injection of new, renewable gases in the gas network has an impact on that gas composition. While e.g. biomethane can be handled without bigger problems (already today around 17 000 gas engines are running on biogas in Europe) the impact of hydrogen blending on engine power plants needs to be carefully assessed: Today engine power plants can operate with a share of 5% hydrogen in the gas pipeline. Higher shares up to 20% will be achievable for most new plants over the coming years and manufacturers are working on solutions for even bigger amounts. However, most existing plants were not designed for high amounts of hydrogen – how far they can be retrofitted is still under examination. Nevertheless, an important aspect, when considering blending of different gases into the gas network, is the need to ensure a certain stability of the gas quality delivered to customers (i.e. at exit point). Limited variations can be handled by the technology without modifications. However, larger changes in the composition – not only related to hydrogen content – may need additional (soft- and/or hardware) adaptations. Short-term variations at the connection point to the power plant must be kept within a reasonable range and the speed of the variation (rate of change) needs to be controlled. For this reason, information on the expected changes need to be communicated by the grid operators in a structured way and well ahead. Should big variations in the amount of hydrogen in the gas pipeline become reality, it will need to be ensured that at the exit point to power plants the gas composition stays within reasonable ranges. Setting up targets to inject certain amounts of renewable gases into the gas pipeline could help accelerating the decarbonisation of the gas sector – as well as its users, such as gas power generation. The aspects mentioned above should be taken into consideration in the discussion.

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.
It is important that all potential customers have access to renewable gases. The relevance of using renewable gas in dispatchable power generation should not be underestimated: (renewable) gas power plants are needed in combination with variable renewables to ensure the stability of the electricity grid and provide enough power and heat, meeting seasonal peak demand. Securing the supply of renewable gas to the power sector is, in this sense, a new dimension of the term “security of supply”.

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.
It is not clear at what stage and for what purpose “cost efficiency” would be considered – for the customers, for the system, of a given technology.... Other aspects, such as the contribution to the well-functioning of the energy system needs to be also considered.

Q5 Which role do you see for power-to-gas infrastructures?
Power-to-Gas infrastructures bring together the electricity and the gas sector; in the same way, gas power plants can combine the gas, electricity and heat sector. Their combination ensures optimum sector coupling. Ensuring sufficient hydrogen or synthetic fuels from Power-to-Gas is key in the decarbonisation efforts. It is therefore of utmost importance that all players are encouraged to invest in this technology. The generated decarbonised hydrogen should be fed into the gas grid and made available to all interested economic sectors, in a neutral way.

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?
One challenge is created by the combination of both tariff systems. If hydrogen is sold to the application paying the highest prices, this is pure hydrogen for industrial customers and transport. Electricity prices do not allow to pay similar prices for hydrogen as input factor for gas power plants. Since, however, the electricity system needs gas plants to provide the residual load, which at the same time need to be decarbonised, there is a need to ensure the availability of renewable gas for power generation. This could be done e.g. via contracts for difference – but the renewable gas amounts need to be ensured.

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?

Infrastructure Investments and Regulation

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?
Looking at the whole gas infrastructure (i.e. beyond the gas grid), it should be noted that gas power plants, currently needed to accelerate the coal phase-out (and by this considerably reduce carbon emissions), can be already equipped or later retrofitted to operate with renewable gases, including different amounts of hydrogen. This ensures that they will not become stranded assets, providing valuable dispatchable renewable power – a capability needed in a system with high shares of variable electricity from wind and PV – as well as heat. However, to achieve this, the supply of renewable gas to gas power plants – central as well as increasingly decentral – is essential.

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?
It is often argued by supporters of a high level of electrification that costs could be saved by decommissioning large parts of the gas infrastructure, especially in the distribution grid. In an increasingly decentralised energy system, we will see a growing share of decentral dispatchable gas power plants, not only to provide electricity when wind and PV do not deliver, but also in cogeneration plants. These power plants need access to the gas grid to perform this key task.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Setting incentives for decarbonising the whole gas grid – not only by providing a parallel infrastructure for pure H2 for a limited customer group.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Yes. A target for renewable gas needs to be defined, also outlining a process to achieve them (a roadmap specifying concrete steps on specific dates to ensure the necessary previsibility). This will ensure that investors feel confident in investing in the technology needed (avoiding the risk of investing in stranded assets).

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?

Other question

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

Survey response 74

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Europex - Association of European Energy Exchanges

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

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.
Hydrogen networks should fall under the same rules as conventional gas networks to ensure a level playing field and to promote competition and open grid access - if the hydrogen is used as an energy carrier in the public energy supply for households, industry, commercial consumers and power plants. In our view, the establishment of an extensive parallel new infrastructure should be avoided wherever possible to ensure economic efficiency.

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.
As regards infrastructure planning, Europex calls for a forward-looking and integrated approach to gas and electricity network planning, taking into account sector coupling aspects as far as possible. Levies, taxes and tariffs should be regarded in a cross-sector approach as part of an overall sector coupling strategy to avoid creating unnecessary barriers to sector integration. Freely formed price signals must constitute the very basis of an efficient sector coupling strategy as they incentivise economic efficiency. As an example, power-to-gas plants could be used in cases of electricity over-supply (for instance caused by high wind production) indicated by low electricity prices in the market.

Q5 Which role do you see for power-to-gas infrastructures?
Any sector coupling strategy must contain a clear definition of roles and responsibilities. When integrating sector coupling technologies such as power-to-gas in the system it is indispensable that the principle of unbundling is fully respected. The Clean Energy Package underlines that “network operators principally should not own, develop, manage or operate energy storage facilities and charging points for EV”. We therefore fully agree with the consultation document that this principle should equally apply to the gas sector as well as to any sector coupling activity (such as the operation of power-to-gas, gas-to-power, etc. plants). Guaranteeing an effective and clear separation of networks from activities such as production, trading and supply is a fundamental pillar for achieving the objectives of a well-functioning internal gas market that operates on a level playing field.

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?

Europex believes that a harmonised EU-wide Guarantees of Origin (GOs) system for renewables can be an effective market-based instrument to track and incentivise the use of renewable gases in the energy system and to maintain the overall integrity of a single gas wholesale market. In addition, such a gas GO system would more actively include consumers in the energy transition by making the origin of gas fully transparent.

The following aspects are important when establishing an EU-wide GO system for renewable gases:
- A maximum of standardisation of GOs for “renewable”, “low-carbon” and “decarbonised” gases for developing the traded market for GOs. The information on the certificate should be based on the requirements as laid out in Article 19 of RED II.
- The standardisation should be developed in close cooperation with the relevant issuing bodies with the overall objective to make them easily tradeable.
- Cancellation of allowances in other member states should be possible as it is currently the case for power GOs. This could be achieved through a model similar to the power GO model:

1. Member state registers remain but they need to coordinate through a common body, like the AIB for electricity. This body could even become an EU body.
2. The requirements for the acceptability of GOs in other member states should be clearly defined. At best, there should be one common standard for all.
3. A coordinated cancellation system is needed to avoid double counting.

In order to establish liquid markets, it is essential that renewable gas GOs can be traded separately from their underlying source. Therefore, a certificate system for gas, similar to that for electricity, should be structured in such a way that a certificate can be traded independently of the commodity. This would in principle enable cross-border transferability of the certificate and would allow certificates from different member states to be traded at the same trading hub.

TSO involvement in the design of the certification scheme should be ensured where technically necessary.

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?

Infrastructure Investments and Regulation

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Fully implementing and comprehensively applying the key elements of the Third Energy Package must remain a top priority, especially where it is not yet consistently implemented, before envisaging any new changes to the market design. As shown by the last ACER Market Monitoring Report, gas market integration has significantly improved in Europe in recent years. Gas wholesale markets have shown increasing levels of price convergence and the overall market liquidity has significantly improved. This applies primarily to North-Western Europe, where the Third Energy Package is already consistently implemented. The harmonised rules for capacity bookings and for the design of balancing markets have enabled and fostered the liquidity in many wholesale markets in Europe. Moreover, as mentioned in the consultation document, the EU gas system has provided a high level of Security of Supply (SoS), proving its resilience also in critical situations. As described in the consultation document, the implementation of entry/exit zones with harmonised rules for capacity bookings, the deployment of balancing market arrangements and transparent methodologies for tariff setting are the cornerstones for the creation of a single integrated gas market in Europe. In particular, the new Tariff Network Code (Regulation (EU) 2017/460) provides stricter transparency requirements on transmission costs to be covered by transmission tariffs. Europex considers the already achieved developments of European gas wholesale markets under the Third Energy Package as a significant success. The creation of the entry/exit zones in the EU has so far significantly contributed to the increase of retail competition and has paved the way to the emergence of hub trading (in the member states that have vigorously implemented the Third Energy Package). Regarding the debate on the possibility of merging different entry/exit zones, Europex considers that market zone mergers should not be a goal in itself but should rather constitute the result of a ‘bottom-up’ process, if indeed needed. Especially in the light of the energy transition – which will most likely lead to a more decentralised energy system - we believe that precise and undistorted local price signals are of key importance. Such price signals will indicate market and infrastructure needs where they occur. Entry/exit zones that are too large carry the risk that price signals could be too imprecise to be used as an indicator for such infrastructure needs or other types of market inadequacies. There is indeed a risk that the larger the market zones, the less precise price signals become. The current set-up with TTF as the central hedging hub in the EU that is surrounded by local driven “demand hubs” - which have more activity for short term supply - is an efficient set-up.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
The integration of renewable gases should not negatively impact the gas market design in place. The objective should be to integrate renewable gases cost-effectively in the existing system. Europex therefore calls for a regulatory framework that is technologically neutral and allows for further flexibility as already stated in the consultation document. Europex favours the use of market-based approaches, based on reliable price signals, for the integration of renewable gases and a successful sector coupling strategy. Europex strongly calls for maintaining a single integrated European wholesale gas market. By ensuring the interoperability of the EU gas infrastructure and regulatory set-up, fragmented, less liquid markets for renewable gases should be avoided. Therefore, as a key principle, renewable gases should be fully integrated into the existing (all-)gas market to ensure that the benefits of liquid wholesale markets are immediately available for all gas sources. The development of heterogeneous markets, in contrast, would risk fragmenting liquidity and might create a patchwork of less developed and divided markets. In our view, in a first step the blending of renewables gases (such as hydrogen) in the existing gas grid should be seen as a possible measure of low cost and high impact that could be implemented based on a common regulatory set-up in the EU. Active cross-border coordination between TSOs and regulators is important to foster and further enable cross-border trading. To be able to still ensure the tradability of the commodity gas incl. renewable gases, also across borders, it is important that quality standards are being defined Europe-wide. The coupling of the electricity and gas sector could be a decisive factor for the speed and success of the energy transition. Sector coupling offers the possibility to release further system and grid flexibility and to put infrastructure and resources to their best use, i.e. for the market and ultimately for the end consumer. Currently, the debate of coupling the electricity and gas sector is to a large extent infrastructure-driven as the need for physical access / transportation / storage is a prerequisite for the further usage of renewable gases on a larger scale and for their possible role in the sector coupling. As for traded markets, sector coupling is already a reality and part of the daily trading business. Gas and electricity contracts constantly being optimised according to the price signals of the wholesale market and other relevant factors.

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?

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
General statement Europex is pleased to contribute to the present consultation on a sustainable gas sector and welcomes the associated stakeholder dialogue. We are convinced that gas will continue to play an important role in the future energy mix as a flexible source of energy, able to compensate for the growing share of intermittent renewable sources and to act as a large-scale energy carrier. In view of the EU's 2030 and 2050 climate and energy goals, it is clear that the gas sector will have to undergo a¬¬¬ transformation process and that renewable and decarbonised gases will play an increasingly important role in the future gas mix. Making the energy transition a success requires cross-sectoral cooperation and a strategy for an optimised and cost-effective use of resources and infrastructure. A comprehensive sector coupling strategy and an adaptive regulatory framework will be required to do both, addressing the challenges ahead and retaining and optimising the market principles in place. Sector coupling and sector integration, i.e. the extension to other sectors like heating/cooling, mobility, etc., must go hand in hand. Further connecting the gas and electricity sectors and their infrastructures will help to release more system and grid flexibility. This enables the integration of a steadily increasing share of renewable energy in the system ("smart increase of electrification" and the "greening of the gas" at the same time). This flexibility would then also benefit the decarbonisation efforts in the other sectors as more options will be available. It is of great importance that any changes to the regulatory framework for gas take into account the reality of physics and traded gas markets which can and do differ from the characteristics of the electricity market. Therefore, not all principles applied in the Clean Energy Package are necessarily applicable to the gas sector and should be carefully assessed before being 'mirrored'. The stepwise liberalisation of the European gas market over the past twenty years has brought great benefits for European consumers. The well-functioning of the established wholesale gas market must be maintained and existing rules should be consistently implemented before considering changes to the market design.

Survey response 76

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Vattenfall AB

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Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
The involvement of Transmission System Operators (TSOs) and Distribution System Operators (DSO) is reasonably clear in a number of core regulated activities related to hydrogen and renewable gases. These regulated activities would include: gas quality management; blending; planning, construction and operation of hydrogen-only grids; conversion, repurposing and decommissioning of existing networks; related safety; running of combined/hydrogen-only VTPs; changes to pipeline systems to ensure suitability for hydrogen & blended gas (connections, upgrading of pipe-joints, metering, compression etc). Sector Coupling technologies, such as Power-to-Gas installations belong to the area of responsibilities of market participants and as a general rule TSOs as well as DSOs should refrain from becoming active in new business models in the framework of sector coupling as these do not belong to the primary responsibilities and tasks of a network operators as described in the Third Energy Package. An exemption of this general prohibition should only be possible in case market participants are not interested in developing and operating Power-to-Gas installations. A similar approach is mentioned in Art. 36 of the reviewed Electricity Directive, where DSOs are only allowed to develop energy storages when there is a market failure. Appropriate involvement of network operators can include experiments and pilot projects. The aim of this involvement should be limited to incentivise the market until a functioning market starts to develop. Scrutiny of the involvement of network operators in these activities should thus be done on a regular basis by the respective National Regulatory Authority (NRA). At the time of drafting the rules of the Third Energy Package, i.e. Gas Directive 2009/73/EC and Gas Regulation 715/2009/EC the development of and hence also the discussion on ownership of Power-to-Gas installations have not been as advanced as today. As it becomes clearer that Power-to-Gas facilities can play a role in accelerating the energy transition and providing flexibility to the electricity network, a revision of the rules on the development, operation and ownership of Power-to-Gas facilities is absolutely necessary. The European Commission should propose binding rules in the expected “Gas Package 2020”. In addition, it should be mentioned in the “Gas Package 2020” that TSO and DSO are obliged to connect Power-to-Gas facilities to the grid.

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.
Newly built gas pipelines should at least be able to accommodate a certain amount of hydrogen in order to make the transition from natural gas to hydrogen easier in the future. The conversion of national gas systems importing low-calorific gas from the Netherlands can be taken as a negative how expensive and complicated the ex-post adjustment is likely to be. The decision of the Dutch government to phase out low-calorific gas in the Netherlands also impacts the export of low-calorific gas to other Member States, that will stop by 2030. Germany and Belgium have introduced a mechanism to recover the costs that are connected to the conversion from low- to high-calorific gas, for instance for adapting household and industrial appliances. . As a lesson learned policy makers should already now start working on introducing a hybrid solution that is able to accommodate a possible conversion from natural gas to hydrogen in the (gas) pipelines.

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.

According to Vattenfall the level of unbundling of hydrogen networks depends on the purpose of the hydrogen pipeline. A distinction should be made between two groups of networks:

1. In case hydrogen – injected into the Transmission of Distribution System –is being used for the purpose of supplying hydrogen to households, industry, commercial consumers and power plants or being transported cross border, the same EU unbundling rules related to TSO and DSO shall be applicable. As different EU unbundling rules for gas TSO and DSO exist, a distinction needs to be made, clarifying whether the hydrogen network qualifies as a distribution or transmission network. Monitoring of the unbundling of these networks should also fall within the jurisdiction of the NRAs.
2. Whereas hydrogen networks are merely designated to a specific group of consumers delivering hydrogen to one or few large industrial consumers the same unbundling rules as of the first group are not absolutely necessary. Generally, these pipelines are oriented to the industrial needs and are not accessible for other consumers due to technical reasons. When shaping a regulatory framework for future hydrogen networks, the co-existence of these already existing pipelines and public grids for all consumers has to be taken into account. Those hydrogen networks can be compared to closed distribution systems mentioned in Art. 28 Directive 2009/73/EC and can be exempted from unbundling rules.

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?

Power-to-Gas is a key technology for the necessary coupling of electricity and gas networks. It is currently the only technology that can be used to interconnect all sectors (electricity, industry, heating and transport) while ensuring energy supply and seasonal storage.

The technology converts renewable electricity into renewable gases, which can be further processed in the value chain of all sectors to support the achievement of the climate targets. Hence, Power-to-Gas infrastructure should be planned taking into account the needs of the electricity, gas, heating and transport sectors. By doing so, Power-to-Gas installations can also play an important role for reducing the curtailment of renewable electricity and help reducing the need for power grid expansion.

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?

While green electricity production around Europe has steadily increased over the last decade and renewable power price have reached levels competitive to conventional electricity generation, renewable power end-consumer prices are often still higher than wholesale market prices. The payment of taxes levies and grid fees that are applicable on top of the wholesale electricity prices often makes Power-to-Gas projects uncompetitive.

In some Member States hydrogen, produced by renewable electricity i.e. so-called "green" hydrogen, is subject to a number of levies that – taking into consideration the somewhat low economic feasibility of green hydrogen – puts green hydrogen into a less favourable position than so-called "grey" hydrogen. This is the case in Germany, for instance, where hydrogen is subject to national levies and grid fees. Thus, exemption from national levies is one important measure to scale-up the production of green hydrogen and should be mirrored in the revision of the Energy and Environmental aid guidelines 2014 (EEAG).

In the course of implementing the European Network Code Tariffs 2017/460 (NC TAR) into national law, some NRAs have set-up legislation that stimulates the use of hydrogen and its integration into the national gas market. The German NRA has, for example, exempted hydrogen injected into the national gas transmission grid from booking transport capacity and paying an entry tariff to the respective TSO for the injection into the gas transmission grid (decision REGENT BK9-18/610-NCG and BK9-18/611/GP).

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

Vattenfall urges the European Commission to establish a legal framework for hydrogen and sector coupling in the so-called Gas Package to be launched in 2020. The legislative proposals the European Commission should further facilitate sector coupling, provide guidelines on the injection of hydrogen into the gas grid, the establishment of a European Guarantee of Origin (GOs) system for renewable and low carbon hydrogen and broaden the definition of a storage facility. The current definition of storage facilities (Art. 2 para. 9 Directive 2009/73/EC) focusses on today's principal applications with natural gas. Its scope should thus be broadened to also allow for hydrogen applications as well. In addition to a European GOs system, Vattenfall urges to the EU to provide guidance on the basis for the categorisation of gases as 'renewable', as well as an emphasis on the need to couple existing renewable generation in order to facilitate the transition, to mature power-togas technologies and bring costs down.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Vattenfall supports the application of a European GOs system to be extended to renewable and low carbon hydrogen as mentioned in Art 19 of RED II. As encouraged in the RED II, a system of certified green premiums, like the existing guarantees of origin scheme for renewable electricity, can differentiate grey from green hydrogen and will generate a willingness of customers to pay more for CO2 free products. In turn, this will trigger demand for these products and it will increase supply chain transparency, required to distinguish between different production processes. In addition to the minimum requirements of European wide GOs systems as referred to Art. 19 RED II the GOs for renewable gas and low carbon hydrogen should take the upcoming CEN 16325 standard on 'renewable and low-carbon' (non-renewable) gases into account .

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?

Infrastructure Investments and Regulation

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?
Contrary to the introduction of a risk of stranded assets, the development of a strong power-to-gas sector is likely to reduce the risk of stranded gas infrastructure assets by repurposing them. By giving these assets a role in a decarbonised energy system, it can prolong their life beyond the near term hydro-carbon based system. In fact, the repurposing of existing assets also has the benefit of reducing the investment cost into new infrastructure thereby enabling a faster and more complete move to a decarbonised system.

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?
The European Ten Year Network Development Plan (TYNDP) and the process of involving stakeholder is a good instrument to analyse whether proposed gas or electricity infrastructural projects are needed to guarantee stability of the grid system and security of supply but foremost taking the need of market parties, such as shippers into account and to avoid stranded assets. On a general note, Vattenfall highly appreciates the initiative by ENTSO-E and ENTSO-G to combine the scenario's of drafting the TYNDP for electricity and gas for the first time in 2019 as it reflects the importance of sector coupling. Responding to the question on an EU framework for decommissioning infrastructure, Vattenfall suggests to implement a similar measure at EU level. This "reverse" TYNDP should evaluate the impact of energy infrastructure that should possibly be decommissioned and actively involve the users of the infrastructure, such as directly connect customers, shippers, asset operators and Power-to-Gas installations.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Measures to stimulate the use of hydrogen, for instance, by exempting renewable and low carbon hydrogen, injected into the gas transmission grid, from booking capacity and entry tariffs should be introduced at EU level, applicable to all Member States.

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?
No, there is not need to amend the current transmission tariff regime at the moment. The implementation of the NC TAR has not yet been finalised in all Member States. In some Member States, where more than one TSO exist and where a so-called post-stamp tariff (i.e. common entry and/or exit tariff per market area) has been introduced, an inter-TSO-compensation mechanism has been set-up to outweigh the losses of extra revenue experienced by some TSOs. Even in Member States, that have implemented NC TAR already, the new rules on transmission tariff regime are often not applicable before 1 January 2020. Before a decision on the amendment of the European transmission tariff regime is taken in order to accommodate renewable and low-carbon gases, the European Commission should make sure that the NC TAR is properly introduced in all Member States and evaluate the functioning of the changes of the tariff methodology at national level.

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

Other question

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

Survey response 77

Contact details and treatment of confidential responses

Contact details: [Organisation][]
EFET

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Within the scope of core regulated activity, there are a series of activities where TSO and DSO involvement seems reasonably clear. These would include: gas quality management, planning, construction and operation of hydrogen-only grids; conversion, repurposing and decommissioning of existing networks; related safety; running of combined/hydrogen-only VTPs; changes to pipeline systems to ensure suitability for hydrogen & blended gas (connections, upgrading of pipe-joints, metering, compression etc). Redesign of capacity and balancing terms as necessary. Connection of third-party power-to-gas facilities. We would see investment in power-to-gas (P2G) capacity as a contestable activity, not least because it is a gas production activity. Power-to-gas technologies would be in competition with each other and with existing facilities (taking decisions whether to sell gas or use it for power production) and virtual services (financial risk management products based on gas and power price indexes, possibly combined with physical activity such as demand management). If authorities wish to promote earlier investment in power-to-gas than is expected independently, then there is no obvious advantage gained by providing support only to the TSO or DSO as potential investor. Merchant facilities (akin to merchant gas storage or merchant CCGTs) could compete. However, there should be some obligations for TSOs to make available all the information necessary for taking such investment decisions and to connect third party facilities. Rules should also provide for commercial operation. In this sense, power-to-gas represents part of a complex value chain including decisions over whether to store gas locally and convert back to power at a later time, to blend into the existing network as H2, to convert to synthetic methane for grid injection or consumption, or to build a separate hydrogen grid (or even to forego production of the power in the first place). “Picking off” specific elements for TSOs without consideration of this wider value chain may result in uncoordinated, unduly costly, and distortive outcomes. We note also in the report, CEER has looked only at whether gas-to-power and other activities are permitted under unbundling rules. Consideration should also be given to regulation of access, transparency requirements, technological neutrality and tariff design for any services which are permitted. The Gas Directive and Regulation also comment on cost-reflectivity of services and cross-subsidisation of activities. Tariffs for a regulated service, or the methodologies behind them, would presumably by subject to regulatory approval and face transparency obligations described by NC TAR.

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.
While we understand that fuel mix and the promotion of renewables is an area of national rather than EU competence, we see significant advantages if neighbouring networks coordinate when planning changes to gas quality specifications. Reasons for this relate to safety and commercial operation. Creating gas quality barriers at interconnection points can reduce the ease and increase the cost of bringing gas from one network to meet a shortage in a neighbouring network. Equally, issues may arise in appliance manufacturing, installation and safety if different networks in neighbouring geographical areas are running on different specifications of gas. In early days, it may be possible for individual DSOs to detach and run on a hydrogen-only basis. Further thought should be given as to whether this is a desirable outcome at scale over 1200 DSOs in Europe. In the long term, reduced interchangeability of gas across networks/borders risks fragmenting liquidity in wholesale markets and reducing efficiency and reliability of price signals. If they are not properly tackled, such costs may potentially be significant and undo many of the benefits from creating a single internal gas market over the last 20 years. The resulting market fragmentation may well threaten the development of hydrogen-producing facilities due to increasing costs and declining demand on smaller markets. This requirement for interchangeability does not necessarily mean a single threshold must be implemented throughout Europe: if the threshold is set to the most constraining factor of the EU network, it would be extremely low and prevent any significant development of blending. On the other hand, imposing a higher threshold could trigger huge amounts of investments across Europe for security reasons, whereas effective flows of H2 may remain marginal in many parts of the network. Market based solutions, such as flow commitments, should be studied to offer a seamless network without enormous investments, and to allow transparent management of different gas qualities.

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.
Hydrogen networks as replacements for natural gas networks would best be regulated in a similar way to existing natural gas networks. This could potentially improve the conditions for repurposing of certain parts of the existing gas network to hydrogen. There may be a regulatory exception made for private networks already created as specialist chemicals, which is recognised in the report. Just as some countries allow exemptions or private networks in natural gas also, so such a regime may be portable and parallel. Transparency around network access and tariff-setting is equally important for third party access to Hydrogen as to Natural Gas networks. The term “gas”, as an energy carrier, can no longer be restricted to conventional natural gas. In the same manner than electricity sector integrates electricity from diverse sources of origin, the gas sector will have to accommodate gases from different technologies. Thus the EU regulatory gas framework should be rather the same in most of relevant topics (retail and consumer protection, competition and State Aid, third party access, market operation, etc…). An inclusive regulatory framework covering different technologies seems more appropriate than separate pieces

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.
We recognise that it is as yet unclear which technologies will best be able to deliver environmental targets effectively, economically and in a risk-managed way. There are therefore good reasons to have mechanisms that allow a range of technologies to continue participation. This way, low level support may be desirable for pilot schemes at low volumes. Care should be taken to avoid continuing levels of support for more established technologies that could end up being heavily distortive. It should also be noted that the principle of technology neutrality does not mean that some externalities cannot be priced in the market. Equally, hidden subsidies (e.g. socialized infrastructure investment) can be considered and corrected. We also note that efficient cost allocation was the very reason for the energy industry’s transformation towards market-based competition. Interventions in market mechanisms are therefore more likely to threaten the efficiency of cost allocation rather than enhance it, particularly if done against the principle of technological neutrality. In this context it is pertinent to look at the transformation that occurred in the electricity sector over the last 20 years and the many lessons learned from it.

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

Power-to-gas infrastructure refers to a class of infrastructures including electrolysis, with or without methanation equipment, which is part of a wider and complex value chain that could facilitate the development of more RES and thereby contribute to achieving Europe’s climate and energy goals.

It can provide a demand-side response for electricity and a supply side response for gas, and in particular hydrogen. As such it competes with other electricity demand side measures including consumption and storage, and with other gas supply side measures including production.

Power-to-gas installations will provide hydrogen or synthetic methane that could either be consumed directly by end-users or be injected in the gas grid. As a means of providing not only a sink for surplus, zero marginal cost generation, that may have additional value in combination with gas storage, but also through production of a gas that contributes to CO2 reductions and increases the utilisation of the existing gas infrastructure.

As stated above, power-to-gas should be a competitive service – whether as infrastructure or otherwise as virtual services or a composite of demand and supply-side activity. EU legislation on unbundling prevents regulated electricity or gas TSOs or DSOs to invest in such assets.

As a source of decarbonised gas from e-RES sources, power-to-gas infrastructure will compete with other renewable gas and clean hydrogen production pathways like biomethane steam reforming with carbon capture and storage or methane pyrolysis.

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?

We note that the increased dependency between the sectors may become a challenge in cases where gas infrastructure is maintained or developed primarily to serve as backup or allow the provision of supply security to the electricity network.

Where power-to-gas-to-power is used as a means of electricity storage, then there is a question about what tariffs are suitable or whether sectoral pancaking act as a barrier to the deployment of these technologies. Power consumed in P2G devices could be exempted from certain taxes (to avoid double imposition), similarly to the provisions for natural gas consumed to generate electricity.

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

The aspect of demand-side response, whereby a P2G unit could be incorporated into the idea of a local energy community and serve as DSR also on the gas side. The mechanisms by which the customers’ ability to be a prosumer on both the electricity and gas side could be examined further.

A key success factor for the market entrance of power-to-gas technologies is the acknowledgement in the target sectors mobility and heating. Both non-EU ETS sectors are facing challenging CO2-reduction targets, which cannot be met through efficiency increase and savings alone. The use of hydrogen in these sectors may create additional economic opportunities for power to gas where it is used for hydrogen production. Regulation in transport and buildings are therefore also relevant, for example in the following ways:

- Emission performance standards of new passenger cars, light-duty vehicles and heavy-duty vehicles,
- Greenhouse gas reduction targets for fuels used in transport,
- Energy performance requirements of buildings.

The adequate acknowledgement would allow to link these sectors and thus avoid higher carbon abatement costs, which would arise without such link.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Guarantees of Origin disclose the source of the specific renewable and decarbonised energy in a way that is transparent to the customer/consumer. They are a recognised way for consumers to access renewable or low carbon gas and are an important factor in gaining demand side traction for the green transition. However, the efficient trading of renewable/low-carbon gas GOs face a number of challenges, including: •Limited number of sellers and buyers – but low barriers to entry •GOs are "rare" (current maximum equivalent of 1,5 - 2 BCM) •Fragmented and national markets •Limited price discovery (and access to information) and no reference price These challenges are not easily overcome, but the first step is to help lay the foundation for trading the "green-value" of green gas. Hence, the "green value" should be capable of being de-linked and traded separately from the commodity. This would enable a GO trading place with sufficient liquidity to exist alongside the gas hubs. The GO framework should ideally be tradable freely across markets with gas transport costs being associated only with the commodity. Furthermore, and to build market recognition and liquidity, the GO framework should be based on same minimum standards as power GOs. We therefore recommend, that such GO should be based on: (1) the minimum requirements of Article 19 of RED II; and (2) upcoming CEN 16325 standard on 'renewable and low-carbon' gases. This would be a first step, but more is needed. In our view, there are several additional requirements which are needed to be fulfilled for the market to develop and to facilitate efficient cross-border trading of GOs, including issues such as: •Public supervision: Regulatory oversight of national registries/issuing bodies to guarantee traceability, avoid possible fraud and enhance market trust. •Tradability on a single platform: Having one respective booking platform in place, rather than having several different once. At least, there should be an obligation of platforms working together. •High level of standardisation: Establishment of reference price(s) based on a mutually and easily recognised standard. Hence, one standard GO framework for "renewable"/ "low-carbon"/ "decarbonised" gas. •Standardised approaches to measurement/mass balancing, to validity times, for cancellation and transferability etc. An additional element required to ensure the integrity of the system is a robust set of rules to address conversions between different energy carriers and their respective GOs. For instance, in the case of the gas system: •between electricity GOs and hydrogen GOs in case of certification of electrolytic hydrogen; •between biogas GOs and hydrogen GOs in case of certification of hydrogen produced through the steam reforming of biogas or pyrolysis; •between biogas GOs and power GOs in case of use of P2G and G2P facilities.

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?
EFET recognizes that problems concerning the liquidity of power GOs arise from non-standardisation, different design of schemes (consumer driven vs policy-driven) and different support mechanisms. For a working GO system in gas it is crucial to develop a certain level of trust in approval, monitoring and measurement that also ensures avoidance of double counting. In our view, differences in national policy and implementation have proved to be barriers to establishing a truly European system for trading power GOs and certificates. The development of a common European Standard for Energy Certificates by AIB should be regarded as one of the core lessons learned for the development of a European trading system for GOs for Gas. Therefore, the associations ERGaR, Certifhy and AIB should engage in working on such a common standard. EFET would also encourage CEN to dedicate robust resources into their relevant work on standardization of GOs for gas. To establish liquid markets, it is essential that the commodity can ultimately be traded regardless of its origin. Therefore, a certificate system for gas should be structured in such a way that a certificate can be traded independently of the commodity. This would allow to trade certificates from different countries at the same trading hub. In addition, cancellation of allowances in other countries should be possible as it is currently possible for power GOs. This could be achieved through a model similar to the power GOs model: •MS registers remain, but they coordinate through an EU body like AIB for power •Requirements for acceptability of GOs in neighbouring countries •Coordinated cancellation system to avoid double counting

Infrastructure Investments and Regulation

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?
First, ACER and NRAs should ensure a high level of transparency. In particular, both power and gas exercises must be fully transparent regarding the resilience of both grids, especially when facing challenging climate events. Market players and end-consumers must be informed of the limits of the future grids, that will become more sensitive to climate events, both because of the generation (with the development of renewables) and the demand (with the possible development of electric heating). In practical terms, this means first identifying stress scenarios (like the "one in 20 years" peak in gas). For power, these scenarios should include cold winter periods without wind, and periods when production is concentrated in an area far from demand. These scenarios should reveal where bottlenecks arise and the likelihood of curtailments. Key assumptions made for the modelling task should also be transparent to the highest extent possible. Sensitivity analysis could also be beneficial for understanding the importance of different parameters for the modelled demand.

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?
There is no single view on the potential level of gas demand in the future. Even if we may anticipate some reduction in the future utilisation of gas infrastructure, there would likely be value coming for the increased security to the energy system, if the network is kept operational. Similar issues arise when significant investments were made in order to ensure better cross-border connectivity and security of supply in general. The picture is likely to differ greatly between countries. Questions arise over who would pay for maintaining gas infrastructure that is underutilized – where these investments have little or no commercial value. Further debate is essential about how to recover the costs of such infrastructure if it is to be maintained. EFET has previously published on this issue during discussions on the Tariffs Network Code.

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?

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
Gas quality standardisation, blending, capacity products, balancing, virtual trading points, whether to separate hydrogen grids, gas system financing, guarantees of origin, tariff level and structure, particular investment price signals (for the necessary transformation of the gas system in the light of ambitious decarbonisation EU policy).

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Changes to gas composition and quality and the means to manage this will require change. Also, the provision of specific linepack services may need to be considered, and whether system entry capacity products in a blended system need to recognise limitations in the grids ability to accept certain gases in high quantities. Where networks may operate using different gases, the operation of balancing markets may be affected.

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?
Some current practices such as accelerated depreciation merely attempts to pass the problem to shippers and may just accelerate a reduction in usage. Similarly, the current tariff logic that the last connected site potentially pays for the entire system may not be sustainable.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
EFET believes this issue cannot be addressed this by tariff design alone. Broader mechanisms for risk- and cost-sharing should be considered. Explicit payments for transportation capacity maintained exclusively or primarily to support electricity supply security could be introduced. Revaluation of RAB to identify and exclude assets that are fully amortised or are not used and useful. Alternative approaches to network tariffs must be carefully evaluated and discussed with stakeholders in case the risk of stranded assets caused by reduced utilisation and changing flow patterns exacerbates.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Standardised terminology should be developed at an early opportunity.

Survey response 78

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Initiative Erdgasspeicher e.V.

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
Flexibility is the key-value brought by gas storage sector in a coupled energy system of the future. Looking at the energy system in total, a study on "Renewable Gases - A System-Update for the Energy Transition" by Enervis initiated by Initiative Erdgasspeicher e.V. (INES) and Bundesverband Windenergie e.V. (BWE) in 2017 concluded that the battery storage capacity that is necessary to provide flexibility for electricity-based systems will be reduced by 150 gigawatts under the assumptions of using existing storage and gas infrastructure compared to an "All Electric" scenario. Using gas-fueled heating systems leads to a cost cut of about 80 billion Euros until 2050. In addition to that, the need for gas-fired power plants to bridge times where wind and solar power cannot provide sufficient amounts of electricity will decrease by more than 50 per cent as a higher heating demand in winter does not need to be covered by the electricity market only. Instead of 110 gigawatts of installed capacity from gas-fired power plants only 50 gigawatts will be necessary. As renewable gases move flexibility demand from the electricity to the gas sector where storage facilities provide considerable capacity for this demand, another cost cut of around 100 billion Euros will be achieved by 2050. PtG will play a crucial role not only in balancing fluctuating electricity supply from renewable sources but also in the process of integrating more and more renewable energy sources to all energy sectors and in decarbonizing the industry, heat and transport sector via renewable gas. INES believes that in fulfilling the current EU Unbundling provisions PtG investment shall be organized market based. Electricity and Gas TSOs shall identify bottlenecks and suitable locations for PtG in the network, based on a coordinated Network Development Planning procedure. The role of TSOs shall be to tender their physical balancing energy demand open for all market participants.

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.
INES wants to underline that there is a huge potential of storing Hydrogen in Underground Gas Storage in Europe which shall be considered in developing an European approach for blending of hydrogen in the gas networks. The review of research programs and experiments with Hydrogen storage, allow to conclude that salt caverns are by nature more compatible with Hydrogen storage. In porous rock fields the phenomena of dissolution in water need additional research which is currently under investigation by the storage industry.

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.
No comment currently.

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.
A market intervention in form of subsidies for the development of Power-to-Gas-facilities aiming at the reduction of technology-costs is needed. The energy system will need PtG at large scale, e.g. to reduce emissions of industrial processes. If learning curves aren't used in advance it could be difficult to go along the pathway of energy transition because the switch to renewable gases isn't feasible when needed at large or industrial scale.

Q5 Which role do you see for power-to-gas infrastructures?
INES shares the view that the key role of PtG in coupling electricity and gas systems as well as between important demand sectors. Through sector coupling, gas infrastructures to transport and store gas can be leveraged to provide flexibility to the power system and transport renewable and decarbonized gas through the gas network. Since PtG will also facilitate the storage of renewable electricity via renewable methane or renewable hydrogen and thereby provide an important system value, it is important to also assess the services and valuation of storages in a coupled energy system in parallel with the development of PtG.

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?
By using energy conversion services and the underlying gas infrastructure, additional investments in the electricity grid might be avoided. This system value provided by the gas infrastructure to the future energy system needs to be reflected in the regulatory framework, especially in the tariff systems. Both the tariff system in the electricity sector and in the gas sector should better reflect the behaviour of grid usage and its implications for network costs. Hence, the principle of cost reflectivity in setting grid charges should be extended to recognize the contribution of energy storage systems to avoid (i) electrical grid constraints and grid extension costs and (ii) curtailment of intermittent renewable electricity generation. Furthermore, no additional levies and taxes should be applied to any energy unit transferred from one sector to another. Otherwise double-payment problems are inevitable.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
The current legal and regulatory framework in place was designed without having in mind PtG technologies and the handling of increasing shares of hydrogen in the gas mix. It is, therefore, necessary to adapt the current framework to enable the scale up of renewable energy in the gas sector and to gradually align the network planning for gas and electricity. Key cost drivers in operating PtG plants are the electricity price, electricity tax, renewable levies, electricity grid fees, CAPEX of plant and utilization hours. Currently many PtG plants need to pay the renewable levies, even though they are a renewable energy production. PtG plants in many countries are classified as final customers and have to pay high grid fees as well as levies and taxes although they usually alleviate the grid and are complement to grid development. Grid charges have a substantial impact on the overall cost and profitability of energy storage devices if one compares them to total operations and maintenance costs. From pilot projects operators learned that there is significant and immediately visible potential for deceasing in costs resulting from an increase in production quantity (economies of scale).

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
No comment currently.

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?
No comment currently.

Infrastructure Investments and Regulation

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?
No comment currently.

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)?
No comment currently.

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?
No comment currently.

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?
No comment currently.

Adapting the Gas Market Design

Q14 What are the critical points that should be addressed regarding the gas market design?
On storage, wherever the current framework does not already recognize/reward the full value of the underground gas storages, INES supports an evolving EU regulatory framework that enables to move to market-based pricing, in order to achieve efficient gas storage, used in a level playing field. The future gas market design needs to ensure that value of positive insurance and system externalities created by gas storage are assessed and adequately captured in the regulatory framework.

Q15 Considering the possible development of renewable gases, in your opinion, do you see a need to update the gas market design?
Market design barriers relate to the internalizing of the scarcity and dependability value in both gas and electricity markets. Without recognizing the value gas storage adds to the energy system in this new role under sector coupling, it will be difficult to attract the investment required for its progression. The scope of the gas directive should be enlarged to include renewable and decarbonized hydrogen and recognizing the value of gas storage under the current 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?
No comment currently.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
No comment currently.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
The value of Gas Storage challenges needs to be addressed in the future gas market design. Government and NRAs need to ensure that value of positive insurance and system externalities created by gas storage are assessed and adequately captured in the regulatory framework. The current approach should be moved towards a more holistic view in optimization of an investment planning across the entire energy system. Gas storage as major flexibility provider could further facilitate market convergence towards the greener-mix by fostering the spread of renewable and low-carbon gases.

Survey response 79

Contact details and treatment of confidential responses

Contact details: [Organisation][]
Eurelectric

Please, mark the box if you wish your response to be treaded as confidential. [If you wish your reponse to be treated as confidential]

Regulatory Challenges for Renewable Gases

Q1 Which activities do you consider relevant for potential TSO/DSO involvement that should be considered in the assessment?
We consider this questions as being relevant in particular when it comes to TSO/DSO involvement in power-to-gas technologies, including electrolysis. From a power-to-gas side, Eurelectric notices that the question of regulation of such activities, which may be considered as contestable activities, is sensitive. Whatever the outcome on this question, ensuring a market-based deployment and operation of those assets would contribute to an efficient use of power-to-gas units. Eurelectric also emphasizes that competitiveness of those technologies will depend on both the availability of electricity at zero-marginal cost and on high load factors to amortize Power-to-Gas plants investments costs. It is clear that in the short to medium term, the market will not deliver large scale power-to-gas technologies because they are not mature yet. That is why we would propose a two-step approach: •In a first phase - in order to develop the technology and make it commercially available - public funding (either European or national) for financially supporting the scale up of green hydrogen and R&D for synthetic methane generation should be envisaged, in order to enable business cases for investors. Those investors will be primarily technology providers, and other commercial entities. It should be assessed whether such support mechanism should be based exclusively on investment grants/aids to facilitate development or should include mechanisms to cover operational costs for the duration of the trial. •In a second phase – once the technology is mature/commercially available, we are of the opinion that there is no reason why power-to-gas plants should be developed, owned or operated by regulated entities; neither by TSOs nor by DSOs. Alike gas-fired power plants, power-to-gas plants are facilities consisting in converting an energy carrier to another one. As power generation is considered - without any controversy - as a contestable activity which cannot be carried out by regulated entities, we believe the same should apply for gas production from power-to-gas plants. The assessment of potential future exceptions for TSO/DSO involvement in power-to-gas activities, such as the ones considered in the CEP for storage and EV charging, should be done carefully and in accordance with the principles of liberalized and competitive energy markets. It is premature to assess whether the same logic can apply to power-to-gas activities. When it comes to the assessment of a potential TSO/DSO involvement in power-to-gas activities or other grey areas, Eurelectric broadly supports the conceptual tool developed by CEER in its conclusions papers “The future role of the DSO” as well as “New Services and DSO Involvement”.

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.

Regarding blending of hydrogen in gas networks, Europe will eventually need a common European threshold instead of 28 different norms and regulations. In a more interconnected energy system, a coherent approach toward hydrogen blending is necessary especially because hydrogen might become the key gas regarding sector coupling and increasing synergies between electricity and gas sectors.

However, before a European wide threshold can be applied, technical, safety and economic aspects have to be clarified.

Blending concentrations across Europe heavily depend on the characteristics of the existing network, natural gas composition and end use applications. It is therefore necessary to understand what is the technically safe level that may vary between specific parts of the transport (generally steel) and distribution system (often polyethylene) in various countries. It will also depend on the availability of carbon neutral hydrogen across Europe.

Defining a common European threshold without a better understanding of these technical and safety aspects would be premature.

Eurelectric therefore is of the opinion that a high European threshold does not seem recommendable until sufficient safety, technical and economic feasibility studies have been carried out, also taking into account cost-effectiveness and optimised management of existing infrastructures. These should encompass both costs of H2 generation and costs of gas networks adaptation. Until then a low, indicative threshold, taking into account all relevant technical and legal conditions and restrictions while being accepted by stakeholders could be a first step to give some directions for this developing market. That is also because increasing the infeed of hydrogen will require extensive cooperation among Member States to prevent barriers to the cross-border tradability of gas.

Last but not least, it needs to be acknowledged that blending hydrogen and natural gas in existing or upgraded gas infrastructure can only be an intermediary step, with carbon-neutral gas needing to be deployed in order to meet the Paris climate goals.

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.

It is unclear at this stage how hydrogen will be optimally and safely used. There are several options, which could also be combined, among them:

- Local use in industrial processes, transport and other applications.
- Injection into the gas network until the technical limit of the network.
- Production of synthetic natural gas through methanization.
- Export of hydrogen to other areas through large scale/greenfield hydrogen pipelines.

The three top possibilities in the list can be locally carried out and do not require the development of a large scale hydrogen network.. Therefore, Eurelectric believes that the establishment of an extensive parallel new infrastructure should be carefully assessed to ensure economic efficiency. In order to minimize the cost of switching to low carbon and renewable hydrogen, Eurelectric considers that: electrolysers should be built either on industrial sites, next to the natural gas grid or next to the renewable energy source.

When it comes to the question on the need to regulate or not dedicated hydrogen networks, we believe this may be premature at this stage. Indeed, developments of dedicated hydrogen networks will be probably very gradual and start at local level (i.e. in a decentralized manner connecting industrial sites). Should a dedicated regulation of hydrogen networks be needed, it should be developed only when such a network starts to develop and has reached a certain scale, in terms of feed-in points, customers and volume. In addition, it should only happen when a physical hydrogen wholesale market would be needed to enable exchanges of large volumes of H2 across Europe.

It would also have to be carefully assessed whether the regulatory framework for gas networks would suffice if hydrogen is used as an energy carrier in the public energy supply for households, industry, commercial consumers and power plants, as defined in the 3rd Energy Package. Such approach would ensure that the same criteria and principles should apply to both hydrogen and gas infrastructures, including third party access, non-discrimination to hydrogen producers and end-users. This would allow for other gases a similar regulation and ensure a level playing field. It would also set clear rules and provide the appropriate protection for a new emerging natural monopoly. But, again, this is something that should only be contemplated when the perspectives for such large scale deployment of hydrogen transportation and distribution are clear.

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.

In our view, if you have the right incentives defined through Energy and Climate policies and markets are well designed, this should favor the most cost-efficient solution to the energy transition. A combination of well-designed markets indeed ensures non-discriminatory market participation by all competing technologies and gives the right economic signals, taking into account the positive or negative externalities.

The only reason to depart from this and opt for an intervention would be the existence of a market failure affecting the delivery of an efficient outcome. The basis for an intervention should not be the identification of “inefficient outcomes” (i.e. big risk of mistakes, arbitrariness), but the identification of a market failure – i.e. it is about acting on causes rather than on consequences, and a “cost efficiency” issue is clearly a consequence (indeed quite arbitrary as it can hardly be evidenced).
In any case, a market failure can only happen when a market is conceivable, and that is not yet the case for power-to-hydrogen or large scale power-to-gas. These are technologies that are still relatively far away from economic and technical maturity. They can potentially be used in a variety of ways, but we still do not know which of those ways will be successful, if any. If they are not being deployed now, it is not because of a market failure, but because of this lack of maturity. Therefore, all the efforts should first be orientated to address this lack of maturity through public funding (either European or national) for financially supporting the scale up of green hydrogen and through R&D for synthetic methane generation. Only when they are commercially available, the identification of possible market failures can start.

Once we are in that situation and a market failure is identified, any intervention should counteract the negative effect of the market failure rather than directly determining what the effect on the outcome is (i.e., the “cost efficiency” issue) and selecting the corresponding “winners / losers”. Preserving the technology neutrality / level playing field is becoming even more important as technology evolution is (a) giving new options to consumers, and (b) increasingly coupling energy sectors. Thus, it is key to enable an effective competition even between energy carriers in order to make sure consumers’ decisions are not distorted by biased economic signals.

In this sense, key elements are (a) taxes (driven by polluter pays principle; non-ETS sectors should be subject to a CO2 cost comparable to that of ETS sectors), and (b) levies and fees, energy policy related charges, etc. driven also by harmonised principles, including a fair allocation / sharing of the decarbonisation financial effort (so far mostly born by electricity consumers).

Last but not least, it is important to ensure that the “cost efficiency” criterion does not only apply to short-term effects but also consider the long-term development of new technologies. In particular, high upfront investment costs are often necessary and should not prevent the development of long-term cost-efficient solutions.

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

Power-to-gas can potentially play two complementary roles: by complementing and facilitating electrification.

Eurelectric Decarbonisation Pathways study finds that 60% of direct electrification is required to achieve a 95% decarbonisation of the European economy. Power-to-gas and other non-emitting fuels have a role to play as electricity alone cannot deliver full decarbonisation.

The coupling of electricity and gas sectors/systems/markets through Power-to-gas is a potential key link in the transition to a deeply decarbonized economy, where needed to complement direct electrification in “harder to abate” sectors:
• The study finds that Power-to-X fuels would represent around 17% of total final energy consumption in 2050 in the most ambitious scenario, hydrogen alone would be around 6% of total final energy consumption in 2050
• The study finds that industry would be the main consumer of hydrogen in industrial processes in 2050 with between 500 and 1,400 TJ, and around 3,100 TJ of other clean fuels that require electricity to be produced.
• A significant amount of additional electricity will then be needed to produce this hydrogen, power-to-gas and other fuels. We assess that ca. 410-800 TWh of electricity will be needed to produce clean fuels required to decarbonize industrial applications, depending on scenario.

Additionally, power-to-gas could also support the electricity system. In a high-renewable future, system balancing and the required firmness and flexibility to ensure security of supply will be provided by competing sources. Traditional sources include conventional firm generation capacity such as hydro and nuclear power, as well as a much larger role played by demand side response, as well as storage. In this context, the flexible production and storage of electric fuels such as hydrogen and power-to-gas or power-to-liquid can potentially be a key contributor to the provision of carbon neutral firm/flexible capacity.

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?

Distortions may exist if grid tariffs are not efficient or if there is some unlevelled playing field due to sector or technology-specific measures or provisions, for instance on networks tariffs (either for injection or withdrawal) or levies.

In particular, in some countries, power-to-gas facilities are classified as “end consumers” in the electricity sector and are therefore charged with all associated taxes and levies.

To fix these distortions, a review of network tariffs and additional taxes/levies should be undertaken. It is important to distinguish between (a) use-of-network tariffs (UoNT), (b) additional levies / charges and taxes.

Use of Network Tariffs (UoNT):
- The risk of double charging affecting power-to gas when using exclusively the electricity network is similar to that affecting any other electricity storage. Hence, it is necessary to design UoNTs that ensure power-to-gas is charged (a) for the variable costs corresponding to both their uptake and injection (two charges), and (b) for the fixed costs corresponding to their access to the grid (a single charge). Ideally, this should not be obtained by introducing a specific network tariff for power-to-gas facilities, but by developing general design criteria to all grid tariffs that ensure efficient economic signals both to injections and offtake from the grid.
- In the same way, when power-to-gas facilities use both the electricity and gas networks they should also receive efficient economic signals, that reflect the costs they cause for both networks -
- In any case, UoNTs should be always sufficient to cover the total regulated network costs. A significant effort in terms of UoNTs design should be undertaken and the best practice report on tariff methodologies to be elaborated by ACER (article 16 new Electricity Regulation) could be a step in the right direction.

Additional levies / charges and taxes: these create significant distortions. There is a need for coordination between energy carriers in order to ensure a level playing field. More specifically:
- Levies and charges of the energy system, including the decarbonisation financial effort (e.g. cost of RES support schemes) should be fairly allocated / shared among all energy consumers (so far they are almost exclusively borne by electricity consumers).
- Taxes should be driven by the “polluter pays” principle: non-ETS sectors should be subject to a CO2 cost comparable to that of ETS sectors.

However, while taxes and levies persist and are not coordinated across energy vectors, it could be argued that storage and conversion of one form of energy into another should be exempted in particular from end consumer taxes and levies. However, this should be carefully designed and monitored, since it could lead to further distortions.

To conclude, Eurelectric does not in general support the implementation of technology specific electricity and gas grid tariff reductions or exemptions to support the development of power to gas production units, or to compensate for services they may supply to the grids. In any case, a level playing field must be ensured:
o Tariff structures should be tailored so that each grid user pays a price covering the costs it induces on the grid;
o Flexibility services supplied through power to gas technologies should be enabled and valued on the specific markets the services are targeting (demand response, capacity markets, reserve);
o Public support may be needed to prepare the deployment of power to gas technologies, to support future very high shares of RES in the electricity mix. It will be up to policy makers to decide whether Member States should subsidize renewable gas technologies. From a regulatory point of view, if such instruments are implemented, Eurelectric considers this public support should be direct (direct subvention for instance) to ensure visibility and avoid distortion for other grid users, while being adapted to the maturity of relevant technologies.

Q7 Do you see other possible issues regarding power-to-gas technologies that require consideration from a regulatory point of view?
First of all, a regulatory framework requires a consistent and clear taxonomy of the subject matter to be robust. Therefore, to avoid future legal issues, we must establish clear definitions of sustainable gases and other gases (including hydrogen and power-to-gas fuels) based on their CO2 emission along the entire value chain. Such taxonomy must be consistent with the “renewable energy” definition in the new Renewable Energy Directive: "energy from renewable sources’ or ‘renewable energy’ means 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 biogas;" This means that gas produced from power-to-gas could not be considered as additional “renewable” contributing to the EU RES targets for 2030 even when using renewable power as input. In this sense, the potential contribution of power-to-gas to the achievement of the EU’s decarbonisation objective should be assessed exclusively as the energy conversion & storage technology of RES energy already injected into the grid: •It is necessary to unbundle the value of renewable power generation from the value of conversion & storage. •The value of conversion & storage must be additional / differential to that corresponding to the renewable power used as input. Given the uncertainties on the evolution of gas demand in the long run and the ongoing discussions on sector coupling technologies, new investment decisions on gas infrastructure should be carefully assessed. A stronger oversight by ACER and NRAs will be necessary and the increasing importance of links between gas and electricity infrastructure shall be reflected in a new requirement for joint grid planning activities, at both European and national levels. Power-to-gas will be subject to both electricity and gas regulation and network codes with different requirements. This could possibly lead to issues concerning differences between physical characteristics of the power and gas systems and respective applicable legislation.

Q8 What is required to facilitate efficient cross-border trading of renewable gas GOs?
Although it should be clearly highlighted that the main purpose of GOs is about “disclosure” and not “support”, the introduction of GOs for renewable gas could be perceived as a tool to support the implementation of targets or quotas. Eurelectric does not support the introduction of objectives or quotas for renewable gas penetration. Until power-to-gas reaches maturity, renewable gases should be used primarily when no electric alternative to fossil fuel exists. It is indeed the case for some industrial processes, shipping, etc. To facilitate the development and use of renewable gases in those cases, the implementation of a trading system for renewable guarantee of origin can be a pivotal instrument. Cross-border trading already takes place but impacted by variations in value due to standards and fungibility, and requirement for equivalent physical gas flows. Obviously, if power-to-gas is mature and competitive, the need for a cross-border trading of renewable gas GOs would have to be further assessed. Should we go for such approach, we agree that a standardized system is required in which the GOs can be traded independently from the commodity (Book&Claim) as it is the case with guarantees of origin for electricity. A potential obligation to physically transport the gas in order to be able to trade guarantees of origin throughout Europe would prevent the establishment of a liquid market for such GOs. A European-wide system enables transparent and trustworthy trading across borders. This includes standardisation of certificates, definitions and interoperability of procedures for national registries: oGOs for renewable gas present more challenges than GOs for electricity, given the diverse nature of renewable gases (due to the different feedstocks used, the different qualities, etc). Given that renewable gases may not be equally ‘green’, they may not all qualify for the same number of certificates. oTo address these challenges, we believe the key elements would include a standardised European definition of ‘renewable gas’, the creation of a tradeable certificate which is recognised and valued across national borders and a system which allocates the appropriate number/value of such certificates to the different sources of renewable gas (e.g. bio-methane, bio-SNG, P2G, hydrogen). oCertificates should be clearly defined to which type of renewable gas they apply. Certification could extend beyond renewable gases also to low-carbon hydrogen. Differences in type or quality should be clearly labelled on the certificate. This would allow the market to set different prices depending on quality. In this case, the GO system for low-carbon gases should be clearly separated from the GO system for renewable gases. Otherwise, mixing-up all of these gases into the same GO system would lead to some confusion or complexity in the management of the GO scheme.

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?
Guarantees of Origin in the power sector have developed in the last decade, despite no harmonization and with different requirements, diverse markets and very different traded products from a European country to another one. One of the key success factors for such development is to enable cross-border trade of GOs for renewable gas, despite diversity of those traded products. In order to establish liquid markets, it is essential that the commodity can be traded regardless of its origin. Therefore, a GO system for gas, similar to that for electricity, should be structured in such a way that a GO can be traded independently of the commodity. It requires clear definitions and consumer communication/expectation management on international trade vs. actual local benefit. In general, the current renewable electricity GO system appears to be a well-designed and suited tool, as it constitutes a guarantee of reliability, while also enabling "green offers" to develop for consumers having a willingness to pay a premium for it. It should be recognized that the purpose of GOs is "disclosure" and not "support". To avoid confusion, it should therefore be preferable to clearly distinguish support mechanisms and GOs and make sure that "windfall profits" do not arise when RES production benefits from both a support scheme and the sale of corresponding GOs.

Infrastructure Investments and Regulation

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?
Eurelectric would like to remind the important role of TYNDPs and CBAs methodologies which should forecast the dynamics in power and gas markets in the coming decades. The growing interdependencies between gas and electricity in Europe will require a more integrated infrastructure planning, a co-ordinated risk preparedness and system operation across sector. In this context, sector integration, sector coupling and the cost efficient use of existing infrastructure should be seen as key principles. A coordinated electricity-gas approach would support the good management and development of the infrastructure networks in a cost-effective way, based on efficient investment plans. The ongoing coordination between ENTSO-E and ENTSOG, underlined by the article 11(8) of the Regulation (EU) No 347/2013, is an opportunity for reaching such a goal. Therefore, the delivery of the TYNDP 2020 and their underlying scenarios must be encouraged, based on a common framework of the European Cost Benefit Analysis of grid Development Projects. As mention in the Regulation, prior to submitting their respective methodologies, both ENTSOs shall conduct an extensive consultation process involving all relevant stakeholders, national regulatory authorities and other national authorities. Regulators as well as the European Commission have played an important and active role in this process and its assessment so far. Going forward, as far as ACER's and NRA's responsibilities are concerned, Eurelectric believes that: •ACER and NRAs should play a key role in ensuring that the ENTSOs' TYNDP scenarios reflect the new reality and include long term projects for gas demand that are compliant with the Paris agreement, in line with the most recent analysis and take into account the maturity of promising technologies such as power-to-gas. Such hypothesis and scenarios should take into account technology costs and competitive alternatives for clean energy carriers, demand side flexibility potential, energy efficiency and conversion losses, the impact of the overall gas volumes on bio resources and on the electricity system, foreseen imports and their implications, as well as infrastructure requirements for different types of gases and blends. Concretely, for the upcoming TYNDP 2020 and the future ones, it is essential that both ACER and NRAs play a major role, in particular for the approval of CBA methodologies and PCI assessment. Whether it refers to gas or power PCIs, public authorities must ensure that CBAs and PCIs are unbiased and assessed, individually, through the appropriate scenario (ex: yearly volume, daily peak, 2-week cold snap, low RES availability, etc...) at the appropriate geographical scope and via the relevant cross-commodity or coupling approach. Following those key principles should ensure a cost-effective and future-proof approach to infrastructure requirements and investments to avoid future stranded assets. •While the coordination at European level between the ENTSOs on the TYNDPs and the level of the involvement of NRAs and ACER is already described in detail in Regulations (347/2013 and 715/2009), it would be beneficial if NRAs could ensure an enhanced coordination at national level when grid development plans for gas and electricity are being elaborated. Alike at European level, national grid development plans for gas and electricity should reflect the new reality and include long term projects for gas demand that are compliant with the Paris agreement, in line with the most recent analysis and duly take into account the maturity of technologies such as power-to-gas.

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)?

As highlighted in our response to the previous questions, assessments for the need for new infrastructures should be carried out in a coordinated and hybrid manner between electricity and gas TSOs, in order to assess if (subject to the technology becoming mature and commercially available) or how power-to-gas interactions are able to provide an appropriate answer able to meet the demand (whether it refers to flexibility, security of energy supply or to congestion lifting). Such coordinated approaches for grid planning networks management and identification of investment needs are of utmost importance, to avoid costly grids reinforcement and to ensure a cost-effective and optimised management of existing infrastructures.

Furthermore, Eurelectric believes that before making financial investment decision, any gas PCI project (as for any power PCI project) should be subject to a sound, comprehensive, fair and unbiased cost-benefit analysis; this should be considered as a prerequisite to prevent any further risk of stranded assets.
A robust scheme at European level would be necessary:
• Projects selection, CBA when the project is at a sufficiently advanced stage, and proposal for sharing costs and congestion revenues;
• The decision by each regulator approving the costs that would be covered by tariff. Comparison by the European Commission of all the projects according to the ratio "amount of subsidy requested to balance the budget vs expected benefits of the projects". The lowest ratios should be prioritized in granting subsidies and any derogation should be duly justified.

It should be possible to integrate the projects in the PCI list but only to benefit from the administrative facilities from the beginning to allow to start the permitting process. The financing decisions should intervene later in the process only when all the information is available for a sufficiently robust CBA.

Finally, Eurelectric considers that the current gas network code on Capacity Allocation mechanism (CAM NC) is a good basis to assess market willingness to pay for a given PCI project. Some provisions of the CAM NC set that a market test should be carried out prior any decision for approval of a PCI and this does not limit the ability of authorities to make a decision to still build the infrastructure for any valid reason. Therefore, market tests as set by the CAM NC should be the driving factor.

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?

On the one hand, it is now broadly acknowledged that the role of natural gas will be declining substantially on the path to a carbon neutral economy, as highlighted in the European Commission’s Long Term Strategy (3% to 4% of total final energy consumption in full decarbonisation scenarios). Decarbonisation of the energy system and the expected decrease of natural gas consumption to meet long-term climate goals may therefore lead to the question of decommissioning parts of the current gas infrastructure.

On the other hand, the potential of developing hydrogen, biomethane and other renewable gases in the future can contribute to future use of the gas infrastructure, thus reducing the volume of stranded assets. Indeed, existing gas infrastructure could be used for the transport and distribution of hydrogen, biomethane or renewable gases, after technical feasibility & safety considerations have been addressed. If power-to-gas technologies mature and become commercially available, the risk of stranded assets could be significantly diminished.

What is crucial is to ensure that gas regulation schemes do not incentivize building more infrastructure if not necessary, as many of them do now. The continued use of the existing gas infrastructure should also not be seen an objective in itself. Gas regulation schemes should prevent unnecessary re-investments in gas infrastructure where possible and promote timely investments in alternative solutions which lead to CO_2 reduction. To do so, gas regulation schemes should be subject to a continuous monitoring of the maturity and competitiveness of hydrogen, biomethane and power to gas technologies and be based on gas demand forecasts that are compliant with the Paris agreement and in line with the most recent analysis.

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?
As mentioned by CEER, Eurelectric supports that any potential decommissioning of gas assets should be subject beforehand to a robust cross-border assessment with the adjacent Member States which may be impacted (in terms of security of supply, market functioning), based on CBA. Together will transparent forward plans under TYNDP, the role of NRAs will be key and their close cooperation is necessary to solve such issues. Some sort of market test should indeed be used. For instance, if capacity bookings are below a certain threshold during a duration of x years, a mechanism could be used to ask market participants for interest in the future of the asset in question. Moreover, it should be checked whether there is alternative infrastructure that could be used for the same purpose, or whether the infrastructure could be reused for other purposes (e.g. alternative products that could be shipped through, like hydrogen to help building the backbone for a hydrogen infrastructure or for the transport of CO2 to support CCS), thus avoiding the need for (full) decommissioning. Finally, Eurelectric considers that approaches suggesting the acceleration of depreciation periods for stranded assets for tariff calculation, which are potentially subject to decommissioning on the short or mid-term, should be carefully assessed, including cross-border impacts. Those kind of measures would heavily penalize existing gas end-users, gas-fired power plants included; yet, those ones make the gas system running, thus it would be quite unfair for them to bear the financial burden resulting from oversized investments made in the past. Such kind of measures would be very detrimental to gas-fired power plants, as any significant increase of the transport costs may slide those plants out of the merit order on the electricity market. Hence, it would potentially lead, not only to a further decrease of gas consumption - and thus hinder sector coupling -, but also induce a potential spill-over effect on further need of decommissioning of additional gas infrastructures. Therefore, the remaining costs of a decommissioned gas asset should be dealt with through a European fund that could address these extreme scenarios.

Adapting the Gas Market Design

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

Before defining new changes, we would support the full implementation of the Gas Target Model and the gas network codes. This should take priority before any new changes are being proposed. We are pleased to this that the evaluation of NC implementation forms part of the ongoing work carried out by the European Commission in preparation for a potential Gas Package.

As stated in the scope of the Quo Vadis study carried out by the EC in 2017, Eurelectric considers that the following points should be considered in a future review of the gas market design:
-The question of cross-borders tariffs at interconnection points - and their potential evolution in the coming years - is of upmost importance. Gas TSOs should aim at achieving the most efficient dispatch, notably for cross-border capacities, to capture maximum social welfare for both electricity and gas. To achieve this purpose, gas TSOs' costs recovery should be set in a transparent way. In particular, it should identify which investments and assets are being considered in the definition of interconnection tariffs and could be decoupled from specific border charges to enable an optimized use of interconnection capacities. Low cross-border tariffs would strengthen the connection between gas markets and foster their liquidity and maturity across Europe. As for electricity, it would facilitate the trade and transport of gas from supply sources to end-users and prevent distortive effects for gas-fired generators, which are critical to deliver firmness and flexibility to the electricity system, particularly during the transition. As mentioned in our answer question 13, any significant increase of gas transport tariffs at interconnection points would be very detrimental to gas-fired power plants, as it may slide them out of the merit order on the electricity market.

-Regarding gas markets integration, Eurelectric believes the market design should evolve focusing on achieving an optimal use of gas assets and transport capacities. The underlying objective of such an evolution is to have a better functioning market with increased access for a range of market players to different trading zones or hubs: cost-efficiency should prevail and gas market design should evolve to ensure such cost-efficiency. Convergence of gas hubs must be encouraged, however, Eurelectric considers that market models suggesting merging of markets zones or implementing a unique market zone across Europe may have some major drawbacks. Merging zones may require significant investments in infrastructures to make the merged zone relevant and viable in any circumstances, potentially leading to stranded assets. Therefore, evolving towards a unique European gas market area may lead to potential inefficiencies in handling large structural congestion. From a cost-benefit perspective, such mergers could be of limited interest and would potentially raise some major operational issues for networks management for TSOs. From a gas end-user point of view, the key issue is to have an easy access to the gas hub/market place and delivery periods (ex: day-ahead, week-ahead, month-ahead, etc.), wherever it is located, at the most affordable price possible.

-Last but not least, as already mentioned, growing interdependency between gas and electricity in Europe, consistency in the evolution of gas and electricity market design (e.g. tariff and capacity allocation regimes) should be addressed. In the past, we observed a certain level of disconnection between the electricity and the gas regulatory frameworks. Therefore, coordination between electricity and gas infrastructure investments and a consistent evolution of both market designs must be ensured. In a broader view, electricity and gas market designs should ensure synergies with other sectors and opportunities for a whole system approach.

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

The principal goal should be that "new" decarbonised and renewable gases can be supplied and traded on a level playing field with natural gas as part of the gas market. Possible barriers for entry (e.g. in the form of undue technical requirements) should be eliminated

Public funding - either European or national – for financially supporting R&D for green hydrogen or synthetic methane generation should be envisaged, in order to enable business cases for investors in the development of water electrolysis plants, as soon as there are fuelled from green electricity. Those investors will be primarily technology providers and mainly consortia involving market parties and network operators. It should be considered whether such R&D support mechanism should not only be an investment grant/aid to facilitate development, but should also cover operational costs for the duration of the trial. Obviously, power-to-gas plants should be allowed to participate in ancillary services markets.

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?
First of all, Eurelectric believes that priority should go to the full implementation of the network codes, including the TAR network code on harmonised transmission tariff structures for gas. The TAR NC will be realized in the forthcoming year and includes increased transparency requirements for TSOs to explain their methodology behind the calculation of tariffs. Not all TSOs are doing it fully and this should be addressed as a matter of priority. Grid tariffs should not be used to support or incentivize renewable gases, since they should be focused on recovering grid costs and providing efficient economic signals. Before new rules may be developed, a sound analysis of the possible impact on the gas sector would be needed. Changes that may result in a less liquid and more fragmented European market should be avoided and it needs to be assessed if and where specific actions are appropriate and needed. It should be self-evident that infrastructure is paid by all its users. Otherwise, there would be an imminent risk of cross-subsidisation. Eurelectric agrees with CEER analysis set out in chapter 6.2 of its consultation. The diagnostic made by CEER, which was also raised into the FROG study performed in 2018, remains valid and is fully relevant. In particular, there is a risk that termination of long-term contracts of gas transport capacities at some interconnections points, combined with the decrease and more volatile gas demand in the coming years, would lead to significant changes in the use of European infrastructures and in price formation on certain hubs. The bottom-up approach, as proposed by CEER, seems interesting and may deserve further investigation. Risks of fragmentation of gas markets may be not be uniform in Europe because the termination of gas contracts may happen at different moments. The same criteria should apply but at different moments depending on when the problem arises in the country. However, we also note that under the current regime, tariffs can increase as a result of decreasing gas consumption. This could be addressed by first of all employing smart climate policy aimed at optimal, timely and cost-effective CO2 reduction strategies. Such strategies can promote the development of new, decarbonised and renewable gases and thereby enable that (parts of) current assets remain used. Optimal and cost-effective strategies for CO2 reduction also help to reduce the consumption of natural gas in a timely fashion. Secondly, a redesign of the tariff regime seems necessary at a certain point. Otherwise, tariffs may go up substantially when natural gas use decreases, which may lead to more customers switching away from gas and prompting new tariff increases, etc. Although a revision of the tariff regime appears necessary in the near future, it is difficult to set an appropriate timing of such a revision. This will strongly depend on future CO2 reduction policies, the development of both natural gas and decarbonised gases demand and of alternative solutions. Moreover, the study currently performed in the European Commission on the capacity/commodity releases programmes may provide further elements to address this issue.

Q17 If yes, how could the current tariff system, with particular regards to cost allocation methodologies, be amended?
Eurelectric takes note of the CEER example on LNG terminals, which are described as assets providing benefits like security of supply, market integration, increasing competition or decarbonisation which may justify keeping them working even if they are underutilised. Therefore, amending the cost allocation methodologies in order to integrate those kind of benefits may be justified, providing it is based on a clear and transparent methodology and prevent any risk of discrimination.

Other question

Q18 Are there other regulatory challenges for a sustainable gas sector not addressed in this document?
Externalities, both positive and negative, should be a key criterion in the decision-making process to invest in a new project or decommission an existing asset during the energy transition. Due to some subjective criteria, such externalities remain complex and debated, but must be quantified. Therefore, it would be at the best interest that a broad discussion at European level should be carried out to set the basis for a CBA methodology.