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The EU Hydrogen and Gas Decarbonisation Package:

help or hindrance for the development of a European hydrogen market?

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Executive Summary

The European Commission has identified 'renewable' and 'low-carbon' hydrogen[1] as major elements of its decarbonisation strategy. The REPowerEU Communication[2] of 2022 set the target for renewable hydrogen consumption at 20 Mt/y by 2030, of which 10 Mt/y would be imported. In December 2021 the Commission published the Hydrogen and Gas Decarbonisation Package which included proposals for regulation of hydrogen infrastructure.[3] The final package is expected to be agreed with the EU Parliament and EU Council by the end of 2023.

The proposals for hydrogen regulation must be seen in the context of the EU's decarbonisation policies aimed at reducing emissions by 55 per cent by 2030, the 'Fit for 55' package. The EU Commission has predicated its proposals on the establishment of an integrated EU hydrogen market and has used the PRIMES model to develop scenarios for energy usage which meet the Commission's goals. It has used the METIS model to simulate the operation of energy markets within the EU, and hence the impact of policy choices on the development of EU energy infrastructure. However, this means that the Commission's proposals are 'path dependent' on the EU hydrogen market developing in line with its scenarios. This in turn depends on agreement on all the elements in the Fit for 55 package being aligned with the Commission's scenarios, and on Member States putting in place effective policies to meet the EU-level targets.

There is little allowance for the considerable uncertainty about the development path of the hydrogen market. Unlike natural gas at the time of liberalisation, there is no well-established mature hydrogen market and infrastructure. The Commission is being heavily influenced in its approach by its experience in trying to liberalise natural gas markets over the last quarter century, including the issue of unbundling networks from gas production and supply. Although the Commission does recognise that the hydrogen market is yet to be developed, it is open to question if it has learned the right lessons from its past experience given the very different challenges involved.

The Commission expects there to be two gaseous networks, one for methane (including biomethane and synthetic methane as well as natural gas) and one for hydrogen. Based on the REPowerEU target the Commission anticipates a need for infrastructure to transport up to 14.7 MT/y of hydrogen, of which 6 MT/y will also need hydrogen import infrastructure. (A further 4 MT/y of hydrogen will be imported in the form of ammonia or other hydrogen derivatives.) The Commission expects there to be a requirement for significant cross-border infrastructure for hydrogen transportation, as well as hydrogen storage of renewable energy to mitigate the intermittency of renewable electricity generation.

The Commission's policy objectives include:

- facilitating the emergence of an open and competitive EU hydrogen market;
- removing barriers to, and ensuring incentives for, investment in hydrogen infrastructure;
- addressing the risk of natural monopolies in hydrogen infrastructure;
- ensuring cross-border integration within the EU and with third countries and unhindered cross-border flows of hydrogen;

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[1] The European Commission distinguishes between renewable hydrogen which is based on renewable sources of energy only, e.g. electrolysis using renewable electricity. Low-carbon hydrogen can be derived from methane reforming or coal gasification with Carbon Capture and Storage, or using electrolysis where the electricity is not renewable e.g. nuclear or electricity from the grids with a sufficiently low-carbon footprint. The precise definitions are still being finalised. Unlike other jurisdictions such as the UK where low-carbon hydrogen is defined based on its carbon footprint, the Commission distinguishes by energy source as well.

[2] European Commission (2022) REPowerEU Plan

[3] European Commission: Hydrogen and gas decarbonisation market package

- providing transparency of the repurposing of existing natural gas networks to transport hydrogen; and
- enabling cost-efficient planning on the basis of scenarios in line with climate target objectives.

Potential problems which the Commission has identified include:

- lack of rules governing hydrogen infrastructure;
- the need for a definition of low carbon (as opposed to renewable) hydrogen;
- lack of rules on hydrogen infrastructure investments including repurposing of existing gas pipelines;
- hydrogen infrastructure likely to be a natural monopoly and therefore a hindrance to competition;
- diverging hydrogen quality rules and hydrogen blending levels hindering cross-border flows;
- intra-EU entry/exit tariffs hindering the establishment of a fully integrated, liquid, and interoperable EU internal market as a result of the 'pancaking' effect[4] where hydrogen crossing several borders pays tariffs at each border;
- insufficient energy integration in network planning;
- varied network planning between Member States and separate planning for electricity and gas;
- lack of transparency on potential for repurposing or decommissioning existing infrastructure.

The Commission's analysis is based on the way it expects the hydrogen market to develop. There are several vulnerabilities to this analysis including: the failure of low-cost hydrogen imports to materialise as quickly as expected; dependence on Member States' policies for the ramp-up of EU hydrogen production and use; the ramp-up of additional renewable electricity required in the EU to produce hydrogen (500 TWh is only slightly less than current levels of EU wind and solar generation); and the Commission's mistaken analysis of the tariff pancaking issue.

The Commission's legislative proposals include:

- regulated third-party access and ownership unbundling for hydrogen networks with limited exceptions to this to the end of 2030, and possible limited exemptions thereafter for interconnectors;
- regulated third-party access to hydrogen storage and negotiated third-party access for hydrogen import terminals;
- No cross-border tariffs on hydrogen networks and discounts for renewable gases in natural gas networks;
- A separate European Network of Network Operators for Hydrogen (ENNOH) by end 2025;
- a definition of low-carbon hydrogen by end of 2024 with greenhouse gas savings of at least 70 per cent;

[4] 'Pancaking' refers to the accumulated effect of cross-border tariffs on the delivered price of natural gas or hydrogen that crosses several borders from point of entry into the EU grid to point of delivery. For example, depending on the contractual path chosen, LNG delivered and regasified at Rotterdam could be sold to a customer in the Slovak Republic. Such gas would pay an entry tariff into the Dutch grid, then exit and entry tariffs as it went from the Dutch to the German grid, and so on from the German to Czech grid, and from the Czech grid to the Slovak grid. As discussed later in the paper the EU Commission erroneously believes that pancaking is a barrier to trade. However, as the tariffs for each section of the gas' transport are regulated, the cumulative costs should reflect the cost of transporting the gas from its first entry into the system to its exit from the system.

- the ability to transport up to 5 per cent hydrogen blended into natural gas networks at cross-border points; and
- improved integrated planning of energy networks.

The regulated approach proposed by the Commission should work well once the hydrogen market is well established with a mature supply and customer base, and well-developed infrastructure. The Commission has also provided regulatory certainty to market participants as the framework is detailed and builds on the experience of the gas market. However, the proposed framework only really becomes valid once the hydrogen market and associated infrastructure has developed as until then there are no natural monopolies. Full blown regulated third-party access is burdensome for embryonic networks. Strict ownership unbundling prevents risk sharing of the type that was common in the early days of the gas pipeline and LNG industries. The Commission recognises the advantage of providing some regulatory flexibility in the early years of the hydrogen market but the date at which this is withdrawn (2030) leaves very little time for the market to develop.

The Commission is moving too slowly with a deadline of the end of 2024 for its definition of low-carbon hydrogen; the sooner a definition is in place, the sooner companies can invest in hydrogen production which meets the required standard.

A separate organisation for hydrogen operators (ENNOH) will take time to set up. An organisation for both natural gas and hydrogen network operators based on the European Network for Transmission System Operators for Gas (ENTSOG) would be quicker to set up and benefit from common expertise and is therefore a better option. The disadvantages that the Commission foresees in a combined organisation can be overcome via the current regulatory framework and transparency of operation.

The proposal to remove cross-border tariffs on hydrogen networks, is based on the Commission's fallacious analysis of the pancaking issue and its view that cross-border transport tariffs hinder trade. Proposals for zero tariffs at cross-border points are a bad solution in search of a non-existent problem and should be shelved. Removing cross-border tariffs will require several network operators to agree revenue-sharing mechanisms which will be complex; this does not solve a problem but creates one. Discounts on tariffs for low-carbon and renewable gases in natural gas networks are also problematic as they represent a cross-subsidy between different groups of network users and mean that tariffs do not reflect costs. Cost-reflective tariffs allow for better comparison between different forms of energy transportation, so it would be better to subsidise renewable gases directly rather than via network tariffs.

It is difficult to tell if 5 per cent hydrogen blending is the right level, and certain technical implications are still being evaluated by the industry. Both Parliament and the Council propose a 2 per cent maximum. There is also considerable ongoing debate as to the merits of blending hydrogen into the gas network given the likely scarcity of renewable hydrogen in the early years.

Improved planning and cooperation between energy networks is useful. To some extent there may be more of a central planning approach for hydrogen by default if Member States choose to subsidise hydrogen networks explicitly as a means to stimulate the market. The high cost of hydrogen compared to fossil fuels means there is not sufficient value in the supply chain for the industry to be self-financing in the way that the natural gas market was in its early days.

The Commission has succeeded in its aim of providing a clear framework for the regulation of a future mature hydrogen infrastructure. With some minor changes, such as the regulation of storage and import terminals, it has followed the same template as that used for the successful liberalisation of the gas market, which ensures that gas flows to where it is needed and the EU can attract supplies from abroad. The Commission is also renewing its commitment to competitive gas markets, including for hydrogen. For this it should be applauded.

However, the key issue is whether the Commission has allowed enough time and flexibility for the hydrogen market and its associated infrastructure to reach maturity. The Commission relies heavily on matching its regulatory proposals to its scenarios for hydrogen usage but has not considered what could happen if the hydrogen market develops less quickly, or in a different manner to that which it expects. There are many uncertainties concerning both the production of hydrogen, and its demand.

It is also not possible to gauge from the Commission's figures how much hydrogen infrastructure will be in place by the time the full regulatory model is imposed in the 2030s. Hydrogen consumption does not directly correlate with the need for hydrogen networks or infrastructure because of the opportunity for production to co-locate with hydrogen consumption, or for hydrogen users to move closer to where hydrogen is produced within the EU or abroad. This is very different from the natural gas industry where the location of gas production is determined by geology and is mainly outside the EU and concentrated in a few regions. Hydrogen is also more difficult to transport over long distances compared to natural gas. Therefore hydrogen might need less transportation infrastructure than natural gas. Based on the Commission's original Fit for 55 proposals, the Commission expects very little direct gaseous hydrogen consumption in the 2030s. Even though the REPowerEU expectations for hydrogen are more than double those of Fit for 55, the amount of gaseous hydrogen consumed will still be very modest until the late 2030s. This begs the question as to why the Commission is insisting on a regulatory model better suited to a mature infrastructure at such an early date.

The Commission's proposals for flexibility up to 2030 do not give the industry sufficient time, given that it is already 2023. Longer flexibility periods, as proposed by the Parliament and Council, or a dynamic approach as originally proposed by the Agency for the Cooperation of Energy Regulators (ACER), would be better. By increasing the regulatory burden for hydrogen infrastructure, the Commission's proposals increase the need for government support as developers will be less able to manage the uncertainty risk inherent in the hydrogen market. Consequently, the Commission's proposals risk slowing the development of the EU hydrogen market in the early years, even though they would be sensible once a hydrogen market has developed.

Overall, there is much that makes sense in the package, particularly if the hydrogen market develops in the way the Commission expects. However, if it develops differently, for example more slowly, a greater degree of regulatory flexibility is desirable.

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Introduction

The European Commission has identified ‘renewable’ and ‘low-carbon’ hydrogen[5] as major elements of its decarbonisation strategy. These types of hydrogen have a much lower carbon footprint than traditionally produced hydrogen and therefore can be used as an energy source for consumers who cannot easily electrify their processes, for example high temperature heat in industry, heavy transport, or maritime and aviation fuel. The Hydrogen Strategy of 2020[6] set a target of 10 Mt/y of renewable hydrogen use by 2030 whilst the REPowerEU Communication[7] of 2022 increased that target to 20 Mt/y of which 10 Mt/y would be imported. This was in response to the Russian invasion of Ukraine and the desire to free the EU from any dependence on Russian gas supplies. During 2021 the European Commission published its proposals for several new pieces of legislation aimed at meeting its interim decarbonisation targets, namely a 55 per cent reduction in greenhouse gas emissions by 2030, the Fit for 55 Package.[8] The first set of proposals in July 2021 included revisions of the Renewable Energy Directive[9] which includes targets for industrial and transport use of renewable hydrogen.

In December 2021 the Commission published the Hydrogen and Gas Decarbonisation Package.[10] This was aimed at updating current regulation governing natural gas infrastructure, but also put in place rules to encourage the uptake of renewable and low-carbon gases such as biomethane and hydrogen. Whilst biomethane can be transported relatively easily by the existing natural gas network, this is not the case for hydrogen. This means that hydrogen requires either rules to enable its blending into natural gas flows, or rules governing the development and operation of a new and separate hydrogen infrastructure to connect production with demand.

The various elements of the Fit for 55 Package are working their way through the EU legislative process. This paper focuses on the Hydrogen and Gas Decarbonisation Package, and within that, only on the elements relating to hydrogen regulation. Other aspects of the package will be the subject of future OIES research. At the time of writing, the Hydrogen and Gas Decarbonisation Package is still at a relatively early stage in the legislative process, having been somewhat delayed thanks to the focus on the response to the Ukraine war and accompanying energy crisis. The Commission made the original legislative proposals in 2021, and more recently the European Parliament has had initial discussions on its proposed amendments to the Commission proposals and expects to agree these amendments early in 2023.[11] The Council, which represents the Member States, has also had initial discussions on its proposed amendments but has yet to agree its final position.[12] Once both Parliament and Council have agreed their positions, the stage is set for ‘trilogue’ negotiations between Council, Parliament, and Commission prior to agreement on the final package, which is expected to happen late in 2023. This paper refers to the Commissions’ original proposals and the accompanying Impact Assessment,[13] as

[5] The European Commission distinguishes between renewable hydrogen which is based on renewable sources of energy only, e.g., electrolysis using renewable electricity. Low-carbon hydrogen can be derived from methane reforming or coal gasification with Carbon Capture and Storage, or using electrolysis where the electricity is not renewable e.g. nuclear or a electricity from the grids with a sufficiently low-carbon footprint. Both renewable and low-carbon hydrogen must result in greenhouse gas emission savings of at least 70 per cent compared to a fossil fuel comparator of 94g CO2/MJ. Unlike other jurisdictions such as the UK where low-carbon hydrogen is defined based on its carbon footprint, the Commission distinguishes by energy source as well.

[6] European Commission (2020) A hydrogen strategy for a climate-neutral Europe.

[7] European Commission (2022) REPowerEU Plan

[8] European Commission (2021) ‘Fit for 55’ – delivering the EU’s 2030 climate target on the way to climate neutrality.

[9] European Commission (2021) Amendment to the Renewable Energy Directive to implement the ambition of the 2030 climate target.

[10] European Commission: Hydrogen and gas decarbonisation market package

[11] https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-revised-regulatory-framework-for-competitive-decarbonised-gas-markets-1 and https://www.europarl.europa.eu/legislative-train/theme-a-european-green-deal/file-revised-regulatory-framework-for-competitive-decarbonised-gas-markets-2

[12] https://www.consilium.europa.eu/en/meetings/tte/2022/12/19/

[13] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final

well as draft versions of the Parliament and Council proposed amendments. The paper examines the reasoning underlying the Commission's proposals, the suitability of the proposals for regulating a developing hydrogen market, and the key differences between the Council and Parliament amendments. It concludes by assessing whether the package will succeed in enabling the development of a hydrogen market, and where it could be improved.

1. EU Commission proposals in context

The proposals for hydrogen infrastructure regulation need to be considered in context so that the logic underlying the proposals can be understood. This is particularly important here as the proposals are creating a framework for something which does not yet exist, namely a market for low-carbon and renewable hydrogen. As will be seen, the Commission proposals are based on assumptions on not only how big this market will become, but also how it will develop. However, such a development path cannot be taken for granted as many of the variables are outside the Commission's control.

Firstly, whilst European legislation such as the Renewable Energy Directive can set targets for hydrogen use,[14] much depends on the effectiveness of Member States in developing their own policies to meet the targets. This includes subsidies for hydrogen production and use as hydrogen is currently more expensive than other fuels, as well as issues such as planning permits for renewable electricity generation or hydrogen infrastructure. For example, the EU currently does not have enough renewable generation to meet its current electricity needs let alone the additional 500 TWh needed to provide 10 MT/y of renewable hydrogen production by 2030, and progress on this front can be painfully slow. As President van der Leyen has pointed out, it takes up to nine years to permit a new wind park.[15] It is notable that achievement of EU climate change related targets, such as share of renewable energy or energy efficiency, vary across Member States and past analysis by the Commission has warned that many states' National Energy and Climate Plans will not meet EU targets.

This raises a second issue. The Commission has modelled what the energy system needs to look like meet its 2030 GHG reduction target, and outlined the proposed legislation needed to create the necessary change. This ranges from increased targets for renewable energy and energy efficiency, to extending carbon pricing to sectors not currently covered. Using the PRIMES model[16] the Commission analysed different scenarios for the Fit for 55 package and used the information to help develop the policy mix required to meet the targets. In the case of the Hydrogen and Gas Decarbonisation Package all the policy proposals were analysed based on the MIX-H2 PRIMES Scenario which underpinned the Renewable Energy Directive proposals' impact assessment.[17] As the Commission explains:

> *"While the Impact Assessment for a revised Renewable Energy Directive is looking at policy measures to promote the demand and production of hydrogen as well as renewable and low carbon gases, the present assessment explores the policy measures required for optimum infrastructure and efficient markets. By using the MIX-H2 PRIMES scenario, the overall relationships between energy supply and demand are preserved. This ensures consistency with the underlying policies driving the transition to Greenhouse Gas (GHG) neutrality as proposed by the Fit for 55 initiative."*[18]

In other words, the hydrogen regulation proposals are consistent with the quantity of hydrogen expected as a result of the implementation of the other Fit for 55 proposals. However, the Fit for 55 package is

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Brussels 15 December 2021.

[14] For example, targets for renewable hydrogen use in industry, or Renewable Fuels of Non Biological Origin in the revisions to the Renewable Energy Directive

[15] https://ec.europa.eu/commission/presscorner/detail/en/statement_22_3164

[16] https://web.jrc.ec.europa.eu/policy-model-inventory/explore/models/model-primes

[17] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final
Brussels 15 December 2021. Page 5.

[18] Ibid.

subject to negotiations between the Council and the Parliament, so agreement on the policies which could help to meet the targets cannot be guaranteed. Moreover, there is inevitably interdependence between the different policy initiatives, so for example a more robust carbon price will clearly be helpful to hydrogen uptake. The Commission is aware of these linkages, and indeed specifically refers to them in the Impact Assessment.[19] But it is not clear what happens to the energy scenarios if the policies change as a result of negotiation of the different elements of the Fit for 55 package. In the hydrogen context this could mean that the hydrogen market could grow more or less than expected, or in different ways, all with implications for infrastructure needs and regulation. The picture is further complicated by the dependence on EU Member States meeting the targets set at EU level. For example, targets for renewable hydrogen use in industry and transport are set out in the proposed revisions for the Renewable Energy Directive. But it is up to Member States to implement policies to achieve those targets, and to ensure the effectiveness of those national policies.

This 'path' dependency on the assumptions underlying the PRIMES scenarios is reinforced by the other model which the Commissions uses for its quantitative analysis. This is the METIS model which 'simulates the operation of energy systems and markets on an hourly basis over a year, while also factoring in uncertainties like weather variations'.[20] In the context of the Hydrogen and Gas Decarbonisation Package, METIS was used to assess different policy scenarios and their impact on the development and operation of energy infrastructure in the EU.

> *"The scenarios are based on the expected effect the policy packages will have on the development of (cross-border) hydrogen transport capacity (i.e. network infrastructure) and costs. The effect of different policy options on the development of (cross-border) hydrogen transport capacity can only be identified in terms of direction, i.e. different regulatory measures that are part of the policy options can increase or decrease the likelihood that (cross-border) hydrogen infrastructure gets built. Quantitative indicators are then calculated for all scenarios. The key quantitative indicators calculated for each of the scenarios are the effect on costs of hydrogen delivered and the full costs of hydrogen, which include the change in total energy system cost due to the deployment of hydrogen."* [21]

In other words, the regulations for hydrogen are based on a set of assumptions:

- The size and shape of the hydrogen market (as PRIMES includes assumptions about which sectors will use hydrogen as well as the total size of the market);
- The infrastructure needed to service the assumed hydrogen market;
- The impact of policies on the development of the infrastructure.

The challenge is the interdependent nature of these assumptions and the many variables contained therein. There is little allowance for uncertainty, which is important given the considerable uncertainty about the development path the hydrogen market could take. As an earlier paper[22] noted, the key difference between the implementation of the current natural gas regulatory framework and the proposed hydrogen regulation is that at that time there was an existing, profitable, and mature natural gas market with well-developed infrastructure. By contrast there is currently no hydrogen market, let alone any well-developed infrastructure. Whilst PRIMES and METIS are undoubtedly useful in assessing policy impacts, the earlier paper also noted that scenarios are not forecasts,[23] and that policy makers should be careful before assuming the inevitability of a particular development path. A key

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[19] Ibid Page 4 to 5.

[20] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/metis_en

[21] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final
Brussels 15th December 2021. Page 6.

[22] Barnes (2020) Can the current EU regulatory framework deliver decarbonisation of gas? Oxford Institute for Energy Studies.

[23] Ibid. Page 23.

question therefore is the ability of the proposed regulations to cope with different development possibilities.

The METIS model also relies on the judgement of the Commission that 'different regulatory measures that are part of the policy options can increase or decrease the likelihood that (cross-border) hydrogen infrastructure gets built'. Should this judgement be mistaken, there is the risk that the costs assumed with different policy scenarios are wrong, and therefore the proposed policies could be detrimental to the development of the hydrogen market. The chances of the judgement being wrong are increased by the inherent challenges of developing a new hydrogen supply chain, which in turn is part of the much bigger challenge of reengineering the EU's energy system. Unlike previous energy revolutions such as the industrial revolution based on coal, or the switch from coal to oil and gas, the current one is heavily reliant on policy to make up for market failures. This makes any judgement even more difficult because of the scale of what is being attempted and the unprecedented nature of the task.

Finally, it should be noted that the Commission is heavily influenced in its approach by its experience in trying to liberalise natural gas markets over the last quarter century. One feature of this was the opposition the Commission faced from incumbent companies and their government supporters, for example on the issue of ownership unbundling.[24] In its Impact Assessment the Commission makes several references to 'lessons learned' and clearly views the 'blank page' nature of the hydrogen market as an opportunity to create the optimal regulatory framework from the start:

> *'(The regulatory option) takes into account lessons learnt from the liberalisation of the gas and electricity sectors and exploits the fact that we can take a 'greenfield' approach to regulation, in which choices aimed at creating a competitive market can still be made unconstrained by an entrenched factual or regulatory situation.'*[25]

It is however open to question if the Commission has learned the right lessons from its past experience given the very different challenges involved.[26] The Commission does recognise that there will be a transition phase for hydrogen as the market ramps up, which was not the case for the natural gas market. But, as with the impact of its policies on hydrogen infrastructure development, much depends on the Commission's judgement and interpretation of lessons from the past.

Lest the above appear too critical of the Commission's approach, it should be emphasised that the Impact Assessment is a well-written and thoughtful document, worthy of attention by serious analysts. Models such as PRIMES and METIS can be invaluable in understanding the impacts of policy choices, although it would be helpful if there was more detail on the results of the modelling in the Impact Assessment so readers could better understand how EU energy systems might change, and what this means for development of the hydrogen market. The EU system is complex and as the Commission itself has pointed out, requires greater system integration if decarbonisation targets are going to be met.[27] Greater understanding of the way the system works would improve policy making. In this context the modelling is used to show how a given set of policies are the right ones (with all the questions that entails) rather than to create a greater understanding of how the system works. The issue is whether the Commission's conclusions on the type of policies required is correct or if the Commission may have made the mistake of assuming the inevitability of their scenarios.

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[24] An explanation of the development and current nature of gas market regulation is given in Barnes (2020) Can the current EU regulatory framework deliver decarbonisation of gas? Oxford Institute for Energy Studies.

[25] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final Brussels 15 December 2021. Page 89.

[26] This was explored in depth in Barnes (2020) Can the current EU regulatory framework deliver decarbonisation of gas? Oxford Institute for Energy Studies.

[27] See EU Strategy on energy system integration.

2. Commission objectives and assumptions

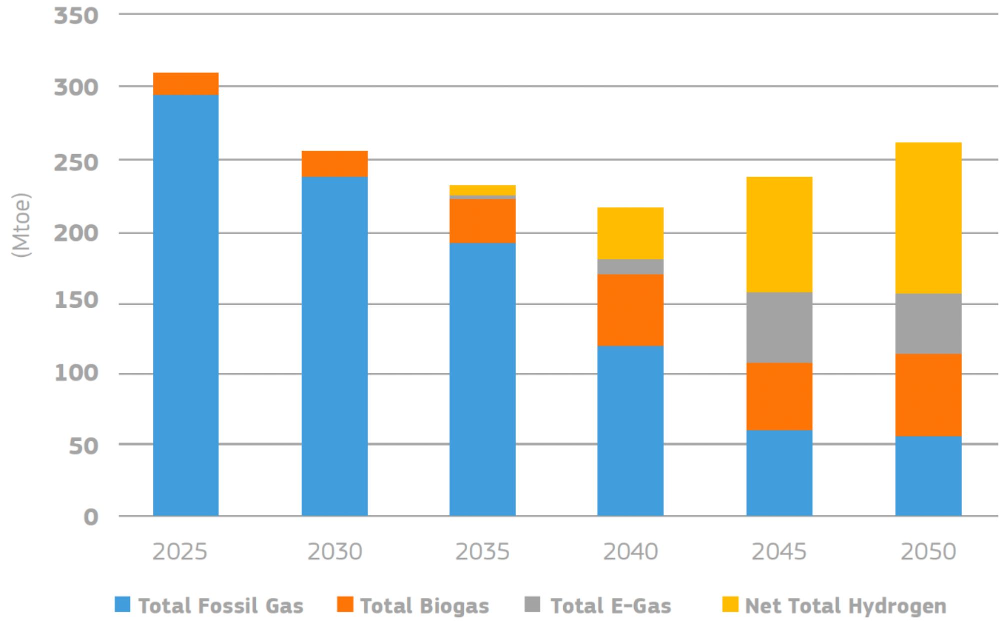
Before analysing the Commission's specific proposals and those of the Council and the Parliament, it is necessary to detail the Commission's objectives and assumptions to enable better analysis of its policy choices.

2.1 Underlying assumptions

The aim of the proposals is to remove regulatory barriers for access to grids and markets for renewable and low-carbon gases. The original package thereby aims to enable decarbonisation of gaseous fuels in the EU by 2050, which the Commission expects to be about 85 per cent of the current level in energy terms, but with a much greater proportion of biomethane and hydrogen.

The Commission's original forecast consumption of gaseous fuels by type is illustrated in Figure 1, taken from the material accompanying the publication of the Hydrogen and Gas Decarbonisation proposals in December 2021, and based on the original Fit for 55 targets. Note that net total hydrogen excludes hydrogen which is further processed for renewable fuels or liquids. It therefore does not show total consumption of renewable hydrogen, as renewable hydrogen used in the production of Renewable Fuels of Non-Biological Origin (RFNBO) such as synthetic fuels, or that used in refineries for production of conventional fuels is not included. Nor is renewable hydrogen used in the production of ammonia (which can be used either as an RFNBO or in fertiliser production) included in these numbers. E-gas also includes hydrogen as it is synthetic methane produced from renewable hydrogen and sustainable CO_2 sources.[28]

Figure 1: Fit for 55 forecast consumption of gaseous fuels



Source: [EU Gas Markets Factsheet] 15 December 2021.

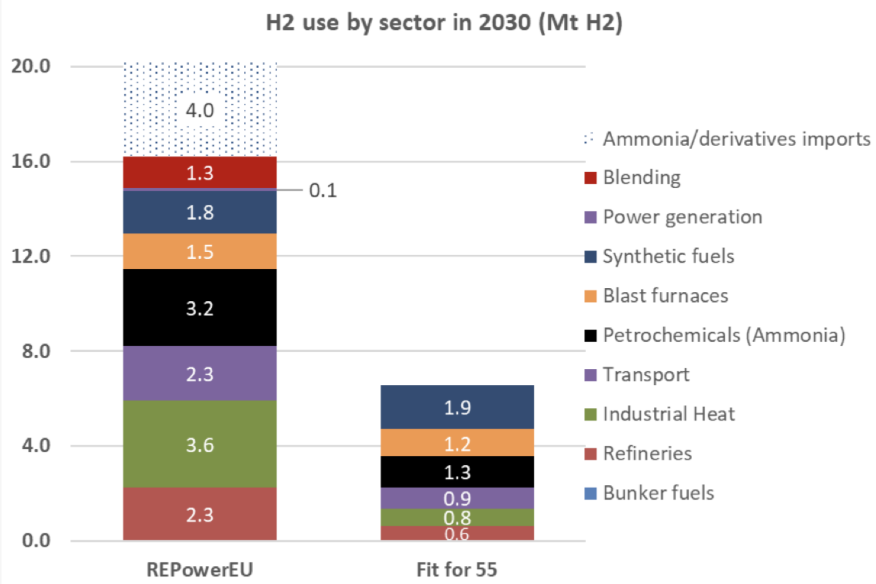
[28] Synthetic methane is CH_4 and therefore emits CO_2 emissions when combusted. To ensure that CO_2 emissions do not increase CO_2 in the atmosphere, the CO_2 used in synthetic methane will have to come from a source which is sustainable, for example from Direct Air Capture (DAC) of CO_2 or from Bioenergy Carbon Capture and Storage (BECCS). In both cases proper carbon accounting would need to ensure that CO_2 emissions from combustion of synthetic methane were netted out by DAC or bioenergy sources capturing an equivalent amount of CO_2 or via a 'closed loop' where emissions from combustion of synthetic methane are captured for re-use. CO_2 captured from industrial or power generation use of fossil fuels would not be sustainable as capturing and then using it in synthetic methane without CCS would delay but not net out the emissions of CO_2. Given the challenges of ensuring the sustainability of such CO_2, and the reliance on CCS which is yet to be developed at scale, the prospects for synthetic methane must be considered uncertain.

At first glance it appears that the need for regulation of hydrogen networks prior to 2040 is minimal given the low volumes of gaseous hydrogen consumption required. However, it is not possible to map the figures shown onto a requirement for hydrogen networks, as hydrogen used in refineries or for ammonia may still need transportation from production to use. Networks will not be needed if hydrogen production is collocated with its consumption as is already the case in some refineries using high carbon ('grey') hydrogen or in fertiliser production. 'Green' ammonia or fertiliser producers, and 'green' steel producers may choose to locate electrolysers as part of their industrial set up. This highlights one of the key differences between hydrogen and natural gas. The latter must be transported from point of production (gas fields) to the point of use. Hydrogen can be produced near the input sources (renewable or nuclear electricity, or natural gas or coal production) and then transported to the point of use, or the feedstocks can be transported to the point of use of the hydrogen (e.g. via electricity or gas transmission networks) and hydrogen produced next to the point of use. Hydrogen is also more difficult to transport over long distances compared to natural gas.

A further possibility is that industry relocates near to the input sources. For example, it is a lot easier to transport steel than to transport hydrogen, which may incentivise steel producers to locate future plants close to plentiful renewable energy sources. The many different variables make it more difficult compared to natural gas to calculate a relationship between the amount of hydrogen consumed and the likely size of future hydrogen networks. What is particularly noticeable is that, based on Figure 1, the Commission sees the need for comprehensive infrastructure regulation after 2030, but consumption of gaseous hydrogen, and hence the need for pipelines, does not become significant until the 2040s.

The Russian invasion of Ukraine resulted in an increased ambition for accelerated deployment of hydrogen by 2050, alongside a reduction in the consumption of natural gas. This was part of the strategy to eliminate the EU's dependence on imports of Russian natural gas. A more detailed breakdown of total hydrogen use in the original Fit for 55 scenario and the more ambitious REPowerEU scenario is illustrated in Figure 2. 1 MT of hydrogen has an energy value of 2.9 Mtoe, so 20 MT of hydrogen in REPowerEU equates to 58 Mtoe, whilst the 6.7 MT of H_2 in the Fit for 55 scenario is 19.4 Mtoe. However, it is not clear from the Commission's material how the detailed breakdown of the Fit for 55 targets in Figure 2 reconciles with the Fit for 55 gaseous consumption figures in Figure 1. Even with the increase anticipated in REPowerEU it is likely to remain the case that hydrogen infrastructure is going to remain quite limited until the late 2030s at the earliest, and yet the Commission is using a regulatory model based on that used for a much more extensive natural gas network.

Figure 2: Comparison of forecast hydrogen use by sector between REPowerEU and Fit for 55



Source: Commission Staff working document. Implementing the REPowerEu Action Plan: Investment needs, Hydrogen Accelerator and achieving the biomethane targets. 18 May 2022

REPowerEU expects a significant increase in hydrogen usage within the EU which has implications for infrastructure investment and regulation (discussed below). There are several key assumptions:

- A reduction in natural gas demand by industry of 35 bcm[29] (about 9%) between 2021 and 2030, based on increased energy efficiency and a switch to alternatives such as electrification and hydrogen. Such a large drop will impact utilisation rates for natural gas infrastructure (especially as industrial demand tends to be baseload) but in turn this raises the potential for repurposing redundant gas pipelines for hydrogen.
- EU production of 10 MT/y of renewable hydrogen, coupled with imports of 6 Mt/y of hydrogen and 4 MT/y of imports of ammonia or other hydrogen derivatives.[30]
- Of the 35 bcm reduction in natural gas demand, 27 bcm is expected to be replaced by 8 Mt/y of hydrogen, with 2 Mt/y replacing oil and coal use.[31]
- 500 TWh of additional renewable electricity generation[32] will be required to produce the 10 MT/y of renewable hydrogen targeted in the EU. This compares to 541 TWh of solar and wind generation in the EU27 in 2020, and total EU27 gross electricity generation (including hydro, fossil fuels, and nuclear) of 2781 TWh.[33]

The expected scale-up of renewable hydrogen production, both in the EU and abroad, is ambitious to say the least. Moreover, the switch from fossil fuels to hydrogen depends on relative commodity prices, government subsidy of hydrogen, and the price of carbon. (The higher the carbon price the more attractive hydrogen is relative to fossil fuels).

The requirement for infrastructure is obviously driven by the supply and demand for hydrogen. Excluding the 4 Mt/y of hydrogen to be imported in the form of ammonia or other derivatives, and the 1.3 Mt/y of hydrogen that the Commission expects to be blended into the natural gas network, up to 14.7 Mt/y of pure hydrogen will need to be transported, and of this approximately 6 Mt/y will also need import infrastructure. This is equivalent to just under 50 bcm of natural gas pipeline capacity, and about 20 bcm of natural gas import infrastructure (either import terminals or pipelines), based on the Commission's figures of 8 Mt/y of hydrogen replacing 27 bcm of natural gas consumption. These are approximations only as they do not take account of expected load factors for hydrogen infrastructure.

In its 2021 Impact Assessment the Commission expected there would be two sets of infrastructure:

- A hydrogen-based infrastructure which will complement and partly replace the current natural gas infrastructure.
- A methane-based infrastructure which will evolve from the current natural gas-based system to one which uses more biomethane and synthetic methane instead of natural gas. Any natural gas still used will need to be coupled with Carbon Capture and Storage.

As noted above, the EU will need significant quantities of import infrastructure but the Commission also predicates its proposed regulatory framework on significant cross-border infrastructure within the EU.[34] This is because renewable energy sources for electricity generation are not evenly spread across EU Member States, so areas with low-cost renewable energy sources (e.g. solar and wind in countries such as Spain) are expected to export hydrogen to those areas which do not enjoy the same benefits.

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[29] Source: Commission Staff working document. Implementing the REPowerEu Action Plan: Investment needs, Hydrogen Accelerator and achieving the biomethane targets. 18 May 202. Table 5 Page 19

[30] Ibid. Table 1, page 9.

[31] Ibid. Table 1, page 9.

[32] Ibid. Page 28

[33] European Commission (2022). EU energy in figures. Statistical Pocketbook 2022. Tables 2.6.2, 2.7.3 and 2.7.8.

[34] Ibid. Page 9 to 10.

The Commission also highlights the need for hydrogen storage because of the potential variability in hydrogen production where intermittent renewable electricity is used. The intermittency of hydrogen production based on renewable electricity depends on the source of the electricity, and the strictness of the rules governing renewable electricity use such as geographical and temporal correlation of renewable electricity generation with renewable hydrogen production. The stricter the rules, the more intermittent the renewable hydrogen production, and hence the greater the need for hydrogen storage. The Commission published its proposals on 13 February 2023 as part of a delegated act. Council and Parliament now can accept or reject the proposals but not amend them.[35] The proposals allow monthly temporal correlation until the end of 2029, and hourly correlation thereafter.

2.2 Problem identification and policy objectives

In its 2021 Impact Assessment the Commission identified three general problem areas concerning hydrogen which the proposals aim to address. Alongside each problem area the Commission also set out the policy objectives that it wants to achieve. Coupled with the Underlying Assumptions above these form the foundation of the Commission's proposals for regulation. By comparing different regulatory options against the problem identification and policy objectives, and using quantitative analysis based on the PRIMES and METIS models, the Commission chose the regulatory options which produce the best outcome.

The Commission's problem identification and policy objectives are summarised below. Detailed discussion of the Commission's proposed regulation follows in Section 4.

2.2.1 Problem Area I: Hydrogen infrastructure and markets[36]

Challenges include:

- Barriers to the deployment of a cost-effective hydrogen infrastructure and a competitive and integrated hydrogen market. This includes the lack of rules governing hydrogen infrastructure and the need for a definition of low-carbon (as opposed to renewable) hydrogen.
- Lack of hydrogen infrastructure investments hindering market development. Pipelines will be the most cost-effective means of transporting hydrogen which will require considerable capital investment. However, there are no rules governing such investment and no rules on repurposing existing pipelines.[37]
- Hydrogen infrastructure is likely to be a natural monopoly and therefore result in uncompetitive market structures. Other forms of hydrogen transport (such as truck) are unlikely to provide sufficient competition to natural monopoly pipeline networks. Repurposing of existing pipelines is cheaper than new-build pipelines which will give a competitive advantage to existing gas network owners so that the hydrogen pipelines will 'inherit' the natural monopoly character of the existing gas networks.
- Diverging hydrogen quality rules could hinder cross-border flows. Hydrogen quality varies by production methods and end use, for example purity levels. Lack of harmonised rules on hydrogen purity in networks could hinder flows and use of hydrogen.

[35]https://energy.ec.europa.eu/delegated-regulation-union-methodology-rnfbos_en.
[36] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final
Brussels 15 December 2021. Section 2.1.
[37] In addition to the Hydrogen and Gas Decarbonisation Package, some of these issues are addressed by the revised TEN-E Regulation. For a detailed analysis of this see Yafimava (2022) 'The TEN-E Regulation: allowing a role for decarbonised gas.' Oxford Institute for Energy Studies.

The main policy objective is facilitating the emergence of an open and competitive EU hydrogen market by:

- enabling the emergence of an efficient and integrated EU market hydrogen market;[38]
- removing barriers to, and ensuring incentives for, investment in hydrogen infrastructure;
- addressing the risk of natural monopolies in hydrogen infrastructure;
- ensuring cross-border integration within the EU and with third countries and unhindered cross-border flows of hydrogen.[39]

2.2.2 Problem Area II: Renewable and low-carbon gases in the existing gas infrastructure and markets, and energy security[40]

Challenges for hydrogen (as opposed to biomethane) include:

- Intra-EU entry/exit tariffs hindering the establishment of a fully-integrated, liquid, and interoperable EU internal gas market. The cost of transporting from one market (entry/exit system) to the next (the cross-border tariff) could be higher than the price differential of the commodity between those two markets. As hydrogen is transported across more systems (i.e. from system A to B to C and so forth), the more these costs accumulate leading to a pancaking effect;
- Differences in gas quality and hydrogen blending levels negatively impacting cross border flows;
- LNG terminals equipped to receive mainly natural gas. Although LNG terminals cannot be adapted to receive liquid hydrogen, they could be adapted to receive ammonia or methanol;
- Long-term supply contracts for unabated natural gas may lock in natural gas and hinder supply of renewable gases to 2050;
- Current security of supply arrangements are focused on natural gas and not on renewable gases. The effects of repurposing natural gas infrastructure are not taken into account by current legislation.

The main policy objective is to ensure access of renewable and low-carbon gases to the existing methane networks and to ensure their security of supply by:[41]

- Ensuring access to LNG terminals for renewable and low-carbon gases;
- Ensuring unhindered cross-border flows of renewable and low-carbon gases;
- Integrating renewable and low-carbon gases to improve resilience of threats to natural gas supply.

[38] At first glance this sub-objective appears to repeat the main policy objective. However, the Commission is stating that an 'open' and 'competitive' EU market must be 'efficient' (i.e. work well) and 'integrated' (i.e. be one single EU market, not separate regional or national markets within the EU). This can be understood in the context of the Commission's experience of liberalising natural gas markets. Natural gas was traded across borders prior to liberalisation but the market was certainly not efficient in terms of price setting or integrated in the way that the EU gas market is today. It is also worth noting that 'integrated' requires cross-border infrastructure for hydrogen.
[39] Ibid. Section 4.
[40] Ibid. Section 2.2.
[41] Ibid. Section 4.

2.2.3 Problem Area III: Network Planning[42]

Challenges for hydrogen include:

- Insufficient energy integration in network planning. Joint electricity and gas infrastructure scenario planning is required as part of the EU Ten Year Network Development Plan (TYNDP) but not as part of national network development plans (NDPs).
- Varied network planning between Member States and separate planning for electricity and gas. NDPs are not required for network operators which are ownership unbundled.
- Lack of transparency on the potential for repurposing or decommissioning existing infrastructure. Current development plans are for additional investments rather than repurposing or decommissioning existing infrastructure.

The main policy objective is to ensure transparent and inclusive infrastructure planning by:[43]

- Providing transparency of the repurposing of existing natural gas networks;
- Enabling cost-efficient planning on the basis of scenarios in line with climate target objectives.

2.3 Analysis of Commission's approach

On the one hand REpowerEU's expected dramatic increase in hydrogen production and use can be seen to support the Commission's justification for its regulatory choices for hydrogen infrastructure. Hydrogen will move from being a bit player to a significant part of the energy mix, and infrastructure regulation is required to ensure that this is underpinned by a competitive market. On the other hand, the questions arises whether the proposed regulation will help or hinder development of the hydrogen market (by creating additional regulatory obstacles) or whether the regulatory framework will still be suitable if the ambitious targets are not met. Prudent regulation should allow for a range of circumstances; there is a risk that the Commission is staking everything on one potential outcome. Recent events have illustrated how quickly energy markets can change; the Commission has taken a judicious approach in the past, for example the Security of Supply Regulation requirements for cross-border infrastructure. The Commission did recognise that gas flows within Europe could change significantly and created a regulatory framework which allowed for that possibility, even though it came at a cost (investment in infrastructure that was not needed until Russia cut gas flows to Europe). The Commission's current proposals for hydrogen infrastructure regulation do not allow for different outcomes as the Commission assumes that the hydrogen market will develop in line with its scenarios, and that therefore comprehensive regulation is required at an early stage.

A more robust analysis would have considered whether the proposed regulation was appropriate for different outcomes from those envisaged, namely that it would take more account of the inherent uncertainties in the development of a hydrogen market. The Impact Assessment has looked at how its policy proposals would fit with its targets, and if the regulation would help meet those targets. It has used the PRIMES and METIS models to see what impact different regulatory policies would have, alongside qualitative analysis. Unfortunately, many of the variables that will determine the development of the hydrogen market are outside the Commission's direct control or depend on other actors as well as the Commission. There are several potential vulnerabilities in the Commission's analysis:

- Low-cost imports of renewable hydrogen fail to materialise quickly given the challenge of developing new supply chains and the technical challenges associated with transporting hydrogen over long distances.

[42] Ibid. Section 2.3.
[43] Ibid. Section 4.

- The ramp up of supply and demand for EU-produced renewable hydrogen are dependent on Member State's support schemes. Lack of finance or sub-optimal design of such schemes could hinder progress.
- Production of renewable hydrogen in the EU is dependent on a large increase in renewable generation which can be impacted by government support schemes and other issues such as permitting. Loosening rules regarding the use of renewable electricity in hydrogen production[44] risks increasing the carbon footprint of renewable hydrogen, and thus undermining decarbonisation.[45]
- Market participants may take a different view of the risks involved in developing hydrogen infrastructure, compared with the Commission's preferred approach, resulting in different outcomes.
- The Commission's analysis of the problem of cross-border tariffs and pancaking is wrong. Other chosen solutions such as ownership unbundling to tackle the issue of natural monopolies are also open to question.

Specific analysis related to the issues highlighted above will be explored further in Section 4. However, most of the vulnerabilities relate to the early stages of the hydrogen market rather than the ultimate realisation of a competitive and integrated EU hydrogen market. The Commission is right to aim for a situation similar to the current natural gas market where gas can flow to where it is most needed based on price signals. A large single market has also proven attractive to external suppliers. Both aspects have ensured the EU has coped much better with the Russian-induced energy crisis than it would have done before the Third Energy Package was introduced, as well as ensuring economic benefits for gas consumers when the EU could choose between LNG or Russian gas. An integrated hydrogen market will provide opportunities for Member States rich in renewable resources to supply such energy to those less well endowed. A competitive market will help ensure that Europe's decarbonisation will be done at the lowest cost as hydrogen producers compete not only with each other and imports, but also with electrification or energy efficiency as the best way to reduce greenhouse gas emissions. The key question therefore is whether the Commission's proposals will help or hinder the development of such a market. This is examined in more detail in the following section.

3. Analysis of Commission's Proposals

The Commission analysed different combinations of policy options against the problems identified. The preferred policy options were then put into the proposed revisions of the current Gas Directive[46] and Gas Regulation.[47] This section analyses these proposals, including proposed amendments by the Council and the Parliament.

[44] These are governed by a delegated act defining use of electricity in the production of Renewable Fuels of Non-Biological Origin (RFNBOs) under the Renewable Energy Directive. The proposed rules were published on 13 February 2023. See: https://energy.ec.europa.eu/delegated-regulation-union-methodology-rnfbos

[45] For an explanation of how this works see Bellona (2021) Cannibalising the Energiewende? 27 Shades of Green Hydrogen. By allowing looser rules on additionality and temporal correlation of renewable electricity and hydrogen production, renewable hydrogen will be able to use some fossil fuel grid electricity. This will mean that renewable hydrogen could have the same carbon footprint as low-carbon hydrogen based on reforming of natural gas, and certainly a higher carbon footprint than the name 'renewable hydrogen' implies.

[46] Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen. Brussels 15 December 2021. COM (2021) 803 final

[47] Proposal for a Regulation of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen. Brussels 15 December 2021. COM(2021) 804 final

3.1 Dismissal of alternative approaches

The need for a regulatory framework for hydrogen has been much discussed since the Commission published its Hydrogen Strategy in 2020. One key group of stakeholders have been national energy regulators, represented by the Council for European Energy Regulators (CEER) and the EU regulatory body established in 2009, the Agency for the Cooperation of Energy Regulators (ACER).[48] In 2021 CEER and ACER proposed a regulatory framework based on 'dynamic regulation' where the need for more intensive levels of regulation depended on the state of market development. CEER / ACER argued that this would enable regulation to be implemented which was appropriate to the development stage of the market, and thereby avoid over-regulating the market in its early stages. However, it is notable that the Commission dismissed this approach early on when assessing the options.[49] The Commission's rationale was 'the expected disadvantages of the proposed approach of ex post regulation, in particular the lack of legal certainty for the required investments in hydrogen facilities and infrastructures with long life cycles and depreciation periods'.[50] Furthermore the Commission identified the 'risk of regulatory fragmentation across different Member States (having) a detrimental effect on network interconnectivity and the integration of national hydrogen markets and, thereby, on cross-border trade and market development'.[51] Whilst there are weaknesses with the 'dynamic regulation' approach, it has precedents in other network industries such as telecoms, as well as being proposed by the very regulators who have been instrumental in ensuring the success of the EU single gas market. The Commission's own approach has risks and a more detailed comparison of the two approaches would have been beneficial. Instead, the Commission appears to have made up its mind in advance, that a more deterministic approach is the way forward. This exacerbates the weakness of the Commission's dependence on given market development scenarios explored above. The Commission has effectively only analysed variations of its own approach, rather than other solutions to the regulatory challenges.

3.2 Problem Area I: Hydrogen infrastructure and markets

The Commission's preferred option is called "Main regulatory principles with a vision".[52] It consists of regulated third-party access (rTPA) for hydrogen pipelines and storage, with negotiated third-party access (nTPA) for import terminals, vertical unbundling of hydrogen networks from production and supply, horizontal unbundling of hydrogen networks from electricity and gas networks, certification and definitions for low-carbon hydrogen and low-carbon fuels. To encourage investment, it includes a lighter touch rTPA approach up to 2030, as well as some cross-subsidy between gas networks and hydrogen networks, and grandfathering of rights of way for existing natural gas infrastructure when repurposed for hydrogen. There is an EU-wide hydrogen quality standard at cross-border points.

3.2.1 Key provisions

- **Hydrogen suppliers are free to set the price at which they sell to the market** and customers are free to choose their supplier. National law should not unduly hamper cross-border trade in

[48] ACER is a statutory body established by EU regulation with specific duties and responsibilities. CEER is the 'trade association' of the EU national energy regulators. Although the two frequently cooperate they are separate organisations.

[49] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final Brussels 15 December 2021. Section 5.2.

[50] Ibid.

[51] Ibid.

[52] Ibid. Sections 5.1.2.3.2 and 6.1.6.

hydrogen or the development of liquid trading of hydrogen. (Gas Directive Articles 3 and 4, and Gas Regulation Article 3)[53] [54]

- **Renewable and low carbon gases must have access to the market and infrastructure irrespective of whether they connect to transmission or distribution networks**. (Gas Directive Article 26)
- **Non-discriminatory regulated third-party access to hydrogen networks** based on published tariffs which are approved by regulators. Until 31 December 2030 Member States may apply a system of negotiated third-party access instead. (Gas Directive Article 31) Tariffs and access to the network will be on an entry/exit basis from 1 January 2031. (Gas Regulation Articles 3 and 6)
- **Network capacity contracts for hydrogen networks to be maximum of 20 years for existing networks and 15 years for infrastructure completed after the Regulation enters into force**. (Gas Regulation Article 6)
- **Negotiated third-party access to hydrogen import terminals** used for the import of ammonia or liquid hydrogen and the conversion to gaseous hydrogen for injection into the hydrogen network. (Gas Directive Article 32)
- **Regulated third-party access for hydrogen storage and linepack** based on published tariffs which are approved by regulators. (Gas Directive Article 32)
- **Hydrogen network, storage, and terminal operators have their tasks defined** including operating, maintaining, and developing transportation and storage infrastructure able to meet reasonable demand for their use; not discriminating between infrastructure users; minimising hydrogen leaks; building sufficient cross border capacity to integrate European hydrogen infrastructure. (Gas Directive Article 46)
- **Hydrogen network operators should be ownership unbundled** so that hydrogen network owners cannot be involved in the production or supply of gas. Member States can decide not to apply this to hydrogen networks which were part of a vertically-integrated company (i.e. also owning production and / or supply of hydrogen) when the Directive came into force. In this case an Independent System Operator (ISO) may be implemented where a company separate from the owner is responsible for the operation of the network, but the vertically-integrated company still owns the network assets. Until 31 December 2030 Member States may allow hydrogen networks to operate as an ISO where the same company may own production and / or supply of hydrogen, and own *and operate* the network but there are strict rules separating the operation of the network from production and supply activities. (Gas Directive Article 62)[55]
- **Hydrogen network operators must be at least legally separate from electricity or gas network operators (horizontal unbundling).** (Gas Directive Article 63)
- **Hydrogen network operators must be certified**. Networks controlled or owned by third countries must also be certified to show that they do not put at risk the EU's security of supply. (Gas Directive Articles 65 and 66)

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[53] All following references to the Gas Directive, unless otherwise stated, refer to Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen. Brussels 15 December 2021. COM (2021) 803 final.
[54] All following references to the Gas Regulation, unless otherwise stated, refer to Proposal for a Regulation of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen. Brussels 15 December 2021. COM(2021) 804 final
[55] Note there is a typographical error in some versions of the Commission's proposed revisions of the Gas Directive where Paragraph 1 of Article 62 refers to article 56 (1) to (3) whereas it should refer to Article 54 (1) to (3). Confirmed with the Commission by email 21 January 2022.

- **Hydrogen network, terminal and storage operators, and hydrogen system operators must keep separate (unbundled) accounts**. (Gas Directive Articles 64 and 69)
- **Hydrogen networks must have separate regulated asset bases from gas and electricity networks.** Cross-subsidies between regulated asset bases are allowed so long as they are via dedicated charge at offtake points in the same Member State as the beneficiary of the cross-subsidy. Cross-subsidies can only be for a limited period and cannot exceed one-third of the depreciation period for the subsidised infrastructure and must be approved by regulators. (Gas Regulation Article 4)
- **Existing hydrogen networks which are part of a vertically-integrated company when the Directive enters into force may receive a time-limited derogation** from the requirements for regulated third-party[56] access, ownership, and account unbundling. The derogation is limited to existing capacity at the time the Directive comes into force. The derogation expires at the request of the vertically-integrated company, or once the hydrogen network connects to another network, or if the network expands capacity, or by 31 December 2030 at the latest. (Article 47)
- **Geographically confined networks can receive a derogation until at least 31 December 2030, or, after 1 January 2031, until it connects to another hydrogen network or a competing renewable hydrogen producer wishes to use the network.** Geographically confined networks are defined as those with a limited number of offtakers in a limited industrial or commercial area. (Gas Directive Article 48)
- **Hydrogen pipelines connecting the EU to third countries**[57] **are subject to the same rules as hydrogen networks within the EU.** To ensure this the EU will sign an intergovernmental agreement with the third country specifying rules on third-party access, unbundling and certification of renewable and low-carbon hydrogen. (Gas Directive Article 49).
- **Certification of renewable and low-carbon fuels (including renewable and low-carbon hydrogen).** Renewable gases will be certified in line with the Renewable Energy Directive (see also Footnote 35). Low-carbon fuels and hydrogen which are produced in the EU or imported must have greenhouse gas emissions savings of at least 70 per cent compared to fossil fuel comparators. The methodology used to assess the greenhouse gas savings will be adopted in a delegated act by 31 December 2024.
- **Hydrogen network operators must cooperate to ensure that differences in hydrogen quality do not hinder cross-border flows of hydrogen.** (Gas Regulation Article 39)
- **The European Network of Network Operators for Hydrogen (ENNOH) will enable and promote the development of the hydrogen market by enabling cooperation of hydrogen network operators.** ENNOH will: develop the network codes for access to hydrogen networks; publish an EU Ten Year Network Development Plan and supply an adequacy report every two years; publish an annual supply outlook where hydrogen is used in electricity generation or in households; publish a hydrogen quality report by 15 May 2026 and every two years afterwards; and cooperate with the European Networks for electricity and gas (ENTSOE and ENTSOG). (Gas Regulation 42)
- **Hydrogen network operators must publish detailed information on the services they offer, including hydrogen quality, supply, and demand and from 1 January 2031 provide detailed information on tariffs.** (Gas Regulation Article 48)
- **ENNOH will develop network codes which will govern access to and operation of hydrogen networks** including energy efficiency, interoperability between network operators, financial compensation for cross-border infrastructure, capacity allocation and congestion management, tariff structures, valuation of assets transferred from a different asset base,

[56] Third party access means a company can use infrastructure owned by another company.
[57] Third countries are those which are not a member of the EU.

balancing, and cyber security. The codes will be based on guidelines developed by ACER. Both codes and guidelines will be approved by the Commission. (Gas Regulation Article 54)

- **New hydrogen interconnectors between Member States, import terminals, or storage facilities can apply for exemptions from regulated and negotiated third-party access** for a defined time period, so long as the investment enhances competition and security of hydrogen supply, contributes to decarbonisation, would not go ahead without an exemption and does not harm competition in the markets affected by the exemption. Exemptions are approved by national regulators or ACER, with final approval by the Commission. (Gas Regulation Article 60).

3.2.2 Analysis

The Commission has set out a clear framework for the regulation of hydrogen infrastructure which largely replicates the current framework for natural gas infrastructure. The main differences are no distinction between transmission and distribution networks for hydrogen, regulated third-party access for hydrogen storage as opposed to negotiated third-party access for gas storage, and negotiated third-party access instead of regulated third-party access for hydrogen import terminals. These differences are justified on the basis that hydrogen storage is likely to be more limited than gas storage for technical reasons but is also more crucial for the hydrogen system because of the intermittency of renewable electricity generation. Hydrogen import terminals have more potential for competition because of the different means of transporting hydrogen (e.g. ammonia, methanol, LOHCs, hydrogen).

Suitability of the proposed regulatory framework

Overall, the regulated approach proposed by the Commission should work well once the hydrogen market is well established with a mature supply and customer base and a well-developed infrastructure. The approach proposed has worked very well in the gas market which was already well developed when it was liberalised from the mid 2000s onwards. The Commission has also clearly met the objective of providing regulatory certainty to market participants as the framework is detailed and builds on the experience of the gas market. Gas market participants and infrastructure operators will be very familiar with the way network codes are developed and implemented and the day-to-day operation of regulated infrastructure and their experience can easily be shared with hydrogen market stakeholders. Moreover, the Commission is correct that its proposed framework will prevent any competition problems as a result of the natural monopoly characteristics of pipeline networks. Experience of gas market liberalisation showed that the same measures successfully addressed similar problems identified by the Commission's competition review of gas markets between 2005 and 2007.

The question is not whether the Commission is right in its final vision for the hydrogen market, but whether its proposals will slow down its development. The proposed framework only really becomes valid once the hydrogen market and associated infrastructure has evolved. Until then there are no natural monopolies as there are no hydrogen networks, apart from very limited ones serving industry. To date the Commission has not seen the need to regulate these limited networks which implies a lack of concern about market failures. The Commission is therefore caught between its current position of not regulating those hydrogen networks that do exist and regulating future ones to avoid the development of competition problems. At what point should the Commission regulate, and what are the risks of regulating too early when market failures have yet to materialise?[58] The Commission recognises this challenge and the advantage of providing some regulatory flexibility in the early years of the hydrogen market. Thus, full ownership unbundling and regulated third-party access do not apply until after 2030, and there are limited derogations for geographically-confined networks, for example those in an industrial cluster which can be considered similar to the existing hydrogen networks.

[58] These questions have also been considered in Barnes (2020) Can the current EU regulatory framework deliver decarbonisation of gas? Oxford Institute for Energy Studies.

However, the need for such flexibility could easily extend beyond those dates. Full blown, regulated third-party access is burdensome for embryonic networks. It could be considered overkill for networks with only a handful of customers, whilst 'one size fits all' network codes may not be appropriate for networks in different stages of early development. Strict ownership unbundling prevents risk-sharing of the type that was common in the early days of the pipeline and LNG industries when producers and buyers of gas and LNG took equity stakes in common infrastructure to share risk associated with the development of the market. The regulatory certainty for infrastructure developers must be weighed against the commercial risk of developing supply and demand for hydrogen. When natural gas markets were developed there was an obvious economic case in that gas could compete with existing fuels such as coal and oil. The risk was the speed with which the gas industry could attract customers and the need to build infrastructure that would be the right size for anticipated demand but would be underutilised in the ramp-up phase.

Renewable and low-carbon hydrogen cannot compete economically with fossil fuels without government subsidy, and face the same market build up risks as natural gas did. There is thus a greater risk that the hydrogen market will not develop in line with the Commission's PRIMES and METIS scenarios. In such a case much of the Commission's rationale for regulating the hydrogen market on its chosen timescale falls away. Put simply, regulation only makes sense if there is actual or imminent market failure. These conditions will not hold if the development of the hydrogen market is delayed. Moreover, the Commission's approach prevents private hydrogen investors from using tools which could make up for other uncertainties e.g. the level or lack of government support. There is a trade-off between regulatory certainty provided by the Commission and the risk appetite of investors. Regulation limits companies' opportunities to accept financial risk (for example a slower than anticipated build-up of the hydrogen market) in return for a lower regulatory burden. If governments lower the financial risk (for example by subsidising hydrogen networks in the early years) then a higher regulatory burden may be acceptable.

The Commission's approach also prevents a greater level of risk sharing between the private and government sectors, for example allowing greater regulatory freedom in return for the private sector bearing more risk. Whilst the exemption mechanism (Article 60 of the Gas Regulation and based on Article 36 of the current 2009 Gas Directive) does provide for such an approach, it cannot be used for hydrogen networks *within* Member States, only for pipelines which cross borders (interconnectors), for storage facilities, and import terminals. The exemption regime has been very successful in delivering new investments in the gas sector in the last twenty years, including many of the LNG terminals which were essential during the gas crisis, but the process is time-consuming and positive outcomes cannot be guaranteed.

Unbundling models

On the issue of ownership unbundling of networks the logic is sound, as ownership unbundling automatically prevents a network owner from favouring affiliate companies involved in production or supply of hydrogen. However, experience in the gas market has also shown that the Independent Transmission Operator (ITO) model which allows common ownership and operatorship of network operators and production and supply, has been equally successful in preventing undue discrimination in favour of affiliates. This has been achieved via the use of strict compliance regimes and the enforcement of regulated third-party access rules which are also a key, but separate, part of the Commission's proposals for hydrogen. Both the US and the UK used an ITO-type approach when they successfully liberalised their gas markets in the 1990s. However, the Commission has chosen only to allow the Independent System Operator (ISO) approach after 2030, which allows common ownership of assets, but states a separate company must be the operator of the network, unlike the ITO model where the same overall group both owns and operates the network. The ISO model is more complex than the ITO model as it requires a high level of trust between asset owner and the ISO. It is possible that hydrogen investors, faced with the problem of many different risks, may prefer an ITO approach.

These debates are ongoing. Both the Council[59] and the Parliament have proposed the continued existence of the ITO approach and delaying until 2036 the date at which the full regulatory regime (e.g. ownership unbundling) applies. In their original recommendations, published prior to the Commission's original proposals, ACER and CEER avoided a fixed date approach via a 'dynamic regulation' approach which would see the implementation of stricter rules when the market conditions justified them.[60] However, as noted above, the Commission dismissed this approach with minimal analysis. The Council has also proposed allowing the ISO model for future hydrogen networks, not just those which are vertically integrated at the time the directive comes into force.[61] As the Hydrogen and Gas Decarbonisation Package is unlikely to be passed until the end of this year, the original deadline of 2030, always ambitious, looks unrealistic. It would mean that networks with economic lifespans of decades would enjoy regulatory relief for only a few years. It is therefore likely that some of the dates will be changed.

It is also worth noting the reaction of ACER and CEER. In their initial response in June 2022 to the Commission's proposals, ACER considered that they were more prescriptive than their original recommendations, but the establishment of core principles was welcomed. ACER / CEER called for more flexibility using derogations and exemptions given the uncertainty of hydrogen network development by 2030.[62] In a more detailed set of recommendations in October 2022[63] they highlighted the need for flexibility and subsidiarity in the regulation of hydrogen because of market development uncertainties. They also called for negotiated third-party access to be allowed for a limited period to enable the sector to mature.

Network Codes

There are other questions about the details of the Commission's approach but these have a less existential impact than the ones outlined above. The Commission's use of the network code approach makes sense for a mature market but underestimates the time required and difficulties in developing such codes. As these are the building blocks of the regulated third-party access regime, they are even more important than the Directives and Regulations. These set out the framework, but it is the network codes which provide the 'nuts and bolts' and which are therefore crucial to achieving the regulatory certainty the Commission wishes to provide. The network codes in the gas market have been largely successful but their development was long and sometimes painful. Main challenges involved different views as to how to develop contractual rules which reflected the physical reality of network operation, and the need for commercial rules which worked in a liberalised market. This was despite the advantage that there were many years' experience of operating the gas networks, and understanding of the interaction of supply, demand, and infrastructure. The hydrogen industry will have less experience in this regard. The Commission is legitimately worried that less clarity or more flexibility in the early days of the market will inhibit market harmonisation in later stages. However, the counter risk is that trying to harmonise everything at the start may delay the development of the market. The risk of entrenched positions being developed may be less than the Commission expects if clear principles are set out at the start and regulators can act as soon as problems look as if they might arise.

ENTSOG vs. ENNOH

The decision to separate ENNOH from ENTSOG probably also falls into the 'too cautious' category. The Commission is right to consider the risk that incumbent gas network operators may have an unfair advantage over potential hydrogen network operators, and that including hydrogen networks within ENTSOG may exacerbate this. There is certainly the risk that gas network operators may regard the repurposing of their networks for hydrogen as the easy way to deal with a potential stranded asset problem, and this in turn could result in poorer service for remaining natural gas users, or inefficient

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[59] EU Council Presidency. Progress Report on the Gas Package. 12 December 2022.

[60] ACER / CEER (2021) "When and how to regulate hydrogen networks?" 9 February 2021

[61] EU Council Presidency. Progress Report on the Gas Package. 12 December 2022.

[62] ACER-CEER (2022) ACER-CEER Reaction to the European Commission's Hydrogen and Decarbonised Gas Market Package.

[63] ACER-CEER (2022) Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021. Decarbonised Gases and Hydrogen volume.

investment in hydrogen networks. However, both hydrogen and gas network companies will be subject to strong regulatory oversight. Transparency rules also go a long way to ensuring that network operators are held to account by other stakeholders, as experience in the gas market has shown. The advantages of a single ENTSOG including hydrogen are speed (no need to establish ENNOH so no additional delays or uncertainty), and common expertise in many areas. The author's experience has been that ENTSOG has functioned very effectively in establishing network codes, even if he has disagreed with its points of view on the content. A draft report by the ITRE Committee of the EU Parliament also proposed that there should not be a separate ENNOH[64] whilst the Council advocates keeping a separate ENNOH.

Hydrogen Certification and Definition

Clear definition and certification of renewable and low-carbon fuels (including renewable and low-carbon hydrogen) is essential as without this there is no certainty that the use of hydrogen will lead to a reduction in greenhouse gas emissions. However here the Commission is moving too slowly with a deadline of the end of 2024; the sooner a definition is in place, the sooner companies can invest in hydrogen production to meet the required standard. As it is the definition of renewable hydrogen, under a delegated act of the Renewable Energy Directive, has already been delayed by more than a year. The Council has proposed that the definition for low-carbon hydrogen be finalised within 12 months of entry into force of the Directive.[65] It has also proposed an article supporting the use of low-carbon hydrogen and fuels to meet decarbonisation targets.[66] However the Council Presidency noted that there were differences of opinion between those Member States supporting low-carbon hydrogen and those who wished to emphasise renewables.[67]

3.3 Problem Area II: Renewable and low-carbon gases in the existing gas infrastructure and markets, and energy security

The Commission's preferred option is called, "Allow and promote renewable and low-carbon full market access and security, and tackle issue of long-term supply natural gas contracts".[68] It includes removing cross-border tariffs for hydrogen to avoid pancaking and improving access to LNG terminals for low-carbon and renewable gases.

3.3.1 Key provisions

- **No tariffs to be charged at interconnection points on hydrogen networks between Member States from 1 January 2031**. (Gas Regulation Article 6)
- **Hydrogen network operators must agree a system of financial compensation for cross-border hydrogen infrastructure.** Before 31 December 2030 regulators decide which costs should be borne by network operators based on proposals from the network operators. After 31 December 2030 hydrogen network operators must negotiate a system of financial compensation to finance the cross-border infrastructure. If they cannot agree by 31 December 2033 the national regulators decide, or if they fail to agree, the decision falls to ACER. (Gas Directive Article 53)
- **Renewable and low-carbon gases (e.g. hydrogen) will benefit from a 75 per cent discount when injected into the gas system, and a 75 per cent discount at injection and withdrawal points into and out of gas storage facilities.** (Gas Regulation Article 16)

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[64] European Parliament, Committee on Industry Research and Energy. Draft Report on the proposal for a regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen. 22 June 2022.
[65] REV 3 Draft of Council proposed revisions to the Gas Directive, Article 8. Given that the package is not expected to be agreed long before the end of 2023 there may not be much difference in the ultimate timings.
[66] Ibid. Article 8a.
[67] EU Council Presidency. Progress Report on the Gas Package. 12 December 2022.
[68] COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT REPORT SWD (2021) 455 final Brussels 15 December 2021. Sections 5.3.2.4 and Section 6.2.5

- **From 1 January of the year following adoption of the legislation, renewable and low-carbon gases will receive 100 per cent discounts at interconnection points on the gas system**, and at entry points from LNG terminals upon showing proof of sustainability. Once the discount causes a fall in revenue of 10 per cent for the network operator, the relevant network operators must agree an 'inter transmission system compensation scheme'. (Gas Regulation Article 16)
- **Gas transmission operators must accept up to a 5 per cent hydrogen blend at interconnection points between Member States from 1 October 2025**. Gas transmission network operators must cooperate to avoid gas quality differences restricting cross-border flows. ENTSOG must prepare a gas quality monitoring report by 15 May 2024 and every subsequent two years. (Gas Regulation Articles 19, 20 and 23)

3.3.2 Analysis

The proposal to remove cross-border tariffs on hydrogen networks, and for renewable and low-carbon gases is based on the Commission's fallacious analysis of the pancaking issue and their view that cross-border transport tariffs hinder trade. It is perfectly possible for the differential in gas prices between markets to be lower than the costs of transporting that gas between the two markets. This can occur if both markets have sufficient supply from different sources to meet their demand at a similar price level. It is also possible for the cost of transport between markets to exceed the price differential as the former depends on the regulatory approved cost of transporting gas between the two markets, whilst the commodity price in each market reflects the balance of supply and demand in that market. The two prices /costs are not driven by the same factors. Where the commodity cost differential is less than the transport cost it simply shows that both markets are well supplied without the need to transport gas from one to the other. The pancaking theory also does not consider that gas shippers can use swaps to minimise gas transport costs, and thereby also lower gas price differentials between markets compared to transport tariffs. For example, prior to the gas crisis, a shipper supplying a customer in Belgium with Russian gas landed via Nord Stream 1 in Germany could 'swap' gas with a shipper selling LNG landed at Zeebrugge to a customer in Germany. Such an approach is both commercially efficient (as it avoids cross-border tariffs) but also physically efficient as it 'nets out' flows of gas moving in opposite directions. Recent events have shown that when markets are not well supplied, gas commodity price differentials do rise above the transport cost once the transport capacity is fully utilised (e.g. the differential between the UK NBP gas price and the TTF gas price). Considering all of this, it is not clear what the problem is which the Commission wishes to solve – when supply is plentiful there is less need for cross-border transport, so gas price differentials are below that transport cost. When supply is not plentiful, price differentials rise above the regulated transport cost because demand for gas is greater than cross-border transport capacity. This is exactly how a market should work.

Removing the cross-border tariffs not only does not solve any real problems but it creates new ones. Network operators receive allowed revenue consistent with a regulated rate of return on their regulated asset base. They recover this revenue via tariffs, which are regulated and cost reflective. Cross-border tariffs simply reflect the cost of moving gas from one network to another. By removing the cross-border tariff, network operators will still have to recover the same amount of revenue but they will no longer be able to apply a tariff at the cross-border point being used. Instead, they will have to calculate how to recover revenue for cross-border flows from entry tariffs (where gas is injected into the system) and exit tariffs (where gas is taken out of the system on different networks). This requires different networks with different regulators and different allowed revenues to agree how to share the costs of transporting the gas across their networks. With a cross-border tariff network operators only have to calculate how to structure tariffs for their own network. This is complicated enough in an entry/exit regime as it involves the modelling of likely flows within the network, but this is much simpler than negotiating with several networks if gas is nominated to flow across several borders. The removal of cross-border tariffs makes no sense at all, as it is a solution for a problem which does not exist and creates additional problems of its own.

Discounts on tariffs for low-carbon and renewable gases are also problematic as they represent a cross-subsidy between different groups of network users. This is ironic given that the key principles of the Hydrogen and Gas Decarbonisation Package are that it should prevent undue discrimination and tariffs should be cost-reflective. There are sound reasons for this: cost-reflective tariffs ensure that investments in production and demand, and the corresponding infrastructure, are taken where they are most cost-efficient. Cost-reflective tariffs also allow for better comparison between different forms of energy transportation, for example whether it is more efficient to use renewable electricity on site, or to use it produce hydrogen and then inject it into the network. In the case of biogas it may be more efficient in some cases to use it to produce electricity rather than purify it and input into the grid. Whilst discounts will undoubtedly help low-carbon and renewable gases, it would be more economically efficient to subsidise such gases directly rather than via the network tariff system.

The Council has on the one hand made matters worse by proposing 100 per cent discounts for renewable gases but maintaining them at 75 per cent for low-carbon gases which further distorts matters. On the other hand, it has allowed national regulators to decide whether or not to apply such discounts for injection from production or storage as some Member States with a high share of low-carbon or renewable gases were concerned at the impact on their systems.[69] Countries with plentiful sources of renewable gases could find their own systems short of revenue because of a large share in their gas mix, and also potentially the draw of such gases across a border where they would also enjoy tariff discounts. It would make it difficult for network operators to recover revenue without increasing charges significantly for other network users. The Council also proposed removing tariff discounts to and from third countries. Meddling with tariffs muddies network investment signals and therefore can make the overall system less efficient. The proposal is a perfect example of good intentions but bad policy.

The proposal for blending capability of up to 5 per cent at cross-border points is curious given the Commission itself is less convinced about the value of blending hydrogen into natural gas flows. However, the Commission is clearly concerned that such blending could adversely impact cross-border gas flows. It is difficult to tell if 5 per cent is the right level; note it is not a target for hydrogen blending but only a requirement that networks be capable of accepting such a blend. Compared to the 20 per cent hydrogen blend that some advocate, 5 per cent is a conservative number. However, there are technical implications which are still being evaluated by the industry. Both Parliament and the Council propose a 2 per cent maximum. ACER / CEER proposes allowing restriction of cross-border flows to below 5 per cent based on a cost-based analysis.

There is also considerable debate as to the merits of blending hydrogen into the gas network. The Commission itself is not wholly convinced, while some argue that supply of renewable hydrogen will be so limited in the early years that it is better to focus its use on hard-to-electrify sectors such as heavy industry, rather than 'waste' it by blending it into natural gas flows. On the other hand, blending could provide a 'sink' into which intermittently-produced hydrogen could be put without the need for storage. Blending could also help promote hydrogen via 'virtual' trading of hydrogen, so long as a sufficiently robust tracking system is put in place.

3.4 Problem Area III: Network Planning

The Commission's preferred option here is "National Planning based on European Scenarios".[70] It includes requirements for joint electricity and gas scenarios at a national level in addition to current requirements at a European level, as well as linkages to Member States' National Energy and Climate Plans. There is also provision for regulatory oversight of hydrogen network planning.

3.4.1 Specific provisions

- **Hydrogen infrastructure operators must exchange information with gas transmission operators** developing ten-year network development plans. (Gas Directive Article 51)

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[69] EU Council Presidency. Progress Report on the Gas Package. 12 December 2022.
[70] Ibid. Section 5.4.2.3 and Section 6.3.4

- **Hydrogen network operators must provide regulators with an overview of the infrastructure they intend to develop** including use of repurposed gas pipelines. Hydrogen terminal and storage operators must provide the network operator with all relevant information. Member States may require hydrogen network operators to submit detailed ten-year network development plans similar to those required of gas networks. (Gas Directive Article 52)

3.4.2 Analysis

Many of the changes relating to planning refer to gas networks and aims to 'fill the gaps' between the current requirements and the need for a greater integrated approach between gas and electricity at a national level, mirroring the cooperation between ENTSOE and ENTSOG at an EU level. There is a lighter touch for hydrogen infrastructure but the requirement for information sharing with gas networks and regulators is useful.

To some extent there may be more of a central planning approach for hydrogen by default if Member States choose to subsidise hydrogen networks explicitly as a means to stimulate the market. The high cost of hydrogen compared to fossil fuels means there is not sufficient value in the chain for the industry to be self-financing in the way that the natural gas market was in its early days. Member States can choose to subsidise production or consumption of hydrogen to bridge the gap. If support is sufficient, then producers or users will have sufficient resources to pay for their own use of hydrogen infrastructure. However, hydrogen networks would still face the problem of insufficient customers and revenue shortfalls during the early ramp-up stages of the hydrogen market. The Member States could decide to support the build out of hydrogen infrastructure, so it is 'right sized' for expected future demand. This could also help solve the 'chicken and egg' problem facing producers and consumers, namely that neither of them can commit to sales and purchase agreements unless they know infrastructure will be in place. If Member States do decide to take this approach, there will be central planning to decide the amount of infrastructure needed as governments will have to decide how much they wish to invest.

The Commission is correct that greater transparency and cooperation between networks during planning is very useful, as it gives investors some idea of how the future *might* develop. However, planning cooperation cannot be a substitute for sound economic signals on the costs of using infrastructure. Even if market participants are subsidised, knowing the true economic cost of using infrastructure is essential to ensure that investments are made efficiently. For example, knowing the true costs of transporting renewable energy from point A to point B, whether as hydrogen or as electrons, will ensure only those who value hydrogen most will use it. As there are energy losses from converting electrons into hydrogen molecules, this will in turn ensure that decarbonisation is done at the lowest cost. Any planning approach should cover all energy networks involved in the energy transition – electricity, natural gas, and hydrogen – as well as related networks such as CO_2 transportation and storage. This will ensure energy users, as well as their suppliers, have the best overview of how patterns of energy use and transportation are impacted by different cost factors, and hence help companies make economically efficient decisions.

4. Conclusions

Success for the Commission's proposals will depend on the same key element as good comedy – timing. The Commission has succeeded in its aim of providing a clear framework for the regulation of a future mature hydrogen market infrastructure. With some minor changes, such as the regulation of storage and import terminals, it has followed the same template as that used for the successful liberalisation of the gas market. It also renews its commitment to competitive gas markets, including for hydrogen. For this it should be applauded, as the current gas market framework has served the EU well in ensuring that gas flows to where it is needed, and in ensuring that the EU can attract sufficient supplies to avoid physical shortages.

The regulated approach proposed by the Commission should work well once the hydrogen market is well established with a mature supply and customer base, and well-developed infrastructure. The Commission has also provided regulatory certainty to market participants as the framework is detailed and builds on the experience of the gas market. However, the proposed framework only really becomes valid once the hydrogen market and associated infrastructure has developed. Until then there are no natural monopolies. Full blown regulated third-party access is burdensome for embryonic networks. Strict ownership unbundling prevents risk sharing of the type that was common in the early days of the gas pipeline and LNG industries. The Commission recognises the advantage of providing some regulatory flexibility in the early years of the hydrogen market but the date at which this is withdrawn (2030) leaves very limited time for the market to develop.

The key issue is whether the Commission has allowed enough time and flexibility for the hydrogen market and its associated infrastructure to reach maturity. The Commission relies heavily on matching its regulatory proposals to the scenarios for hydrogen usage but does not consider what may happen if the hydrogen market develops less quickly, or in a different manner to that which it expects. There are many uncertainties concerning both the production of hydrogen, and the demand for it.

It is also not possible to gauge from the Commission's figures how much hydrogen infrastructure will be in place by the time the full regulatory model is imposed in the 2030s. Hydrogen consumption does not directly correlate with the need for hydrogen networks or infrastructure because of the opportunity for hydrogen production to co-locate with hydrogen use, or for hydrogen users to move closer to where hydrogen is produced. This is very different from the natural gas industry where the location of gas production is determined by geology and is mainly outside the EU and only in a few regions. Hydrogen is also more difficult to transport over long distances compared to natural gas. Based on the Commission's original Fit for 55 proposals, the Commission expects very little direct gaseous hydrogen production in the 2030s. Even though the REPowerEU expectations for hydrogen are more than double those in Fit for 55 the amount of gaseous hydrogen consumed will still be very modest until the late 2030s. This begs the question as to why the Commission is insisting on a regulatory model better suited to a mature infrastructure at so early a date.

The Commission's proposals for flexibility up to 2030 are insufficient given that it is already 2023 and the economic lifespan of infrastructure can be measured in decades. Longer flexibility periods, as proposed by the Parliament and Council, or a dynamic approach as originally proposed by ACER, would be better. By increasing the regulatory burden for hydrogen infrastructure, the Commission's proposals increase the need for government support for this infrastructure as developers will be less able to manage the uncertainty risk inherent in the hydrogen market. Consequently, the Commission's proposals risk slowing the development of the EU hydrogen market in the early years, even though their proposals are sensible once the market has developed.

The Commission is moving too slowly (with a deadline of the end of 2024) for the definition of low-carbon hydrogen; the sooner a definition is in place, the sooner companies can invest in hydrogen production which meets the standard.

A separate organisation for hydrogen operators (ENNOH) will take time to set up. An organisation for both natural gas and hydrogen network operators based on ENTSOG will be quicker to establish and benefit from common expertise and is therefore a better option. The disadvantages that the Commission foresees in a combined organisation can be overcome via the current regulatory framework and transparency of operation.

The proposal to remove cross-border tariffs on hydrogen networks is based on the Commission's fallacious analysis of the pancaking issue and their view that cross-border transport tariffs hinder trade. Removing cross-border tariffs will require several network operators to agree revenue-sharing mechanisms which will be complex; this does not solve a problem but creates one. Proposals for zero tariffs at cross-border points are a bad solution in search of a non-existent problem and should be ditched. Time taken by network operators agreeing revenue-sharing mechanisms represents an unnecessary opportunity cost when time is already short, and there are plenty of other risks which require managing.

Discounts on tariffs for low-carbon and renewable gases in natural gas networks are also problematic as they represent a cross-subsidy between different groups of network users, and mean that tariffs do not reflect costs. Cost-reflective tariffs allow for better comparison between different forms of energy transportation, so it would be better to subsidise renewable gases directly rather than via network tariffs.

It is difficult to tell if 5 per cent hydrogen blending is the right level, and the technical implications are still being evaluated by the industry. Both Parliament and the Council propose a 2 per cent maximum. There is also considerable debate as to the merits of blending hydrogen into the gas network given the likely scarcity of renewable hydrogen in the early years.

Improved planning and cooperation between energy networks is useful. To some extent there may be more of a central planning approach for hydrogen by default if Member States choose to subsidise hydrogen networks explicitly as a means to stimulate the market. The high cost of hydrogen compared to fossil fuels means there is not sufficient value in the supply chain for the industry to be self-financing in the way that the natural gas market was in its early days.

Overall, there is much that is sensible in the package, particularly if the hydrogen market develops in the way the Commission expects. However, if it develops differently, for example more slowly, a greater degree of regulatory flexibility is desirable.