FLORENCE SCHOOL OF REGULATION

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POLICY BRIEF

Reflections on priorities for the forthcoming EU Hydrogen legislation

1. Introduction

Over the last two years, the European Union (EU) has made clear its intention to incorporate a large portion of low carbon and renewable hydrogen in the energy mix, from essentially zero today to as much as 20% of final energy consumption in just 28 years. This was made explicit in the context of the European Green Deal[1] by the European Commission (the Commission) in its Hydrogen Strategy,[2] which was endorsed by the European Parliament and the Council of the European Union.[3]

Since then, the Commission has tabled its 'Fit for 55' package, in which some of the legal framework applicable to low carbon and renewable hydrogen was expanded, together with incentives for its production and consumption. These proposals must still go through the legislative process and no doubt many points of detail will be fine-tuned or revised. Once these proposals are agreed on and enter into force (around the end of 2025), the legal and support framework for the production and consumption of renewable hydrogen can essentially be considered to have been addressed.

1 See the Communication "The European Green Deal," COM(2019)640 final, here.
2 See the Communication "A hydrogen strategy for a climate-neutral Europe," COM(2020) 301 final, here, p. 1.
3 See the Council of the EU's conclusions, "Towards a hydrogen market for Europe," published on 11 December 2020, available here. See the European Parliament's resolution of 19 May 2021 on "A European Strategy for Hydrogen," available here.

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However, the Fit for 55 package has left the framework applicable to other forms of 'low-carbon' hydrogen almost completely unaddressed. In its Hydrogen Strategy[4] the Commission recognised that, while it considered that renewable hydrogen should be prioritised, it would not suffice to achieve the EU's wider Green Deal and hydrogen objectives and other forms of 'low-carbon' hydrogen are needed – at least in the transition period – to rapidly reduce emissions from existing hydrogen production and support the growth of a hydrogen economy. A framework for the development of low-carbon hydrogen is therefore required.

Establishing an appropriate framework to support the growth of low-carbon hydrogen is important. While it remains to be seen how the market and technology will develop, there are a number of indications[5] that achieving the Green Deal and net-zero objectives in a cost-effective and timely manner will require significant quantities of clean but non-renewable hydrogen.

The Fit for 55 package also contains no proposals regarding how the transmission and distribution of (renewable or low-carbon) hydrogen should be regulated. Getting the hydrogen transport framework right is of primary importance to the future growth of the hydrogen economy.

These two key aspects will be covered in a 'hydrogen and decarbonised gas market package'[6] to be tabled by the Commission at the end of 2021.

In this contribution, we consider what legal and policy elements might be included in the future 'hydrogen and decarbonised gas market package' to address these two fundamental issues: (i) the framework to support the growth of low carbon hydrogen, and (ii) the transmission and distribution network for hydrogen.

2. Definitions, certification and guarantees of origin

The first aspect of the legal framework for low-carbon hydrogen relates to the need to establish an appropriate legal status. This requires proper legal definitions, standards and a suitable accreditation framework (i.e. certification/guarantees of origin).

2.1 Definitions

Establishing a clear definition of what qualifies as low-carbon hydrogen is the necessary starting point to draw up other legislative and substantive provisions, such as support mechanisms, guarantees of origin and certification and, indirectly, State Aid criteria.

Although the Fit for 55 package almost exclusively covers renewable hydrogen, the Commission's reform proposal for the Energy Tax Directive[7] provides a definition of low-carbon fuels, as follows:

Article 2 (5) of the reform proposal

> b) 'low-carbon fuels' shall mean low-carbon hydrogen and synthetic gaseous and liquid fuels the energy content of which is derived from low-carbon hydrogen, as well as any fossil-based fuels, which meet the technical screening criteria for determining the conditions under which a specific economic activity qualifies as contributing substantially to climate change mitigation according to Article 10 of Regulation (EU) 2020/852 of the European Parliament and of the Council and Annex I to Delegated Regulation (EU) […]/[…]. 'Recycled Carbon Fuels,' as defined by Article 2(35) of Directive (EU) 2018/2001, shall be included in this category.

In substance, this definition covers three categories of fuels: (i) low-carbon hydrogen, (ii) low carbon hydrogen-based fuels (either gaseous or liquid) and (iii) any fossil-based fuels. It requires that, to qualify as a 'low-carbon fuel,' these three categories must comply with one condition: they

4 On Page 6 of the Strategy the Commission states "In the short and medium term, however, other forms of low-carbon hydrogen are needed, primarily to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen."

5 See, among others, IEA (2020), Energy Technology Perspectives 2020 Special Report on Carbon Capture, Utilization and Storage, available here, p. 24 and "A Cost-effective Decarbonisation Strategy, FSR Study https://fsr.eui.eu/publications/?handle=1814/68977.

6 EU Hydrogen and decarbonised gas package. Summary web page available here.

7 The Energy Tax Directive refers to Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity, available here. The proposal for its reform that was tabled as part of the 'Fit for 55' package is available here.

meet the technical screening criteria applicable under the Taxonomy Regulation.

While from a formal legal perspective this definition presents a number of practical difficulties[8] and requires a number of interpretations that merit clarification during the legislative process, the principle underlying this definition is sound, since:

- it covers a wide variety of fuels, including non-renewable clean hydrogen and also fuels that are based on such hydrogen;
- it is essentially technology agnostic insofar as it includes as many ways to produce clean hydrogen and other low-carbon fuels as are covered in the Delegated Regulation under the Taxonomy Regulation; and
- it features (via the Delegated Regulation under the Taxonomy Regulation) clear greenhouse gas emission thresholds to meet.

One key element to identify in this respect is the GHG threshold that should be applied to plants for the production of hydrogen and hydrogen-based fuels. This threshold will be central in drawing the line between *existing* 'qualifying' low-carbon hydrogen manufacturing plants and excluded ones.

While further examination is required, it is highly uncertain whether existing SMR plants with retrofitted carbon capture and storage (CCS) will be able to meet the threshold, or if only *new* steam methane reforming plants (SMR) with best available CCS technology will be able to. If this is indeed the case, the most cost-effective forms of low-carbon hydrogen available to the EU in the next decade would be taken out of the market because of such a pure Taxonomy-based threshold, and existing hydrogen producers with non-amortised SMRs would have an incentive to continue producing grey hydrogen rather than producing low-carbon hydrogen (as they would wish to amortise their existing SMR). Given that most grey hydrogen production and consumption today is 'captive,' excluding existing SMRs from the option of producing 'low-carbon compliant' hydrogen would be likely to run contrary to the EU's GHG and hydrogen market objectives.

On the other hand, new low-carbon hydrogen plants need to meet the highest possible standards, notably those included in the Delegated Act under the Taxonomy Regulation. We therefore propose a lower qualifying threshold, but only for existing SMR plants, and for an interim period until they are reasonably amortised (until 2040, for example). This would encourage existing grey hydrogen producers to rapidly convert to CCS rather than creating an in-built disincentive to do so and resulting in an incentive to continue grey hydrogen use.

The Commission may therefore legitimately choose to rely on the substance of the definition already included in the reform proposal of the Energy Taxation Directive, and if the above interpretation of the Taxonomy Delegated Act is indeed correct, as follows:

8 First, it attempts to define a rigorous notion of 'low-carbon fuels' based on the undefined notion of 'low carbon hydrogen.' Therefore, the only practical way to understand what 'low carbon hydrogen' means in the context of this definition is to assume that the 'low carbon' descriptor is merely redundant as long as such hydrogen meets the technical screening criteria applicable under the Taxonomy Regulation. Otherwise, the definition is incomplete and unusable. Second, the condition outlined in the definition, which seems to apply to the three categories of fuels outlined above, formally contradicts the functioning of the Taxonomy Regulation. The technical screening criteria provided in the Commission's Delegated Regulation under the Taxonomy Regulation only apply to economic activities, not to goods, products or fuels. The only practical way to understand how to apply this condition is therefore to assume that it applies not to the fuels themselves but to their production processes, i.e. that the words "which meet" should be understood as "the production processes of which meet." Without this assumption, once again the definition is unusable. Moreover, the said Delegated Regulation does not cover all economic activities or production processes. Therefore, one also has to assume that if the activity used to produce "fossil-based fuels" is not listed in the said Delegated Regulation, such fuels can never qualify as 'low-carbon fuels.' Otherwise, heavy oil could directly qualify as a 'low-carbon fuel,' which is clearly not intended. Furthermore, the wording meant to include 'recycled carbon fuels' in the "low-carbon fuels" category leads to two major ambiguities. The first of these relates to the applicability of the technical screening criteria: should recycled carbon fuels be automatically included as "low-carbon fuels" without their production process having to meet the technical screening criteria of the Taxonomy Regulation or, on the contrary, should recycled carbon fuels be merely included as one of the categories of fuels that could qualify as low-carbon fuels if it meets these technical screening criteria? The second ambiguity relates to coordination between this definition and the Renewable Energy Directive (REDII): the notion of 'recycled carbon fuels' as defined in Article 2(35) of Directive (EU) 2018/2001 does not include any reference to a lifecycle greenhouse gas emissions threshold. This threshold must only be met for a specific batch of recycled carbon fuels to count towards Member States' targets (see Article 25(2) REDII), not to formally qualify as 'recycled carbon fuels.'

'Low-carbon fuels' shall mean non-renewable fuels, including among others those based on fossil fuels:

i. that fit in one of the following categories: hydrogen or synthetic gaseous and liquid fuels the energy content of which is derived from hydrogen; and

ii. the production processes of which meet:

   a. for hydrogen production facilities that were constructed and finished before the entry into force of this Directive, and until [1 January 2040], the following lifecycle greenhouse gas threshold *[a technical threshold set at a level that includes the majority of existing production facilities when they have been fitted with reasonably efficient carbon capture and storage technology*] as calculated pursuant to any of the acceptable carbon accounting methodologies used to assess whether a specific economic activity meets the technical screening criteria and qualifies as contributing substantially to climate change mitigation according to Article 10 of Regulation (EU) 2020/852 of the European Parliament and of the Council and Annex I to Delegated Regulation (EU) […]/[…] ;

   b. for others, a defined GHG-saving requirement, which may for an interim period [until 01.01.2040] be based on [*threshold to be inserted*].

This definition alone is, however, insufficient to cover all the cases in which the production process of non-renewable fuels – such as clean hydrogen – could have a climate benefit. In particular, it fails to fully account for the value of fuel production processes that could have an overall negative greenhouse gas emission and absorption balance (negative carbon hydrogen), such as methane pyrolysis.[9] This technology, and other similar technologies that may be developed in the future, should arguably qualify for a more favourable Taxonomy category, given that it is not only low or zero emission but it actively sequesters carbon.[10] The EU needs to promote such options, and therefore a definition of 'negative carbon hydrogen' is required.

Starting from the above definition of 'low-carbon fuel,' the Commission may therefore need to include an additional definition, such as the following:

'**Negative-carbon fuels**' shall mean fuels:

i. that fit in one of the following categories: hydrogen or synthetic gaseous and liquid fuels the energy content of which is derived from hydrogen; and

ii. the production process of which has overall greenhouse gas emissions and an absorption balance which results in net removal of greenhouse gases from the atmosphere or avoidance of emissions that otherwise would have been released into the atmosphere; and

iii. for which this balance is determined pursuant to any of the acceptable carbon accounting methodologies used to assess whether a specific economic activity meets the technical screening criteria and qualifies as contributing substantially to climate change mitigation according to Article 10 of Regulation (EU) 2020/852 of the European Parliament and of the Council and Annex I to Delegated Regulation (EU) […]/[…].

9 Methane pyrolysis is an endothermic process in which methane at very high temperatures decomposes into gases, liquids and solids. When renewable electricity (to drive the reaction) and bio-methane (as feedstock) are used it can be zero-carbon or even carbon negative as there are no process emissions and the carbon content of the methane is permanently sequestered in solid form, as a by-product. It is also possible to use a blend of biomethane and fossil methane (natural gas), for which the carbon sequestered in the biomethane offsets the supply chain methane emissions of the natural gas.

10 https://fsr.eui.eu/publications/?handle=1814/72003

These two definitions cover the entire spectrum of cases where the production of (non-renewable) clean hydrogen contributes to the EU's energy transition and climate objectives: the specific case of hydrogen, and also other hydrogen-based low and even negative carbon fuels. This is similar to the definitions in the REDII, i.e. 'renewable fuel of non-biological origin' (RFNBOs), which covers renewable hydrogen and other synthetic fuels based on renewable energy.

2.2 Certification and guarantees of origin for low and negative carbon fuels

From the perspective of meeting the EU's Green Deal objectives, it would make sense for the Commission to pursue a parallel approach between low and negative carbon fuels and green hydrogen (RFNBOs).

As mentioned above, the Commission acknowledges that low-carbon hydrogen will need to play an important role in developing the hydrogen market,[11] and a number of studies support this. While electrolysis and pyrolysis hydrogen are indeed likely to provide the solution for zero and negative carbon hydrogen in a fully decarbonised future, constrained (and therefore expensive) indigenous renewable electricity supplies and the lack of physical import opportunities mean there is considerable doubt whether renewable hydrogen will be able to meet all the EU's requirements for clean hydrogen in the coming two decades.

This means that legislation is required for low carbon and carbon negative fuels regarding guarantees of origin (GOOs) and certification, similar to that for renewable hydrogen under the RED II (as proposed to be amended). Unless such instruments are available for low carbon and carbon negative hydrogen, purchasers will not have a reliable and trustworthy method of buying and trading the product. At minimum this will hamper the development of the market.

Regarding GOOs, the REDII allows – but does not require – Member States to issue guarantees of origin for all non-renewable sources of energy. Although this principle is basically sensible (e.g. regarding coal, oil etc.), a different approach is needed for low carbon and carbon negative fuels.

Therefore, we suggest that the Commission should propose to mirror, *mutatis mutandis*, the system of GOOs outlined in Article 19 of the REDII – including the proposed reforms tabled in the Fit for 55 package. Member States should be obliged to certify low carbon and carbon negative hydrogen that meet definitions such as those proposed above.

Regarding certification, a detailed system of auditing and verification – based on a mass balance approach – is established in Article 30 of the REDII. Although the national and voluntary certification schemes applicable to low carbon and carbon negative fuels should be different to those applicable to RFNBOs, there is no reason why the overall certification framework provided in Article 30 should not be valid. Similarly, the upcoming Union database should track low carbon and carbon negative fuels in a way analogous to renewable fuels.

As a result of this, there seems to be no reason why certification schemes should not specify the precise amount of lifecycle GHG per tonne of hydrogen 'contained' in the specific low-carbon hydrogen in question. In any event, a calculation of emissions will have to be made to ensure that the plant meets the Taxonomy/lower temporary threshold for existing SMR plants. This would provide an incentive for low-carbon production to achieve higher GHG reductions, creating a 'race to the top.'

2.3 Support mechanisms and policies

In the Fit for 55 package the Commission indirectly reinforced the incentives for Member States to support renewable hydrogen (in particular via new/increased national targets in transport and industry) and for certain sectors to consume renewable hydrogen (in particular via advantageous tax policies and quotas on fuels used in maritime transport and aviation).

An important discussion will no doubt take place during the legislative procedure on whether such a 'renewable hydrogen only' support approach actually makes sense. As mentioned above, there are a number of important indications that in practice renewable hydrogen is likely to remain significantly more expensive than green hydrogen during the next 10-20 years. Furthermore, because of likely physical constraints on

11 In addition to the studies mentioned in the footnote above, see the speech by Commissioner Simson at the CCUS Forum, https://ec.europa.eu/commission/commissioners/2019-2024/simson/announcements/speech-commissioner-simson-carbon-capture-utilisation-and-storage-forum_en

renewable electricity supply during this period, it is questionable whether there will be enough renewable electricity to meet the EU's hydrogen needs during this period. In particular, it should be noted that in line with the 'energy efficiency first' principle, renewable electricity should be used for direct electrification, buildings and transport before hydrogen production, as such an approach delivers a greater GHG reduction.

In this light there are important grounds for taking a non-discriminatory approach at the EU level to support schemes/quotas etc. for renewable, low carbon and carbon negative hydrogen in the transition period. There are many 'moving parts' that will play a determining role in the EU's future low and zero-carbon hydrogen market, including (i) the overall electricity price (which largely determines the price that electrolysers will need to pay), (ii) the physical availability of sufficient renewable electricity in the EU for both hydrogen and direct electrification, transport and buildings, the (iii) possibility of importing renewable hydrogen, (iv) the cost of natural gas and (v) the availability of cost-effective CCS infrastructure. It is not possible to predict these factors for the next 5 years, let alone the next 40. The EU therefore needs an 'Internal Market for Hydrogen' that determines the low and zero-carbon hydrogen mix at each point in the decarbonisation cycle, nevertheless remaining aligned climate targets and other technological priorities of the EU.

The ETS mechanism can be relied on to push low-carbon hydrogen out of the market post-2050, and if the regulatory framework ensures a rapid maturing of all technologies there seems to be no reason why the market should not determine the appropriate balance of decarbonised hydrogen during the transition. Political and regulatory intervention to make a 'technology choice' at this early stage would be based on very imperfect knowledge of future costs and supply constraints. Indeed, to avoid any arguments about the risks of stranded costs/grandfathering of low-carbon hydrogen, one option is to make it clear from a legal perspective, already at this legislative stage, that only zero and negative carbon hydrogen will qualify for certification/guarantees of origin post-2050.

When drafting the hydrogen/gas package, the Commission may therefore wish to focus on requiring Member States to fully internalise the 'energy efficiency first' principle when designing support schemes and also reflect this in the above-mentioned transport quotas/requirements contained in the proposed RED III. The most appropriate manner to do so would be to ensure technology-neutral support schemes (based on tonnes of GHG saved per € required in subsidy) unless support is specifically required for a certain technology for R&D&D[12]/first industrial deployment with the aim of bringing it to maturity and thus lowering its cost. This mirrors the existing approach in EU law to renewable electricity support schemes.

Moreover, it should be noted that, in line with the internal market rules and following the precedent set in the electricity market,[13] Member States may not discriminate between different types of hydrogen imported from other Member States based on the production method used. In other words, Member State legislation not directly concerning financial support schemes should be 'colourblind,' at least with respect to imports of hydrogen within the European internal market.

3. Hydrogen networks

There are a number of reasons why legislation on a hydrogen network should be based on the rules developed over more than two decades for the existing natural gas network. For example, a hydrogen network is arguably an essential service for companies wishing to trade in clean hydrogen. Without access to a competitive internal market, it will be much more difficult for this to function smoothly. Moreover, apart from very limited exceptions, it will make no sense to have parallel hydrogen networks, and to a very large extent it will need to be run as a monopoly activity.

However, there are equally a number of reasons why it is not appropriate to simply transpose the existing gas rules *mutatis mutandis* to the emerging hydrogen grid:

- The gas rules were developed to regulate an existing mature network and market. The hydrogen grid (apart from some small diameter privately owned networks that will not form the basis of the future grid) remains to be developed.

12 Research and development and demonstration.
13 Member States are not allowed to discriminate between electricity produced in different ways when this electricity is imported from other Member States.

- The hydrogen grid will to a large extent develop from repurposed gas pipelines rather than new build as this is a far cheaper option, and

- during the initial period of grid development, it will need to be 'over-built'[14] as demand for transmission services will ramp up over time. Therefore, the same issues regarding congestion management, for example, will not initially be relevant. Equally, funding issues for the hydrogen grid are different to those for natural gas.

- The 'energy system integration' issues between gas and electricity networks are even more important when hydrogen is added to the mix. The correct location of electrolysers – which are essential for electricity storage solutions – will be very important in terms of efficient use of gas, hydrogen and electricity grids, and will require a careful balancing exercise to ensure optimum integration.

- The planning methodology for the hydrogen grid and its interaction with the (progressively repurposed) natural gas grid will be important. Ensuring that hydrogen grids are built quickly enough to permit the emerging market to develop and with the correct capacity and ensuring repurposing takes place at the optimum moment will be challenging.

In this light, a simplistic wholesale transposition of the existing natural gas legal framework would not make sense. However, it would logically form the basis of the future hydrogen regulatory framework and over time would be likely to largely, if not completely, parallel the existing gas rules. On this basis, we put forward the following suggestions for the framework for the future hydrogen legislative package with respect to grid regulation.

3.1 Basic network regulatory model: Third party access (TPA)

Once it is widely developed, the hydrogen network will certainly be an essential facility, and therefore the regulated third party access (TPA) approach should apply, with tariffs and congestion management rules subject to ex-ante regulatory control by the national regulatory authorities (NRA). However, during the initial stage of grid development a stepwise approach makes sense, balancing regulatory cost and access guarantees.

For example, during the early years of network operation, congestion will not be an issue and, providing that tariffs are published, the issue of discriminatory tariff-setting may equally not pose important difficulties. A 'one-size-fits all' approach here will probably not make sense. The Netherlands, for example, are moving ahead with the development of the hydrogen grid very quickly, while other countries, notably those in central and eastern Europe, are likely to proceed more slowly.

On the other hand, it makes sense to set out the regulatory model that will certainly apply once the network has reached a certain level of maturity – based on the regulated TPA principles contained in the Gas Directive and Regulation. This will provide investors with long-term transparency and predictability.

The most logical approach would therefore be to legislate that in the absence of a specific derogation granted by the NRA and approved by the Commission all networks must by default be regulated under the TPA model in parallel with the 'Article 36' procedure for new infrastructure under the Gas Directive. One option would be to provide a general sunset clause requiring that any such derogation must terminate by a given date. However, given that networks will evolve at very different speeds in the Member States, a more effective approach may be to require that any derogation is time-limited (to say 10 years) and any renewal must be the subject of a new decision, therefore with a need for Commission approval.

3.2 Who should operate the grid and the issue of 'horizontal unbundling'

There are some obvious similarities between operating a gas and a hydrogen network, particularly if, as seems likely, the future grids will be large diameter networks largely made up from repurposed natural gas pipelines.

In this light, it is somewhat self-evident that gas transmission system operators (TSOs) will/

14 By 'over-built' we mean that infrastructure could be developed to serve not just the existing demand (as would normally be the case) but an expected demand for hydrogen, which should be carefully identified, quantified and included in the network development plan approved by the national regulatory authority (NRA).

should be the natural owners and operators of the future hydrogen grid. Otherwise, it will be difficult and complicated to agree the valuation and transfer of pipes for repurposing, as it will be for issues such as the expropriation of assets (including licenses to operate and rights of way). However, this issue could be left to subsidiarity.

In terms of horizontal unbundling – the question of whether a TSO that owns and operates both a natural gas and hydrogen network should be required to operate them through separate companies – it is important to understand the different drivers of horizontal and vertical unbundling.

No issues of discrimination arise from the joint ownership of a gas and a hydrogen grid. The only potential issue concerns potential cross-subsidisation between gas and hydrogen activities (see 'Financing the grid' below). However, any such issues can be dealt with through a requirement to hold separate accounts for these activities. There is no merit in requiring legally separate gas and hydrogen network companies and functional unbundling as seen in the vertical unbundling independent transmission operator (ITO) model. This would only add costs to the system for no substantive benefit.

3.3 Vertical unbundling

Vertical unbundling covers the question of whether a hydrogen (or joint gas/hydrogen) TSO should be allowed to own and operate a hydrogen production facility as well as operating the grid. This is the 'classical' issue when discussing unbundling.

Naturally, such ownership can give rise to discrimination risks, as the TSO may favour its own hydrogen activities in the event of allocation to scarce transmission capacity, or with respect to tariffs.

However, one should be careful to simply assume a need to transpose the approach of the natural Gas Directive to the hydrogen network without considering the specific circumstances. There are positive reasons why a hydrogen/gas TSO might own/operate an electrolysis facility, for example for speed of development and grid management. As the grid will be built 'over-capacity,' the ability and interest to discriminate is unlikely to exist for some time.

Therefore, an approach for consideration would again be to adopt a phased-in approach, allowing Member States the freedom to choose the best approach during the initial development of the hydrogen market specific to their situations, for example enabling TSOs to invest in hydrogen facilities only for an initial period (say 10 years from the entry into force of the new Directive).

After the end of the initial period, one option is for the same unbundling rules to apply as are contained in the Gas Directive. In this configuration, hydrogen production facilities would have to be separated from the network in conformity with either the ownership unbundling, ITO or independent service operator (ISO) models. In this respect it should be noted (i) that the Commission and ACER have found that all three models have functioned well under the Gas Directive, and since the third package no significant anti-trust cases have found discriminatory conduct and (ii) all TSOs should be treated equally. Member States should be free to choose the correct unbundling model for the longer term for hydrogen, regardless of which model they have chosen for natural gas (i.e. an ownership unbundled natural gas TSO should be able to operate the hydrogen grid under the ITO model, just as an ITO unbundled gas TSO may).

3.4 Tariff principles

The basic tariff principles (transparency, non-discrimination etc.) enshrined in the Gas Directive are applicable here. The detailed rules contained in the Gas Regulation and more specifically grid codes (see below) are, however, likely to be too detailed for the current state of hydrogen grid development.

Discussion has taken place in the Madrid Forum in recent years regarding the 'quo vadis' tariff model for natural gas. This would abolish national entry/exit tariffs and replace them with a single EU entry/exit tariff, the receipts of which would be shared between all EU TSOs. This would avoid 'tariff pancaking' and it represents a valuable theoretical model.

It would require all TSOs and NRAs to agree on issues such as the asset valuation for hydrogen pipelines, repurposing valuation, the regulatory asset base (RAB) and which country gets what share of the total revenue. As the grid will grow at different speeds in different countries, the speed of growth of revenue, and the need to front-load costs, will give rise to likely insoluble discussions and conflicts on the division of revenue. How, for example, to deal with revenues from one grid financed largely by state subsidies and from another financed by debt?

In this light, the Gas Directive provides a viable model for the hydrogen network, combined with a political approach to encourage and promote progressive regional market integration. Such an approach, it is suggested, is most likely to deliver an effective tariff model.

3.5 Financing the grid

It will not be simple to finance the new hydrogen grid as it will need to be 'over-built' in the beginning. Tariff revenues will not, therefore, initially (and probably for at least a decade from the initial investment) cover capital expenditure (CAPEX) and financing costs. Assuming this to be the case, there are two options. The first is to cover the shortfall with government grants, as is the case in the Netherlands. The EU Connecting Europe Facility could finance some investment, but at best this will be a very partial solution to this problem. Alternatives that have been suggested include financing the shortfall from somewhere else, such as tax revenue by way of an annual subsidy, or using revenues from another activity – e.g. gas tariffs. No option provides a 'magic solution' and therefore a degree of flexibility based on subsidiarity is likely to be a reasonable approach.

3.6 Grid planning

An integrated approach to grid planning is required, so that gas, electricity and hydrogen planning is undertaken involving both ENTSOE[15] and ENTSOG.[16] Given that a joint gas-hydrogen TSO is expected to be the standard model, it makes sense for these gas-hydrogen TSOs, together with ENTSOG, to have primary responsibility for hydrogen grid planning, but in close collaboration with ENTSOE.

The existing planning approach based on ten-year network development plans (TYNDPs) that feeds into the projects of common interest (PCI) process is tried and tested and should be extended to hydrogen. This is being effectively dealt with in the revision of the TEN-E Regulation.

One issue that requires consideration is the potential 'over-build' of the hydrogen network. It may be argued that gas TSOs have an interest in aggressively repurposing gas pipelines as natural gas transport volumes decline, thus potentially leading to 'overbuilding' of the hydrogen grid. The 'market test' approach contained in the Capacity Allocation Mechanisms Network Code (CAM NC) cannot be simply taken over to address this issue (the Grid Code requires new infrastructure to be built only where proven adequate demand can be demonstrated), as it would ignore the need to initially 'over-build' the hydrogen network. In fact, the TYNDP process, and the requirement that NRAs approve any hydrogen grid investment that will be placed on the RAB, should be adequate protection in this regard.

3.7 Blending principles

The issue of blending clean hydrogen into the natural gas network is far from simple. We argue that while clean hydrogen remains a scarce and expensive resource (2030<) it should be used to replace grey hydrogen or in demonstration 'clean steel' and 'clean cement' plants. Until there are abundant volumes of renewable energy and renewable hydrogen there is little economic or environmental merit in implementing minimum quotas for natural gas suppliers to blend clean hydrogen into their natural gas sales as it is not an efficient use of the resource. However, there may be a need for 'technical blending' in the short-medium term in very limited and specific circumstances.[17]

Different levels of blending hydrogen into the natural gas network can raise important problems for the internal gas market and interoperability. Therefore, agreed maximum levels of permitted hydrogen in the natural gas system may be required to ensure that gas can flow between Member States without expensive blending/de-blending requirements. Such a level would need to be relatively low, as levels above 10% are not universally accepted as being possible without significant system mod-

15 The European Network of Transmission System Operators for Electricity (ENTSOE)

16 The European Network of Transmission System Operators for Gas (ENTSOG)

17 For example, when an electrolyser or low-carbon hydrogen supplier cannot physically deliver contracted hydrogen to a customer because the network is not yet sufficiently developed. In such circumstances virtual supplies combined with blending and guarantees of origin may be a solution.

ification and changes in certain end use appliances. Blending can also give rise to concerns over the energetic value of the final product, as natural gas has a considerably higher energy density than hydrogen – and therefore requires larger volumes of blended natural gas than pure natural gas alone.

3.8 Grid codes

Currently the EU has adopted five Network Codes and Guidelines with respect to natural gas (Balancing, Capacity Allocation Mechanisms, Congestion Management Procedures, Interoperability and Tariff). These are highly complicated technical legal requirements on TSOs and NRAs. We argue that in the current state of hydrogen market evolution, these are not applicable to the hydrogen network. It is too early to state whether they will ever be simply 'transposable.' Their principles will certainly be relevant to the hydrogen network over time, but they will no doubt require changes to details.

Therefore, a provision enabling the subsequent adoption of hydrogen network codes would be the appropriate approach in this respect.

4. Conclusions

The forthcoming hydrogen legislation is important for the EU's Green Deal. During the transition period a combination of decarbonised hydrogen products will be needed. By 2050 the EU will need to cover its needs with renewable and carbon negative hydrogen. Whether this will be 10% or 25% of energy needs in 2050 is unknowable, but in any event within less than three decades the EU needs a new energy system of clean electricity and clean molecules – the ratios of the specific vectors are still to be decided.

The regulatory framework is important in this respect. We suggest that the analysis in this short paper points to an important truth. There is a huge degree of uncertainty regarding the size, speed and nature of the EU's future hydrogen economy. We cannot predict today whether green, blue or turquoise hydrogen will be the most competitive and by how much, and how this will vary over time (as we cannot predict future renewable electricity costs and availability, gas prices and ETS prices, for example). We cannot predict future technological innovation. We cannot predict how customers will react to decarbonised energy choices.

The internal energy market principles have served the EU well. There seems no inherent reason why the principles of competition, technology neutrality and third-party access to grids designed based on energy system integration principles cannot and should not underpin the future development of the EU's low and zero-carbon hydrogen market. These principles require full internalisation of GHG costs, and existing gas network rules require refinement to take factual differences into account. The framework needs to guarantee that the EU is on course for full decarbonisation by 2050. An EU internal market for hydrogen where competition decides winners and losers on the basis of cost, technological neutrality and GHG content, and with a clear mandate for low carbon and carbon negative gases post-2050, is a good starting point.

The Florence School of Regulation

The Florence School of Regulation (FSR) was founded in 2004 as a partnership between the Council of the European Energy Regulators (CEER) and the European University Institute (EUI), and it works closely with the European Commission. The Florence School of Regulation, dealing with the main network industries, has developed a strong core of general regulatory topics and concepts as well as inter-sectoral discussion of regulatory practices and policies.
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