A REGULATORY FRAMEWORK FOR POWER TO HYDROGEN IN GERMANY AND THE NETHERLANDS

A policy brief for TenneT TSO GmbH

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Background of this study

Having committed to a significant reduction of greenhouse gas ("GHG") emissions the European energy sector is undergoing significant changes. An important pillar of Member States' decarbonisation strategies are so called "sector coupling technologies" which aim especially at transferring green electricity produced from wind or solar power into other sectors by means of direct or indirect electrification. In this context so called Power-to-X ("PtX") technologies and in particular (green or blue) hydrogen is seen as a key technological route[1]. Many Member States have already established or announced a hydrogen strategy, e.g. the Netherlands and Germany, and also on EU level itself, the so called "European Green Deal" foresees a future role of hydrogen. Given the political support and industry policy considerations in Europe it is very likely that there will be a hydrogen economy in the medium- to long-term.[2] For TenneT the ramp up of green hydrogen is particularly interesting as

- a ramp up of electrolysers in Europe could change the network flows and thus the necessary network planning and operation;
- TenneT could potentially play a role as technology and market enabler for new technologies by having the role as "innovation hub" as a hydrogen economy ramps up.

Objective of our study

In this context we analysed the following three topics:

- **Current regulatory framework –** What are key regulatory rules today in the Netherlands, Germany and on European level that drive the business for green hydrogen? Where are important gaps? This includes rules on electricity tariffs as well as limitations to ownership for TSOs from unbundling requirements.
- **Ownership of green hydrogen generation pilot plants** – What can be meaningful ownership models in the short-term ("transition model") and long-term ("target model") that allow society to make use of market and network related benefits of P2H2 units?
- **Influencing location or dispatch of green hydrogen –** Since the introduction of unbundling requirements the "automatic" coordination of generation/demand location and network cost is no longer guaranteed. New coordination measures are regularly discussed and in the context of the ramp up of a hydrogen economy (with potentially GWs of new electrolysers coming into the power system), TenneT wants to understand potential options to influence the location or dispatch of new electrolysers entering the system as "lumpy". Here we distinguish between "brownfield" (electrolysers directly integrated into an

1 Green hydrogen is produced based on electrolysis using electricity generated by renewable energy sources(RES-E). Blue hydrogen is based on steam reforming of natural gas but with capturing and usage of the CO_2 emissions ("CCU").

2 Different scenarios from different institutions predict total demand estimates for hydrogen which amount by 2030 to 24 - 95 TWh/a by 2030 in Germany (with about 60 TWhH2/a of non-energy related industrial use) and around 50 TWh/a by 2030 in the Netherlands (with a minimum of about 11 TWhH2/a of industrial use) See DNV GL (2018): Power-to-Hydrogen IJmuiden Ver.

industrial site using heat sinks, oxygen or benefitting from lower electricity network tariffs) or “greenfield project” (electrolysers which are simply connected to the power (and gas) grids without any further link to local heat, oxygen or electricity demand).

In the following we summarize our key findings on each of the three research areas.

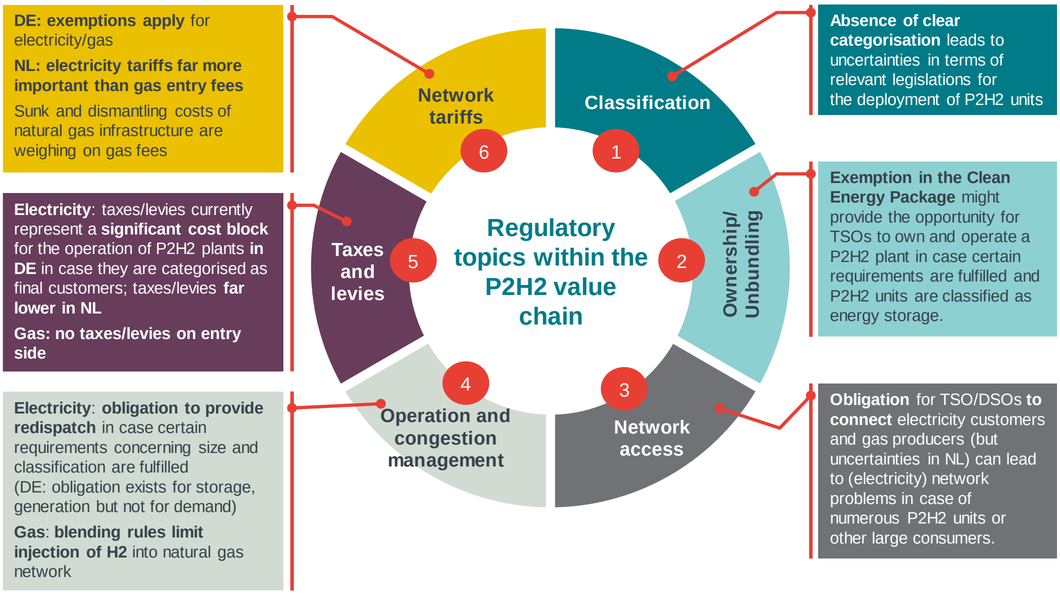
Regulatory framework not yet ready for a hydrogen economy

When considering the regulatory framework of P2H2, the legal classification of hydrogen and P2H2 units (as final consumer of electricity, gas producer, power to energy storage/gas storage and/or fully integrated network component) is essential. However, on EU as well as on national level a clear classification is still missing:

- On **EU level**, according to the wording of Art. 2 para. 59 Directive (EU) 2019/944 of the Clean Energy Package (CEP), it appears as if P2H2 units can be classified as an energy storage. However, further legal interpretation would be required and further developments on this regulation are likely regarding the importance of this topic in future. Subject to the condition that P2H2 units are classified as energy storages, a TSO ownership would be possible under certain conditions according to the Directive, i.e. given a market test, that the facility is not used to buy or sell electricity and that the regulatory authority has granted its approval. Following the same Directive it is also clear, that P2H2 cannot be defined as a “fully integrated network component” in case it is used for congestion management (in our analysis we call this “network related use”). However, this regulation is not yet implemented into national legislation.
- In **Germany**, hydrogen is classified as gas and biogas under the German energy act (“EnWG”). The latter leads to an exemption for P2H2 units from gas network entry tariffs. Due to an explicit reference, newly built P2H2 units are also exempted from paying electricity network tariffs for the first 20 years of operation. The situation is less clear in relation to taxes and levies, which largely effect the business case of P2H2 assets, since there is no explicit reference that P2H2 units are classified as final (instead of wholesale) electricity consumer. Depending on a general classification as an “installation storing electrical energy” P2H2 units > 10 MW (or > 100 kW from October 2021 onwards) are obliged to provide redispatch services. However, this classification as a form of “electricity storage” is not entirely certain.
- In the **Netherlands**, the current gas definition does not include hydrogen, which has wider implications for the application of existing gas related regulation to P2H2 units, e.g. with regard to the organisation of network access and feed-in. Similar to Germany, uncertainties exist with regard to the classification as final or wholesale electricity consumer. This is again relevant for obligations to pay electricity network tariffs, taxes and levies, though these are far lower than in Germany (and thus have less impact on the business case than in Germany).

An overview of the current regulation of P2H2 units and its gaps and hurdles along the P2H2 value chain is provided in Figure 1.

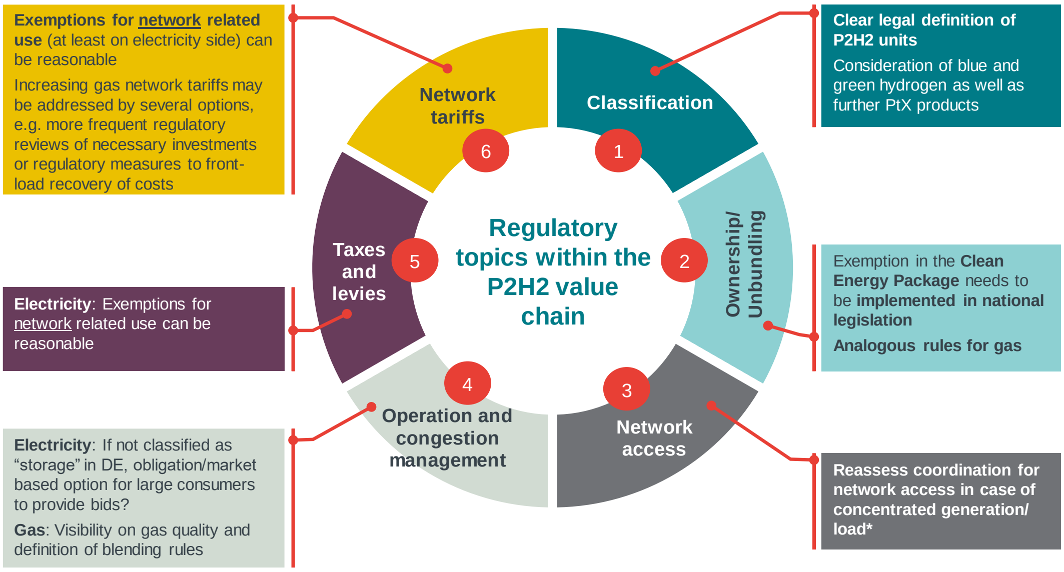
Figure 1 Several regulatory gaps and hurdles exist across all topics and on EU level as well as in Germany and the Netherlands



Source: Frontier Economics.

These gaps and hurdles could be addressed by the suggestions for regulatory changes outlined in Figure 2.

Figure 2 Suggestions for regulatory changes



Source: Frontier Economics.

During the ramp up phase of green hydrogen TSOs can support innovation – in the long run P2H2 assets will be owned and operated by market participants

Simplified business calculations for an electrolyser built today[3] show that even without considering operation and maintenance costs, network tariffs, taxes and levies, a positive business case is reached only for sale prices for green hydrogen above 50 EUR/MWh$_{H2}$ when applying today's power price profiles. Therefore, we can conclude:

- simply removing taxes and levies from retail electricity prices for electrolysers will not be sufficient to allow for a positive business case;
- at current prices for (grey) hydrogen of about 30 EUR/MWh to 45 EUR/MWh (ca. 1 - 1.50 EUR/kg) a positive business case for green hydrogen is not feasible unless a "premium" is paid by buyers for the "green" benefit of the gas. This premium could in theory result from
  - a supply side premium (e.g. feed-in subsidy programs or premium similar to RES-E promotion);
  - a demand side premium or obligation – e.g. from the mobility sector (e.g. fleet targets for OEM), fuel sector (renewable fuel quota on refineries as part of the RED II), industry (steel) or heating sector if green hydrogen is accounted differently than grey hydrogen (Other options to price carbon emissions are also discussed – e. g. expansion of EU ETS to other sectors such as mobility sector, national carbon taxes etc. For the business case of green hydrogen it is important that the green "attribute" will be significantly rewarded) .
- In addition, the business case could be improved by rewarding network related benefits in case the electrolyser can be used at a location that allows for this. In such a situation lower electricity procurement costs can help lowering green hydrogen production costs. A similar concept is applied in Germany with the so called "Nutzen-statt-Abregeln" in context of power-to-heat units (§13 para. 6a EnWG).

Looking forward we expect cost reductions for electrolysers and RES-E technologies. Again, simplified calculations assuming learning curve effects (e.g. lower investment costs and increased electrolyser efficiency) suggest that the prospects of a positive business case are possible – indicating e.g. a potential break-even price of about 34 EUR/MWh[4] of green hydrogen in the long-term (excluding network costs, taxes and levies on consumed electricity).

Overall, in the short run the network related operation and benefit dominates electrolyser operation, in the long run the benefit of market driven operation will be

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3 For the calculation we assumed CAPEX of 800,000 EUR/MW$_{el}$, 67 % efficiency of the electrolyser and a life time 20 years.

4 This value refers to the lower end of forecasts for CAPEX (200,000 EUR/MW$_{el}$) and the upper end of forecasts for the efficiency of the electrolyser (80 %) each in 2050 and a life time of the electrolyser of 20 years.

dominant. In the short run (with current rules for electricity retail tariffs, RED II and OEM fleet targets) a pure market driven investment is rather unlikely to achieve a positive business case – network related revenues will have to be part of the revenue stream to make projects viable. Not only in the short run, but also in the long run, from an economic perspective it generally makes sense to allow for both, i.e. for realising market and network related benefits when operating the P2H2 units. Accordingly, we focus on so called "hybrid models" where market and network related operation will be combined (see Figure 3), i.e. there is at least the opportunity that a market player can offer its P2H2 unit also for redispatch or that a TSO can offer unused capacity of its P2H2 unit for market related use to market players.

Figure 3 Potential target models based on ownership and operation

Source: Frontier Economics.

In the short-term, a **"hybrid TSO model"**[5] could provide a pragmatic solution for accelerating the ramp up of P2H2 for greenfield projects:

- TSOs could step in by promoting innovation (for a limited number of units and/or time) to allow initial investments and technology development. Costs for the electrolyser would then go into the regulated asset base (RAB). The allocation of related risks and opportunities can be controlled via regulation (risks allocated to TSO and risk allocated to network users).
- For this, legal uncertainties with regard to unbundling need to be addressed and in case the exemption in the CEP can be applied, a market test would be required. However, further major changes to the current regulatory framework

[5] A hybrid TSO model refers to TSO ownership of the P2H2 plant, which is used for network as well as market related use.

are not necessarily required. A ramp up of P2H2 by sole use of a "hybrid market model" would require addressing the regulatory gaps and barriers (see first research area), setting up market support mechanisms and ensuring consideration is given to system effects (e.g. on the electricity network) more explicitly, which may take some time to develop and could lead to delays.

- As a "transitional model" the hybrid TSO model allows monetising both the market and the network related use and thus can probably provide the "fastest" business case (if located at the suitable location in the network). This can be an option for a limited number of plants in the coming years which allows initial experiences to be gained with the technology and provides initial development opportunities for manufacturers of relevant technologies.

However, to build up an industry **long-term** and to provide stable positive business cases a **hybrid market model** will be preferable. Several design options are possible, but a model that includes influencing the location of greenfield projects seems best for optimising between network and market related aspects (further discussed below). While implementing and running the transitional model, the regulatory framework could be adjusted to provide the basis for the future hybrid market model. It is important that a level playing field between P2H2 and other green technologies (e.g. synthetic methane, power to liquids, energy storage technologies) is established. A transition from the hybrid TSO model towards a hybrid market model for greenfield projects can take place in different ways:

- A market test could be applied regularly, so that the TSO is e.g. required to tender the plant every five years.
- Alternatively, the transitional TSO model could be limited to a certain number or capacity of P2H2 units.

Overall, the transitional model would ensure a quick ramp up of P2H2, but the rules directed at a transition towards a market model, would at the same time guarantee the implementation of a target model as a "hybrid market model" that makes sense in the long run.

Ramp-up of green hydrogen should be coordinated with electricity networks to optimize overall system costs in the short as well as the long run

From a TSO's perspective, the future ramp up of (green) hydrogen in Europe induces risks as well as opportunities.

Risks result from an "uncontrolled" growth of electrolysers which could impose problems on the network, because the lead time required for building a new transmission line is usually far longer than the time required for building a new electrolyser – not least due to public acceptance problems. This is true in particular for electricity transmission grids while gas transmission networks usually have some more headroom to cope with additional gas infeed at least at the moment (depending on pressure level and due to "1 in 20 winter" assumption during network planning)[6]. The situation might be different in the future with increasing

[6] With very peaky production also some gas networks might face congestion issues, in particular in lower pressure level gas networks. Currently new products for gas networks are debated. However, the gas

share of hydrogen produced by electrolysis, especially for gas distribution networks: the intermittency of renewable electricity sources may result in congestion where gas injections exceed gas demand in a given area. One “simple” approach to address this problem could be the restriction of the capacity of P2H2 units (or other demand that wants to be connected) in general or in certain grid areas, even though this would neither be in line with climate change goals nor with existing regulation. Concerns regarding discrimination of certain user groups or political pressure (e.g. accusations of blocking the energy transition) can be expected if network access was denied to P2H2 units based on intransparent or too general criteria.

However, taking network issues into account is important from a TSO’s perspective and in order to limit overall system costs. In order to lower system costs the TSO could aim at

- influencing the location of the new electrolyser; and/or
- influencing the operation of an electrolyser (similar to redispatch of power plants).

The actual influence on location is greater for greenfield than for brownfield projects as the latter are less flexible as they are physically linked to existing industrial facilities using heat or oxygen.

The main **influence on location** is therefore on greenfield projects. Depending on the timeframe considered (short- or long-term) and the model chosen, this influence can happen in different ways:

- **TSO as co-owner** – In a hybrid model, where the TSO is (co-)owner during the transition phase, the TSO can directly influence the location decision.
- **Coordination with market parties** – In a hybrid model, where a market participant owns and operates the P2H2 unit, the influence could be realised in one of several ways:
  - If the greenfield project receives supply side support (via a subsidy program) the prequalification or allocation of subsidies could take into account location and network costs (e.g. as it is done today in context of offshore wind in the Netherlands where certain regions are determined ex ante or onshore wind/PV in Germany where the so called “Netzausbaugebiete” (preferred expansion areas) are defined while imposing regional caps on the selection of subsidised projects.
  - The TSO could auction electrolyser support in certain areas (e.g. similar to the “Besondere Netztechnische Betriebsmittel”, special network technical assets in Germany).
  - Both coordination approaches listed above only address a limited number of greenfield projects and only those that require support. In order to influence location more broadly, other methodologies such as regional network tariffs can be introduced. However, it is important not to unduly discriminate network users (e.g. similar rules need to be applied for

network is more “robust” than an electricity network (“buffering of the network through pressure levels”) and due to energy efficiency and decarbonisation some gas infrastructure will be freed up.

batteries, power-to-heat or other (new) consumers etc.). Also politically such an approach will be more difficult to realise.

The main **influence on dispatch** can be both on greenfield and brownfield projects and this influence can – again depending on the timeframe considered and the model chosen – happen in different ways:

- **TSO as co-owner** – In a hybrid model where the TSO is (co-)owner during the transition phase the TSO can directly influence the operation of the unit.
- **Coordination with market parties (greenfield)** – In a hybrid model for greenfield projects where a market participant owns and operates the P2H2 unit the influence could be realised via
  - a cost based redispatch (in case the P2H2 unit is seen as an installation storing electrical energy, which is covered via § 13a para. 1 EnWG); or
  - a market based redispatch (as in the Netherlands, where are consumers > 60 MW are obliged to provide bids) or via other products such as "Abschaltbare-Lasten-Verordnung" ("ABLaV").
- **Coordination with market parties (brownfield)** – In a brownfield situation where the unit is 100 % owned by an industrial customer, similar procedures as for other industrial demand can be applied:
  - A cost based redispatch (in case the P2H2 unit is seen as an installation storing electrical energy, which is covered via § 13a para. 1 EnWG). However, the actual cost calculation is much more complex in brownfield projects and costs can be very high if TSOs have "deep" intervention rights into industrial processes outside emergency situations; or
  - a market based redispatch (as in the Netherlands) or via other products such as ABLaV (as for greenfield projects or other demand).