Study on requirements and implementation of ENTSOG'S Cost Benefit Analysis for hydrogen infrastructure for ACER

ECONOMIC & ENERGY CONSULTANTS

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ASME	American Society of Mechanical Engineers
ATR	Autothermal Reforming
BCR	Benefit to Cost Ratio
BF-BOF	Blast Furnace – Basic Oxygen Furnace
BIL	Bipartisan Infrastructure Law
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CBAM	Cost Benefit Analysis Methodology
CCS	Carbon Capture and Storage
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CoDG	Cost of Disruption of Gas Supply
CoDH	Cost of Disruption of Hydrogen Supply
CREG	Belgian Commission for the Regulation of Electricity and Gas
DOE	U.S. Department of Energy
DRI	Direct Reduced Iron
DRI-EAF	Direct Reduced Iron – Electric Arc Furnace
DSO	Distribution System Operator
EC	European Commission
EERE	Energy Efficiency & Renewable Energy
EHB	European Hydrogen Backbone
EIB	European Investment Bank
ENPV	Economic Net Present Value
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EoI	Expression of Interest
ERR	Economic Rate of Return
EUDP	Energy Technology Development and Demonstration Programme
ETS	Emissions Trading System
EU	European Union
FCEV	Fuel Cell Electric Vehicles
FID	Final Investment Decision
FNB Gas	Association of supra-regional gas transmission companies in Germany
FRI	Italian Sustainable Growth Fund
GDP	Gross Domestic Product
GHG	Greenhouse Gases
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IP	Interconnection Point

IPCEI	Important Projects of Common European Interest
JRC	Joint Research Centre
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
MEGCs	Multiple Element Gas Containers
METIS	Markets and Energy Technologies Integrated Software
MIMIT	Ministry for Business and Made in Italy
MOOI	Mission-oriented Research, Development and Innovation
MS	Member State
NCV	Net Calorific Value
NDP	National Development Plan
NECP	National Energy and Climate Plan
NOx	Nitrogen Oxides
NPV	Net Present Value
NRA	National Regulatory Authority
NSEC	North Seas Energy Cooperation
OEMs	Original Equipment Manufacturers
OPEX	Operating Expenditure
PAC	Paris Agreement Compatible
PCI	Project of Common Interest
PEM	Proton Exchange Membrane
PMI	Projects of Mutual Interest
PMx	Particulate Matters
PPE	French Multi-Annual Energy Plan
PRIMES	Price-Induced Market Equilibrium System
PtG	Power-to-Gas
PtX	Power-to-X
PV	Photovoltaic
RES	Renewable Energy Source
RFI	Request for Information
SDR	Social Discount Rate
SMR	Steam Methane Reforming
SOx	Sulphur Oxides
TEN-E	Trans-European Network for Energy
TSO	Transmission System Operator
TYNDP	Ten Year Development Plan
TWh	Terawatt-hour
VoLL	Value of Lost Load

Executive Summary

The recast TEN-E Regulation (Regulation (EU) 2022/869) requires ACER (Articles 11(2) and (3)) to provide an opinion on the draft single-sector Cost-Benefit Analysis (CBA) methodology for hydrogen infrastructure projects prepared by ENTSOG, to be taken into account by ENTSOG when amending its draft CBA methodology and submitting it to the European Commission for approval. This Study aims to support ACER in this task, by formulating **recommendations for ENTSOG's CBA methodology for hydrogen infrastructure**, ensuring compliance with the recast TEN-E Regulation, and factoring in the particularities of the hydrogen market and infrastructure development.

Hydrogen is an energy carrier expected to substantially contribute to achieving the European Union (EU)’s 2030 and 2050 decarbonization targets. As hydrogen is a nascent energy vector, **markets and infrastructure will have to develop hand-in-hand**. The emerging hydrogen market, characterized by hydrogen’s properties, applicability to end-uses and technoeconomic characteristics should be examined first, to subsequently conduct informed hydrogen infrastructure projects’ assessment within the frame of a Cost-Benefit Analysis methodology.

Hydrogen demand and supply

The progressive uptake of **hydrogen demand** is expected to **start with existing hydrogen users** who will move from grey to blue and/or green hydrogen, e.g., by using green hydrogen as industrial feedstock. **Next**, consumers may appear in **sectors that can relatively easily displace the use of fossil fuels with hydrogen**, particularly in the heavy-duty transportation sector, where electrification is not deemed as a technically feasible decarbonization option. In the **medium-term**, the **use of hydrogen in industrial high heat processes** is envisioned and as regards **long-term** applications, these concern the **power and heating sectors and other transportation modes**. However, the extent of future hydrogen use in the aforementioned end-uses will **depend on its economic and technical advantages** versus other alternative energy carriers, mainly RES electricity, that could be employed to decarbonize these sectors. For hydrogen to be used as a means of decarbonization in various end-use applications, national policy targets and measures should **incentivize hydrogen use**. The following Table presents the short-term and long-term end-uses for green hydrogen identified by selected Member States (MSs) and the U.S., indicating that there are **significant commonalities in the pathways the countries are envisioning to develop hydrogen markets**.

Short-term and long-term demand for blue and green hydrogen in the reviewed countries

	DE	FR	NL	DK	IT	BE	U.S.
Industry*							
feedstock	🟢	🟢	🟢	🟢	🟢	🟢	🟢
heat processes	🟡	-	🟢	🟢	🟡	🟢	🟡
Refining	🟢	🟢	🟢	🟢	🟢	-	🟢
Transportation							
heavy duty	🟢	🟢	🟢	🟢	🟢	🟢	🟢
public passenger transport	🟢	🟢	🟢	-	🟢	-	🟢
commercial vehicles	🟢	-	🟢	-	-	-	-
civil vehicles	-	-	🟢	-	🟡	-	-
maritime transportation	🟡	-	🟢	🟡	🟡	🟡	🟡
air transportation	🟡	-	🟡	🟡	🟡	🟡	-
Power sector	-	🟡	🟡	-	🟡	🟡	🟡
Heating sector	🟡	-	🟡	🟡	🟡		🟡

🟢: *Short-term demand* 🟡: *Long-term demand* **Chemicals industry, steel, cement, aluminium, ceramics and glass*

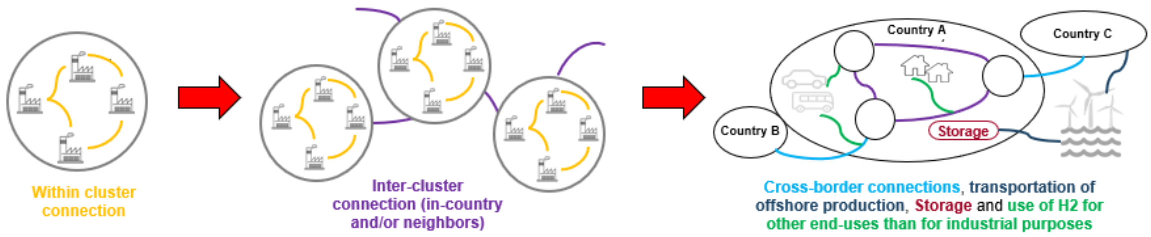
Moving on to the **supply of green hydrogen**, the available options for the EU MSs are **to produce and use it and export the hydrogen surplus and/or to import hydrogen from other MSs or from abroad**. The **role of each Member State**, i.e., "*net importer*", "*net exporter*", "*transit*" / "*entry/exit*" country will **depend mainly on** the country's **RES generation** potential, **network system** (extent of natural gas networks, Liquefied Natural Gas (LNG) terminals, storage facilities) **and electrification** targets (as in MSs where green electricity can be largely employed to meet the country's CO2 reduction targets, there will be limited demand for hydrogen). Another aspect that is important to be highlighted is that the hydrogen demand and supply targets set within the EU appear to concern green hydrogen only, despite the fact that **blue hydrogen is recognised as a transitional low-carbon fuel**. Lastly, as with demand, supply is also expected to be **supported via measures and policies**.

Hydrogen transportation and network planning

As regards the **transportation of hydrogen**, developing the relevant infrastructure appears to be mainly **demand driven**, for which securing **long-term binding commitments from prospective shippers/network users** to the extent possible is recommended, so as to **avoid stranded assets**. The development of infrastructure should be primarily based on **linking emerging consumption centres with available supply**, while other critical elements that need to be taken into consideration include network sizing, routes and timing, expected flows, use of existing gas grid (via repurposing) and/or building new hydrogen infrastructure including storage facilities. Once again, the development of hydrogen infrastructure has to be **supported by appropriate measures and policies** and **a regulatory framework has to be developed** to coordinate the development of infrastructure and to clarify the roles of relevant stakeholders.

Regarding the planning of hydrogen infrastructure, the analysis of selected EU MSs reveals a preference for a **gradual approach to network development synchronised with the build-up of hydrogen supply and demand**. As shown in the Figure below, the initial conversion of grey to green hydrogen will lead to the development of local infrastructure connecting industries to create industrial cluster networks. The next step will involve inter-cluster connections (in-country and/or with neighbouring MSs). Eventually, an extensive "*hydrogen backbone*" is envisioned by each MS, with cross-border connections, offshore hydrogen production potential and storage facilities, which will allow the use of hydrogen for multiple end-uses. It is also worth noting that the currently planned hydrogen networks will largely make use of existing natural gas pipelines.

The gradual build-out of demand and infrastructure



Matching hydrogen market needs with infrastructure development

For the above gradual build-out of hydrogen infrastructure to materialize and avoid the effect of stranded assets, it is essential to **match hydrogen market needs with infrastructure development**. Based on the practices observed in the selected MSs, this could follow **a five-step process**. It starts from the **hydrogen demand and supply targets** set by the Government, followed **by market consultations** to identify future hydrogen infrastructure needs, which is then followed by **market tests**, including a **non-binding** and a **binding** phase. The commitments that result from the latter signal the hydrogen infrastructure projects based on market demand that will enter the last phase of implementation. Nevertheless, especially in these early stages of hydrogen infrastructure development in the EU, some projects may require other types of support (e.g., public funding, incentives) to make them viable.

Stepwise process for matching hydrogen market needs with infrastructure development

	1 Initiation	2 Market consultation	3 Non-binding EoI phase	4 Binding commitment phase	5 Implementation
What	• Targets for hydrogen supply and demand set by the Government • MoUs signed with countries to cooperate on hydrogen projects • Pre-feasibility studies (for national network and/or cross-border interconnections) conducted by the TSOs	Market consultations to identify future hydrogen infrastructure needs based on expected hydrogen demand and supply	Non-binding EoI phase calling for future hydrogen infrastructure users to express their interest in hydrogen infrastructure in a specific region within the country or for cross border infrastructure	Binding commitment phase is calling for future hydrogen infrastructure users to sign binding contracts for accessing the infrastructure. The technical design with associated timing for start of operations, the terms and conditions for the provided services and the relevant tariffs will be specified	Construction and commissioning of the hydrogen infrastructure by the TSO according to the technical characteristics and timing agreed upon during the EoI process
Who	• Government • TSOs	• TSOs • Producers and consumers • Public/institutional stakeholders	• TSOs • Producers and consumers • Regulator	• TSOs • Producers and consumers • Regulator	TSOs

Assessment of hydrogen infrastructure projects should take into account the conditions for matching hydrogen markets and infrastructure development, and the underlying uncertainties related to the evolution of the hydrogen supply chain.

Recommendations for ENTSOG's CBA methodology for hydrogen infrastructure

In order to be compliant with the recast TEN-E Regulation, ENTSOG's CBA methodology for hydrogen should seek consistency with ENTSO-E CBA Guidelines, define and cover the hydrogen infrastructure key costs and benefits, and provide clarity and transparency in the application of the methodology and interpretation of its outputs.

The Study provides **recommendations for improving ENTSOG's draft CBA methodology for hydrogen infrastructure**[1]. The identified recommendations, categorized into **four thematic groups**, are presented below.

[1] ENTSOG, 28 February 2023, Preliminary Draft Single-Sector Cost-Benefit Analysis (CBA) Methodology, for public consultation

Recommendations for enriching ENTSOG's proposed hydrogen CBA Methodology

I. CBAM approach consistent with ENTSO-E

- I.1 Application of common key CBA elements
- I.2 Application of common rules for clustering
- I.3 Consistency of interlinked assessment
- I.4 Consistency in the CBA methodologies' documents

II. Assessment of costs & benefits

- II.1 Inclusion of all costs associated with hydrogen infrastructure development
- II.2 Assessment of benefits in line with the hydrogen sector development
- II.3 Avoidance of correlation between indicators

III. Baseline and assumptions of the analysis

- III.1 Reference grid in line with development of hydrogen infrastructure
- III.2 Sensitivity analysis on uncertainty parameters
- III.3 Validation of project commissioning
- III.4 Setting of commissioning year in clusters
- III.5 Use of long-term shipper commitments in modelling

IV. Clarity of implementation and results

- IV.1 Clarity on the application of the methodology
- IV.2 Application span of the CBA methodology
- IV.3 Transparency of project information and analysis assumptions
- IV.4 Transparency of the model features

Annex V of the recast TEN-E Regulation requires ENTSOG's hydrogen CBA methodology to be consistent with the ENTSO-E CBA Guidelines, to the extent that sectorial specificities allow it. We recommend **alignment of ENTSOG's methodology with that of ENTSO-E's** on the following topics:

#	Recommendations to increase consistency of CBA methodologies	Level of priority[2]
I.1	i. Use of the same social discount rate by ENTSOs	Priority intervention
	ii. Use of a 25-year assessment period	Priority intervention
	iii. Consistent definition of the first year for counting benefits by ENTSOs	Supplementary improvement
	iv. No use of residual value	Supplementary improvement
I.2	▪ Application of stricter clustering rules, consistent with ENTSO-E (clustering of projects up to 5 years apart, and enabler allowed to be up to one maturity level apart from enabled project) ▪ Description of the high-level process for clustering projects	Priority intervention
I.3	▪ Consistent interlinked assessment with electricity infrastructure, using the same assumptions ▪ Description of the principles for assessing cross-sectoral (hybrid) projects	Priority intervention
I.4	ENTSOs use a common high-level structure for the CBA documents and high-level outline for the project fiches	Longer-term consideration

All the costs associated with the development of a hydrogen infrastructure project should be included in its economic analysis. At the same time, the benefits under which the project is assessed should reflect the expected evolution of the hydrogen sector. Recommendations for **enhancing the assessment of hydrogen projects costs and benefits** include:

[2] - Priority intervention: Recommendations with high impact, to be implemented in the current version of the methodology.
- Supplementary improvements: Recommendations with medium or low impact, that could be addressed in the current version of the methodology.
- Longer-term considerations: Recommendations to be considered for future revisions of the CBA methodology or when developing the TYNDPs.

#	Recommendations to improve assessment of hydrogen projects	Level of priority
II.1	i. Definition of cost items for repurposing natural gas infrastructure	Priority intervention
	ii. Qualitative assessment of negative environmental externalities of projects	Supplementary improvement
II.2	i. Revision of the indicators used to monetize sustainability, to capture the impact of projects in reduction of emissions due to switching from other fuels to hydrogen in hard-to-abate sectors	Priority intervention
	ii. Revision of the indicator used to monetize socioeconomic welfare, to include the projects' impact on the welfare due to the reduction of energy system costs in hard-to-abate sectors. Until a revised approach is developed, the methodology should clarify the limitations of the proposed indicator	Priority intervention
	iii. Revision of the indicator used to monetize security of supply, to assess disruptions on a hydrogen cluster and not country-wide level. Until the joint model can support this assessment, the analysis could be carried out by project promoters, according to guidelines provided by ENTSOG. Expansion of the security of supply indicator, to include the potential impact of repurposing natural gas infrastructure on supply of gas consumers	Priority intervention
	iv. Inclusion of an indicator (quantitative or qualitative) to assess the projects' impact on market integration	Priority intervention
	v. Inclusion of an indicator monetizing the projects' impact on reducing methane emissions and increasing hydrogen emissions	Longer-term consideration
II.3	Avoidance of correlation between indicators	Supplementary improvement

The baseline of the analysis, and the assumptions under which hydrogen projects are assessed, should take into account the **uncertainties related to the build-up of hydrogen markets and infrastructure, and of the assessed project itself**.

#	Recommendations related to baseline and assumptions	Level of priority
III.1	▪ Revision of the rules for setting the reference grid, to balance between a conservative (e.g., only infrastructure confirmed through market testing) and an optimistic (e.g., implementation of PCI projects) view of future grid evolution ▪ Increase of the hydrogen model granularity to represent hydrogen clusters instead of countries	Priority intervention
III.2	Sensitivity analysis only on selected uncertain parameters (e.g., shadow carbon prices, CAPEX, commissioning of projects, cost of disrupted hydrogen)	Priority intervention
III.3	▪ Project promoters should provide justification for the expected commissioning year ▪ Once sufficient historic data is available ENTSOG can establish a validation mechanism of commissioning (consistent with ENTSO-E)	Supplementary improvement
III.4	Setting the commissioning year of a cluster with enabler projects according to the year of the last enabler to be commissioned	Priority intervention
III.5	Inclusion of long-term shipper commitments in modelling	Longer-term consideration

Clarity and transparency on the implementation of the CBA methodology and the presentation of its results is essential for allowing the methodology's understanding and replicability by third parties, and for facilitating the interpretation of its outcomes by decision makers. Recommendations for **improving the methodology's clarity and transparency** include:

#	Recommendations to improve clarity, transparency and interpretation of CBA results	Level of priority
III.1	Revision of indicators' descriptions and inclusion of examples to provide clarity on the calculation of benefits	Priority intervention
III.2	Application of methodology for all TYNDP projects and scenarios	Longer-term consideration
III.3	Project fiches with complete information for the assessed projects	Longer-term consideration
III.4	Publication by both ENTSOs of document describing the joint model	Longer-term consideration

These recommendations discussed above seek to **enhance the effectiveness and applicability of the CBA methodology** in assessing hydrogen infrastructure projects. ENTSOG could therefore consider, at least the priority interventions, when revising the current draft CBA Methodology for hydrogen infrastructure.

1 Introduction

1.1 Background & objective of the Study

The Union-wide Ten-Year Network Development Plans (TYNDPs) are infrastructure development plans aiming to ensure a coordinated pan-European approach to electricity and gas / hydrogen grid development, drawn up by ENTSO-E and ENTSOG respectively, every two years. They are elaborated based on scenario development, infrastructure gaps identification and the assessment of the socio-economic benefits that each proposed project would bring to the EU energy system. The latter is accomplished via the employment of CBA methodologies developed by ENTSO-E and ENTSOG in consultation with ACER and the European Commission (EC). The infrastructure projects that are included in the latest plans can qualify as Projects of Common Interest (PCIs).

The Regulation (EU) 2022/869 of 30 May 2022 (recast TEN-E Regulation) revised the EU rules on Trans-European Networks for Energy (the 2013 TEN-E Regulation – Regulation 347/2013) to better support the modernization of Europe's cross-border energy infrastructure and achieve the Union's 2030 and 250 decarbonization targets. The recast TEN-E Regulation updated the infrastructure categories eligible for support through the TEN-E policy, incorporating -among other categories- hydrogen infrastructure, including pipelines, storage facilities, liquefied pure hydrogen and hydrogen derivative terminals, compressor stations and other equipment. Therefore, going forward hydrogen infrastructure projects should also be included in the TYNDPs and be eligible for inclusion in the PCI list and the newly introduced list of Projects of Mutual Interest (PMI), i.e., infrastructure projects linking the Union's networks with third-country networks.

The recast TEN-E Regulation mandates ENTSOG to develop a single-sector CBA methodology that allows the assessment of the hydrogen projects' impact on the EU energy system. This methodology, has to be developed consistently with other CBA methodologies for electricity and other energy infrastructure projects according to the recast TEN-E Regulation: "*The methodologies for a harmonized and transparent energy system-wide cost-benefit analysis for projects on the Union list shall be uniform for all infrastructure categories, unless specific divergences are justified*." ACER is involved in the preparation of this CBA methodology, in particular by reviewing ENTSOG's draft methodology and providing an opinion, which ENTSOG shall take into consideration when preparing the final version.

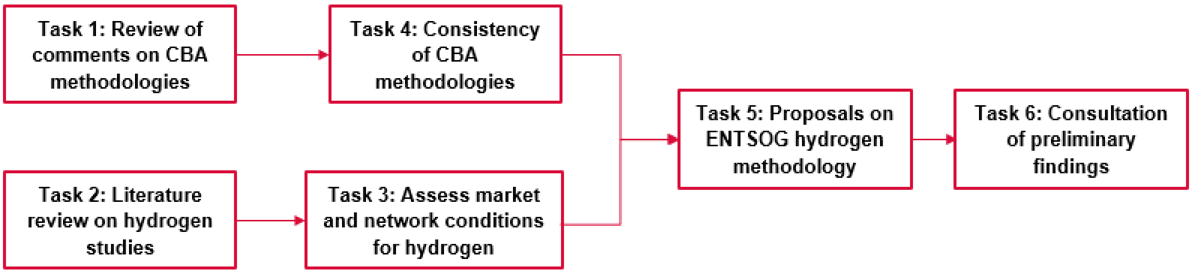
The aim of the present Study is to **provide ACER with recommendations for ENTSOG's CBA methodology for hydrogen infrastructure** which shall be fit for the purposes of the TYNDP and PCI selection processes, and compliant with the recast TEN-E Regulation. In order to be able to provide the recommendations, the Study also focuses on the **market and network conditions which can justify building hydrogen infrastructure**, attempting to shed light on the "*chicken and egg*" dilemma of whether the infrastructure should proceed and incentivize demand, or the demand should drive the need for infrastructure.

This Study entails review of ENTSOG's natural gas and hydrogen CBA methodologies. To distinct between the two, the Study refers to the ENTSOG Single-Sector Cost-Benefit Analysis (CBA) Methodology Preliminary Draft as "*hydrogen CBA Methodology*" and to the 2nd ENTSOG methodology for cost-benefit analysis of gas infrastructure projects as "*gas CBA Methodology*".

1.2 Overview of the Study

Implementation of the Study comprised six interlinked Tasks, shown in the Figure below. These Tasks included a review of past ENTSOs' CBA methodologies (Task 1) and identification of areas for which improvement of consistency between the methodologies is required (Task 4). Furthermore, analysis of the hydrogen sector development according to publicly available literature (Task 2) and planning in selected countries (Task 3) was carried out. The results of the first four Tasks were used in Task 5, to formulate recommendations for enhancing the hydrogen CBA Methodology, prepared by ENTSOG. The outcomes of the Study were presented to stakeholders (Task 6).

Figure 1: Overview of the Study's Tasks



In more detail, Tasks 1 and 4 dealt with past ENTSOs CBA methodologies. The Study identified previous recommendations on the CBA methodologies made by ACER and the EC which have not been implemented yet and provided **recommendations to ACER on resolving the identified shortcomings** (Task 1). Recommendations were also formulated on the matter of **consistency between the ENTSOs' CBA methodologies** to meet the recast TEN-E Regulation requirements of having consistent single-sector methodologies, while considering sectoral specificities of network planning and project evaluation (Task 4).

Tasks 1 and 4 entailed: examination of the ENTSOs draft CBA methodologies submitted to ACER and the EC for review, analysis of the corresponding opinions provided by ACER and the Commission, and review of the updated versions of the documents, to identify which of ACER's and EC's comments were adopted, and the key areas for which consistency between the methodologies should be sought. In this context, the following documents were reviewed:

For ENTSOG's CBA methodology:

- 2nd ENTSOG methodology for cost-benefit analysis of gas infrastructure projects - Draft for ACER and Commission opinions, 24 July 2017
- Opinion No 15/2017 of the European Union Agency for The Cooperation of Energy Regulators of 24 October 2017 on the Draft 2nd ENTSOG Cost-Benefit Analysis Methodology
- Commission Opinion of 24.10.2018 on the draft cost-benefit analysis methodology concerning trans-European gas infrastructure
- Adapted ENTSOG methodology for cost-benefit analysis of gas infrastructure projects Approved by the European Commission, 18 February 2019

For ENTSO-E's CBA methodology:

- Opinion No 05/2017 of the European Union Agency for the Cooperation of Energy Regulators of 6 March 2017 on the Draft ENTSO-E Guideline for cost benefit analysis of grid development projects
- Opinion No 03/2020 of the European Union Agency for the Cooperation of Energy Regulators of 6 May 2020 on the ENTSO-E Draft 3rd Guideline for cost benefit analysis of grid development projects
- 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects of 28 January 2020, Draft version
- 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects of 19 October 2022, For approval by the European Commission
- Draft 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects of 20 December 2022, for public consultation

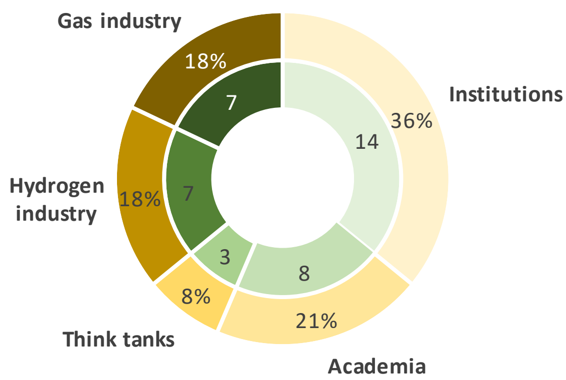
Other relevant documentation:

- Opinion No 02/2021 of the European Union Agency for the Cooperation of Energy Regulators of 3 May 2021 on the ENTSOG draft Ten-Year Network Development Plan 2020
- Opinion No 07/2017 of the European Union Agency for The Cooperation of Energy Regulators of 20 March 2017 on the ENTSOs' Draft Consistent and Interlinked Electricity and Gas Market and Network Model

Task 2 entailed a review of documents and studies related to CBA methodologies for hydrogen infrastructure or other types of technoeconomic assessments for newly constructed or repurposed hydrogen infrastructure. This review aimed to **analysing the main elements of the hydrogen sector development**, and to **identify elements and best practices which could be applicable**, directly or indirectly, to **ENTSOG's hydrogen CBA Methodology**.

For this literature review, 39 documents were reviewed in total, from a variety of stakeholders, including institutions (EC, ACER, IEA), the gas and hydrogen industry, academia, and think tanks. The Figure below shows the sources of the documents reviewed under Task 2.

Figure 2: Overview of literature reviewed in Task 2



The information elicited from the aforementioned sources concerned the main elements and considerations related to the development of the hydrogen sector, as well as methodological approaches, analyses and conclusions related to technoeconomic assessment of hydrogen infrastructure, which could be applicable, directly or indirectly, to ENTSOG's hydrogen CBA Methodology. The literature review resulted in analysing the following thematic areas:

- Hydrogen demand, including an overview of its main uses and the main drivers of hydrogen consumption examined in the reviewed literature.
- Hydrogen production and supply, particularly in relation to production modalities, and the related uncertainties and assumptions.
- Hydrogen transportation and storage, focusing especially on the transport modalities and drivers for their optimization, costs, limitations and challenges of the different hydrogen transport options, storage development options and costs.
- Cost elements that should be included in an economic analysis of hydrogen infrastructure.
- Benefits of hydrogen identified and examined in technoeconomic analyses of hydrogen infrastructure.
- Interlinked power-gas-hydrogen models used in past studies to assess hydrogen sector development.
- Identification of methodological elements from reviewed reports and studies that could be taken into consideration when developing a CBA methodology for hydrogen infrastructure.

Task 3 involved the **assessment of the market and network conditions which can justify building hydrogen infrastructure**. As the basis of this assessment, the analysis focused on **plans of selected countries to establish hydrogen markets and develop the required infrastructure**, as well as their **ongoing actions to match market needs with roll-out of infrastructure**, by conducting market consultations and market tests. The EU Member States selected for review included **Belgium, Denmark, France, Germany, Italy and the Netherlands**, all of which have progressed with planning of their hydrogen sectors, by setting specific targets for hydrogen market development, and have identified network interventions and requirements to address the supply and demand needs. A high-level analysis of hydrogen development in the **United States (on Federal level)** was also performed, to form an example of hydrogen planning outside the EU. For each country, the following were examined: the targets for developing hydrogen demand and production and associated measures foreseen in the country's hydrogen strategy and other relevant documents, development plans for hydrogen infrastructure, as well as the activities being carried out for market consultations (e.g., expressions of interest and market testing) related to the development of hydrogen projects[3]. The outcomes of the countries' analysis, together with findings from the literature review, provided inputs to build a framework for assessing the conditions for developing hydrogen markets and infrastructure.

[3] All information provided in the current report was sourced up to mid-February 2023.

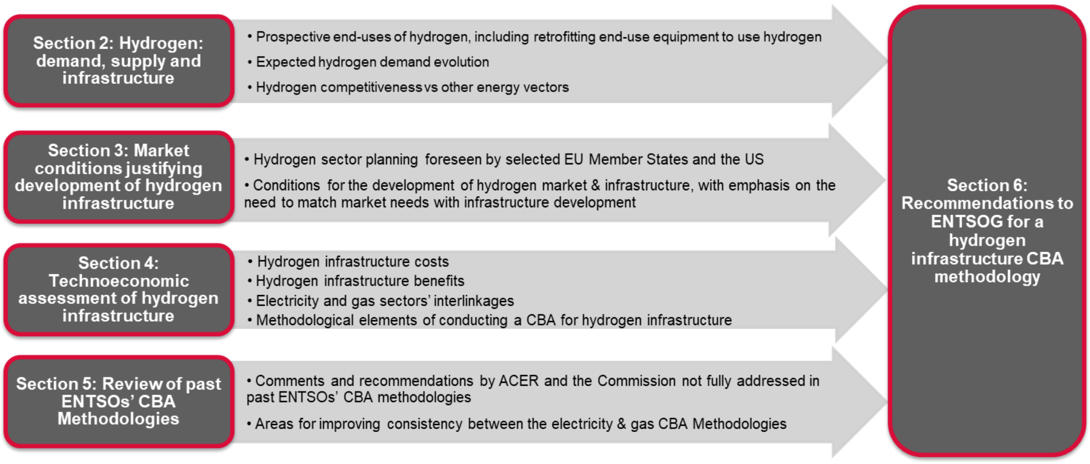
Task 5, using the outcomes of Tasks 1 – 4 as inputs, **formulated recommendations** to ENTSOG's "Preliminary Draft Single-Sector Cost-Benefit Analysis (CBA) Methodology" (published on 28th February 2023), with a view **to enriching and enhancing the proposed methodology**.

Under Task 6, the main findings and recommendations of the Study were discussed with **National Regulatory Authorities (NRAs), ENTSOG and the Commission, and presented in a public webinar**. An overview of the webinar's results is provided in Annex II.

1.3 Structure of the report

The Study is structured into seven Sections which address multiple aspects of hydrogen and hydrogen infrastructure, which either directly or indirectly point to the recommendations made towards ENTSOG for the enrichment and enhancement of the proposed hydrogen CBA methodology. The structure of the remainder of this document is presented in Figure 3.

Figure 3: Structure of the Study



Section 2 portrays the picture of the main elements considered with regards to hydrogen demand, supply and infrastructure, based on the literature reviewed. Hydrogen demand is examined in relation to the applicability of hydrogen in different types of end-uses, the demand evolution trends according to different studies and reports, and hydrogen's competitiveness vis-à-vis alternative energy vectors. Hydrogen supply is analysed with respect to different sourcing options and production modalities, and the uncertainties related to the evolution of supply. Additionally, the different hydrogen transport options are examined, considering their costs, limitations, and potential optimization.

Section 3 presents the hydrogen sector planning foreseen by selected countries, including their hydrogen demand targets, supply options considered, measures taken or investigated to support the establishment of hydrogen markets and their plans for hydrogen infrastructure build-out. Based on the above, the conditions for the development of hydrogen market and infrastructure are identified, with emphasis on the need and means to match market needs with infrastructure development.

Section 4 elaborates on several elements that are of importance when considering the technoeconomic assessment of hydrogen infrastructure, as identified in the literature review. These relate to hydrogen infrastructure costs and negative externalities, hydrogen infrastructure benefits considered, interlinkages between hydrogen, electricity and gas sectors, and methodological elements of conducting a CBA for hydrogen infrastructure.

Section 5 identifies comments and recommendations by ACER and the Commission on past CBA methodologies, which have not been addressed fully by the ENTSOs. This Section also elaborates on the potential areas of consistency between the ENTSOG and ENTSO-E methodologies, in accordance with Annex V of the recast TEN-E Regulation.

Section 6 presents the recommendations for ENTSOG's proposed hydrogen CBA Methodology, identifying those that are considered in the Study as priority ones.

Annex I provides a detailed country-by-country analysis of the national plans for hydrogen market and infrastructure development, for the countries reviewed in Section 3.

Annex II provides an overview of the outcomes of the public webinar "*ACER webinar on a consultancy study on hydrogen networks*".

2 Hydrogen: demand, supply and infrastructure

In order to be able to effectively assess hydrogen infrastructure projects, it is important to take into consideration the basic elements of the hydrogen supply chain, i.e., demand, supply and transportation. This Section presents considerations met in the reviewed literature with regards to the hydrogen supply chain, focusing on:

- The **end-uses that are expected to drive hydrogen demand**, forecasted hydrogen consumption evolution trends for the short (up to 2030) and long term (up to 2050), and the estimated cost-effectiveness of hydrogen versus conventional fossil fuels and other low-carbon fuels.
- Possible **pathways for sourcing and producing hydrogen**, particularly for use within the EU, considering uncertainties and assumptions surrounding hydrogen supply, especially with regard to the costs associated with the future hydrogen supply chains, from production to end-use application.
- The **different hydrogen transportation options**, particularly in relation to the transportation modes that are expected to be preferred on the basis of optimizing costs as well as tackling with constraints and limitations.

2.1 Hydrogen demand

2.1.1 Types of hydrogen end-use

The prospective end-uses of hydrogen, discussed in literature, include applications in multiple economic sectors. Not all of these applications however have the same potential of materializing. In some cases, **hydrogen appears to be the dominant decarbonization solution (use in the industrial sector as feedstock and for process heat), or one of the primary options (such as fuel for heavy duty vehicles and shipping)**. In other cases, hydrogen would be in direct competition with electrification, for uses that electricity has already began substituting fossil fuels (electric light duty vehicles, heat pumps for heating of buildings). Figure 4 summarises potential end-uses of hydrogen, grouping them according to their potential for implementation.

Hydrogen appears to be the main option for substituting fossil fuels in the industrial sector, as **sustainable feedstock**, and as fuel, particularly at industries requiring **high-grade heat**, for which electrification is highly cost intensive. Several studies highlight the prospects of using hydrogen in industrial processes, and especially in industries with hard-to-abate emissions. The Hydrogen Council [1], PWC [2], and scientific papers [3, 4] discuss the potential hydrogen use in iron and steel industries and chemical production/recycling of plastic. They also stress the importance of hydrogen as a heat provider in industrial sector processes (steam boilers, furnaces and process reactors) [2, 3], and the potential use of hydrogen in high temperature heat uses (melting, gasifying, drying etc.), principally in the cement industry [1]. Hydrogen may also be used in mining equipment, as well as in port areas (for fuel bunkering, port logistics) [4]. As industrial feedstock, the prospective significant use of hydrogen for the synthesis of fuels and chemicals is highlighted, principally for ammonia production, but also for oil refining as well, although the latter use is predicted to gradually disappear, as noted by the Hydrogen Council [1].

Figure 4: Uses of hydrogen and their potential of implementation[4]

Current hydrogen uses	Ammonia production	In most existing applications grey hydrogen is used. Green hydrogen can substitute grey hydrogen in the short term, often with small retrofitting requirements
	Methanol production	
	Oil refineries	
Longer-term applications with significant potential	Steel production	Use as a zero-emission reducing agent in DRI routes, and heat production
	Other high-grade heat industrial processes	Use for high-grade heat production in industries expensive to electrify
	Aviation	Use in the form of hydrogen-based fuels especially for short up to medium range flights, competing with biofuels
	Shipping	Use in fuel cells, liquid hydrogen, or hydrogen-based fuels, especially for mid-range maritime shipping, competing with biofuels
	Heavy duty vehicles	Use in fuel cells, especially in long-haul trucking, for which electrification is not possible, competing with biofuels
	Power system balancing	Compete with batteries for balancing the power system. Use of hydrogen storage facilities increases flexibility
Applications with low potential	Building heating	Electrification / heat pumps appear to be the preferred option, considering efficiency losses if hydrogen is used
	Passenger cars / light-duty vehicles	Use of electric vehicles is already increasing, and is considered more economic than switching to hydrogen

In the transport sector, prospective end applications for hydrogen include road transportation, where Fuel Cell Electric Vehicles (FCEVs) are considered to be the most promising "*clean*" option in **heavy-duty road vehicles** (buses, lorries). Hydrogen could also be used in **shipping**, for certain types of vessels where the use of fuel cells and/or liquefied hydrogen could be suitable (especially mid-range maritime shipping sectors, for example commercial fuel cell driven ferries). Potential uses may also emerge in the **aviation sector**, where hydrogen could be more economic for short up to medium range aircraft, compared to synfuels which may be more cost competitive for long-range aircraft [3, 4].

Use of hydrogen for space and water heating is another potential use. Mijndert van der Spek et al. [3] highlight the possibility to use hydrogen as a heat provider for commercial buildings and secondarily for residential buildings. Nevertheless, the **application of hydrogen for building heating is a long-term and highly uncertain solution**, as electrification and heat pumps are foreseen to be the preferred options (for example in the Netherlands use of hydrogen in buildings is envisaged to be at best limited, to serve as an auxiliary fuel for hybrid heat pumps [2]).

The role that hydrogen could play in providing grid balancing services to match power generation and demand is also highlighted in literature, as a key potential use. Di Wu et al. [5] discuss the impact of using **hydrogen energy storage as a flexibility mechanism**, especially if hydrogen is stored in underground facilities and turned back into electricity to be fed into the power grid.

[4] Consultant's analysis based on IEA [15], the Energy Transitions Commission [16], and scientific papers [3, 4].

2.1.2 Hydrogen consumption evolution trends

In mid-2022 the **EC set new targets for an accelerated green transition and decarbonization of the gas sector**, aiming to phase out dependence on imports of Russian gas before 2030 [6]. The **role of hydrogen in these accelerated targets is more ambitious**, aiming to reach a demand level of 666 TWh (20 MT[5]) in 2030, of which 80% (533 TWh) concerns consumption of green hydrogen, and 20% (133 TWh) use of ammonia and derivatives, to be imported to the EU. Demand for green hydrogen is expected to be driven by industrial heat production (120 TWh), production of ammonia (107 TWh), use in refineries (77 TWh) and the transport sector (77 TWh). Supplies of hydrogen to meet the foreseen demand are envisaged to be sourced 50% by indigenous production of green hydrogen (333 TWh) and 50% by imports (333 TWh, including 200 TWh of green hydrogen and 133 TWh of ammonia and derivatives).

Prior to the EC's accelerated hydrogen ambition, **several studies provided different outlooks of hydrogen demand evolution up to 2050**, mainly by examining alternative pathways and scenarios of energy carries' mix (predominantly electrification, hydrogen and biomethane) to address the European target of zero emissions by 2050.

Table 1 outlines the hydrogen demand forecasts for 2030, 2040 and 2050 included in the reviewed literature, comparing the 2030 figures with the accelerated hydrogen ambition. **Each study provides a different view** on the prospective long-term progression of hydrogen demand. For 2030, **none of these studies foresee hydrogen demand that matches, or is even close to, the new EC hydrogen targets**.

Table 1: Hydrogen demand evolution in literature

Source	Timing of publication	Forecasts (TWh)			Comments
		2030	2040	2050	
EC accelerated hydrogen ambition [6]	May 2022	666	-	-	
Trinomics-LBST study [7]	Apr. 2020	69 – 229	-	863 – 2,138	Demand for an "*electricity-focused*" and a "*hydrogen-focused*" scenario
Navigant [21]	Mar. 2019	-	-	1,711	
European Hydrogen Backbone [9]	May 2022	454	1,455	2,136	Demand for UK and Norway not included
Fraunhofer Institute [10]	Jan. 2022	300 – 350	-	590 – 2,200	Demand for a Paris Agreement Compatible (PAC) scenario and an accelerated decarbonisation scenario

[5] Throughout the report, conversion from MT to TWh and vice versa uses a Net Calorific Value (NCV) of 33 kWh/kg hydrogen [11].

ENTSOs scenario report [11]	Apr. 2022	285 – 322	1,219 – 1,489	1,713 – 2,431	Demand for the "*Distributed Energy*" and "*Global Ambition*" scenarios
Artelys [13]	Nov. 2020	-	-	1,600	
AFRY's report for Agora [14]	Feb. 2021	278	263	270	Includes only use of hydrogen as feedstock

The forecasts from each source are further discussed in the remainder of this sub-section.

A Trinomics-LBST study, on behalf of the EC published in 2020 [7], provides energy end-use demand in EU Member States by 2050, split into transport, residential and services (heating in buildings), and industry sectors. 2050 hydrogen demand ranges from 860 TWh (*"electricity-focused"* scenario) to around 2,000 TWh (*"hydrogen-focused"* scenario). In the *"hydrogen-focused"* scenario, the residential, services and industry sectors account for around 1,100 TWh of hydrogen demand, whereas transportation accounts for 900 TWh, with limited amounts of hydrogen (54 TWh/yr) utilised by hydrogen fuelled gas turbines. Transportation demand is based on gas-fired internal combustion engines and fuel cell vehicles which account for about half of the total vehicles.

A study by Navigant, prepared for EU Transmission System Operators (TSOs) in 2019 [21], presents a more conservative view of hydrogen uptake, as it foresees that in the fuel mix under an "*optimised gas*" scenario, total hydrogen demand in 2050 would be around 1,700 TWh, with demand for transportation comprising 252 TWh (primarily for heavy road vehicles), 786 TWh for power generation with open cycle gas turbines, 627 TWh for industry (processes in the iron and steel, ammonia and methanol, cement and lime sectors) and 46 TWh for buildings heating.

The European Hydrogen Backbone (EHB) [8] provided estimates, in 2021, for hydrogen demand that are mid-way compared to the two aforementioned references, but also backed up by detailed analysis of demand allocation. According to this study, EU and UK (examined together in that study) hydrogen demand in 2050 could be as high as 2,300 TWh. About 1,200 TWh of hydrogen is expected to be demanded by industry, 300 TWh by transport, 650 TWh by power production, and around 150 TWh by the buildings sector under an accelerated renovation scenario. In a subsequent study by EHB [9], in May 2022, that analyses EU (together with UK and Norway[6]) hydrogen demand and supply in 2050 along five geographic corridors, projections of demand are similar to those of the 2021 study, foreseeing a gradual increase of demand, to around 490 TWh in 2030, 1,650 TWh in 2040 to reach 2,400 TWh in 2050.

A recent (2022) study by the Fraunhofer Institute [10] estimates hydrogen demand in 2050 between 590 TWh and 2,200 TWh. In its more conservative scenario, hydrogen demand is driven by industry and transport/mobility applications, and no hydrogen demand is allocated to power or buildings sectors. In contrast, in the scenario with higher hydrogen demand, in addition to the industry and transport sectors, some hydrogen demand is foreseen in the power sector (as reserve in times of low renewable energy generation), and in the buildings sector for heating.

[6] Switzerland is also included in the study, but without demand and supply forecasts.

The TYNDP scenario report of 2022 [11], prepared by the ENTSOs, provides hydrogen demand forecasts in 2050 based on two scenarios; the *"Distributed Energy"* scenario, where electricity comprises 52% of the final energy demand and gaseous hydrogen 17% (including non-energy use) in 2050, and the *"Global Ambition"* scenario, where in 2050 the electricity and hydrogen shares are 43% and 21% respectively. In 2050, demand for hydrogen (including energy and non-energy use) amounts to about 1,700 TWh (86% for final demand and 14% for power generation) and 2,400 TWh (80% for final demand and 20% for power generation) in the *"Distributed Energy"* and *"Global Ambition"* scenarios respectively. Transport sector demand is a considerable part of consumption, accounting for around 35% of final demand in 2050, 545 TWh and 712 TWh in *"Distributed Energy"* and *"Global Ambition"* respectively. Hydrogen demand is assumed to be predominant in heavy duty road transport, shipping and aviation (mainly fuel cells technology for electric mobility and partly as e-fuel for internal combustion engines).

A study by Artelys, prepared on behalf of the European Climate Foundation in 2020 [13], analyses the energy infrastructure needs in Europe by 2050, having their reference demand scenario based on the Long-Term Strategy EC 1.5TECH scenario, with sensitivity analyses related to hydrogen, biomethane and electrification. Aggregate hydrogen demand in 2050 for the EU27 + 7 countries (Norway, Switzerland, the UK, Macedonia, Montenegro, Serbia and Bosnia-Herzegovina) is 1,600 TWh, under this study's reference scenario. The demand stems from industry and as a building block for the production of hydrogen derivatives (e-gases and e-liquids). Demand for hydrogen for power sector flexibility is not included. The sensitivity analysis carried out in the study showed that there could be a 30% decrease in hydrogen demand compared to the reference scenario (down to 1,100 TWh), through a limitation of the role of hydrogen in hard to abate industrial sectors.

Finally, AFRY's report for Agora [14], published in 2021, focuses on assessing a "*no-regret*" industrial demand for hydrogen as feedstock and chemical reaction agent at existing sites with off-grid renewable hydrogen production in Europe. The study does not include industrial demand for hydrogen as a combustion fuel for process heat, as it is considered that other technologies, such as heat pumps and power-to-heat technologies could be more efficient than hydrogen. Hard-to-abate industrial sectors (ammonia production, methanol production, iron ore reduction, production of petrochemicals for plastics and fuels, and plastics recycling) represent a major area of the *"no-regret"* hydrogen demand in the future, due to a lack of alternative decarbonization options. The *"no-regret"* industrial hydrogen demand in 2050 is assessed at 270 TWh (of which 45% in steel industries, and 35% in ammonia production). Hydrogen demand from refineries in Europe is assumed to be high in earlier years but predicted to vanish by 2050, whereas hydrogen demand from steel plants (shifting to production of direct reduced iron steel) and from the chemical industry is predicted to increase over time.

2.1.3 Retrofitting end-use equipment to use hydrogen

Conversion of existing grey hydrogen uses (ammonia and methanol production, oil refineries) **to use green hydrogen would require minimal retrofitting,** apart mainly from the need to replace the grey hydrogen production infrastructure in place [16].

Replacement of fossil fuels with hydrogen to produce heat in industry requires retrofitting of the energy conversion devices (such as kilns, furnaces, boilers, reactors). For example:

- In the cement industry changes range from introducing new processes and practices (use of hydrogen/ammonia mixes) to redesigning equipment (new burners are needed), to adding new protective measures to address corrosion and embrittlement [15].
- In the iron and steel industry, hydrogen can be used either as an auxiliary reducing agent in the Blast Furnace – Basic Oxygen Furnace (BF-BOF) route (supplementing other reducing agents such as coal or natural gas in the blast furnaces to reduce CO_2 emissions) or as the sole reducing agent in the direct reduced iron – Electric Arc Furnace (DRI-EAF) route. The BF-BOF route is often considered as an interim solution to reduce emissions until DRI-EAF using green hydrogen are in place [22]. Application of the DRI-EAF route using hydrogen requires building new DRI plants[7], so transitioning from BF-BOF will require time and investments [15].

According to the Fraunhofer Institute [10], centralized **heating plants** (more in industry and less in district heating), and the **shipping and train sector, can be relatively cheaply adapted to hydrogen and run efficiently**. These sectors can be considered "*low hanging fruit*" for hydrogen uptake. However, as stated in the Gas 2030 Dialog Process [23], there are certain industrial applications that depend on consistent quality and high calorific values of gas (e.g., material applications in chemistry) or constant temperatures (e.g., glass, ceramics), and where the use of hydrogen mix may not be suitable.

The use of hydrogen in decentralised boilers in buildings requires retrofitting of heating equipment, as well as replacement of the existing gas meters. It is expected that **hydrogen will not be the preferred option for decarbonizing heating of buildings**, compared to the use of electricity. In addition to requiring new infrastructure and equipment, **heating with hydrogen is much less efficient that using heat pumps and electrification**, due to energy losses associated with hydrogen conversion, transport and use [24].

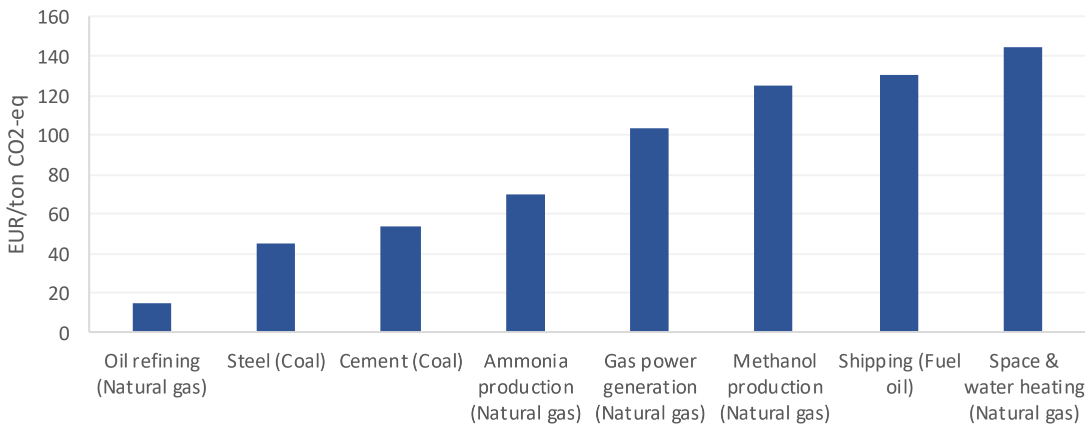
2.1.4 Competitiveness with other energy vectors

According to the Energy Transitions Commission [16], it is difficult to compare potential future hydrogen prices with those of alternatives such as solid-state batteries, pumped-storage hydropower, electric vehicles, biofuels and electrification of high-temperature heat**. Carbon prices are key to make hydrogen use cost-effective versus conventional fossil fuels**. If the Emissions Trading System (ETS) were to be extended to cover the steel sector, and increases in carbon prices in subsequent decades were a public policy priority, that would be a key driver for hydrogen investments. Fossil fuel subsidies, both at production and at consumption level, should also be removed as soon as possible to limit distortion of competition. The Energy Transitions Commission has assessed that **even with a low-cost hydrogen** of 27 EUR/MWh (1 USD/kg), hydrogen **can be competitive to the existing fossil fuels in 2050 only if carbon pricing (explicit or implicit) is imposed**, ranging from 14 EUR/ton of CO2-eq to 145 EUR/ton of CO2-eq, depending on the end-use (Figure 5)[8].

[7] Commercial scale implementation of pure hydrogen DRI-EAF needs further refinement and demonstration [15].

[8] In 2022 the maximum price of emissions allowances amounted to 98 EUR/ton of CO2-eq on August 19th.

Figure 5: Carbon price for hydrogen to be competitive to the cheapest fossil fuel in each end-use [16]



In regard to the cost competitiveness of direct hydrogen **use in fuel cell electric vehicles**, apart from the commodity cost of hydrogen, there are three critical cost components: the **cost of the fuel cell stack, the cost of on-board storage, and the cost of refuelling stations**. For cars the priority is to bring down the cost of fuel cells and on-board hydrogen storage. Building of refuelling stations, with the size and utilisation that brings down refuelling costs to a competitive level is also important, as it could make FCEV competitive compared to battery electric vehicles, at driving ranges of 400–500 km and potentially attract customers that value long range driving. FCEVs overcome some of the challenges faced by battery electric vehicles in long-haul trucks, like battery capacity, long charging times and high-power requirements, that cause payload loss and additional recharging infrastructure costs. Fuel costs make up about half of the total cost of ownership for heavy-duty trucks, so the focus for making them competitive should be on bringing down the delivered price of hydrogen. In long-distance maritime transport, due to the cost of liquefying and high storage costs, hydrogen is likely to be more costly than other low-carbon alternatives [15].

For the buildings sector, particularly residential housing, the prospects for hydrogen conversion in the longer term will depend on several factors, notably hydrogen price and technology cost. Hydrogen may be cost-competitive against natural gas with carbon capture and storage (CCS) and with biogas, however electrification of building heating appears to be more cost competitive, given the inefficiencies associated with the use of hydrogen [24].

Whether hydrogen-based power generation for load balancing can compete on price against natural gas depends on hydrogen, natural gas and CO2 prices.

2.2 Hydrogen supply & production

2.2.1 Sourcing of hydrogen

Today over 95% of hydrogen in the EU is produced via two particularly high carbon-intensive processes, steam methane reforming (SMR) and to a lower extent Autothermal Reforming (ATR), with the remaining 5% produced as a by-product of industrial processes and only a minor fraction through water electrolysis. The majority (64%) of production is taking place in large industrial sites with some amounts coming off as a by-product from other industrial processes. A small percentage (15%) is produced centrally and delivered to points of demand (merchant hydrogen, 15% of total production capacity) [17].

To serve the 2030 hydrogen demand targets, the **European Hydrogen Backbone initiative examines** in its study [12] **five hydrogen supply corridors** covering Europe's entire geography. The corridors connect significant production centres distributed on the periphery of the EU area towards the main consumption (industrial) areas at the centre of the continent. **Production is assumed to take place in North Africa (imports to EU), in offshore locations in Northern Europe and the Baltics (utilizing the offshore wind potential) and in South-eastern Europe (utilizing the RES potential in the region)** [12]. However, this study can only be seen as a high-level potentiality, given the numerous uncertainties in terms of demand and supply as well as development of the infrastructure by the MSs. A paper by JRC [25] confirms the above assumptions of potentiality for hydrogen production, by highlighting the regions within the EU where excess renewable potential exists, taking into account the technical potential of renewables for serving electricity demand projections. The paper indicates that, in addition to Northern Europe, the Baltics and South-eastern Europe, there is significant excess RES potential in Southwestern Europe as well.

Matching supply to demand is very important, thus coupling and coordination between production regions and consumption regions in the EU is paramount. An analysis of hydrogen and its evolution in the North-Western Europe by IEA [18], highlights that **successful achievement of national hydrogen ambitions will depend, to a significant part, on successful developments from other (neighbouring or not) countries in the region**. The projected large demand for imported hydrogen in Germany (in general the North-Western region represents 60% of EUs projected demand for hydrogen) before 2030 should align with the export potential and ambitions of Norway and Denmark, as well as France (although not in North-Western Europe). This alignment should also follow suit in terms of cross-border projects as well as a common regulatory framework.

A recent IEA study [15] states that **especially in the case of Europe, production of hydrogen is distinctly more expensive than several other regions in the world. This makes the case for importing of hydrogen a theoretically viable option in economic terms**. It is notable that, according to the IEA estimates, Africa has the potential to produce (for both domestic use and exports) around 16,500 TWh/yr (500 MT/yr) of green hydrogen at less than 55 EUR/MWh[9] (2 USD /kgH2), when the cost, if produced in Europe, is over 82 EUR/MWh (3 USD/kgH2). The Middle East could also produce very significant amounts of blue hydrogen at 35 EUR/MWh (1.3 USD /kgH2).

2.2.2 Hydrogen production modalities

Production of hydrogen can be attained through several techniques that differ in both efficiency and scalability. Green and blue hydrogen represent respectively renewable and low carbon production methods. **As it stands, the global pipeline of hydrogen projects is growing (worth 215 bil. EUR when to attain net-zero emissions investments should be close to 630 bil. EUR), but actual deployment is lagging**. Only about 10% of projects have reached Final Investment Decision (FID), with EU leading in proposed investments (~30%) but China being ahead on actual deployment of electrolysers (200 MW), and Japan and South Korea leading in fuel cells (more than half of the world's 11 GW manufacturing capacity) [26].

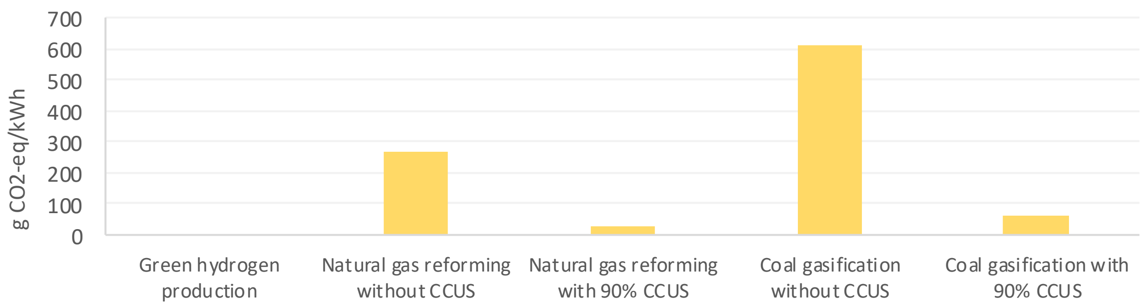
[9] Throughout the report, conversion from USD to EUR uses an exchange rate of 0.9 EUR/USD.

Green hydrogen production (using renewable produced electricity) via the electrolysis of water is a long-proven technology. It is energy intense and if sea water is used then additional energy is required (approx. 5 MWh/ton H2) to desalinate / purify the water to be used for the electrolysis process [19]. There are several electrolyser technologies available (alkaline, proton exchange membrane (PEM), solid oxide electrolyser cell (SOEC)) with different efficiency and cost profiles. **The electrolyser technology is still improving thus affecting the efficiency and cost parameters relating to green hydrogen production**.

One significant barrier towards a more economical production of green hydrogen is that of the electrolysers' costs and technical characteristics. **The high electrolyser costs have made it important to run electrolysers at high capacity in order to reduce capital costs per unit of production**. Analysis by the Energy Transitions Commission [16] has demonstrated that as soon as the electrolyser cost falls below 270 EUR/kW, then the cost of electricity becomes the sole driver of green hydrogen production, if electrolyser utilization (capacity factor) stays above 2000 hours per annum. Given these restrictions in terms of high utilization, **dedicated RES for hydrogen production can benefit from the falling cost of RES technology and foregone grid connection costs unlike in the non-dedicated case**. Given the significant energy requirements for splitting the water molecule, **to utilize photovoltaics (PVs), large areas would need to be dedicated to producing hydrogen, something not possible near densely populated areas** [16].

Unlike green hydrogen, which is based on electrolysis that sources electricity from RES generation and thus its production has a zero-carbon footprint, blue hydrogen is produced by separating the hydrogen from methane in natural gas, thus, to decarbonise the environment, it should be accompanied by CCS. **CCS provides locational limitations that can impact the overall cost of the technology given that the distance and mode of transport to a reservoir is a crucial cost parameter**. **Blue hydrogen production does introduce some CO2 emissions as well as some methane emissions** (potent greenhouse gas). Blue hydrogen through SMR (most scaled up process to extract hydrogen from natural gas) combined with CCS has a carbon footprint of around 30 g CO2-eq/kWh, compared to 270 g CO2-eq/kWh of natural gas [15]. The carbon intensity of different types of hydrogen production are presented in the Figure below.

Figure 6: Carbon intensity of hydrogen production[10] [15]



[10] Only carbon emissions at the power plant are taken into account, and do not include CO2 emissions linked to the transmission and distribution of hydrogen to the end users, e.g., from electricity used for hydrogen compression. It is noted that the full life cycle of hydrogen production may include GHG emissions which are associated with the production and transportation of equipment and materials used for the hydrogen production processes. Such emissions are not considered in the values presented in Figure 6, following the usual practice in literature, to focus only on hydrogen production itself.

Blue hydrogen, produced from natural gas combined with CCS, can be a scalable and cost-effective option albeit with locational and process limitations. It is forecasted by the Energy Transitions Commission that **in regions with very low natural gas prices, blue hydrogen will always be cheaper to produce compared to green hydrogen** (the analysis does not point to any EU countries where such a case will be applicable) [16]. Because green hydrogen is still expensive today and because its ramp-up is linked to the pace of growing wind and solar generation capacity to necessary levels, as well as to the electricity system's capacity to absorb the ever increasing RES penetration, **an early scale-up of blue hydrogen can accelerate decarbonisation** [8, 16, 21] **and pave the way for the greater adoption and proliferation of hydrogen as a clean fuel**.

Biohydrogen based on residues or other sustainable biomass feedstock is compatible with net-zero targets and could deliver substantial amounts of negative emissions combined with CCS. However, **availability of biomass for bioenergy is a problem for scaling up the output** [3].

2.2.3 Uncertainties and assumptions for hydrogen supply

The hydrogen molecule has specific characteristics (compression/volume ratio[11], liquefaction temperature[12]) that are made apparent in its economics. Although the method of its production has been understood since the mid-19th century, the amount of energy required, combined with the overall efficiency, have made the scaling up of the process challenging. **To produce green hydrogen, relatively large volumes of renewable power are required.** For example, the production of approximately 0.3 TWh/yr of green hydrogen (8,400 tonnes of hydrogen) currently requires approximately 10 offshore wind turbines or enough PV panels to cover about 300 football fields [2]. **This is reflected in the cost of production, and the prospects of replacing fossil fuels with hydrogen today in several sectors**. Even at very low production costs (14 EUR/MWh) hydrogen is more expensive and thus unable to replace fossil fuels for sectors like aviation, steel or fertilizer production and shipping [3].

Therefore, **any projections as to the future economics of hydrogen production have a significant degree of uncertainty embedded into them**. This situation creates the first and most significant investability barrier that project developers face today, which is the lack of hydrogen demand visibility. Investors wait for decisions on the enabling regulatory frameworks and funding to incentivize offtakers to enter long- term hydrogen supply contracts. Long-term offtake is a key driver and enabler for project finance and support from financial investors [26].

In addition to energy input and demand ambiguity, **there is uncertainty on future CAPEX with respect to hydrogen from electrolysis**. Electrolyser cost, representing ~60% of total cost [1], today is far from the 270 EUR/kW mark for green hydrogen not needing high utilization of electrolysers to make grid connected / curtailed powered setups economically competitive. In 2020 PEM electrolysers were closer to 900 EUR/kW up to 1350 EUR/kW [27] with significant uncertainties for future costs. Forecasts place it at 430-560 EUR/kW by 2025 and at 210-340 EUR/kW by 2030 [1]. The lack of clear trends for

[11] It takes about three times as much energy to compress a MJ's worth of heat energy if you supply it as hydrogen than if you supply it as natural gas.
[12] Gaseous hydrogen is liquefied by cooling it to below −253°C (−423°F). Liquefaction consumes more than 30% of the energy content of the hydrogen.

the evolution of production costs increases uncertainty with respect to any investment decisions for hydrogen production, thus the necessity for measures and incentives to mitigate risks.

All the above compounding reasons affect the final cost of green hydrogen, something that is evident also in the different scenarios projecting cheaper green vs grey hydrogen by different organisations. According to the **Hydrogen Council, in the most optimistic scenario, green hydrogen will be cheaper than grey hydrogen in 2030 while in the most pessimistic scenario this will be in 2038** [1]. The **World Energy Council predicts that green hydrogen will become profitable around 2030** [28]. **IRENA's study foresees that green hydrogen will be able to compete with grey hydrogen by 2040** [29].

Blue hydrogen suffers from uncertainties relating to the capturing of CO_2 emissions, given that its production methods (extracting hydrogen from methane) are well established. If, for example, technology does not lead to 100% capturing of CO_2 and other emissions, then a compensation for any emissions is a parameter that needs to be considered in any analysis. It is also important to highlight that as it stands, estimations concerning the cost for capturing CO_2 can vary from 15 – 138 EUR/tCO_2 captured. This is a very wide range that is influenced by the CO_2 capturing process characteristics, transport method employed and storage method (potential to store CO_2 in products). To the low end of this cost range, CCS could, in theory, be competitive to the ETS prices [21].

CO_2 storage transport costs are highly variable and subject to distance and volume. This creates a situation where any rigid cost projections are difficult to make. For example, via onshore pipelines the cost can vary from 0.1 to 16 EUR/tCO_2, while for offshore the range is between 2 and 29 EUR/tCO_2. For small volumes, including liquefaction of CO_2, the cost is between 10 and 20 EUR/tCO_2 [21]. These are wide variations, highlighting the difficulty to truly estimate the cost of a blue hydrogen project accurately based on existing benchmarks. There are also issues with respect to public acceptance of CCS in several EU MSs and availability of sites thus making blue hydrogen production harder to support. In Germany, for example, storage of CO_2 is subject to significant public opposition and hence politically difficult to be promoted, while in the cases of Czech Republic or Belgium, there are no depleted reservoirs [20].

There is "*vagueness*" on the cost of hydrogen production from biomass with CCS, as few studies have been published, while more studies can be found for hydrogen from biomass without CCS and even in those cases the cost seems to be non-competitive compared to natural gas-based hydrogen. The uncertainty concerning biohydrogen is **compounded also by the availability of biomass for bioenergy, given significant social, political, and economic factors** including land use and relevant regulation as well as the underlying technology [3].

Finally, an important element to consider relates to the **development of technical standards that have yet to be agreed upon**. This includes standards dealing with hydrogen vehicle refuelling, gas composition for cross-border sales, safety measures, permitting, materials and how to measure lifecycle environmental impacts. Additionally, there is the **uncertainty concerning the "*green-ness*" of hydrogen used for any process given that the same hydrogen can be produced by process with differing CO_2 intensities** [15].

2.3 Hydrogen infrastructure

2.3.1 Hydrogen transportation options

Free hydrogen exists as a diatomic molecule (H2) and has a density at standard temperature and pressure (0 °C and 0.1 MPa) of around 0.09 kg/m^3, which is significantly less than air (1.3 kg/m^3). Its normal boiling and melting points are around -253 °C and -259 °C, respectively, and even as a liquid or a solid, it has extremely low densities [30]. Thus, transporting gaseous hydrogen via truck/rail under pressurized tanks using systems known as Multiple Element Gas Containers (MEGCs) is economically viable only for limited quantities and small distances.

The transport of bulk hydrogen can be parallelized with that of natural gas. That means it can either take place though pipelines or shipping in liquid form. The latter does materialize by chemical conversion into other molecules that have a higher energy density and certain advantages in terms of boiling temperature (ammonia, liquid organic hydrogen carriers, methanol). The specific mode of transport is subject to distance over which the hydrogen should be transported.

Using the pipeline system for natural gas to transport hydrogen either blended in natural gas or as pure hydrogen would require repurposing, to a lesser or greater degree, respectively. For hydrogen blending below 10% in volumetric terms [19], the changes with respect to compression needs will be minimal (although metering and billing will become more complex, and investments will be required [7]) as opposed to higher blending ratios or even more so with pure hydrogen. For transporting pure hydrogen via pipelines, the expected investments on compressors alone (assuming everything else to be fit for purpose) will be necessary to keep the same energy density to the one, attained with natural gas. It takes about three times as much energy to compress 1 MJ (0.278 kWh) worth of heat energy if supplied as hydrogen. **That 3× increase in the work of compression will increase energy cost but also requires a new compressor unit with three times the suction displacement** [31].

The economics of transporting hydrogen are also impacted by the existing infrastructure including storage when considering pipeline hydrogen. Apart from pipelines, transportation is also subject to marine terminals availability, and their capacity to accommodate hydrogen. Marine terminals, with multimodal transportation connections and conversion capacity (liquid to gas, liquid to liquid for trucking / rail) are necessary to link production to demand centres. Finally, hydrogen transport is also possible on land via rail or trucking [32].

It is worth mentioning that **LNG terminals could play the role of the hydrogen entry points to the system** as they provide significant advantages, **having a similar process of storage and gasification of LNG**. Nevertheless, the **boiling temperature of liquid hydrogen is much lower than that of natural gas**, thus certain investments and retrofitting should be made to accommodate hydrogen (in comparison to natural gas, hydrogen molecule is much smaller and leakages are easier, therefore there is a need for much better insulation of the tanks and piping so as to reduce boil off [33]), but the underlying processes share several similarities [32].

A condensed table with the different advantages and disadvantages of each carrier format has been composed by IRENA [34], presented in the Table below.

Table 2: Hydrogen transportation carriers [34]

	CARRIER ADVANTAGES	CARRIER DISADVANTAGES
Ammonia	• Already produced on a large scale • Already globally traded • Low transport losses • High energy density and hydrogen content • Carbon-free carrier • Can be used directly in some applications (e.g., fertilizers, power generation, maritime fuel) • Can be easily liquefied (20°C at 7.5 bar or -33°C at 1 bar)	• High (12-26%) energy consumption for ammonia synthesis • High (13-34%) energy consumption for reconversion (importing region) with high temperature requirement (up to 900°C but more commonly in the 500-550°C range) • Ship engines using ammonia as fuel need to be demonstrated • Might require further purification of the hydrogen produced • Hydrogen compression needed for most applications • Higher NOx (nitrogen oxides) production during shipping would require flue gas treatment • Toxic and corrosive • Flexibility of the ammonia synthesis and cracking still to be proven
Liquid hydrogen	• Limited energy consumption for regasification (most of the energy is consumed in the exporting region, which is expected to have low renewable energy costs) • No need for a purification system at the destination • Easier transport at the importing terminal • Low energy consumption to increase pressure of hydrogen delivered • Liquefaction is already a commercial technology • Carbon-free carrier	• High energy losses for liquefaction (30-36% today), which calls for larger energy supply • Boil-off (0.05-0.25% per day) during shipping and storage • Cryogenic temperatures lead to high equipment cost • Currently available only on a small scale
Liquid Organic Hydrogen Carriers (LOHC)	• Can be transported as oil is today using existing infrastructure, making it suitable for multi-modal transport • Low capital cost for all steps • Can be easily stored	• High (25-35%) energy consumption for dehydrogenation (importing region) • Requires high-temperature heat (150-400°C) for dehydrogenation • Requires further purification of the hydrogen produced • Hydrogen is produced at 1 bar, requiring compression • Only 4-7% of the weight of the carrier is hydrogen • No clear chemical compound that is the most attractive • All the possible carriers currently have a high cost • Carrier losses every cycle (0.1% per cycle) • Carriers would probably contain fossil CO2 • Most of the possible carriers require scaling up multiple times from current global production
Pipelines	• Transport and storage are proven at a commercial scale • Existing network can be repurposed to hydrogen • No conversion is required (only compression) • Carbon-free carrier • Becomes more attractive as the volume increases	• Storage in specific types of reservoirs can lead to losses and contamination (need for purification) • Not all the pipeline materials are suitable for hydrogen • Not all regions have an existing gas network • Cost increases significantly for offshore pipelines • Energy consumption for transport is higher than for natural gas or ships

Focusing on the EU, as mentioned earlier in the Study, the North-Western Europe region represents the majority of the projected hydrogen demand towards 2030 [18]. At the same time this region combines several of the prerequisites in terms of infrastructure including storage. Therefore, given the necessary repurposing investments, the region could be one of the first to develop a large-scale, low-carbon hydrogen full value chain [18]. There are estimations that by 2040, increase of hydrogen production levels and low costs at countries neighbouring to the EU (mainly Ukraine and North Africa) can lead to significant imports to cover increasing demand, considering more challenging conditions in the EU around land availability (for production) and public acceptance of renewables [8].

2.3.2 Costs of different transportation modalities and storage

There are numerous studies mentioning the costs involved with building new hydrogen specific networks [7]. It is difficult to estimate the universal cost very accurately, as this is subject to multiple factors like diameter, route, location, subsurface and length. Nonetheless, the main observation from the data presented [7] is the **significant variation in cost per meter for the same diameter pipeline**. This holds true **for both transmission pipelines and distribution**. For a 700mm diameter transmission pipeline the range in the Trinomics – LBST study [7] is from 1 mil. EUR/km to about 2.2 mil. EUR/km whereas in a study by PWC [2] the range for the same characteristics pipeline is between approx. 1.3 mil. EUR/km and 1.9 mil. EUR/km. For refurbishment, the cost is much lower at around 0.37 mil. EUR/km based on [17]. Compression in hydrogen specific networks is also more expensive, and a large compressor station's costs vary as well between different analyses from a range of 2.2 to 6.7 mil. EUR/MW [39] to around 11.25 mil. EUR/MW, including installation costs [7]. **In the case of repurposing of existing networks, investment cost is very much linked to the level of blending** [10][13].

Concerning the liquefaction of hydrogen for transport, the capital cost is between 68 – 134 EUR/kWh/day (2.5 – 5 mil. USD/tonne/day), with **operational costs being significant and more specifically the energy cost related to the cooling of hydrogen** [39]. An estimation of the levelized cost of hydrogen conversion to intermediate states (liquid or as ammonia) reveals the significant cost attached to it, shown in the Table below.

Table 3: Levelized costs of hydrogen conversion [17]

Conversion process	Unit	Minimum	Maximum	Comment
H2 to ammonia	EUR2019/MWhH2	27	27	Approximate number, small variations can arise due to the cost of electricity in different countries.
H2 to liquid hydrogen	EUR2019/MWhH2	38	74	Cost contribution to the LCOH with liquid delivery. Costs for a liquefier with a capacity of 27,000 kgH2/day. Lower bound: Capital costs only, upper bound including additional recurring costs (e.g., electricity).
Ammonia to H2	EUR2019/MWhH2	34	34	Based on a decentralized configuration for reconversion to hydrogen.

Adding to the thinking that using ammonia as a carrier for hydrogen is not necessarily economically sound, BloombergNEF[14] notes that even if hydrogen is recovered from ammonia, by using the latter as primary fuel, green ammonia could extend fossil-fuel consumption and thus delay climate action. It is estimated for example that power from Japanese coal plants burning 50% green ammonia from Australia would cost 120 EUR/MWh in 2030—more than it projects for power from offshore wind and solar plants in Japan backed up with battery storage [35].

[13] By up to 43 % for industrial end-users and up to 16 % for households at a blending level of 20 Vol-%.
[14] BloombergNEF is a leading provider of forward-thinking primary research and analysis on the trends driving the transition to a lower-carbon economy.

Trucking of compressed and liquid hydrogen is limited to small quantities and presents a significant cost in terms of capital expenditure for the specialized tanks required. The investment cost for compressed and liquid hydrogen is between 790 USD/kgH2 for systems at 25 MPa and 1,100 USD /kgH2 for transport at 50 MPa for the former and 200 USD /kgH2 for the latter.

Large-scale underground storage such as salt caverns, depleted gas fields, and rock caverns cost estimates (in MWh of hydrogen stored) **can be significant** and, depending on the technology employed, can range from 280 EUR/MWh to 1232 EUR/MWh of stored hydrogen [17].

2.3.3 Limitations and challenges for hydrogen transportation and storage

There are **several limitations and challenges for hydrogen transportation, given the lack of any fully realized supply chains at large scale**. The flexibility that blending offers by utilizing existing natural gas pipeline networks is certainly an important entry pathway. There is, however, **significant ambiguity as to the level of blending possible**. The **variation between different studies on the blending possibility ranges from 2% to 20%** in volumetric terms, linked to risks associated with corrosion in the transmission grid, and negative impacts for end-user appliances. Therefore, managing the volatility in gas composition and in particular variations of the calorific value of the gas mix is an important element to enable blending [7, 10, 16, 36]. Blending above the 20% is still evaluated, however, it seems that above this limit, the composition does increase the severity of vented explosions and there are active projects trying to evaluate based on evidence the capacity of today's pipelines in Europe for the supply of pure hydrogen for domestic applications [3].

Converting existing infrastructure or building a new one for pure hydrogen would require, aside from works related to the valves and piping materials[15], a **significant increase in the number of turbines and compressors as opposed to the natural gas case**. Siemens also points to potential technical limitations with respect to very high transport capacities with the existing turbo-compressors [19]. Additionally, the repurposing of existing infrastructure for transportation of pure hydrogen is still under investigation, given potential material fracturing of carbon steels, because of hydrogen, while mitigating this (depending on approach) could be very capital intensive "*which would significantly diminish the economic potential of pipeline reassignment*" [37].

The limitations of liquefaction and shipping of hydrogen, either to be used itself as an end-use fuel or by incorporating it into larger molecules for transport, is limited by the **poor conversion efficiency**. **Liquefaction of hydrogen would consume up to 35% of the initial hydrogen** quantity, while conversion to ammonia and LOHCs and reconversion to hydrogen is even more taxing, given that **ammonia and LOHCs** are much easier to transport than hydrogen, but they often cannot be used as final products and a **further step is needed to liberate the hydrogen before final consumption** [15]. Additionally, it should be mentioned that current LNG carriers do not just require small modifications to be able to transport liquid hydrogen. This is more of a misconception, given the broad similar characteristics of the two gases (hydrogen and methane). The **challenges of vessel adaptation** are demonstrated clearly in a graph by Alles [38] showing the big differences in the base parameters of the two gases for liquid transportation.

[15] Operating parameters might need adjustment for certain types of steel and operating conditions. Fittings and control valves, the suitability for hydrogen of the membranes and seals used must also be determined.

Figure 7: Differences in natural gas – hydrogen liquefaction parameters [38]

	Compression	Liquefaction	Flammability limits (% in air)
Natural Gas	3.6 psi	−160 °C	15%
H_2 Hydrogen	11,603 psi	−253 °C	74%

Storage is key for the advancement of hydrogen and fuel cell technologies for stationary power, portable power, and transportation. A storage system can be located either aboveground or underground. Underground storage can involve salt caverns, depleted gas fields, aquifers, or other underground formations. A limitation here relates to the geography / location of the storage site, since they require specific geological formations, which may not always be available. **From all underground storage solutions, salt caverns are considered the most advantageous option** for storing large volumes of hydrogen, given their air tightness, high-pressure resistance and, flexibility [39].

Given its low density, hydrogen requires specialist forms of storage for material energy content to be stored. Tanks used to keep hydrogen in gaseous form must sustain a high pressure of between 350–700 bars. On the other hand, liquid hydrogen needs to be stored at cryogenic temperatures, as it has a boiling point of −252.8°C [41]. Storing it in pipelines and vessels is easier to achieve than underground solutions, plus there are no geological restrictions, however, this method of storing is more than an order of magnitude more expensive than underground storage alternatives.

An analysis by PWC [2] on the potential for underground storage in the Netherlands showed that there is sufficient space under Dutch soil for the development of around 320 onshore salt caverns for hydrogen storage and stressed that for the development of an average salt cavern the construction time required would be 3 to 4 years[16]. As such, construction time is a factor to be considered in hydrogen migration planning time horizon. A **limiting factor is always the large investments necessary** with BloombergNEF estimating that **to store just 20% of the hydrogen production necessary to limit global warming by 1.5 degrees is close to USD 637 billion** [40].

2.3.4 Optimization of transportation options

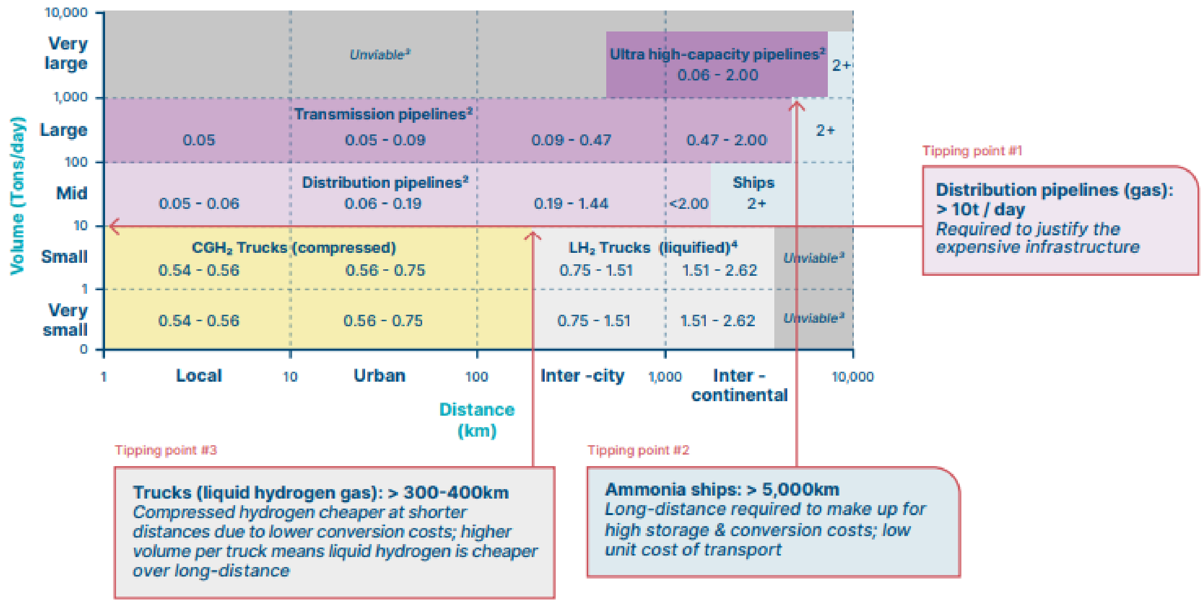
Transportation optimization is subject to volume and distance. Those two parameters do play the most important role in what the optimum (in economic terms) mode of transport is. Additionally, storage locations are important for optimality of network design and thus overall transport optimization.

The Energy Transitions Commission [16] examined[17] the costs of different hydrogen transportation options (pipelines of different capacity, ammonia ships, trucks moving compressed and liquified hydrogen), vis-à-vis transported volumes and distance. This analysis indicates that:

[16] Noting that Clagayan et al. (2019) "Technical Potential of Salt Caverns for Hydrogen Storage in Europe" estimates that "*Germany has the highest technical storage potential, with a value of 9.4 PWhH2, located onshore only in salt domes in the north of the country*."
[17] The analysis is using as sources BloombergNEF and the European Hydrogen Backbone

- **For transport of small volumes of hydrogen (<10 tonnes/d), use of trucks is the least cost option**. Compressed hydrogen is preferable for smaller distances (less than 200 km) and liquified hydrogen for larger ones. For the competitiveness of hydrogen to small-end users (refuelling stations), trucking costs should come down.
- **For transport of more than 10 tonnes/d use of pipelines is the option with the lowest cost**, with sizing of the pipelines depending on the transported volumes.
- **Transport of hydrogen as ammonia via ships appears to be the preferable solution only for intercontinental distances of thousands of kilometres** that demand high capacities (>100 t/day). Shipping hydrogen as ammonia for end-use as ammonia could also be economical at shorter distances, as is the case currently with ammonia trade. This avoids high-cost transformation of ammonia back to hydrogen at destination. It should be noted that shipping of hydrogen as ammonia and reconverting it to hydrogen is so inefficient and thus expensive that considering transporting green electricity (through HVDC) or transporting natural gas and produce hydrogen plus CCS could be more cost competitive.

Figure 8: Transportation cost of hydrogen vis-à-vis volume and distance [16]



NOTE: [1] Including conversion and storage; [2] Assumes salt cavern storage for pipelines; [3] Ammonia assumed unsuitable at small scale due to its toxicity; [4] While LOHC (liquid organic hydrogen carrier) is cheaper than liquid hydrogen for long distance trucking, it is unlikely to be used as it is not commercially developed.

SOURCE: Adapted from BloombergNEF (2019), *Hydrogen: The Economics of Transport & Delivery*, Guidehouse (2020), *European Hydrogen backbone*

Concerning the optimality with respect to new or retrofitted pipelines, the determining factor is cost, with the analysis stating that "*Retrofitting existing high-capacity gas pipelines to enable hydrogen transportation is likely to cost ca. 40 to 65% of new pipeline construction, with the range dependent on the precise materials used in the initial pipeline*" [42].

3 Market conditions justifying development of hydrogen infrastructure

EU Member States are in the process of developing their national hydrogen markets and infrastructure, setting **targets for the evolution of demand and supply** and providing **measures and incentives to attain them**, and **planning hydrogen infrastructure** to support the emerging consumption and supply centres. ENTSOG's hydrogen CBA Methodology could benefit from taking into account the experience gained so far from the EU Member States' planning, particularly with regards to how development of the hydrogen market can justify the setup of hydrogen infrastructure. The latter can facilitate the reflection of the actual hydrogen sector development in the structuring of TYNDP's scenarios and the assessment of projects' impact.

This Section presents the key findings from **reviewing the plans of selected countries to establish hydrogen markets and develop the required infrastructure**, in an attempt to decode -to the extent possible- the "*chicken and egg*" dilemma of whether the infrastructure should proceed and incentivize demand, or the demand should drive the need for infrastructure.

In more detail, the EU Member States reviewed include Belgium, Denmark, France, Germany, Italy and the Netherlands, all of which have defined pathways (formed by one or more of the following bodies: Governments, Hydrogen committees comprised by governmental and other stakeholders, TSOs/TSOs' subsidiaries/parent companies) for developing their hydrogen markets, and are planning the development of hydrogen infrastructure. A high-level analysis of the U.S. hydrogen strategy and development plans (on federal level) was also carried out, to look into approaches for developing hydrogen markets outside the EU and to showcase the similarities and differences with hydrogen planning in the EU. An overview of the findings is provided in this Section, and a detailed country-by-country analysis can be found in Annex I.

Based on the above the **conditions for developing hydrogen markets and infrastructure were assessed**. The analysis focused on the main elements that impact the development of the main blocks of the hydrogen supply chain, i.e., supply, demand and transportation. Drawing from the experience and practices observed in the reviewed countries, the assessment also examined the process for carrying out market tests, to secure the commitments of the market participants to finance and develop the hydrogen infrastructure.

3.1 Hydrogen sector planning

3.1.1 Hydrogen demand targets and supply options

Table 4 presents the **hydrogen demand targets** set by the reviewed countries and the **hydrogen supply options** that they have considered, in order to meet their future domestic hydrogen demand and -in some cases- engage in EU/international hydrogen trading[18].

[18] In the U.S. as "clean hydrogen" is considered the "decarbonized" hydrogen produced from natural gas, coal, renewable energy sources, nuclear energy, and biomass. By "decarbonized", the Roadmap refers to hydrogen produced with a carbon intensity equal to or less than 2 kg CO2-eq produced at the site of production per kilogram of hydrogen produced. As "green hydrogen" / "renewable hydrogen" in the EU is considered hydrogen produced by feeding renewables-based electricity into an electrolyser. As of February 2023, the European Commission proposed a new set of rules as to what can be called "green hydrogen". According to these rules,

Table 4: Hydrogen demand targets and supply options in the reviewed countries

Country	Hydrogen demand targets	Hydrogen supply targets/options
Belgium	• Demand for **20 TWh/yr in 2030** (domestic & transit) • Demand for **200 – 350 TWh/yr** (bunkering fuels included) by **2050** (~50% for transit to neighbours)	• **Domestic production** from **150 MW** of electrolysis capacity installed by **2026** • Three H2 **import** routes: North Sea route (pipeline), Southern route (pipeline) - mainly Iberia and North-Africa, Shipping route - Middle East, Africa, or the America's
Denmark	CO2 reduction by using Power-to-X (PtX) fuels and products: • **0.5 – 1.9 mil. tonnes/year by 2030** • **1.1 – 3.5 mil. tonnes/year 2050**	**Domestic production** from **4 – 6 GW** of electrolysis capacity installed by **2030**
France	**20-40% of total H2** and **20-40% of industrial H2 consumption** to be sourced from **low-carbon and renewable H2** by **2030**	• **Domestic production** from **6.5 GW** of electrolysis capacity installed by **2030** • No H2 imports or exports are foreseen up to 2030 • Later on, H2 **imports** are foreseen from (or through) Spain and exports to Belgium and German
Germany	Demand for **90 to 110 TWh/yr** of green H2 by **2030***	• **Domestic production** from **5 GW** of electrolysis capacity installed by **2030** (=14 TWh/yr of green hydrogen production = 1/7 of the projected H2 demand) • Another **5 GW** of capacity to be added, if possible, by 2035 and **no later than 2040** • **Imports**: in the short-term from EU countries bordering the North & Baltic Sea, and southern European countries. In the long -term by engaging in international trade
Italy	• Demand for **23 TWh/yr by 2030** (around 2% of the final energy mix) • Around **20% in final energy consumption by 2050****	• **Domestic production** from **5 GW** of electrolysis capacity installed by **2030** to meet part of the demand • The above will be complemented with **imports**, mainly from north Africa
Netherlands	Demand for **11 – 22 TWh/yr** of green H2 for the production of steel and chemicals and for the refining sector and for **5 – 16 TWh/yr** for all transport modalities by **2030** (Source: Roadmap, 2022)***	• **Domestic production** from **3 – 4 GW** of electrolysis capacity installed by **2030** (500 MW in 2025) • Up to 2025:H2 **imports** from the Middle East and North America and smaller volumes from EU countries, such as Portugal and Spain • After 2025: H2 **imports** from inside and outside the EU
U.S.	Demand for **330 TWh/yr** of clean hydrogen by **2030**, **660 TWh/yr** by **2040**, and **1650 TWh/yr** by **2050**	• **Domestic production** without providing quantitative details

** The respondents to the German TSOs' Hydrogen Generation and Demand Market Survey -conducted in 2021- reported around 29 GW of electrolysis capacity to be installed by 2032 which is significantly higher than the capacity predicted in the National Hydrogen Strategy (5 GW by 2030).*
***According to SNAM (2019), the H2 demand in 2030 will be 26 TWh (= 2% of the total energy demand of 1,283 TWh) and equal to 220 TWh in 2050 (= 23% of the total energy demand of 955 TWh)*
**** According to the National Climate Agreement (2019), there is large potential demand for H2 for industrial applications on coastal regions (approximately 35 – 59 TWh/yr), while additional demand may emerge in the same regions for H2 for electricity production. The results of the Hynetwork Services' Market Consultation in 2020 indicated that in 2030, producers expect to produce and transport roughly 100 TWh of H2 and users expect to use roughly 20 TWh. By 2035 these amounts increase to 225 and 80 TWh, respectively.*

hydrogen produced using nuclear energy can be classified as green under certain circumstances: Grid power can be counted as green if it originates from a bidding zone where electricity is produced at less than 18 gCO2eq/MJ. A grid with a high share of electricity from nuclear energy will have low CO2 emissions. If this electricity is used for electrolysis, then the hydrogen thus produced can also be green, according to the new definition.

Most of the reviewed countries have **set specific targets for hydrogen demand by the year 2030 and/or 2050**. There are two exceptions; Denmark has set targets in the form of avoided CO2 emissions due to the use of green hydrogen and France has specified the percentage of total hydrogen and of industrial hydrogen consumption to be low-carbon and renewable by 2030.

Some noteworthy observations in the reviewed countries’ hydrogen supply and demand targets are the following:

- Half of Belgium’s 2050 demand target will serve transit activities and the other half is destined for domestic consumption. On the same time, the domestic production is the lowest observed among the examined countries (in MW scale), indicating that Belgium will act as an importer for both its own needs and for serving as an entry/exit country for hydrogen to its neighbours.
- Germany’s demand target for 2030 will be mostly covered by imports, as the domestic production of hydrogen is expected to cover only a small fraction (1/7) of the projected hydrogen demand.
- Denmark’s domestic production is on the higher end even though the country is close to reaching its decarbonization targets through electrification. This indicates that Denmark expects to be able to export large volumes of hydrogen to its neighbours, most of which is planned to be sourced from offshore hydrogen production in the North Sea.
- Italy’s advantageous geographical position will allow the country to bring hydrogen volumes from North Africa into Europe, targeting especially to transit them into Germany.
- The Netherlands presents the unique characteristic of aspiring to start the imports from countries outside the EU, i.e., from the Middle East and North America, based on the rationale that natural gas supply routes are already established among the Netherlands and these regions.

3.1.2 Hydrogen demand for different end-use sectors

The country analysis has indicated that there are **significant commonalities on the pathways the countries are envisioning to develop hydrogen markets**. It is interesting to note that the U.S. Federal demand targets are similar to those of EU Member States.

In the majority of the examined countries, the short-term targets include use of hydrogen in the industrial sector, mainly as feedstock (in some cases also in heat-demanding industrial processes), and in the transport sector, particularly as fuel for heavy duty vehicles. Other uses, such as offering flexibility in the power sector or use for building heating are either long-term prospects, or not considered at all.

An **overview of the long and short term uses** each country foresees are demonstrated in Table 5.

Table 5: Short-term and long-term demand for hydrogen in the reviewed countries

	Germany	France	Netherlands	Denmark	Italy	Belgium	U.S.
Industry*							
feedstock	🟢	🟢	🟢	🟢	🟢	🟢	🟢
heat processes	🟡	-	🟢	🟢	🟡	🟢	🟡
Refining	🟢	🟢	🟢	🟢	🟢	-	🟢
Transportation							
heavy duty	🟢	🟢	🟢	🟢	🟢	🟢	🟢
public passenger transport (buses, trains, ferries)	🟢	🟢	🟢	-	🟢	-	🟢
commercial vehicles	🟢	-	🟢	-	-	-	-
civil vehicles	-	-	🟢	-	🟡	-	-
maritime transportation, including inland navigation	🟡	-	🟢	🟡	🟡	🟡	🟡
air transportation	🟡	-	🟡	🟡	🟡	🟡	-
Power sector	-	🟡	🟡	-	🟡	🟡	🟡
Heating sector	🟡	-	🟡	🟡	🟡		🟡

🟢 : Short-term demand (up to 2030) 🟡 : Long-term demand (up to 2050), "-" in major sectors (in Bold font): Not mentioned in the country analysis or more detailed information is provided for the sub-sectors (in Italics font), "-" in sub-sectors: Not mentioned in the country analysis

**Chemicals industry, steel, cement, aluminium, ceramics and glass*

3.1.3 Measures to promote hydrogen market development

In order to **incentivize the production and use of low-carbon and green hydrogen**, the **measures** summarized in the Table below are being implemented, or expected to be implemented, by the reviewed countries.

Table 6: Support measures per reviewed country

Measures	DE	FR	NL	DK	IT	BL	U.S.
Funding investments in electrolysers in the industrial sector and for hydrogen production and other hydrogen-based transportation fuels	✓	✓	✓	✓	✓	✓	✓
Funding investments in hydrogen-powered vehicles and for the construction of refuelling infrastructure for vehicles	✓	✓			✓		
Providing operating aid to low carbon/green hydrogen production applications, for example in the form of new subsidy schemes that remunerate the green hydrogen producer on the basis of the avoided tonnes of CO2 versus the production of grey hydrogen	✓	✓	✓	✓	✓	✓	
Funding investments in industrial, mobility or stationery clusters that combine production and/or and use of low carbon/green hydrogen		✓		✓	✓		✓
Exempting electricity used to produce green hydrogen from taxes and other surcharges	✓					✓	✓
Introducing CO2 pricing for fossil fuels used in transport and the heating sector	✓						
Extending existing subsidy schemes applicable for RES to the production of hydrogen			✓				
Establishing 'Carbon Contracts for Difference (CfD) to support the use of green hydrogen in the industrial sector	✓						
Simplifying the RES regulation, designating additional areas that can be used for RES-based production of hydrogen and combining hydrogen production with offshore wind RES projects in integrated tenders	✓		✓		✓		
Funding projects to achieve 'hydrogen readiness' for installations on the end-use side	✓				✓		
Supporting research and development to enhance domestic manufacturing of electrolysers and thus lower the cost of hydrogen production		✓	✓	✓	✓	✓	✓
Supporting research and development for fuel cells, storage equipment, and other hydrogen related components	✓	✓			✓	✓	✓

All the above measures are intended to incentivize the production and use of hydrogen in selected EU Member States and the U.S. In one particular case, the **Dutch government** is considering imposing certain **obligations to increase hydrogen demand**. One of the obligations relates to the blending of green hydrogen in the natural gas grid (either physically or through certificates) and the other one relates to the obligatory blending of sustainable fuels, including hydrogen with conventional aviation fuels.

In the EU, to secure funding for the aforementioned measures, the Member States aim to **leverage existing national and EU funds and financing instruments** (such as the Recovery and Resilience Facility, ReactEU, Horizon Europe, Innovation Fund), as well as to establish **new dedicated funding programs**[19]. One such hydrogen-specific funding mechanism, the "*Hydrogen Shot*" is already in place in the U.S. to reduce the cost of clean hydrogen production to 1 $/kg in one decade.

3.1.4 Hydrogen transportation plans

Table 7 presents the hydrogen transportation plans laid out by the Government and/or the gas TSOs/their subsidiaries/parent companies in order to **connect hydrogen supply with demand**.

Hydrogen infrastructure planning in the examined countries focuses on the **transportation of hydrogen in gaseous form via pipelines**. Supply of hydrogen via ships is considered in certain cases (Belgium, Netherlands) as a long-distance import source, but without any specific infrastructure planned, and without specifying the carrier in which hydrogen is to be received (liquid hydrogen, ammonia, LOHC).

The build-up of the hydrogen networks is planned to be stepwise, starting from point-to-point links, and gradually moving to regional networks (e.g., hydrogen valleys in France, subnetworks in Germany), that will eventually evolve to the country's hydrogen backbone. Connections with other countries may have a localized scope (e.g., link of production in France with consumption in Belgium) or become cross-border interconnections, that allow wider coverage of demand needs via imports.

As indicated in the Table below, the hydrogen backbone, planned in the examined countries, will **mainly utilize repurposed natural gas pipelines**, increasing the use and value of existing gas assets, and expediting a wider coverage of the hydrogen network. Indicatively, Germany estimates that 65% – 70% of the network will utilize repurposed pipelines, the Dutch backbone will comprise 85% of existing infrastructure, and in Italy 70% of the network is foreseen to be repurposed from natural gas.

Table 7: Hydrogen transportation plans in the reviewed countries

Country	Hydrogen transportation plans
Belgium	• **100 – 160 km of additional hydrogen pipelines** (new and/or repurposed) will be in place by **2026**. Maximum advantage will be taken of existing pipelines, such as natural gas pipelines and pipelines used for the transportation of low-calorific gas. • Belgium aspires to **interconnect its hydrogen network with at least Germany, France and the Netherlands** by **2028.** • An open access hydrogen backbone will be established **connecting the ports** (Zeebrugge, Ghent, Antwerpen) **to the industrial zones and with neighboring countries** by **2030.**

[19] Many European Member States are in the process of updating their Hydrogen Strategies and thus updating their demand targets and support measures, potentially due to the fact that market demand has been confirmed based on TSOs activities (market consultations and market tests).

Denmark	• According to the National Hydrogen Strategy: ○ Due to political decisions **the majority of the natural gas grid for at least the next 20 years will be used to transport and store biogas.** ○ The **Baltic Pipe connection will transport large quantities of natural gas** through Denmark to Poland until at least **up to 2038.** • In **2021**, Energinet and Gasunie published a technical pre-feasibility study for transporting hydrogen via a **350-450 km pipeline from Esbjerg or Holstebro in Denmark to Hamburg in Germany.** • The natural gas TSO is currently investigating the **possible routing of the Danish hydrogen backbone.**
France	• Build-up of infrastructure within local ecosystems favourable to its production and consumption, particularly for industrial and transport **from today up to 2030.** • Creation of **hydrogen valleys** interlinking local ecosystems via a regional pipeline-based transport grid, integrating H2 storage infrastructures **from 2030 up to 2035.** • Structuring an **interconnected grid at European level** for pipeline-based transport, incorporating storage infrastructures and ensuring transit into neighboring EU Member States **from 2035 up to 2050.**
Germany	• **Subnetworks** will be in place by **2027**. The largest coherent subnetworks will be located in the East, Schleswig-Holstein and the North-West. • The hydrogen network will consist of **7,600 – 8,500 km length of pipelines** by **2032**. The natural gas repurposed pipelines are estimated between 4,900 – 5,900 km and the new-dedicated ones will range from 2,300 – 2,900 km[20].
Italy	• **2,300 km of H2 network** (70% of which will be repurposed from natural gas) will be in place by **2032** to bring production from North Africa and Southern Italy to consumption areas and up to 500 MW compression stations to enable hydrogen export. • **1.5 bcm of storage capacity** will be available (one new site and reconversion of one existing field) by **2035** • The **first tranche of the Italian hydrogen backbone** will be to **connect Italy to countries with higher demand like Germany.**
Netherlands	• Progressively, **industrial clusters will be connected via pipelines to each other, to other countries and to hydrogen storage and import locations**. 85% of the infrastructure will be developed by repurposing existing natural gas pipelines. The whole network will be in place by **2030**. • The infrastructure will consist of approximately **200 km of new pipelines**, and **1,000 km of existing repurposed natural gas pipelines** and of around **320 onshore salt caverns for hydrogen storage.**
United States	• A recent legislation established a program to support the development **of at least 4 regional clean hydrogen hubs** that **can be developed into a national clean hydrogen network** to facilitate a clean hydrogen economy. • Developments in both hydrogen supply and demand will be key determinants of **how much hydrogen pipeline capacity will be needed, when it will be needed, and where**.

3.1.5 Market consultations and open seasons

Stakeholders[21] that are looking to develop hydrogen networks are currently engaged in ongoing actions to match market needs with roll-out of infrastructure via market consultations and market tests.

Market consultations have taken place: for informative purposes before Expressions of Interest (EoIs) and market testing (Belgium), in order to shape the country's Hydrogen Strategy (France), to collect feedback regarding the future regulatory regime for hydrogen (Belgium) and the future contractual framework for hydrogen networks (Netherlands), or to elicit expression of interest that have not yet been followed by binding commitments (Denmark & Germany). Market consultations is also serving

[20] A final assessment as to which pipelines would specifically have to be newly built or converted is currently not possible due to the highly dynamic developments in the gas market.
[21] In the reviewed countries these stakeholders are either the gas TSOs or their subsidiaries/parent companies.

as the first step of **market testing which has been conducted/planned** in many of the examined countries to determine the **sizing of the initial phase of hydrogen infrastructure**. Future market tests will determine the **network expansion and upgrade needs**, to cover new areas and address increases of hydrogen demand.

Table 8: Market consultations and open seasons in the reviewed countries

Country	Market consultations and Open seasons
Belgium	• In early 2021, **Fluxys** invited interested parties to participate in a **market consultation**, in the form of a Request for Information (RFI) which still remains open. This process provided Fluxys with a clear overview of how market needs develop geographically and over time, hence demonstrating interest for hydrogen network infrastructure. Also, Fluxys encouraged RFI participants to a "matchmaking process" to facilitate mutual exchanges between hydrogen future offtakers and suppliers. • **Fluxys** invited interested parties to **express their interest** for specific infrastructure proposals (open season): Closed[22]: Antwerp, Mons, Ghent; Open: Liège, Charleroi; Pending: Import infrastructure proposal within the port of Zeebrugge.
Denmark	• In 2021, **Energinet and the Danish Energy Agency** entered into a **market dialogue (non-binding EoI)** with 19 market actors from Denmark and abroad who had expressed interest in Danish hydrogen infrastructure. The dialogue revealed that the need for transport is closely correlated with the need for large-scale hydrogen storage and exports to other countries, that there is need for infrastructure already before 2030 and that hydrogen infrastructure will initially be of most interest in Jutland, with a connection to hydrogen storage and exports to Germany. • In 2022, the **Danish Energy Agency, Evida and Energinet** launched another **market dialogue** to collect information from promoters with projects (i) producing hydrogen, (ii) expect to use hydrogen, (iii) both will be a producer and a consumer, in order to understand their hydrogen infrastructure needs.
France	• In June 2021, **GRTgaz and Teréga** launched the **first national consultation** for the low-carbon & renewable hydrogen market, to identify the needs of market actors. The two gas TSOs received 133 contributions enabling them to identify 90 production and/or consumption sites. The two TSOs intend to repeat the process on an annual or bi-annual basis. • The market consultation results were enriched by discussions with interested parties from the H2 market. • From June to September 2022, **GRTgaz in coordination with Fluxys launched its first hydrogen Call for EoIs**, calling on regional stakeholders to express their interest in a **cross-border low-carbon hydrogen transport network** linking Valenciennes in France and Mons in Belgium's Hainault region. • From September to November 2022: **GRTgaz launched its second hydrogen Call for EoIs** for the **Port of Dunkirk.** • In early 2023: **GRTgaz launched its third EoI** for a low-carbon hydrogen transport network to be developed **between Fos-sur-Mer and Manosque.** • In early 2023, **Géométhane** called on all local stakeholders to **express their interest** for a hydrogen storage project in salt caverns on the Manosque site.
Germany	• In early 2021, the German TSOs conducted a **Hydrogen Generation and Demand Market Survey** to collect information on the planned hydrogen generation and future demand in Germany. The market survey respondents reported almost 500 projects, including 488 hydrogen projects with a total demand of 231 TWh in 2032, 427 TWh in 2040 and 598 TWh in 2050. The reported electrolysis capacity was of around 29 GW in 2032, 40 GW in 2040 and 56 GW in 2050. • In late 2021, the promoters of more than **250 projects with a total demand of 165 TWh had concluded Memorandums of Understanding (MoUs)** with the corresponding TSOs (These projects can be included in the German Gas National Development Plan (NDP) 2022-2032).

[22] Even after the closure date for a Specific Infrastructure Proposal, interested parties may still fill the RFI and Fluxys will keep finetuning their infrastructure mapping.

Netherlands	• In October 2020, **Hynetwork Services** conducted a **Market Consultation** in order to understand the preferences of market parties for the technical specifications of the Dutch national hydrogen transport network. • In October 2021, **Hynetwork Services** invited companies to **express their interest to contract in future hydrogen pipeline infrastructure** in the Netherlands. • In 2022, **Hynetwork Services** conducted a **consultation process about the general terms and conditions for hydrogen transport and connection services.**
United States	• In 2020, DOE set up the ***"H2 Matchmaker"*** which is an online portal aimed to **assist hydrogen suppliers and users to align potential needs in specific geographic areas** within the U.S. and explore opportunities towards realizing regional hydrogen hubs.

3.2 Conditions for the development of hydrogen market & infrastructure

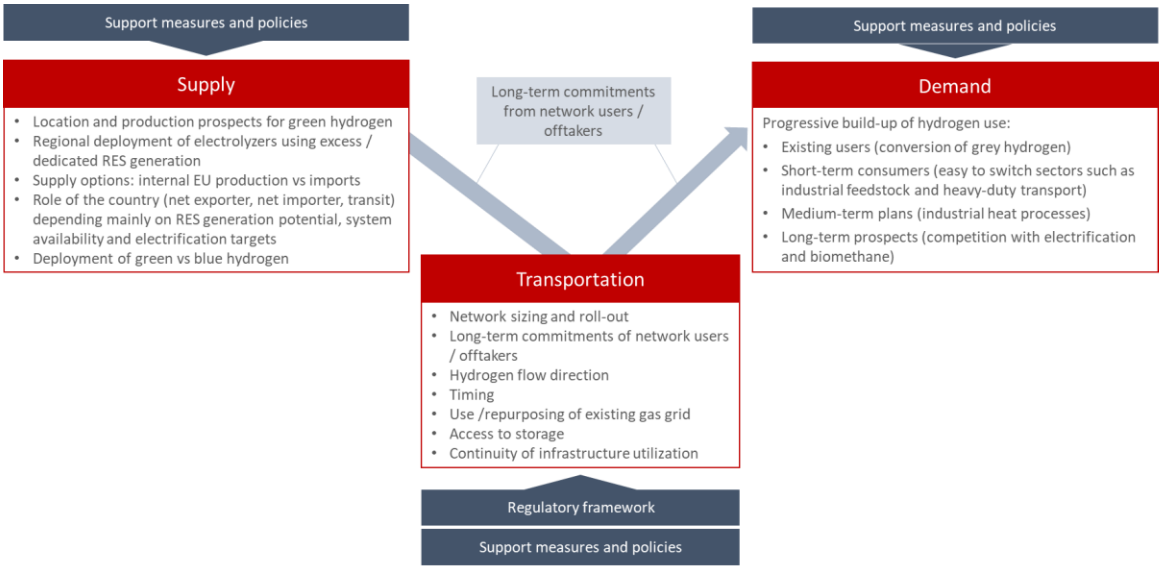
Demand for hydrogen, which to a large extent is supported by the **policy targets set** and **the measures** applied to incentivise hydrogen use, drives the development of sufficient **hydrogen production to meet the needs of the final consumers**. The evolution path of green and low-carbon hydrogen demand typically includes **substitution of existing grey hydrogen** demand and broad use of hydrogen as **industrial feedstock**, followed by its gradual introduction in other sectors. Availability of in-country green hydrogen production depends partly on the **conditions in the country's power sector mix** as well as **climate and geography**. Off peak capacity from nuclear power as well as dedicated renewable generation are the primary green sources for production. Additionally, the level of renewables penetration in the electricity mix can determine the extent to which otherwise curtailed electricity from grid connected renewables could potentially be used to produce hydrogen[23]. In the absence of sufficient indigenous hydrogen production to cover demand, **imports from other countries**, within the EU or from third countries, should be sought.

Depending on the location of the most cost-effective supplies, **hydrogen transportation requirements may range** from small distances, for localized production and consumption, to overseas and long-distance imports transited through transmission systems to reach the final consumption centres. Infrastructure to accommodate demand of hydrogen transportation should be developed **progressively, synchronised with the needs of the hydrogen market**. In this respect, planning for and developing infrastructure will largely rely on securing long-term binding commitments from prospective shippers (consumers and/or suppliers), so as to ensure utilization of the infrastructure, and avoid asset stranding.

The **key elements** that formulate the **conditions under which the hydrogen markets and infrastructure are developed**, are outlined in the Figure below that presents the elements identified in each part of the hydrogen supply chain. These elements are analysed in the remainder of this Section, taking into account the outcomes of the literature review on hydrogen demand, supply and transportation, analysed in Section 2 and the findings from the review of national planning for hydrogen discussed in Section 3.1.

[23] The first EC Delegated Act, that defines the situation under which hydrogen could be branded "*green*", places very specific restrictions on the use of existing renewable installations to produce hydrogen so as to essentially protect the decarbonization of the electricity market as well as its consumers from cross-sectoral rent extraction between the hydrogen and electricity markets.

Figure 9: Overview of elements for hydrogen markets and infrastructure development



3.2.1 Demand

As shown in Section 3.1, it appears that the most common way to build demand for low carbon/green hydrogen in the **short-term** (based on the target setting in the countries reviewed) is to target:

- **Sectors that already use (grey) hydrogen** and in most cases have hydrogen infrastructure in place, especially industrial sectors that need hydrogen as a feedstock for the production of ammonia, methanol, etc., and the refining sector, and
- Sectors where using renewable-based electricity directly is not reasonable or technically feasible, particularly certain **parts of the transportation** sector such as heavy-duty/long-haul trucks.

In the **medium-term**, the use of hydrogen in **industrial heat processes** is envisioned by almost all the selected countries. However, this demand for gaseous fuels could also be met by biogas and biomethane.

As regards **long-term** applications, the following were observed:

- In the **power sector**, the use of hydrogen is examined as a seasonal and long-term storage option for electricity produced via RES to address congestion problems in the electricity transmission system and increase the possibilities for integration of RES in the energy mix (both in a centralized and decentralized manner). Nevertheless, for RES storage applications, hydrogen technologies are expected to compete with batteries, even though the storage capacity of these two technologies is very different today. However, both sectors are currently advancing, and the market will eventually determine the optimum between the two storage options based on their future cost-efficiency.
- In the **building heating sector**, the extent of future hydrogen use will be determined based on its economic and technical advantages versus other alternatives that could be employed to decarbonize the sector, such as heat pumps and biomethane.

- For **other modes of land-based transportation**, i.e., other than heavy-duty transportation, both fuel cell and battery-powered electric vehicles could be used in a complementary manner.
- For **air and maritime transportation**, more research and technological advancements are needed for hydrogen derivatives, such as e-ammonia and e-kerosene to be used.

Overall, the long-term use of green hydrogen will primarily depend on its **cost-competitiveness against other means of decarbonization** which in turn will be affected by a number of other important factors, including technological advancements in hydrogen production and use technologies, infrastructure availability, regulatory framework and state support to promote private investments. Although most countries foresee a future assessment of the potential use of these long-term applications, in most of these (especially in building heating and light vehicles) hydrogen appears to be at disadvantage against electrification [24].

3.2.2 Supply

The supply targets set by the analysed countries and the activities pursued by the stakeholders involved in hydrogen infrastructure planning, reflect their **willingness to domestically produce hydrogen** and their **plans to become a net exporter, a net importer or act as a transit country** for hydrogen supply in the long-term.

The rationale for becoming a **net exporter** is built on the following conditions:

- **Domestic availability of RES capacity** can be employed for the production of green hydrogen, especially in the case that the country is close to reaching its decarbonization targets by using mature technologies and as a result does not have to extensively rely on green hydrogen for its own needs.
- Being in **vicinity of countries with low RES domestic potential** and/or **high future hydrogen needs**, most commonly due to intense industrial activity.
- Planning of **cross-border hydrogen infrastructure** allowing exports to its region. Being **able to repurpose existing natural gas infrastructure**, shall expedite the completion of necessary interconnections and lower the costs of hydrogen transportation. For large-scale exports, access to **international ports** is necessary in order to be able to ship liquid hydrogen across the globe.

A country may expect to become a **net importer** of hydrogen based on the following conditions:

- The domestic available **RES potential is limited** and/or it seems more reasonable to use it for direct electrification applications.
- The country is able to support the development of large-scale green **hydrogen production in partner countries** with exceptional untapped RES potential.
- The future needs in green hydrogen are estimated to be on the higher-end due to **industrial and transportation needs**.

Lastly, several countries expect to be able to serve as **transit (or entry/exit)** countries[24] facilitating imports and exports with their neighbours and in the long-term within an international hydrogen trade market. The conditions for being able to become a transit country are:

- The **position of the country** on the path of future international hydrogen corridors (either on land or shipping routes), connecting hydrogen producers with hydrogen users, in a similar way as with today's natural gas trade. Such an example is the Netherlands, which expects to source hydrogen from the Middle East, North America and from EU Member States, such as Portugal and Spain and thus become a transit country on an international and EU-wide level.
- The country's **ability to become a hydrogen hub country on a regional level**. For example, Italy aims to source from North Africa and export to EU Member States with high demand, such as Germany.
- The existence of an **extensive natural gas system**, which is **fit for repurposing** to hydrogen infrastructure can expedite the establishment of hydrogen transit flows.

The actual role of each country in connecting supply with demand will be solidified in the future based on the evolution of costs that relate to hydrogen production and transportation.

Another important aspect of hydrogen supply is the examined countries targets with respect to the deployment of **green vs blue hydrogen**. In the reviewed EU Member States, domestic supply is most commonly denoted by setting a target for installed electrolysis capacity in the short-term (up to 2030). Therefore, the target concerns the production of green hydrogen, following the example set by the EU Hydrogen Strategy[25]. However, **most countries recognize the transitional role of blue hydrogen** without setting specific targets for its production (except for the Netherlands, where the Port of Rotterdam expects the first plant for blue hydrogen produced from natural gas and refinery fuel gas to be ready by the end of 2026).

In the U.S., where the overarching goal is to have net-zero Greenhouse Gas (GHG) emissions by 2050, as in the EU, there is no differentiation between green and blue hydrogen. The strategy refers to "*clean*" hydrogen which is defined as hydrogen produced with a carbon intensity equal to or less than 2 kg CO2-eq produced at the site of production per kilogram of hydrogen produced. Therefore, in the U.S. hydrogen produced from natural gas, coal, RES, nuclear energy, and biomass is considered as "*clean*", provided that it meets the above CO2-eq threshold, and a mix of the aforementioned production routes are likely to be used through at least 2050.

3.2.3 Transportation

The **modalities for transporting hydrogen** include:

- Pipelines, transporting mainly hydrogen in gaseous form (pipelines transporting liquid ammonia may also be a feasible option depending on the supply chain and end-use).

[24] Transit countries may be either net importers or exporters themselves, for example Belgium expects to become a transit country and be a net-importer.

[25] On February 14th 2023, it was announced that the European Commission intends to allow hydrogen derived from electricity grids with high levels of nuclear power to be considered green as long as the producer buys a long-term contract for renewable energy equivalent to its consumption.

- Trucks, transporting compressed hydrogen or liquids (liquid hydrogen, ammonia or LOHC).
- Ships, transporting liquid hydrogen, ammonia or LOHC.

The main drivers for selecting the suitable hydrogen transportation option are the **volumes transported**, and the **distance between hydrogen production and consumption**. As discussed in Section 2.3.4, the study by the Energy Transitions Commission [16] has indicated that use of pipelines is more cost-efficient for transporting medium to large volumes of hydrogen up to a distance of 5,000 km, while for larger distances use of ammonia ships is preferable (Table 9). For small volumes and limited range transportation via trucks is the most cost competitive option.

Table 9: Comparison of hydrogen transportation modalities [16]

Transportation modality		Volume	Distance
Trucks	Compressed H2	Up to 0.33 GWh/d (10 tons/d)	Up to 200 km
	Liquid H2	Up to 0.33 GWh/d (10 tons/d)	More cost efficient for distances below 1,000 km
Pipelines	Distribution	Between 0.33 – 3.3 GWh/d (10 – 100 tons/d)	Up to 2,000 km
	Transmission	Between 3.3 – 33 GWh/d (100 – 1,000 tons/d)	Up to 5,000 km
	Ultra-high transmission	Between 33 - 200 GWh/d (1,000 – 6,000 tons/d)	Over 5,000 km
Ships	Ammonia	> 3.3 GWh/d (1,000 tons/d)	Over 5,000 km

An additional element that affects the form in which hydrogen is to be transported, especially using ships, is **its end-use**. Using ammonia as a carrier may be more advantageous if it is also going to be the final product consumed (e.g., as feedstock or transport fuel). If ammonia is to be broken down for hydrogen extraction, the overall efficiency drops to levels that could make ammonia less attractive than liquid hydrogen (around 30% of hydrogen energy content is used for transforming from ammonia back to hydrogen [43]).

Hydrogen infrastructure planning in the examined countries focuses on the **transportation of hydrogen in gaseous form via pipelines**. Supply of hydrogen via ships is considered in certain cases (Belgium, Netherlands) as a long-distance import source, but without any specific infrastructure planned, and without specifying the carrier in which hydrogen is to be received (liquid hydrogen, ammonia, LOHC).

In all the examined EU Member States, planning for hydrogen infrastructure is following a **gradual approach**, in terms of network coverage and size, **progressing together with the build-up of hydrogen supply and demand**. To mitigate the uncertainties of the hydrogen market development (including both the uncertainties of hydrogen uptake in different sectors, and the availability of hydrogen sources), to reduce the risks of underutilized hydrogen assets, and to avoid unnecessary interventions in the natural gas infrastructure that may cause security of supply issues, hydrogen infrastructure is being **planned in phases**, the design of each linked with **commitments from prospective shippers**. Stakeholders[26] that are looking to develop hydrogen networks are currently conducting **market tests** (the process of market testing for hydrogen infrastructure in each reviewed country is discussed in

[26] In the reviewed countries these stakeholders are either the gas TSOs or their subsidiaries/parent companies.

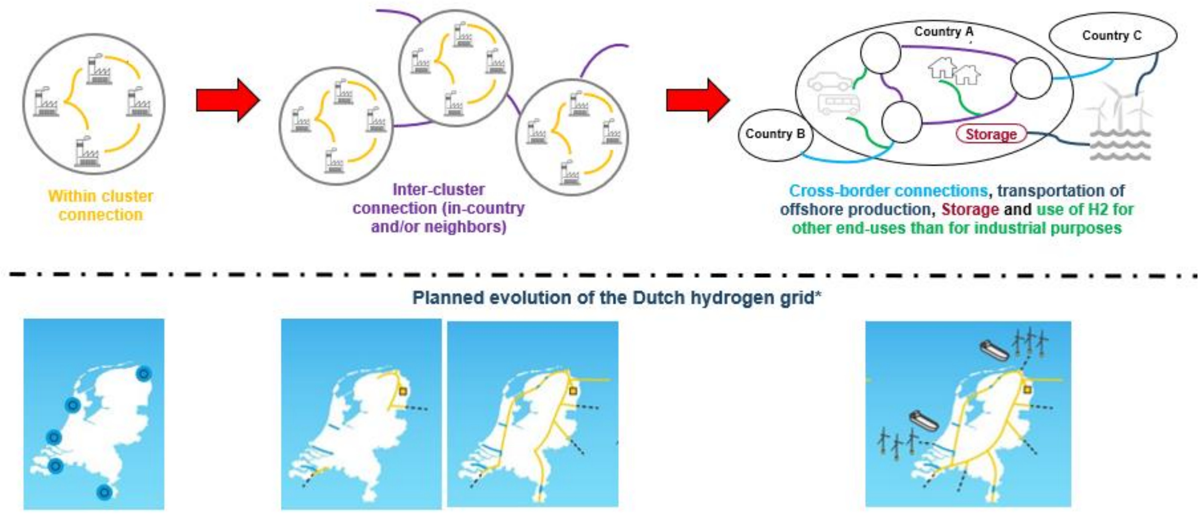
Section 3.1.5 and in more detail in Annex I), that will determine the **sizing of the initial phase of hydrogen infrastructure**. Future market tests will determine the **network expansion and upgrade needs**, to cover new areas and address increases of hydrogen demand.

The hydrogen backbone that is being planned in the examined countries will **mainly utilize repurposed natural gas pipelines**, increasing the utilization and value of existing gas assets, and expediting a wider coverage of the hydrogen network. Indicatively, Germany estimates that 65% – 70% of the network will utilize repurposed pipelines, the Dutch backbone will comprise 85% of existing infrastructure, and in Italy 70% of the network are foreseen to be repurposed from natural gas. Repurposing of natural gas infrastructure should **seek to accommodate flows of pure hydrogen, but at the same time ensure that natural gas can continue being delivered to final consumers**, as a transitory fuel. ACER has identified **key conditions for repurposing natural gas infrastructure** [44]:

- Presence of **loop (parallel) lines of natural gas pipeline systems**, of which at least one string could be repurposed for pure hydrogen.
- Ensuring **security of natural gas supply to consumers**, during and after the conversion of a line (or loop) to pure hydrogen.
- There is **hydrogen market uptake** in the location or regions serving that pure hydrogen corridor.

The development of hydrogen transmission systems is **following the gradual build-up of demand**. The initial conversion of grey to green hydrogen (or transitionally blue hydrogen) would require mainly development of **small infrastructure locally**. The creation of hydrogen clusters could lead to the need for **regional distribution and transmission pipelines** that can link production and consumption centres. **Large-scale roll-out** of transmission infrastructure is necessary when the clusters are to be interconnected, with a view to developing additional consumption centres in the country, and/or to providing wider accessibility to national and cross-border hydrogen production, as shown in Figure 10 (with the case of the Dutch hydrogen network expansion serving as an example).

Figure 10: The gradual build-out of demand and infrastructure



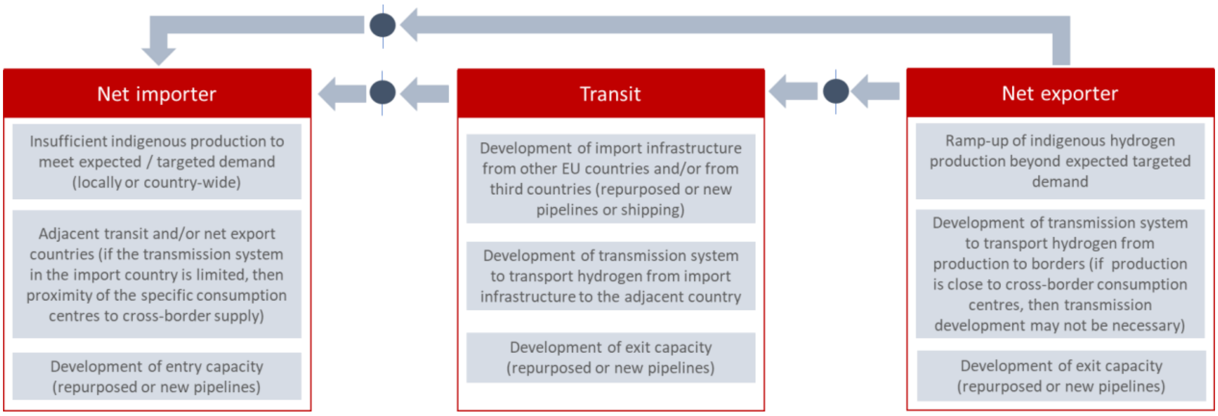
**Source: Gasunie, [Accelerating the energy transition]*

Even at these early phases of the European hydrogen infrastructure development, the need for **regional coordination** becomes evident from the EU Member States' strategies and network planning. Depending on the countries' hydrogen production potential, the possibilities for external supplies, and their targets for hydrogen uptake, establishment of cross-border infrastructure may be required even before the in-country transmission system is widely developed, to facilitate hydrogen flows that match demand and supply. For example, Germany is planning to rely on imports to cover demand of the initially developed industrial clusters in the northern part of the country, before the transmission network of the country begins to expand[27]. To meet Germany's short-term import needs:

- Denmark (net exporter) is planning an interconnection with Germany as part of its backbone network.
- The Netherlands is planning to initially connect local hydrogen production clusters with German consumption across the borders as early as 2026 – 2028.
- Belgium aspires to interconnect its hydrogen network with Germany by 2028.
- Italy's first hydrogen backbone segment will connect Italy to countries with higher demand like Germany.

The development of **cross-border hydrogen infrastructure** is triggered by the needs of the import countries to supplement any indigenous production with supplies from other EU countries and/or from external sources. The importer's needs determine the size of the import infrastructure, and potentially its routing, in case hydrogen will be consumed locally and will not be transported throughout the country. From the supply side, infrastructure that can export hydrogen should be available at the export and transit countries. Figure 11 summarizes these **main conditions for cross-border transportation of hydrogen**.

Figure 11: Conditions for cross-border hydrogen transportation



For an optimized regional development of hydrogen infrastructure, the **timing** at which supplies of hydrogen are ready to be transported, from export countries and through transit countries to consumption centres, should be synchronized with the evolution of demand needs at the import countries. Building infrastructure to match regional supply and demand would therefore require securing the commitment of stakeholders in all countries involved, including producers in export countries, importers/traders and producers in transit countries, importers/suppliers and final

[27] See Annex I for a detailed description of Germany's planned network roll-out.

consumers in import countries. This could be attained through **regional consultations** and **market testing processes**, and the **close cooperation and coordination of the hydrogen infrastructure operators** in each country.

The **duration of the binding commitments** of the market participants to use the infrastructure should be **sufficiently long**, so as to ensure long-term utilization of the infrastructure and provide confidence for the infrastructure investors by reducing revenue risks. Indicatively, in its market test for the Belgian hydrogen network, Fluxys calls for long term subscriptions to be able to take a final investment decision [45]. From the side of **prospective shippers**, there **appears to be preference for shorter-term commitments**. In the Netherlands, during the market consultation stakeholders expressed preference to contracts of 5 – 10 years [46] (producers showed preference for 10-year contracts and consumers to 5-year contracts).

Access to storage is important for ensuring supply flexibility and sufficiency, especially as hydrogen demand is increasing. France, Italy and the Netherlands, that are seeking to become hydrogen transit countries, have already included development of underground storages in their hydrogen network planning. Belgium, that has limited potential for storing hydrogen in its underground storages, is looking at a European approach for storage. As part of developing hydrogen infrastructure, it is therefore critical to consider the **establishment of pipeline routes that will connect hydrogen supply with storage and consumption centres, on a national or regional level**.

An aspect of hydrogen network planning that is not examined in detail by the strategies and development plans of the EU Member States reviewed, is how **transitioning from blue to green hydrogen** would impact the developed transmission infrastructure. In countries that aim to establish blue hydrogen production as an interim step towards decarbonisation, it has to be ensured that infrastructure linking production with consumption can have future accessibility to green hydrogen supplies, otherwise once blue hydrogen phases out there is a risk of the infrastructure being underutilized or stranded.

Taking into consideration the analysis above, **key elements** for the **development of hydrogen infrastructure** are outlined in the Table below.

Table 10: Key elements for hydrogen infrastructure development

Element	Description
Network sizing and roll-out	Hydrogen infrastructure should be expanded progressively to match the demand needs with the available supplies, at the particular phase of the hydrogen market development. The size of the network may seek to address not just short-term market needs but also mid-term (5 to 10 years) anticipated demand and transit needs.
Long-term commitments of shippers	Binding commitments of prospective shippers (consumers and/or suppliers) are necessary to ensure that the developed infrastructure will be utilized. Market consultations gauge initial interest, that can then result in capacity contracting. The market testing process should include all beneficiary countries, so as to identify entry and exit flows. Commitments of market

	participants should be long-term to provide certainty for the use of the developed infrastructure.
Hydrogen flow direction	Hydrogen flows, and the corresponding infrastructure needs, depend on whether the country is a net importer, exporter, or transit. If hydrogen demand in an EU Member State cannot be met with in-country production, interconnections are necessary to transport hydrogen produced in other Member States or landing at the EU from third countries.
Timing	Infrastructure development to accommodate cross-border flows should be synchronized in the involved countries. Supply and transmission infrastructure be in place in time to transport hydrogen to the receiving country when demand needs arise.
Exploitation of existing natural gas assets	Repurposing of natural gas infrastructure, where possible, can reduce costs for transporting hydrogen, and expedite availability of transmission infrastructure. Repurposing should not impact the security and continuity of natural gas supply to final consumers, until natural gas is phased out.
Access to storage	Hydrogen storage facilities should be developed to provide flexibility and security of supply. For countries with limited storage potential the development of regional storage in neighbouring countries could be considered.
Continuity of infrastructure utilization	Planning of infrastructure dedicated to blue hydrogen has the risk of becoming a stranded asset once the market transitions to green hydrogen. Planning of infrastructure, in case blue hydrogen is to be used as a transition fuel, should take into consideration the subsequent availability of green hydrogen supplies.

3.2.4 Matching market needs with infrastructure development

Based on the practices observed in the selected countries (discussed in Section 3.1.5), matching hydrogen market needs with infrastructure development, is a **five-step process** starting from the hydrogen demand and supply targets set by the Government, followed by market consultations to identify future hydrogen infrastructure needs, which is then followed by market tests, including a non-binding and a binding phase. The commitments that result from the latter indicate the market interest-based hydrogen infrastructure projects that will enter the last phase of implementation, i.e., construction and commissioning. Figure 12 presents this stepwise process.

Figure 12: Stepwise process for matching hydrogen market needs with infrastructure development

	1 Initiation	2 Market consultation	3 Non-binding EoI phase	4 Binding commitment phase	5 Implementation
What	• Targets for hydrogen supply and demand set by the Government • MoUs signed with countries to cooperate on hydrogen projects • Pre-feasibility studies (for national network and/or cross-border interconnections) conducted by the TSOs	Market consultations to identify future hydrogen infrastructure needs based on expected hydrogen demand and supply	Non-binding EoI phase calling for future hydrogen infrastructure users to express their interest in hydrogen infrastructure in a specific region within the country or for cross border infrastructure	Binding commitment phase is calling for future hydrogen infrastructure users to sign binding contracts for accessing the infrastructure. The technical design with associated timing for start of operations, the terms and conditions for the provided services and the relevant tariffs will be specified	Construction and commissioning of the hydrogen infrastructure by the TSO according to the technical characteristics and timing agreed upon during the EoI process
Who	• Government • TSOs	• TSOs • Producers and consumers • Public/institutional stakeholders	• TSOs • Producers and consumers • Regulator	• TSOs • Producers and consumers • Regulator	TSOs

Looking at the discrete steps in more detail, the **initiation** step starts when **targets for hydrogen supply and demand are set** by strategies/roadmaps launched by a country's Government/pertinent Ministry. The strategies/roadmaps may be built based on a consultation process with relevant stakeholders, e.g., in the form of a non-binding EoI process involving companies, local authorities and R&D centres. In parallel (as reported in many of the reviewed countries hydrogen strategies), the country signs MoUs with other countries in order to jointly develop hydrogen production and transportation projects. In the context of this phase, the Government/relevant Ministry requests the countries TSOs, either exclusively the gas TSO[28]/hydrogen TSO or in cooperation with electricity TSOs, to conduct pre-feasibility studies to identify potential scenarios for the country's future hydrogen backbone. These pre-feasibility studies may also concern cross-border infrastructure and in this case the cooperation of the national TSO(s) with the TSOs of neighbouring countries is needed.

In the second step, that of **market consultation***,* **hydrogen production and demand consultation(s) are conducted by the country's TSO(s)**, to identify current and future hydrogen projects in the country and adjacent projects in neighbouring countries. Such a consultation may for example be part of the TSO's planning process, or requested by the Government to undertake the development of the country's hydrogen backbone. The market consultations are open to potential hydrogen producers / suppliers / importers and end-users, as well as to public and institutional stakeholders, associations, infrastructure operators and academic experts[29]. The purpose of this step is to:

[28] Or a subsidiary of the gas TSO or the parent company of the gas TSO

[29] The French TSOs' market consultation had the following participation: Industry: 44%, Energy shippers / suppliers / traders / producers / energy infrastructure operators: 26%, Public / Institutional / Local authority Stakeholders: 16%, Engineering companies / consultancies / research organizations / Suppliers of equipment or technological solutions: 10%, Transporters: goods / passengers: 4%. Of the industrial participants, 56% were hydrogen consumers only, 27% were consumers and producers, 2% were producers only and 15% were neither producers nor consumers. Of the public stakeholder respondents 76% were consumers and producers, 14% were neither producers nor consumers, 5% were producers only and 5% were consumers only. Of the energy business respondents 63% were consumers and producers, 20% were producers only, 11% were neither

- understand the **needs for hydrogen infrastructure**, and
- to collect **feedback** on the TSO(s)' proposed infrastructure design and timing for implementation, services to be offered, contractual framework and tariff methodology principles for the construction and operation of the country's hydrogen backbone.

The consultations may start as a **nationwide and/or cross-border** (in cooperation with neighbouring countries) processes and progress in subsequent regional consultations based on the identified needs. The process of these consultations may entail a kick-off webinar, followed by online documents/platforms where interested parties can indicate their plans to use the future hydrogen backbone and provide their feedback. Another format for future infrastructure users to express their interest is through online platforms, where they can log their future production/offtaken volumes and be able to follow the evolution of expressions of interest on the country's/region's maps. The TSOs may also facilitate bilateral interactions between potential hydrogen suppliers and offtakers and/or engage themselves in one-to-one conversations with future key players.

The process of market consultation can be repeated on an annual or bi-annual basis to continuously receive feedback on the market participants' infrastructure needs. The outcomes of the market consultations **feed updated modelling/feasibility studies** delivered by the country's TSO(s), including the needs for repurposing existing natural gas infrastructure and constructing new hydrogen pipelines. According to ACER & CEER [47], the repurposing on existing natural gas infrastructure "*should be assessed on a case-by-case basis by cost benefit analyses (CBAs)*" and "*as a first step, the role of the National Development Plans (NDPs) of gas network operators could be extended to identify also assets that could be converted to hydrogen*"[30].

Following the market consultation, in the third step, **the TSO launches EoIs**, calling on stakeholders to **express their non-binding interest in hydrogen infrastructure in a specific region within the country or for cross-border infrastructure** in coordination with a TSO from a neighbouring country. At the **non-binding EoI phase** respondents are invited to express their interest based on documentation presented to them including an *"Information Memorandum"* informing them of the whole EoI process and an "*Infrastructure Proposal*", showing them the TSO's indicative plans for the development of the infrastructure. The information requested by the participants could include: expected operations start date, expected date when binding commitment is possible, locations of entry or exit to the hydrogen network, hourly capacities (peak) and yearly volumes of hydrogen supplied/offtaken, daily/seasonal usage profile, pressure requirements, etc[31]. The non-binding phase may be followed by **bilateral iterations**, where the TSO will engage in further discussions with parties having submitted the EoI to

producers nor consumers and 6% were consumers only. The Dutch market consultation had in total 58 participants and 31% were consumers and producers (from the following sectors: storage, import, port operator, trading, chemicals, refineries, steel, oil & gas), 19% were producers (from the following sectors: offshore wind, offshore gas transport, power, energy) and the remaining 50% were users only (from the following industries: steel, glass, aluminum, manufacturing, food, chemicals, paper).

[30] In Germany, by late 2021, the promoters of more than 250 projects with a total demand of 165 TWh had concluded memoranda of understanding MOUs with the corresponding TSOs. The signing of a MoU was a prerequisite for the projects to be included in the 2022-2032 Gas Network Development Plan.

[31] At the non-binding call for interest by GRTgaz and Fluxys for Belgium-France cross-border hydrogen infrastructure 17 companies expressed an interest in connecting their production or consumption site to the proposed transmission network, for production capacity ranging from 300 to 600 MW and an associated hydrogen consumption of between 1.5 and 3 TWh/year.

further align on the necessary dimensioning of the network and the according capacity, the timing and phases, the offered services and the terms and conditions. During the non-binding phase, the TSO may propose a non-discriminatory tariff structure and be able to disclose indicative tariff for every specific connection proposal. The Regulator, if its mandate requires it, will ultimately define the tariff structure and access rules for new and repurposed hydrogen pipelines. To ensure participation in the EoI only of parties keen to proceed with the development of hydrogen supply chains, the TSO may require participants to provide guarantees for taking part in the process.

The fourth step, the **binding commitment phase**, calls stakeholders to commit to their future needs for hydrogen infrastructure use for a specific technical design with associated timing for start of operations and terms and conditions. Capacity commitments should be long-term, to ensure utilization of the infrastructure under development.

The binding commitments are the final step of this process towards the fifth, **implementation,** step. Nevertheless, to proceed with construction of the hydrogen network (repurposed and new) the TSO would need to secure financing of the project that in addition to the long-term payments of booked capacity through such open seasons can also include other funding sources such as subsidies, use of system tariffs, etc.

4 Technoeconomic assessment of hydrogen infrastructure

In order to formulate contextualized recommendations to ENTSOG's proposed hydrogen CBA Methodology, it is important to delve into several elements that are to be taken into account for the technoeconomic assessment of hydrogen infrastructure. This Section investigates how the reviewed literature elaborates on the assessment and analysis of hydrogen infrastructure costs and benefits. Furthermore, the use of modelling to capture the cross-sectoral interlinkages of hydrogen, electricity and gas is reviewed. Lastly, the use of methodological elements in literature, related to conducting a CBA for hydrogen infrastructure, is explored, including the selection of the proper economic performance indicators, the value of the social discount rate, the importance of the project commission date, the length of the assessment period, the treatment of the residual value and the parameters to be used for the conduction of the sensitivity analysis.

4.1 Assessment of hydrogen infrastructure costs and negative externalities

4.1.1 Investment costs

The **investment cost elements of hydrogen pipelines and storages are the same with those of natural gas**. Therefore, the disaggregation of CAPEX for new hydrogen infrastructure projects would not differ from that of natural gas projects (for example a hydrogen pipeline investment costs would entail pipe and compressor capital costs [48]). However, as the compression needs of hydrogen are different than that of natural gas [8], **the additional compressors required should be taken into consideration when designing the investment costs of a hydrogen project**.

The unit investment costs for hydrogen infrastructure reported in public sources vary considerably. The study carried out in 2020 by Guidehouse and Tractebel on behalf of the EC [17], which provides an overview of costs for hydrogen transmission, indicates that the cost of a new dedicated hydrogen pipeline, with 48 inches diameter, may range from 2.01 to 3.28 mil. EUR/km. **To capture this uncertainty in investment costs when carrying out a CBA for a hydrogen project, sensitivity analysis on the CAPEX provided by the project promoter is required**, so as to ensure the robustness of the economic results.

Projects that entail **natural gas infrastructure repurposing need to consider appropriate CAPEX and OPEX implications**. As retrofitting of natural gas compressors is not efficient [19], investments should include **costs for new dedicated hydrogen compressors**, together with **new metering equipment**. Beyond the investments required for the repurposing itself, the DNV study on future regulatory decisions on natural gas networks [49] identifies additional indirect costs, associated with the **potential strengthening of the natural gas infrastructure, transfer of assets from a natural gas to a hydrogen network operator**, as well as **costs and externalities related to the discontinuation of the networking services** to any natural gas network users that continue to be connected to the grid. The costs identified by DNV may include:

- Costs arising from separation of assets and organizations, and related to the transfer.
- The asset transfer value.
- Possible costs of a disconnection of existing gas users.

- Possible cost for enhancing the rest of the natural gas transmission system.
- Implications on security and reliability of supply for residual natural gas network users.

4.1.2 Operating expenses

The **level of O&M costs of hydrogen infrastructure are not the same with those of natural gas**. The increased risk of leakage for hydrogen [50], results in **additional surveillance and maintenance needs**, and **more frequent replacement of valves, flanges, seals, and other equipment** to reduce the probability of hydrogen leaks. The additional compressing needs also result in higher operation costs for the compressors.

For repurposed pipelines O&M costs should also account for the **additional needs for integrity assessment and risk management**, due to the increased material degradation and risk of steel embrittlement [37].

4.1.3 Negative externalities

The **construction and operation of hydrogen infrastructure would have similar negative externalities to other types of energy infrastructure**, such as land use and aesthetic loss, noise from construction and equipment operation, impact to ecosystems, etc. However, such issues, or any other potential negative externalities specific to hydrogen infrastructure, are not discussed in the reviewed literature.

There are **safety considerations for hydrogen**, compared to other fuels, due to higher leak risks and flammability [48]. To address the safety issues, the reviewed studies factor in **increased OPEX, compared to natural gas**, for monitoring and maintenance [2], to minimize any risks of accident, and do not include any potential externalities.

The quantification of the **impact of fugitive hydrogen** is still being discussed in literature [51]. When out in the atmosphere, hydrogen reacts with hydroxyl radicals and decreases their concentration and effectiveness as a cleansing agent for many GHGs and pollutants [52]. As such, hydrogen impacts GHG emissions by slowing down the progress of removing them from the atmosphere.

4.2 Assessment of hydrogen benefits

4.2.1 Types of benefits identified in literature

Only few of the documents reviewed include methodological approaches for appraising the benefits of individual hydrogen infrastructure projects; namely the JRC CBA for candidate hydrogen projects [53], and the EC study, carried out by Trinomics and Artelys, for measuring the contribution of gas infrastructure projects to sustainability as defined in the TEN-E Regulation [54]. In other studies examined, as described further in this Section, potential benefits of hydrogen infrastructure are only identified qualitatively, or are assessed implicitly, within the frame of comparing alternative decarbonization scenarios / pathways and of identifying optimal hydrogen planning options, on an EU-wide level, for the achieving a net-zero emissions EU energy system by 2050. Nevertheless, the approaches and elements considered for the impact of hydrogen uptake in these studies can provide insights when assessing project-specific benefits of hydrogen investment projects.

The **benefits of hydrogen infrastructure development that can be identified in the literature** (regardless of whether they are monetized or assessed either quantitatively or qualitatively) are mainly associated with **sustainability, cost savings from fuel switching to hydrogen, power-gas sector coupling and infrastructure optimization, and strengthening security of energy supply**. These benefits are outlined in the Table below.

Table 11: Benefits of hydrogen infrastructure identified in literature[32,33]

Benefit	Type of assessment	Sources
Reduction of GHG emissions	Quantitative / monetization	[53, 54]
Reduction of energy costs	Monetization	[21, 53]
Strengthening power system flexibility and stability	Quantitative / monetization	[5, 56]
Security of supply	Quantitative / Qualitative	[12, 53]
Cost effectiveness of repurposing natural gas infrastructure	Monetization	[49]
Societal acceptance of hydrogen infrastructure	Qualitative	[2, 8]

4.2.2 Reduction of GHG emissions

Reduction of GHG emissions is one of the main benefits that needs to be taken into account when assessing hydrogen infrastructure projects. There are, however, only limited methodologies in the reviewed literature, described below, that directly address project-specific impact on GHG emission savings. Instead, most studies assess the impact of the overall energy infrastructure to reducing emissions towards the zero-carbon goal, but do not allocate these reductions to infrastructure projects.

JRC includes in its draft CBA methodology [53] a **monetized indicator** assessing the variation of GHG emissions. Application of this indicator involves:

- **Calculation of the GHG emissions' savings** achievable thanks to the assessed hydrogen project from the increase of low-carbon and renewable hydrogen deployed in the system (calculation of GHG emissions with and without the assessed project).
- Monetization of GHG emissions' savings using a **social cost (shadow cost) of carbon**.

According to JRC, GHG emissions assessed in the calculations should include emissions caused directly by the project, and indirect emissions resulting from energy consumption. All other indirect emissions caused along the whole value chain are not considered. These **indirect emissions can be of particular importance especially if the project is to initially transport blue hydrogen**, due to the methane emissions in the natural gas supply chain [57].

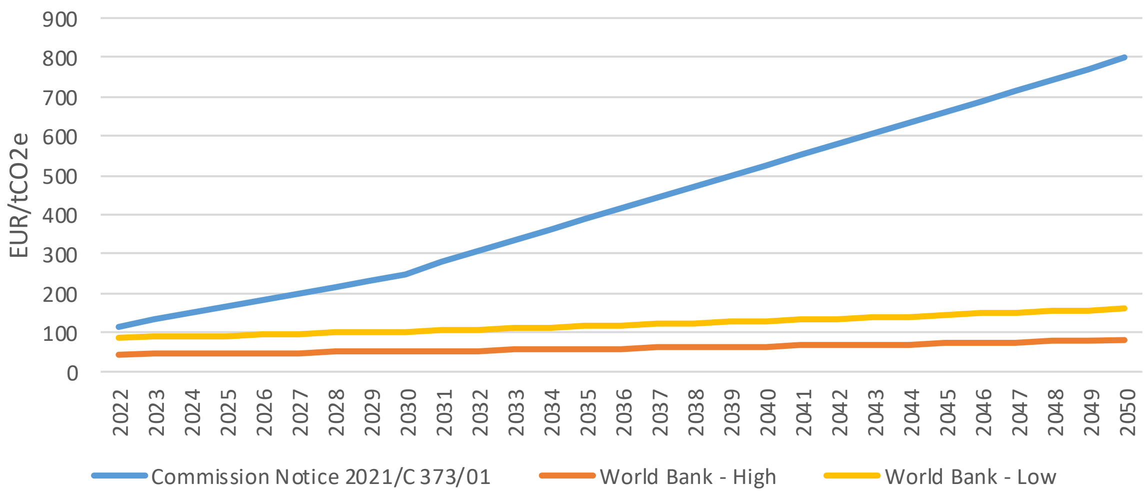
To calculate the GHG emissions JRC suggests using the EIB Project Carbon Footprint Methodology [58], in line with the Commission technical guidance on climate proofing of infrastructure (Commission

[32] Job creation in the hydrogen sector is also identified as a potential benefit [17]. However, such a benefit is usually assessed for projects with national or local/regional impact, and is thus not listed in the Table.
[33] National Grid provides a framework for monetizing asset deterioration risks, and assess the impact of investments reducing these risks. Such investments are primarily related to system rehabilitation, refurbishment and maintenance CAPEX and thus appropriate for a national investment appraisal framework, but are not relevant to the discussion on assessing new or repurposed hydrogen pipelines with regional impact.

Notice 2021/C 373/01) [59], or justify the use of any other source of emissions' benchmarks. For sourcing the evolution of shadow costs of carbon, JRC proposes the use, where applicable, of carbon values in Tables 5 and 6 of Commission Notice 2021/C 373/01.

It has to be noted that **there is a large discrepancy in the foreseen evolution of the shadow cost of carbon from different sources**. Indicatively, the 2050 estimated shadow cost in the Commission Notice 2021/C 373/01 (using costs calculated by EIB) is over 5 times higher than the high scenario recommended by the World Bank in its shadow price of carbon in economic analysis guidance note [60] (Figure 13). Both the World Bank and EIB calculate shadow cost of carbon aiming to meet the Paris Agreement target of 1.5°C reduction by 2050, however the two institutions apply different methodologies to derive the price evolution[34].

Figure 13: EC and World Bank evolution of shadow cost of carbon[35]



Sources: Commission technical guidance on climate proofing of infrastructure, World Bank in its shadow price of carbon in economic analysis guidance note

Given these differences, **the source used for shadow costs plays a decisive role in the economic feasibility results** of the assessed projects. **Extensive sensitivity analyses on shadow costs should be considered** when conducting CBA analysis, to avoid distortion of economic indicators' results due to an overestimation of the savings from GHG reduction.

Another document analysing the emission reduction benefit is the Trinomics and Artelys study [54], performed for the EC, which elaborates on how CO2 emission savings of gas infrastructure projects[36] can be quantified (monetization of these CO2 savings is not discussed). The rationale of quantification

[34] The World Bank is using a basis the carbon prices estimated by the Carbon Pricing Leadership Coalition in the "Report of the High-Level Commission on Carbon Prices" (2017) until 2030, and is applying a 2.25% annual growth rate for the period 2030 – 2050. The EIB is using the results of selected models from the IAMC (Integrated Assessment Model Consortium) database, that are consistent with the 1.5˚C target.

[35] The Commission Notice 2021/C 373/01 presents carbon prices in 2016 prices, whereas the World Bank guidance note uses 2017 prices. The prices from the two sources are comparable, given the 1-year difference between them. USD prices are converted to EUR using an exchange rate of 0.94 USD/EUR.

[36] The study was carried out prior to the recast TEN-E Regulation, and focuses primarily on the impact of natural gas projects on sustainability, but also expands on renewable and low-carbon gases.

is similar to that proposed by JRC, i.e., computation, with and without the assessed project, of the gas use increase, due to fuel switching, and the corresponding change in CO2 emissions.

The study suggests using the same calculation as with CO2, to evaluate the effects of fuel switching on emissions of other, non-GHG, gases (NOx, SO2). However, as the emission factors greatly differ depending on the use of the fuel, it is suggested that ENTSO-E and ENTSOG construct, for their TYNDP works, a joint database of emissions factors of non-GHG, with a decomposition by fuel and by sector and sub-sector and by country.

The study highlights the **need to use an interlinked model to identify cross-sectoral CO2 savings**. According to the study, to effectively capture the links between gas and electricity and measure CO2 impacts with and without the assessed project, the interlinked model should have an hourly time resolution, and have a detailed representation of the electricity generation sector (age classes of assets, RES integration, etc.).

The proposed methodology also examines the methane emissions resulting from the assessed gas projects. Due to the complexity of estimating the total methane emissions caused by the changes in gas flows within the European system resulting from the assessed project, it is proposed to limit the estimate to methane emissions at a national level:

- Use the IEA methane emissions tracker [62] (or a similar source) to obtain the volume of methane emissions from downstream gas for each country (for the latest year available).
- Divide these methane emissions by the gas consumption in the country during the same year.
- Multiply this methane emission factor by the level of gas consumption allocated to the assessed infrastructure projects.

Although methane emissions (a particular potent greenhouse gas) are not relevant to hydrogen infrastructure projects, **the environmental benefit from reducing emissions of fugitive and vented methane in natural gas infrastructure due to switching to hydrogen, could be assessed** using an approach similar to that described above. It is noted that if such a benefit is to be examined, the impact of fugitive hydrogen originating from the new infrastructure project should also be factored in, to fully capture the impact of replacing natural gas with hydrogen.

The Trinomics – LBST study [7], prepared for the EC, is also assessing cost savings due to emission reduction. In this study the CO2 emission avoidance costs are calculated for different storylines of power, hydrogen and biomethane evolution. The calculation is carried out in the model used (further described in Section 4.3.3), by estimating the energy system costs with and without CO2 costs for each storyline.

4.2.3 Reduction of energy costs

The **potential reductions in energy costs, resulting from the substitution of other energy vectors with renewable and/or low carbon hydrogen, is a benefit of hydrogen** uptake that is monetized in the reviewed literature.

JRC, in its draft CBA methodology [53], considers fuel cost savings stemming from the switching from alternative fuels with hydrogen, as part of a hydrogen project's benefits. The benefit is **monetized** by **comparing the total costs of hydrogen and alternative fuels**, with and without the hydrogen project being assessed, taking into consideration the quantity used and the unit price of each fuel. The assessment does not determine the specific sectors on which the analysis and fuel replacement should focus on.

Key inputs required in this assessment are the expected volumes of alternative fuels being substituted by hydrogen, and the prices of the substituted fuels and hydrogen. The JRC methodology does not specify the elements to be considered when defining the fuel and hydrogen prices, or the reports or studies that can be used for their sourcing. **When performing such an assessment**, the following principles need to be taken into account:

- The assessment should be carried out for **all expected hydrogen uses**, assessing the different costs and characteristics of each sector.
- The **price of hydrogen should include the full cost of its supply chain**, from production to end-use.
- In case a hydrogen project **is planned to transport different types of hydrogen** during the study period, then the **different costs should be accounted for** when performing the cost comparison. For example, if blue hydrogen is transported, then the CCS costs should be considered at the supply side.
- The **conversion costs at the final consumers**, to allow use of hydrogen, should be taken into consideration, together with any additional costs for using hydrogen (e.g., if hydrogen is transported via an ammonia pipeline, then the separation costs at the final consumer should be accounted for).
- Caution is required to ensure that any **carbon taxes or levies** applied in the substituted fuels, to promote hydrogen switching[37], are **not double counted** in the shadow carbon prices used to monetize the GHG emission reduction benefit.

Potential savings from the uptake of hydrogen are also calculated in studies performed by Trinomics – LBST [7], Navigant [21], Frontier [20], and Artelys [56], which analyse scenarios of the impact of renewable and low-carbon gases' use on the energy system costs. Although the focus of these studies is the holistic assessment and optimization of hydrogen planning across the EU to achieve the 2050 decarbonization target (such as the comparison of a scenario maximizing use of green gases vis-à-vis a scenario maximizing electrification for EU-28 [21]), similar **cost elements can be considered when assessing project-specific impact of hydrogen infrastructure on energy costs' savings**.

Navigant [21] and Frontier [20] calculate energy costs separately for different end-uses and infrastructure. As shown in Table 12, the sectors analysed are very similar in both studies. The cost elements per sector, for the Navigant study, are presented in Table 13.

[37] The role of carbon pricing is highlighted in literature as an essential and powerful lever *"to create incentives to develop alternatives to fossil fuel use in each of the major potential end-uses of hydrogen"* (Energy Transitions Commission [16]).

Table 12: Sectors analysed for energy system costs' calculation

Navigant study [21]	Frontier study [20]
Building heating	Space and water heating
Industrial processes	Industry – process heat
Transport (road transport, aviation, shipping)	Transport (focus on road transport)
Power sector	Electricity & gas generation/ import
Electricity infrastructure	Electricity transmission – distribution
	Gas networks

Table 13: Sectors analysed for energy system costs' calculation

Sector	Costs
Building sector heating	▪ Heating technology costs ▪ Insultation costs ▪ Energy / fuel costs
Industrial sector processes	▪ Energy / fuel costs (cost up to the final consumption) ▪ Technology costs (retrofitting costs)
Transport sector	▪ Energy / fuel costs (cost up to the final consumption) ▪ Technology costs (retrofitting costs)
Power sector	▪ Variable RES generation costs ▪ Dispatchable electricity generation costs ▪ (Costs allocated to the building, industrial and transport sectors are excluded to avoid double-counting of savings)
Energy infrastructure	▪ Costs to integrate biomethane in existing gas grids ▪ Costs for hydrogen integration, transport, distribution and storage ▪ Costs for new electricity infrastructure

The Trinomics – LBST [7] and the Artelys [56] studies analyse energy system costs from the point of view of costs for energy supply from various sources and for energy infrastructure. Costs are examined for dispatchable generation, RES, storage (batteries, PtG, pumped storage), energy supply, investment and operational costs of power and gas infrastructure.

In all the studies discussed above, the calculated energy system costs result from the use of interlinked models that simulate jointly the electricity, hydrogen and gas sectors. It therefore becomes **evident from literature that linking the energy sectors to assess a hydrogen infrastructure project is necessary to capture its sector-coupling impacts on energy system costs**. Using a stand-alone hydrogen model is meaningful only if hydrogen supply and demand is fully separate from use and infrastructure of electricity, as for example in the no-regret hydrogen study by Agora [14], that assumes hydrogen consumption only by industrial consumers as chemical feedstock and reaction agents, and therefore there is no interaction with the electricity sector.

4.2.4 Strengthening power system flexibility and stability

The **use of hydrogen as a means to store energy can enhance the flexibility and stability of power systems relying on RES**. The paper by Di Wu et al. [5], performing a techno-economic assessment of using hydrogen as an energy storage medium, has identified benefits that may be used to assess a combined hydrogen production, transportation and storage system, together with electricity re-generation[38]:

- **Reduction of costs for ancillary services**
- **Reduction of peak capacity needs**, reducing costs deriving from capacity payment mechanisms
- **Optimization of investment requirements** for electricity transmission and distribution system upgrade, by reducing peak loads

The contribution of hydrogen infrastructure is also assessed in the Artelys study on costs and benefits of a pan-European hydrogen infrastructure [56], using the simulation results of the METIS model (use of the METIS model is discussed further in Section 4.3.1). The calculation uses the hourly resolution of the model, to calculate daily, weekly and seasonal residual loads, which are then allocated to the different storage technologies (electrolysers, batteries, EVs, pumped storage).

4.2.5 Strengthening security of energy supply

JRC, in its draft CBA methodology [53], assesses a hydrogen project's impact on security of supply by evaluating the extent to which it reduces curtailed hydrogen demand. Quantification is carried out by comparing **hydrogen demand curtailment** with and without the project, and monetization by applying a cost of hydrogen disruption.

Although security of supply and reduction of dependence from other fuels is a benefit indicated by some studies and papers [4, 12, 15, 20], none of the reviewed documents includes any quantification or monetization of hydrogen infrastructure's impact on the energy system's security of supply.

4.2.6 Cost effectiveness of repurposing natural gas infrastructure

DNV, in its study on future regulatory decisions on natural gas networks [49], identifies **potential benefits in repurposing gas network assets compared to continuing their operation** with no or very limited gas flows. Such benefits may arise from avoiding assets becoming stranded and/or from optimizing hydrogen infrastructure development if repurposing is more cost effective than building a new dedicated hydrogen asset.

The option of proceeding with the repurposing of an asset, even if there is still a small residual utilization by natural gas end-users, is elaborated in the study. In this case, a cost-benefit analysis is proposed by DNV, to assess the net benefits of repurposing.

When using an EU-wide interlinked model to assess projects, normally net benefits relating to repurposing vis-à-vis continuing operation of natural gas infrastructure would be captured, at least to

[38] The paper considers additional benefits for hydrogen energy storage, which however require hydrogen production directly by end-users, such as reduction of peak loads, participation in demand response.

an extent[39], in the calculation of the energy system costs with and without the repurposed transmission project. A more thorough analysis of the repurposing benefits would be meaningful only on a national level (e.g., as part of the natural gas transmission network development plan as proposed in the DNV study [49]), to assess within country flows and routes, and compare the alternatives of repurposing vs developing new hydrogen assets.

This benefit should be taken into consideration when comparing solutions for developing hydrogen infrastructure, to decide the least-cost option. Within the scope of ENTSOG's TYNDP and PCI selection, any considerations related to this benefit will already be internalized in the costs of the selected solution, and therefore no additional assessment should be considered.

4.2.7 Societal acceptance of hydrogen infrastructure

The European Hydrogen Backbone initiative [8] and a study on the value of gas infrastructure [20] identify a benefit of **improved societal acceptance for using gas infrastructure to transport hydrogen, as opposed to building new electricity transmission and distribution lines** to meet the decarbonization targets via electrification. The rationale of this benefit is that to transport the same amount of energy with a single underground gas pipeline, multiple overhead high voltage direct current (HVDC) or high voltage alternating current (HVAC) transmission lines, and therefore using repurposed gas pipelines can raise less environmental and land use concerns compared to having to build several power transmission lines. An alternative would be to construct underground power lines, which increases costs considerably [8].

This benefit **focuses particularly on the qualitative comparison of hydrogen uptake vis-à-vis further electrification** to reach the net-zero carbon goal. Its effectiveness in assessing benefits of a specific hydrogen project is limited, and the impact on associated costs is already captured when assessing potential savings in energy system costs (Section 4.2.3).

4.3 Power and gases interlinkage modelling

The reviewed documents include **studies that involved the use of interlinked gas, hydrogen and electricity models**, applied to examine the impact of alternative decarbonization pathways or the potential future investment requirements for hydrogen infrastructure:

- A study by Artelys [56], prepared for the EC, used the METIS model to assess the impact of regulatory measures on the development of cross-border hydrogen capacity. The inputs and assumptions of the model are described in Section 4.3.1.
- Another study performed by Artelys on behalf of the European Climate Foundation [13] uses an interlinked model ("*Artelys Crystal Super Grid*") to assess future EU energy infrastructure needs in order to meet the European decarbonization targets. The inputs and assumptions of the model are described in Section 4.3.2.

[39] With an EU-wide modelling approach, high-level cost savings due to redirecting natural gas flows and introducing new hydrogen supplies, as well as security of supply impacts, such as curtailed demand of natural gas in the market, may be identified. However, localized impacts, such as covering the energy need of existing natural gas end-users in a specific area of the country, by alternative routes within the country or by promoting switching to alternative energy sources, cannot be efficiently simulated.

- The Trinomics – LBST study [7] applies a dedicated modelling tool to analyse the contribution of biomethane and hydrogen to the decarbonisation of the EU energy system, and the associated impacts on gas infrastructure. The inputs and assumptions of the model are described in Section 4.3.3.

The no-regret hydrogen study by Agora [14] also includes modelling in its analysis. However, contrary to the other studies that are modelling sector coupling and interlinkages between hydrogen and electricity infrastructure, this study considers the hydrogen system in isolation from the electricity system. This is due to the study's main assumption that hydrogen will be produced by dedicated RES and will be consumed only by industrial consumers as chemical feedstock and reaction agents.

4.3.1 Inputs and assumptions used by Artelys in the METIS model

The METIS model was used in this study [56] to optimize investments in electricity, gas and hydrogen, covering supply, storage and cross-border capacities. Final demand was an input to be model. The analysis was carried out in hourly time resolution, for the year 2030.

The METIS model:

- Receives as inputs installed capacities of different power generation, technical and economical characteristics of different energy supply and consumption technologies, projections of end-use demand, infrastructure capacity, investments and costs, and CO2 and energy commodity prices.
- Provides as outputs required investments in electricity, gas and hydrogen pipelines, hydrogen and biomethane production, energy storages and gas-to-power capacity, as well as operational management of the power and gas systems (hourly dispatch, flows).

Demand and main assumptions are based on the Commission's MIX H2 PRIMES scenario for 2030, including fuel prices, electricity generation capacities, final energy demand structure (power, gas and hydrogen demand). The carbon price used amounts to 45.5 EUR/tCO2.

Only green hydrogen, indigenously produced in the EU, is simulated (no imports and no production of blue or grey hydrogen is assessed).

Three major infrastructure scenarios are assessed in the model:

- A business-as-usual scenario, that assumes no cross-border hydrogen capacities (this is used as the baseline for comparison with the other scenarios).
- A scenario using the 2030 cross-border hydrogen capacities published by the European Hydrogen Backbone in 2021. Two variants of this scenario are assessed, one allowing further extension of cross-border capacity if needed, and the other restricting it.
- A scenario assuming the capacities included in the 2035 vision of the European Hydrogen Backbone, which may be further extended by the model if necessary.

The model decides whether additional hydrogen capacity is needed, and if this additional capacity shall be developed by investing in repurposing or in new hydrogen pipelines.

4.3.2 Inputs and assumptions used in the Artelys Crystal Super Grid modelling

To perform this study [13], Artelys applied the "*Artelys Crystal Super Grid*" software, which uses the same inputs and outputs as the METIS model, described in Section 4.3.1.

The base demand scenario used was the Commission's long-term strategy 1.5TECH scenario. As sensitivities, additional scenarios with different mix of RES, hydrogen and biomethane were examined.

The reference grid used by Artelys includes the electricity infrastructure of the ENTSO-E TYNDP 2018 and the low infrastructure scenario of the ENTSOG TYNDP 2018. For hydrogen infrastructure no cross-border connections are initially assumed, and the model is allowed to develop interconnections (repurposed methane or new hydrogen pipelines), and storage.

Assumptions for hydrogen infrastructure costs (pipelines and compressor stations) are based on published information by the European Hydrogen Backbone.

The commodity prices used by Artelys are based on different sources (ENTSOs' TYNPD, IEA WEO and EC scenarios), while the CO2 price is sourced from the 1.5TECH scenario (350 EUR/tCO2).

4.3.3 Inputs and assumptions of LBST interlinked modelling

The LBST model [7] simulates the transport of electricity, (bio)methane and hydrogen (other energy carriers such as coal and oil are out of scope), needed to satisfy the corresponding end-user demand in the industry, buildings and transport sectors.

Three storylines are examined, giving priority to electrification, biomethane and hydrogen respectively, aiming to achieve a GHG emissions' reduction of 49% by 2030 and 100% by 2050.

The energy prices used in the model are those of ENTSOG TYNDP 2018. The carbon price evolution assumes 84 EUR/tCO2 in 2030 (used by ENTSOG in the Sustainable Transition scenario) and 350 EUR/tCO2 in 2050, forecasted in the EC long-term strategy.

The transmission grid modelled uses the electricity transmission capacities included in ENTSO-E TYNDP 2018, and the low infrastructure scenario of ENTSOG TYNDP 2018.

4.4 Elements of cost-benefit analysis methodology

In the literature reviewed, only the JRC CBA methodology [53] provides a complete methodological framework for performing a cost-benefit analysis of hydrogen infrastructure[40]. Nevertheless, some assumptions and approaches from other reviewed documents can add value when considering specific elements of the CBA methodology.

4.4.1 Economic performance indicators

The JRC methodology [53] proposes the use of **net present value (NPV) and benefit-to-cost ratio (BCR) as the economic indicators** to assess hydrogen infrastructure projects, which are the minimum economic performance indicators stipulated in the recast TEN-E Regulation.

[40] JRC also provides a similar CBA methodology for gas smart grid projects [59].

The paper by Di Wu et al. [5] is also using BCR to compare different cases of hydrogen use and transportation (ranging from local use of hydrogen to its transportation, storage and use for power generation), to identify the economically preferred option.

Some of the studies calculating energy system costs are also using cost savings in order to compare different scenarios of hydrogen uptake. Navigant [21] is calculating the present value of cost savings in 2050, while Frontier [20] is using undiscounted cost savings in 2050. The use of cost savings (discounted or undiscounted) is not sufficient by itself to fully assess the costs and benefits of hydrogen projects, and thus cannot be applied as stand-alone indicators in a CBA methodological framework.

4.4.2 Social discount rate

In the few documents that assess the societal impact of hydrogen uptake and investments[41], **the social discount rates used vary**:

- The JRC methodology [53] proposes the use of 4% discount rate, in line with the value currently assumed for other PCI energy infrastructure categories.
- Trinomics – LBST [7] is applying a 3% social discount rate, which they justify as being in line with the average rate for a conservative gross domestic product (GDP) growth of 1% in Europe.
- Navigant [21] is applying a 5% social discount rate, which they justify as being in line with the EC Annex III to the Implementing Regulation on application form and CBA methodology[42], that recommends a 5% discount rate for Cohesion EU Member States and a 3% discount rate for other EU Member States.
- The paper by Di Wu et al. [5] uses a discount rate of 8% to perform economic analysis, without however providing the rationale for this value. It is noted that this analysis that does not have a specific geographical scope and thus does not capture the macroeconomic situation in of a particular region or country.

As shown above, the **studies and methodologies carried out within the EU context use social discount rates in the range of 3% to 5%**.

4.4.3 Project commissioning

The commissioning date of hydrogen projects provided by project promoters, affects both the annual split of investment costs, and the year at which the project starts providing net benefits.

The reviewed literature does not provide timelines for the implementation of hydrogen infrastructure, or treatment of project commissioning dates. Nevertheless, Mijndert van der Spek et al. [3] highlight the issue of public acceptance as a potential barrier for large-scale deployment of hydrogen. The **lack of acceptance may result in significant delays to the expected commissioning date of hydrogen projects**, and therefore affect the time at which benefits can be provided. To **address the uncertainty**

[41] Most of the studies reviewed that analyse costs, focus on the minimization of investments, and thus calculate discounted cash flows by assuming a financial discount rate or weighted average cost of capital.
[42] Article 2.3.1 of Annex III of the Commission Implementing Regulation (EU) 2015/207 of 20 January 2015

in the hydrogen projects' implementation, **sensitivity analysis could be performed** on their commissioning year, to examine the impact of delays on the projects' economic viability.

4.4.4 Assessment period and residual value

The JRC methodology [53] uses as an **assessment period the minimum between the longest technical lifetime of any equipment and 25 years**[43]. The methodology does not explicitly describe how residual value of the assessed projects should be treated.

The PWC study [2] on developing hydrogen transmission in the Netherlands uses a **30-year assessment period** and depreciation period for hydrogen assets, thereby not assuming any residual value. The Navigant study [21], that examines the year 2050, is also assuming **depreciation of 30 years**.

Concerning the **technical lifetime of hydrogen assets, information is not consistent** in all the documents reviewed, as shown in Table 14.

Table 14: Lifetime of hydrogen assets in literature

Type of asset	Technical Lifetime	Source
Hydrogen pipeline	50 years	[39, 50]
	42.5 years[44]	[13]
Hydrogen compressor	15 years	[50]
	20 years	[39]
	24 years[45]	[13]
Underground hydrogen storage	30 years	[14]
	40 years	[39]
Ammonia and methanol pipelines	40 years	[39]
Liquefaction	20 years[46]	[39]

4.4.5 Sensitivity analysis

The JRC methodology [53] does not foresee the performance of sensitivity analysis to assess the robustness of the economic indicators' results. Sensitivity analysis is performed to a limited extent in the rest of the reviewed literature. **Analysis of the results' sensitivities on selected parameters is performed** in some of the studies, however these are limited and different for each study:

[43] According to JRC: *"…b) the maximum reference period for energy projects as referred to in Article 15(2) and Annex I to Commission Delegated Regulation (EU) No 480/2014."*, which corresponds to 25 years.
[44] Using the average depreciation period for pipelines presented in the European Hydrogen Backbone "How a dedicated hydrogen infrastructure can be created" (July) 2020, which indicates a range between 30 and 55 years
[45] Using the average depreciation period for pipelines presented in the European Hydrogen Backbone "How a dedicated hydrogen infrastructure can be created" (July) 2020, which indicates a range between 15 and 33 years
[46] JRC [39] considers liquefaction as an "unproven technology" and assumes a lifetime of 20 years.

- Trinomics – LBST [7] performs sensitivity analysis on hydrogen production costs, carbon price, natural gas price and biomethane production costs.
- Navigant [21] examines sensitivities with different natural gas prices, to test the competitiveness of green hydrogen.
- Artelys, in its analysis on behalf of the European Climate Foundation [13], performs sensitivity analyses with respect to hydrogen demand levels, bio-methane supply, and wider use of direct electrification to supply low-temperature heat.
- Artelys, in its METIS study on costs and benefits of a pan-European hydrogen infrastructure [56], assesses the sensitivities of results when changing the hydrogen production parameters (reduction of electrolyser minimum capacity, change in electricity supply modalities) and variation in the pipeline CAPEX.

The parameters on which sensitivity is performed in each study are tailored to the needs of the particular assessment and do not cover fully the requirements of a sensitivity analysis for a CBA. To assess the robustness of a CBA for hydrogen projects, **sensitivity analysis should be performed on parameters that encapsulate uncertainties related to the implementation and impact of the assessed infrastructure**, such as investment costs, carbon prices, and project commissioning.

5 Review of past ENTSOs' CBA Methodologies

The hydrogen CBA Methodology proposed by ENTSOG should take into consideration, where relevant, comments and recommendations made by ACER and the Commission in its previous CBA methodologies (that concerned natural gas infrastructure). Furthermore, the CBA methodologies of both ENTSOs should be consistent, taking into account sectorial specificities, as required in Annex V of the recast TEN-E Regulation.

This Section identifies **comments and recommendations by ACER and the Commission which were partially covered, or not addressed** by both ENTSOG and ENTSO-E in subsequent versions of the methodologies, or the 2020 TYNDP. This Section also discusses the **main areas in which alignment between the ENTSOs should be considered**, to enhance consistency between their CBA methodologies.

This assessment was based on ENTSOG's gas CBA Methodology[47], and ENTSO-E's 3rd Guideline for CBA[48], for which opinions by ACER and the Commission have been issued. The changes in ENTSO-E's Draft 4th Guideline for CBA[49] were also taken into consideration.

5.1 ACER & EC opinions on ENTSOs past CBA methodologies

The review of the opinions by ACER and the Commission on the ENTSOs' CBA Methodologies has indicated that a number of comments and recommendations were partially covered, or not addressed by the ENTSOs in the subsequent versions of the methodologies, or the TYNDP 2020.

The Table below summarises the main findings of the analysis, focusing particularly on **issues with relevance to the consistency of the ENTSOs' methodologies and to issues that should be considered in ENTSOG's hydrogen CBA Methodology**. Issues that are similar for both ENTSOs have been grouped together. Comments and recommendations on how the identified issues can be addressed are also included in the Table.

[47] Adapted ENTSOG methodology for cost-benefit analysis of gas infrastructure projects Approved by the European Commission, 18 February 2019

[48] 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects of 19 October 2022, for approval by the European Commission.

[49] Draft 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects of 20 December 2022, for public consultation.

Table 15: Key ACER and EC comments partially or not addressed by ENTSOs

#	Issue	Entity	ACER / EC Comment	Changes in the CBA Methodology	Comments and recommendations
1	Socio-economic welfare	ENTSOG	ENTSOG modelling outputs show the total socio-economic welfare. The surplus should be disaggregated to consumer and producer surplus.	No relevant changes were made in ENTSOG's gas CBA Methodology.	Disaggregation of welfare to consumers and producers would benefit the assessment of hydrogen projects, as production of hydrogen will take place to a large extent (depending on assumptions for hydrogen imports) within the EU. The impact of a hydrogen project on the consumer surplus is linked not only to the availability of hydrogen from a cheaper source (H2-to-H2 competition), but more importantly to the substitution of another energy carrier with hydrogen (H2-to-other carrier competition). Each economic sector has a different energy mix, and different switching costs. Therefore, **to effectively examine the projects' impact, all sectors should be assessed, each with its particular characteristics**, as calculation only of a total welfare may not capture sector-specific costs and benefits of hydrogen switching.
2	Environmental impact	ENTSOG	Negative externalities (methane emissions in construction and operation of infrastructure, noise by compressors, impact on marine ecosystem by LNG terminals, etc.) should be assessed, quantitatively, or at a minimum qualitatively.	Partially addressed. Promoters may include in the project fiche additional costs related to the environmental impact. However, there is no guidance on the type and quantification of these costs. These costs are not included in the monetized assessment of the project.	The negative environmental impact, due to the construction and operation of a project, should be part of the CBA assessment. Listing costs related to the environmental impact without taking them into consideration in the economic analysis (as currently done by ENTSOG) is not consistent with a complete economic assessment of a project. The **negative project impact should either be monetized and part of the economic analysis, or assessed qualitatively** (e.g., by project promoters with guidance by ENTSOG).
		ENTSO-E	• The analysis of system resilience should take into account disaster and climate resilience.	No relevant changes were made in the ENTSO-E 3rd Cost	The residual externalities assessed in the CBAM, and accounted for as project costs, could also include any direct or indirect emissions caused by a project (e.g., if a

			• The assessment of the societal and environmental impacts should be quantified and possibly monetized (including mitigation measures that are included in the investment costs, as well as residual externalities).	-Benefit Analysis Methodology (CBAM).	project increases natural gas flows, that in turn increase methane emissions). If such negative externalities were to be assessed, a methodological approach for their estimation, per type of project, and monetization should be provided by the ENTSOs. Another element of environmental impact that needs to be taken into consideration in a project's economic analysis is its climatic resilience. Typically, however, costs associated with the project's climate resilience are included in its CAPEX and OPEX and thus are indirectly taken into account in the CBA.
3	Disclosure of project costs	ENTSOG	The project promoters should be required to provide to ENTSOG cost data on a project level. These costs should not be treated as confidential, since they concern investments for regulated infrastructure.	Partially addressed. Promoters must provide cost-data, but they have the option not to publish them in the project fiche and to publish instead alternative figures either calculated by the promoters or by ENTSOG.	The **costs used to assess a project should be transparent**, considering that the results of the economic analysis affect whether a project in included in the TYNDP and whether it is selected in the PCI list. The approach already followed by ENTSO-E to disclose costs, i.e., **disclosing the CAPEX and OPEX provided by the project promoter, together with a justified uncertainty range for the capital costs**, should also be followed by ENTSOG. Using an uncertainty range allows project promoters to take into account all uncertainties associated with the current stage of their project's development. There is therefore no justification for not disclosing the project costs in the project fiche and publishing alternative figures instead.

4	Overlapping indicators	ENTSOG	Indicators that are overlapping with monetized benefits and/or other indicators should be removed. Clarification on which indicators are monetized, quantitative or qualitative should be provided.	Partially addressed. Some quantitative indicators remain in ENTSOG's gas CBA Methodology. Although clarification on monetized, quantitative or qualitative indicators has been provided, further guidance (e.g., in the form of examples) is necessary.	The ENTSOs, in their CBAMs, have already categorized benefits into monetized, quantitative, and quantitative. There is still, nevertheless, a need to **identify and highlight any potential correlations between the monetized and quantitative indicators**, as both categories of benefits are used in the assessment of the projects and their selection as PCIs. The description of the indicators would benefit from **quantitative examples of their application and calculation**. This would provide better understanding to the project promoters on how the indicators are used, and would also facilitate the replicability of the CBAM by third parties outside the TYNDP assessment framework.
5	Transparency on modelling	ENTSOG	ENTSOG should publish information on the model, including at least: • Description of the model used to monetize benefits • Solvers and optimizations used • Main features of the topology • Main modelling assumptions • Name and features of the modelling tools • Interaction of gas and electricity models • Model implementing approach for gasification of new areas • Definition of main assumptions	Partially addressed. ENTSOG's gas CBA Methodology provides details on the topology of gas infrastructure included in the model. Other key information concerning modelling (modelling approach, assumptions, inputs) is provided in the TYNDP 2020 Methodology (Annex D).	Information concerning the ENTSOG model is included in the CBAM and the TYNDP methodology. Elements of the model, especially concerning sector-coupling with electricity are also included in the 2022 TYNDP scenario building guidelines. ENTSOG should ensure that the **CBAM describes the model sufficiently**, including information that is included in the TYNDPs 2020 and 2022 (such as modelling approach, inputs / outputs, interactions with the electricity model). Information that may change with each TYNDP (such as the assumptions) can be including in implementation guidelines of the CBAM[50].

[50] If ENTSOG follows ENTSO-E's approach to develop implementation guidelines that accompany the CBAM and can be revised with each TYNDP.

6	Treatment of project commissioning	ENTSOG	For multi-phased projects or clusters, the benefits count from the year of the first phase/project to be commissioned. They should count from the completion of the last project in the group.	No relevant changes were made in ENTSOG's gas CBA Methodology.	The commissioning date of a project is an input that should be provided by its promoter. Nevertheless, a **sanity check on the validity of the commissioning dates should be carried out by the ENTSOs**, given their impact on the results of the economic analysis. The approach for assessing the commissioning dates should be part of the CBAM. ENTSO-E has included a relevant approach in its draft 4th Guideline for CBA, based on historic data of past projects' development. A similar approach could be considered by ENTSOG (also to ensure consistency). **The first year of counting benefits in case of clustered projects should change for both ENTSOs**, as the current approaches can result to overestimation of benefits. The interdependencies of clustered projects (e.g., the existence of enabler projects in the case of ENTSOG) should be taken into account when setting the start of benefits for the whole cluster.
		ENTSO-E	• ENTSO-E should propose concrete and effective criteria to assess the validity of the commissioning dates indicated by promoters. • For projects with more than one investment, the benefits count from the average of the year of commissioning of the earliest and latest investments. This treatment is contradicting the notion of clustering of investments in one project.	• No universal criteria for assessing the validity of commissioning dates were added (the Implementation Guidelines will cover only the cases for which there is no information in the relevant National Development Plans. • No changes in the starting year for the project's benefits were made in the ENTSO-E 3rd CBAM.	

7	Time horizon	ENTSO-E	The methodology examines 2 study years in the mid-term horizon and at least one year in the long-term. This does not seem to be consistent with the TEN-E Regulation requirements about the 5-year time intervals. Clarity on the examined study years is required.	Only minor justification (in footnotes) was provided by ENTSO-E in the subject[51].	The ENTSOs' methodologies should have **consistent study horizons for which the joint scenarios are developed**. These study horizons should take into account the need for including in-between time intervals that facilitate the economic analysis.
8	Reference Grid	ENTSO-E	Regarding the short-term horizon, projects which have at least completed their environmental permitting could be eligible for inclusion in the reference grid. Principles on how to construct the reference grid for the second study year of the mid-term horizon, and the long-term horizon are missing.	• For the short-term horizon the criteria proposed in the ENTSO-E 3rd CBAM do not reassure "*reasonable certainty*" of the projects' implementation to be eligible for inclusion in the reference grid. • No principles for the 2nd year of the mid-term and the long-term horizon included in the ENTSO-E 3rd CBAM.	The **principles for establishing the reference grid should be common for ENTSOG and ENTSO-E** and ensure that includes **all infrastructure that will be in place during the study horizon with a "*reasonable certainty*"**. For this reason, the ENTSOs should use the same definition of "*reasonable certainty*" of the implementation of projects. The rationale followed by ENTSOG for the natural gas grid, which includes in the reference grid the infrastructure currently in place and the FID projects, has a high degree of certainty. The ENTSO-E approach of defining different reference grids for different time horizons, increases the uncertainty, especially in the mid and long-term.
9	Project interdependency / clustering	ENTSO-E	The treatment of complementary and competing projects, and the criteria for their inclusion in the reference grid are missing. Clustering rules are required, to ensure that projects with very diverging levels of maturity are not clustered together.	• No criteria for interdependent projects were included in the ENTSO-E 3rd CBAM. • Clustering rules were included.	The **rules for clustering of projects should be consistent for both ENTSOs**. The inclusion of complementary projects in clusters should be validated by the ENTSOs.

[51] The comment by ACER on time horizon concerned the previous TEN-E Regulation (347/2013), as the recast TEN-E Regulation Annex V (Energy System-Wide Cost-Benefit Analysis) no longer defines a specific time horizon for the CBA methodology. Nevertheless, the comment by ACER should be addressed by ENTSO-E in its CBA methodology, with regards to providing clarity in the time horizon used, and consistency with the horizon applied by ENTSOG.

10	Sensitivity analysis	ENTSO-E	Sensitivity analysis when carrying out the project-specific CBA should be obligatory and not optional. Clarity should be provided regarding sensitivity analysis and parameters (such as fuel and CO2 price), which require a scenario-based approach.	No relevant changes were made in the ENTSO-E 3rd CBAM.	Given the uncertainties associated with the project being assessed, as well as the evolution of the energy market itself, **sensitivity analysis should be an integral part of the CBA**. The approach followed by ENTSOG, examining the sensitivity of the economic indicators on parameters associated with the project and the market, should also be applied by ENTSO-E.
11	Economic assessment indicators	ENTSO-E	The NPV and BCR should be more clearly identified as CBA indicators being part of the assessment framework. The years of analysis are not properly included in the calculation of NPV and BCR.	Only minor changes were made in the ENTSO-E 3rd CBAM, clarifying the time at which benefits will start counting.	The **formulas used to calculate the economic assessment indicators should be depicted properly and in detail** in the CBAM. To ensure clarity, especially with regards to how the years of the analysis are taken into consideration and how annual economic cash flows are treated, they could be **accompanied by calculation examples**. Furthermore, to enhance consistency between the ENTSOs methodologies, the same formulas could apply for both CBAMs.

Some of the comments provided by ACER and the Commission, which were not addressed by ENTSOG in its gas CBA Methodology, were addressed in the TYNDP 2020. Nevertheless, for some of the comments addressed in the TYNDP, **the corresponding methodological approaches should be part of the CBA Methodology** (and therefore should be part of ENTSOG's hydrogen CBA Methodology):

- The approach used to assess and allocate sustainability benefits by considering the **contribution of project to CO2 reduction** (and other externalities reduction such as PMx, NOx and SOx).
- The approach used to **assess fuel switching**.
- **Treatment of long-term contracts and long-term capacity booking** in the model (this point is applicable to natural gas and not to the renewable and low-carbon gases, however natural gas infrastructure has to be part of the assessment until its phasing-out).
- The **approach used to determine the Cost of Disrupted Gas** (CoDG), which should be **complemented with the Cost of Disrupted Hydrogen** (CoDH).

5.2 Consistency between gas and electricity methodologies

ACER, with the support of the NRAs, has been tasked (Article 11(8) of the recast TEN-E Regulation) with the promotion of consistency across the energy system-wide CBA methodologies for projects falling within the scope of Annex II of the recast TEN-E Regulation, including the methodologies developed by ENTSO-E and ENTSOG.

The CBA methodologies of the ENTSOs **need to be aligned, up to the extent possible and take into account sectoral specificities**, to ensure uniformity and consistency in the assumptions, methodological approach and presentation of results. Despite the differences in evaluating electricity, gas and hydrogen projects, especially with regards to their expected benefits, there are several aspects at which the methodologies prepared by the ENTSOs can be consistent.

Review of ENTSOG's gas CBA Methodology and ENTSO-E's Draft 4th Guideline for CBA has shown that there is a number of areas for which **consistency needs to improve**:

- **Overall consistency of the documents**: structure of the methodology, use of implementation guidelines, content of project fiches.
- **Elements of the CBA methodology**: study horizon[52], length of assessment period[53], economic performance indicators, treatment of starting year for benefits, residual value of the project, sensitivity analysis, allocation of costs and benefits to EU Member States.
- **Assumptions**: use of common assumptions where possible (e.g., GHG prices, estimation of Value of Lost Load (VoLL) / CoDG, demand & supply, prices of fuels, cost of generation), setup of reference grid, consistency of data needs and sources, use of the ENTSOs' joint scenarios.

[52] The study horizon depicts the years for which detailed analysis of the project's impact is performed, using modelling and separate datasets of results are generated.
[53] The assessment period is the time period for which the economic analysis is performed for the project.

- **Clustering of projects**: use of common project phases, application of consistent rules and criteria for clustering.
- **Analysis**: interlinkages of electricity, gas and hydrogen markets modelling.
- **Treatment of project promoters' inputs**: CAPEX and OPEX provided by the promoters, negative externalities reported by the promoters, use of standard costs for non-mature projects, project implementation status, review of commissioning dates.

These areas of consistency improvement are further analysed below.

5.2.1 Overall consistency of the documents

Although ENTSO-E and ENTSOG develop CBA methodologies individually, there should be consistency with regards to the structure of the documents, and the way that the project-specific results of the assessment are presented.

Structure of the CBA methodologies and use of implementation guidelines

The ENTSOs structured their CBA methodologies differently:

- ENTSOG has included all CBA related elements, in its methodology for CBA. Further detailing on certain elements was then provided in the methodology Annex D.1 of the TYNDP 2020.
- ENTSO-E is accompanying its Guideline for CBA of grid development projects with the "*implementation guidelines*". The Guideline for CBA gathers the methodological elements for the CBA, whereas the implementation guidelines include the input data, sources used for assumptions, details for the calculation of benefits. The implementation guidelines are revised together with each new edition of the TYNDP.

Both ENTSOs should follow the same approach in structuring their methodologies. ENTSO-E's approach could be applied by both ENTSOs, by **using a main document** (CBA methodology) that establishes the CBA methodological framework, elements and directions, **complemented by implementation guidelines** that define the inputs, assumptions and approaches to calculate indicators. **Implementation guidelines can change with each TYNDP preparation** and be regularly consulted at the beginning of each TYNDP cycle.

It would also add value to **align the key terminology for both ENTSOs**, as there are some cases in which different terms are used for the same notion. Indicatively:

- ENTSO-E uses the term clustering and ENTSOG the term grouping of projects.
- For projects within the same cluster / group, ENTSO-E uses the terms main investment and supporting investments, while ENTSOG uses the terms enabler and enhancer.
- ENTSO-E uses the term study horizon to refer to the years that are analysed, while ENTSOG sometimes uses the term time horizon to refer to the assessment period (e.g., Section 3.2.2 of ENTSOG's gas CBA Methodology reads: *"The total benefit is calculated by aggregating the benefits in supply cost saving for all the considered time horizon"*).

Presentation of results

Both ENTSOG and ENTSO-E use project fiches to present information about the projects included in their TYNDPs (ENTSOG uses the project fiches only for projects that are candidate PCIs). The structure of these fiches is not defined in the CBA methodologies. The information provided (even for elements which should be consistent) is different for gas and electricity projects.

To ensure that consistency regarding the projects' technical description, the input provided by promoters for their assessment, the analysis conducted by the ENTSOs and its presentation to the public, the **minimum contents of the project fiches should be agreed between the ENTSOs, and consulted with the Commission and ACER**. An outline of the project fiches' contents could be indicated in the CBA methodologies (to ensure consistency) and the detailed contents could then be reflected in the implementation guidelines.

Furthermore, there should be consistency on the types of projects for which the project fiches are published by the ENTSOs. To this end, and to provide transparency on all infrastructure within the TYNDPs, ENTSOG should **publish the fiches not just for candidate PCIs, but for all projects included in the TYNDP**, following ENTSO-E's practice.

5.2.2 Elements of the CBA methodology

There are critical elements affecting the results of the projects' economic assessment, which differ in the ENTSOG and ENTSO-E methodologies. Such elements include the study horizons, length of assessment period, treatment of a project's residual value, calculation of economic performance indicators, treatment of the starting year for a project's benefits, performance of sensitivity analysis.

Study horizons

The ENTSOs agree and develop scenarios for specific study horizons (e.g., in the TYNDP 2022 for 2030, 2040 and 2050).

The recast TEN-E Regulation does not specify the study horizons to be examined in the CBA (contrary to Regulation 347/2013 that required development of datasets with 5-year intervals). Nevertheless, the **ENTSOs should agree on the study horizons**, making sure that the sample is sufficient to capture the potential changes in the projects' impact within the whole length of the assessment period.

Currently, ENTSO-E calculates the CBA indictors depending on its resources (and possibly considering also other internal reasons) unilaterally, picking scenarios and study horizon from the set for which scenarios are developed. This approach deprives decision-makers and the public from a balanced overview and analysis of the projects' benefits, and can even result to a biased presentation of projects' benefits.

ENTSOG assesses the systems needs and the projects' contribution against all scenarios and all years of the study horizons.

To ensure consistency, **both CBA methodologies should foresee that the CBA analysis will be implemented on all study horizons and scenarios developed by the ENTSOs**.

Length of assessment period

ENTSOG uses an assessment period of 25 years from the commissioning of the project (considered as the economic life of the project), the same assessment period with the one applied by ENTSO-E. The **25 years assessment period already used by the ENTSOs is a reasonable time horizon compared to a longer assessment period**, for the following reasons:

- **Conservative approach**: the more extended the assessment period the more uncertainty is introduced in the analysis. The 25 years period is already a long period, to which a high degree of uncertainty is attached. Not taking into account benefits later than this period avoids overestimation of benefits which may not be even materialised at all (or not at the extent expected).
- **Complexity and higher uncertainty for longer assessment period**:
    - Additional study horizons: a longer period, e.g., 40 years would require the development of additional long-term scenarios, as for example for a project commissioned in 2030, forecasting of benefits for up to 2070 would be needed. Extending project benefit results beyond 2050 does not seem a reasonable approach, as it would weaken the plausibility of the CBA results, and the formulation of scenarios for years close to 2060 and 2070 would be quite challenging.
    - Cost estimation: for such a long period, one-off costs (e.g., for refurbishment) would also have to be considered, and ENTSOs should develop guidelines on the practice to be applied (moreover, evaluating today the cost of a component in 25 years introduces additional uncertainties).

To ensure consistency in the calculation of the economic performance indicators (economic net present value, benefit-to-cost ratio), the **ENTSOs should use the same approach to assess the evolution of benefits for the duration of the assessment period**. Both ENTSOs indicate in their methodologies that they use linear interpolation to calculate the values between the agreed study horizons. However, neither specifies how values of benefits are interpolated from the start of the analysis to the first study horizon, or for the years after the study horizon until the end of the assessment period.

Consistency is also necessary in **the way ENTSOs assess projects with technical lifetime shorter than the length of the assessment period** and for which the promoter has not foreseen replacement costs. In such cases:

- For stand-alone projects, the costs and benefits should be accounted for only until the end of the technical lifetime, and then have zero values until the end of the assessment period.
- For projects grouped in a cluster, a conservative approach would be to calculate the benefits and costs of the whole cluster until the end of the lifetime of the single project with the shortest lifetime (especially in case this project I an enabler for the cluster), i.e., assuming that the whole cluster will cease operating. If this approach is followed, it has to be ensured that

all projects in the cluster are depreciated at the year that the shortest technical lifetime ends. The approach followed should be foreseen in the clustering rules that the ENTSOs agree on.

Residual value

ENTSOG does not include the residual value of the project in the calculation of the economic performance indicators, but performs a sensitivity analysis which calculates the net benefits if the project's residual value was to be factored in. To perform the sensitivity analysis for the residual value, ENTSOG calculates the undepreciated value of the investments at the end of the assessment period, i.e., focuses on the remaining financial value of the project, and not on its net economic benefits.

ENTSO-E considers zero residual value for projects, and does not consider any scenarios or sensitivities that include benefits for the project after the assessment period.

The **use of zero residual value in the calculation of the economic performance indicators provides a conservative view of a project's benefits**, as it only focuses on the assessment period, and does not consider potential continuation of its impact in a longer-term period, which is uncertain.

Both ENTSOs should follow the same approach with regards to the project's residual value. It is proposed to **limit the analysis only to the assessment period, excluding residual value from the economic analysis, and not to perform any sensitivity analysis on this parameter**, based on the following rationale:

- There is **large uncertainty with regards to the long-term economic impact of energy projects**, especially for a post-2050 outlook. If residual value is used in economic analysis, it will inherently incorporate assumptions for the future development of the energy sector beyond 2050, in addition to the scenarios already examined in the TYNDPs. This would add uncertainties that will make the interpretation of results by decision makers more difficult.
- **Calculating the residual value will increase complexity of the economic analysis and its results**. The definition of net benefits after the assessment period would require additional long-term scenarios to be established by the ENTSOs, increasing the number of different economic results that decision markets will have to evaluate. An alternative approach for estimating the net benefits, which is to assume that the benefits for the last year of the assessment period will remain constant until the end of the project's economic life, provide an oversimplified approach, that can lead to overestimation of the project's benefits.
- The calculation of residual value as the **undepreciated value of the investments** at the end of the assessment period is fitting for the financial assessment of a project, and **does not take into account the net economic benefits** for the remainder of the project's economic lifetime.

Economic performance indicators

Both ENTSOs use the economic net present value (ENPV) and benefit to cost ratio (BCR) as the main economic performance indicators. However, the formula used by ENTSO-E to calculate NPV should be revised, to **consider the first year after commissioning as the first year of the calculation**. To facilitate the recipients of the CBA results in understanding them, the methodology should include a **description**

of the meaning of ENPV and BCR, with the descriptions being consistent in both methodologies. Also, all the necessary implementation details should be included in the CBA methodology.

The **formulas and the application in the assessment period used by both ENTSOs for the economic performance indicators should be the same**, to ensure consistency in the calculations. Furthermore, the addition of supplementary indicators could be considered. The economic payback period of the project can provide additional information as it indicates how early in the assessment period the benefits can outweigh the costs. The economic rate of return (ERR) is another economic indicator used in CBAs of energy infrastructure[54], however there are shortcomings in its application to compare assessed projects (ENTSOG notes these shortcomings in its CBA methodology), so its use would not add value to the ENTSOs' CBA methodology.

Treatment of the starting year of benefits

ENTSOG starts counting the benefits of multi-phased projects or clusters from the year[55] of the first phase/project to be commissioned (a sensitivity is caried out using the commissioning year of the last project to be commissioned). ENTSO-E counts the benefits of project groups starting from the average of the year of commissioning of the earliest and latest investment. Neither of these approaches captures adequately the impact of the project at the correct timing and can lead to overestimation of the project's benefits.

The first year that the benefits start counting for a project should be consistent for both ENTSOs. To ensure that the project is fully operational, **benefits could be considered starting one year after commissioning** (as currently applied by ENTSOG). An alternative would be to count the benefits proportionately to the timing that the project is commissioned inside the year (e.g., 1/4 of the benefits if the project is to be commissioned in Q4), which however is a more complex approach, and would require from project promoters to provide more accurate timing for commissioning of their infrastructure.

The rationale for setting the starting year for the project's benefits, **in case of multi-phased projects or clusters of projects**, should be consistent for both ENTSOs, following a conservative approach that **considers benefits from the year following the commissioning year of the last project necessary for the clustered projects to commence their operation**. For ENTSOG, that is categorizing clustered projects as enablers and enhancers, counting benefits may start one year following commissioning of the last enabling project.

Both ENTSOs **should be transparent and clear with regards to the starting year of benefits** used to perform the economic analysis, for each project and cluster of projects. This information should be published together with the projects' economic results.

[54] The EC Guide to Cost-Benefit Analysis of Investment Projects [63] uses this indicator because it allows *"comparability and ranking for competing projects or alternatives"*.

[55] ENTSOG models each project 1 year after its commissioning, to make sure that the infrastructure is in place for the whole year.

Sensitivity analysis

Apart from the demand scenarios examined, ENTSOG includes sensitivity analysis in its CBA methodology, on predefined key parameters affecting the economic indicators, such as project costs, commissioning year, residual value, social discount rate, cost of disruption. On the other hand, ENTSO-E treats sensitivity analysis as optional, and in a proposed list of parameters to be examined, does not include project-related or monetization-related elements.

Given the uncertainty in multiple inputs affecting the results of the economic performance indicators, **sensitivity analysis should be an integral part of both ENTSOs' CBA**. A **minimum set of parameters should be common for the ENTSOs, including project inputs (e.g., CAPEX, commissioning year), and assumptions (e.g., CoGD / VoLL, societal cost of carbon)**.

It should be highlighted that sensitivity analysis on the societal cost of carbon is expected to become more relevant over time, as the societal cost of carbon evolution is the key driver for assessing sustainability monetized impact. Considering that there is a large divergence in the forecasts of societal costs performed by different institutions (see Section 4.2.2), different price trends have to be considered, to ensure that the uncertainty in prices is reflected in the analysis. Indicatively, the Commission Notice 2021/C 373/01 [59] (using costs estimated by the European Investment Bank in 2020 [61]) projects a societal cost of carbon of 800 EUR/ton CO2eq in 2050, while the World Bank [60] is assuming a 2050 price of 121 EUR/ton CO2eq.

Allocation of costs and benefits to Member States

The recast TEN-E Regulation (Annex V paragraph (7)) requires the ENTSOG and ENTSO-E methodologies to identify the EU Member States to which a project has net positive impact (beneficiaries) and net negative impact (cost bearers). Currently the ENTSOs' CBA methodologies do not include an approach on how net benefits are to be allocated to Member States, as the projects' impact is calculated on an EU-wide basis.

Including an approach for allocating costs and benefits on a country level requires consistency with regards to the principles followed, such as:

- Whether the allocation of benefits will be carried out for all supply and demand scenarios, or for a selected one.
- How the project costs will be allocated to different EU Member States (e.g., in case an interconnector proposed by the same promoter is crossing two or more countries, or if a project is transiting through a 3rd country).
- If and how significantly impacted Member States will be defined.

5.2.3 Assumptions

Although the specificities of the gas and electricity sectors result in ENTSOG and ENTSO-E using different monetized and quantified indicators, there should be consistency in assumptions used to perform the analysis:

- The supply and demand scenarios used as inputs in the modelling performed by ENTSOG and ENTSO-E should be internally consistent, using the same assumptions and input sources.
- The supply and demand scenarios should be used in the same manner by the ENTSOs when applying their CBA methodologies.
- Parameters used to calculate the indicators, and which are the same for electricity and gas (use of VoLL / CoDG to monetize security of supply, use of societal cost of carbon to monetize sustainability, assessment of fuel switching in power generation) should use common approaches and sources of input data to the extent possible.
- Assumptions applied to establish the reference grid used in the analysis should be consistent.

Scenarios used in the CBA methodologies

The ENTSOs develop jointly scenarios that project the long-term energy demand and supply in the EU. These scenarios use uniform assumptions and data sources as inputs, such as evolution of fuel commodity prices, emission factors and market price of carbon. The result of the joint scenario building is that ENTSO-E and ENTSOG share the same view as regards to the evolution of demand and supply of gases (methane and hydrogen) and electricity.

Although joint scenarios are in place, **the ENTSOs are not using them consistently during the application of their CBA methodologies**. ENTSOG is calculating the monetized benefits for all the scenarios and for the whole assessment period, and the quantitative benefits for the study horizons, but only for the PCI candidate projects. ENTSO-E is calculating the monetized and quantitative benefits only for specific scenarios and time horizons[56], and does not calculate the economic performance indicators (ENPV, BCR) for each project. The lack of a complete dataset of results for electricity projects in ENTSO-E's TYNDP allows only partial understanding of the projects' impact and does not provide them with the possibility to be compared in a holistic manner.

The ENTSOs should follow a consistent approach for the use of the joint scenarios, that is described in the CBA methodologies. Calculations should be carried out for **all projects included in the TYNDP**. **Monetized benefits and the economic performance indicators** should be calculated for **all scenarios and for the whole duration of the assessment period**. **Quantitative benefits** should be calculated for **all scenarios and each study horizon**.

Value of lost load / Cost of gas disruption

Both ENTSOs monetize a disruption's impact of electricity and gas by using value of lost load for electricity and cost of gas disruption for gas infrastructure, respectively. Although the value of a disruption has a different value for the electricity and gas sector, **the ENTSOs should at least use a common approach for defining this value** (e.g., use a without warning value, disaggregated value at country level or customer category level), **and refer to the same sources**, to the extent possible, for

[56] In TYNDP 2020 ENTSO-E presented 2025 and 2030 results for National Trends and only 2030 results for the Distributed Energy and Global Ambition scenarios. In the 2022 TYNDP only the National Trends 2030 and Distributed Energy 2030 and 2040 results are presented.

the input data used (e.g., use of the same sources for macroeconomic indicators, for statistical data, etc.).

Societal cost of carbon

The impact on sustainability is assessed for both electricity and gas/hydrogen projects. Both ENTSOs aim to use societal cost of carbon to monetize the benefits. To ensure consistency, **the same source should be used by both ENTSOs in their calculations, together with sensitivity analysis** as mentioned in Section 5.2.2 above.

When using the societal cost of carbon, both ENTSOs should ensure that there is **no double-counting with carbon taxes or levies** that are internalized in the cost of electricity production[57], or the cost of natural gas and other fuels.

Fuel switching

The interlinkage between fuel switching of other fuels with natural gas and hydrogen in the electricity sector is managed through the joint ENTSO-E and ENTSOG scenario building. The assumptions used for the different fuel prices in the **joint scenario report should be consistent with the fuel prices used when monetizing the impact of projects to fuel switching**.

Setup of reference grid

ENTSOG is examining three alternative scenarios of infrastructure development (infrastructure levels): existing infrastructure level (current infrastructure and infrastructure with FID status until the end of the corresponding year[58]), low infrastructure level (including all FID projects) and the advanced infrastructure level (including projects with FID and advanced status[59]). Even though in its TYNDP methodology ENTSOG characterises the existing infrastructure level as the reference grid, all infrastructure scenarios are analysed and reported in the same manner.

ENTSO-E, according to the CBA guideline, forms its reference grid by taking into consideration the existing infrastructure, and the most mature projects that are in construction phase, have successfully completed environmental impact assessment, are at *"permitting"* or *"planned, but not yet permitting"* phase.

The criteria used to set up the reference grid should be the same for both ENTSOs, to ensure that the same view on the future *"reasonably certain"* infrastructure is used.

5.2.4 Clustering of projects

ENTSOG is performing a grouping of projects on the basis of the following principles:

- Competing projects are assessed separately.

[57] Discussed by ENTSO-E in *Section 4: Methodology for Additional Societal benefit due to CO2 variation (B2)* of the CBA Guidelines.
[58] For TYNDP 2020 the reference grid included FID projects to be commissioning by 31st December 2019.
[59] Non-FID projects for which commissioning is expected within the next 6 years, and have either started the permitting phase or FEED.

- Enhancer(s) are grouped together with the enhanced project; an additional group separating the main investment from the enhancers is assessed separately.
- Enabler(s) are grouped and assessed together with the main investment.
- For multi-phase projects, each phase is assessed separately.

ENTSO-E uses different rules for clustering of investments:

- One main investment must explicitly be defined, which is supported by one or more supporting investments.
- Competing investments cannot be clustered together.
- Investments can only be clustered if they are at maximum of one stage of maturity apart from each other (projects under consideration are not clustered with others).
- If an investment is significantly delayed compared to the previous TYNDP, it can no longer be clustered within this project.

A consistent approach needs to be established by the ENTSOs for grouping / clustering projects. The characterization of projects as "*competing*", "*enhancers*" and "*enablers*" by ENTSOG, with clear definitions, facilitates grouping, and the rules established by ENTSO-E that take into consideration the maturity difference and the projects' delays, provide more certainty that projects can indeed be considered together. So, **a combination of the principles currently applied by the two ENTSOs could be considered**.

The extent to which one project is supporting another (for ENTSO-E's clustering approach) or is an enabler / enhancer (for ENTSOG's clustering approach), is important for deciding whether they should be clustered. To ensure the appropriate clustering of projects, **the ENTSOs should at least require the project promoters to justify the rationale of each proposed grouping**, by describing the impact and importance of each project to the cluster. The ENTSOs should then finalize the clusters, grouping only projects that are interdependent.

5.2.5 Interlinkage of modelling

ENTSOG and ENTSO-E must develop an interlinked model for the consistent assessment of electricity, gas and hydrogen infrastructure, in accordance with the recast TEN-E Regulation. This **interlinked model will allow the joint assessment of certain indicators, which are currently being considered individually for electricity and gas infrastructure**. Such indicators could potentially include:

- Assessment of energy security of supply, that takes into account the contribution of power, gas and hydrogen availability to address a disruption.
- Sustainability, interlinking supply of natural gas and hydrogen with reduction of GHGs for power generation.
- Fuel switching, interlinking the availability of hydrogen production from various sources (curtailed RES, dedicated RES, connected to the grid) with substitution of competing fuels at the markets targeted by the assessed projects, based on cost competitiveness.

5.2.6 Treatment of project promoters' inputs

Certain inputs provided by project promoters in the applications they submit for the TYNDPs, related to project costs, implementation status and timing of commissioning, can be assessed and treated the same way by the ENTSOs.

Assessment of environmental externalities

ENTSOG allows project promoters to provide qualitative and quantitative information about their project's costs related to the environmental impact, including costs in the CAPEX / OPEX as well as additional costs. There is however no specific guidance on how these inputs should be defined and calculated.

ENTSO-E has established individual indicators for assessing environmental impact (indicator S1), social impact (S2) and other residual impact (S3).

Neither of the ENTSOs is considering any negative externalities in the economic assessment, outside the costs already included by the project promoters in their CAPEX and OPEX inputs. Even in the case of ENTSOG, that additional costs can be provided by the promoters, these are not used for the calculation of the economic performance indicators.

Assessment of the projects' environmental impact should be carried out by both ENTSOs in a consistent manner, e.g., using the indicators currently set up by ENTSO-E. If additional environmental costs, outside CAPEX and OPEX, are requested by the project promoters, then **guidance on these economic costs should be provided by the ENTSOs**, and the costs should be included in the economic assessment.

Inputs for CAPEX and OPEX

ENTSOG requests from project promoters to provide CAPEX and OPEX data for their projects. For CAPEX, the methodology defines specific elements to be considered, splitting them into initial investment and replacement costs. On the other hand, there is no explanation of which expenses are considered as OPEX.

ENTSO-E describes in its CBA Guidelines the costs that are to be considered as CAPEX and OPEX (annual maintenance and operation costs), as well as cost elements which should not be included (e.g., operating expenses should exclude system losses, costs for purchasing energy for storage investments). For CAPEX, promoters are required to provide and justify an uncertainty range. The CBA Guidelines also foresee that CAPEX and OPEX for non-mature projects[60] will be calculated by ENTSO-E using benchmarks. CAPEX will be defined using standard investment costs, and OPEX as a yearly percentage of CAPEX, which will be defined in the implementation guidelines. It is noted that such a percentage was not defined in the draft implementation guidelines for the TYNDP 2022.

The same level of detail should be requested by the ENTSOs from project promoters with regards to which **costs are to be included** in (or excluded from) CAPEX and OPEX, to what **level of granularity** the promoters should submit costs to the ENTSOs and provide **guidelines on how the cost values are to**

[60] Projects classified as "*planned, but not yet in permitting*" and "*under consideration*"

be reported (e.g., definition of base year in case values are to be provided, how CAPEX will be allocated until commissioning, treatment of already incurred costs, etc.).

Furthermore, the **benchmarking of CAPEX and OPEX for non-mature projects**, as foreseen in ENTSO-E's methodology, could be applied, either to set the costs, or to allow comparison with cost data provided by the project promoter.

Project implementation status

ENTSOG classifies projects according to their status into FID, advanced non-FID (projects with commissioning 6 years after the year of the TYNDP with permitting phase started, or FEED has started) and non-advanced non-FID. This classification is used throughout the TYNDP.

ENTSO-E uses a different classification for the projects' status (in line with ACER's classification for PCIs' monitoring): under consideration, planned but not yet in permitting, permitting, under construction, commissioned, cancelled. ENTSO-E also categorises projects into mature (permitting, under construction) and non-mature (under consideration, planned but not yet in permitting).

A common classification of the projects' status, in line with the one used by ACER to monitor PCIs, could be applied by both ENTSOs, to ensure consistency in other elements as well (e.g., clustering, reference grid, etc.). Further characterization of projects (mature – non-mature or FID – advanced – non-advanced) could also be consistent.

Review of commissioning dates

ACER has requested from ENTSO-E to propose concrete and effective criteria to assess the validity of the commissioning dates indicated by the project promoters. Neither of the ENTSOs currently have such criteria in their CBA methodologies.

ENTSO-E, in its CBA Guidelines, is proposing an approach for assessing a project's implementation, based on statistical analysis of past project's development, and taking into consideration the specific project's specificities. This approach could potentially form the basis for a **common approach of reviewing commissioning dates of infrastructure projects by the ENTSOs**.

6 Recommendations to ENTSOG for a hydrogen infrastructure CBA methodology

This Section provides **recommendations for the ENTSOG's proposed hydrogen CBA methodology**[61]. To formulate the recommendations, the CBA methodology was examined taking into consideration the following elements:

- **Compliance with the recast TEN-E Regulation**, and particularly the principles for energy system-wide cost-benefit analysis foreseen in Annex V, and the criteria for hydrogen projects defined in Article 4(3.d).
- **Consistency of the methodological approach**, to the extent possible, with the ENTSO-E CBA Guidelines.
- Sufficient coverage of hydrogen infrastructure **key costs and benefits**.
- Relevance to the gradual **evolution of the European hydrogen market and infrastructure**.
- **Treatment of uncertainties** related to the hydrogen supply chain.
- **Clarity and transparency** in the application of the CBA methodology and the interpretation of its outputs.

The identified recommendations are analysed in terms of their:

- **Impact** (low / medium / high): the expected impact of the identified issue on the assessment of hydrogen infrastructure.
- **Needs for implementation**: actions that need to be undertaken by ENTSOG (if any) to address the recommendation.
- **Timeline of implementation** (current CBA methodology / future revisions of the CBA methodology / development of next Union-wide TYNDP): the timing that the recommendation should be, or can reasonably, be addressed.

6.1 Overview of the recommendations for enhancing ENTSOG's hydrogen CBA methodology

The recommendations have been categorized in the following thematic groups, to facilitate their analysis and implementation:

I. **Consistency** with ENTSO-E CBA Guidelines
II. **Assessment of costs and benefits** of hydrogen infrastructure
III. **Baseline and assumptions** of the analysis
IV. **Clarity** of implementation of the hydrogen CBA Methodology and its results

[61] Preliminary Draft Single-Sector Cost-Benefit Analysis (CBA) Methodology published for public consultation on 28th February 2023.

The recommendations identified under each group are presented in the Table below and analysed in the remainder of this Section.

Table 16: Groups of identified recommendations

I. Consistency with ENTSO-E CBA Guidelines	I.1 Application of common key CBA methodological elements
	I.2 Application of common rules for clustering
	I.3 Consistency in assumptions for interlinked modelling
	I.4 Consistency in the CBA methodologies' documents
II. Assessment of costs and benefits of hydrogen infrastructure	II.1 Inclusion of all costs associated with hydrogen infrastructure development
	II.2 Assessment of benefits in line with the hydrogen sector development
	II.3 Avoidance of correlation between indicators
III. Baseline and assumptions of the analysis	III.1 Set-up of reference grid in line with development of hydrogen infrastructure
	III.2 Targeted sensitivity analysis on uncertainty parameters
	III.3 Validation of project commissioning
	III.4 Appropriate setting of commissioning year in clusters
	III.5 Use of long-term shipper commitments in modelling
IV. Clarity of implementation of the hydrogen CBA Methodology and its results	IV.1 Clarity on the application of the methodology
	IV.2 Application span of the hydrogen CBA Methodology
	IV.3 Transparency of project information and analysis assumptions
	IV.4 Transparency of the model features

6.2 Consistency with ENTSO-E CBA methodology

6.2.1 Application of common key CBA methodological elements

Annex V of the recast TEN-E Regulation calls for **consistency between the CBA methodologies developed by ENTSOG and ENTSO-E, taking into account sectorial specificities**. Consistency needs to be maintained by the ENTSOs in the key methodological elements of the CBA, including the social discount rate applied, the assessment period used, the economic performance indicators, and the treatment of the residual value of the infrastructure. This will ensure the use of a common assessment framework for all energy infrastructure projects evaluated using the ENTSOG and ENTSO-E methodologies, and the comparability of the economic analysis results for electricity and hydrogen projects.

The proposed consistency improvements for each of the key CBA methodological elements are described below.

i. Social discount rate

ENTSOG proposes the use of a social discount rate of 3% to be used for hydrogen infrastructure, while ENTSO-E in its proposed 4th CBA Guideline continues to use a social discount rate of 4%. This is contrary to the practice followed by ENTSOG in its gas CBA Methodology, that used a common social discount rate with ENTSO-E (4%).

The **same social discount rate should be used in both ENTSOs' methodologies**, to allow assessment of electricity and hydrogen infrastructure projects to be comparable. The **level of the social discount rate, to be agreed by the ENTSOs**, could range between 3% - 5%, in accordance with the requirements for performing economic analysis set by the EC[62].

Recommendation	ENTSOG should coordinate with ENTSO-E so that both CBA methodologies use the same social discount rate
Impact	High – necessary for consistent CBA methodologies
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Current CBA methodology

ii. Assessment period

ENTSOG proposes to set the economic lifetime of all assessed hydrogen projects to 40 years and use this economic lifetime as the assessment period for performing the economic analysis.

The **use of such a prolonged assessment period** (compared to the 25 years applied for natural gas infrastructure projects with the previous ENTSOG CBA methodologies) **creates a number of issues**:

- To cover the whole assessment period, **scenarios should be built up to 2070**. Such long-term scenarios would not provide meaningful results, considering the increasing uncertainty as the scenarios' horizon prolongs. Even in the absence of scenarios until 2070, extending the project benefits, for example, through interpolation would provide neither meaningful nor credible results.
- The assessment period goes **beyond the timeline of the EC 2050 long-term strategy**.
- The assessment period is **not consistent with that applied by ENTSO-E** in its CBA methodology (25 years).
- Drawing from the experience of electricity projects, the **assessment period can be set for 25 years even though the economic lifetime of the infrastructure can be longer**.

It is proposed that **ENTSOG adopts the approach followed by ENTSO-E, using a 25-year assessment period for the economic analysis**, even if the economic lifetime of the project is longer. This way, although uncertainty is still present, all projects can be assessed over a time period for which **benefits can be reasonably forecasted** by considering alternative scenarios linked with the targets set by the EC, as well as with reasonable assumptions and estimates of the technological advancements that will change the supply and demand of hydrogen. Furthermore, the adoption of an assessment period

[62] Article 2.3.1 of Annex III of the Commission Implementing Regulation (EU) 2015/207 of 20 January 2015

shorter than the technical lifetime of the assets, helps balance the risk that some considered benefits may not materialise in the end (at all or not at the extent expected), reducing potential over-estimation of benefits.

Despite the use of a common assessment period for all projects, it should be clear in the methodology that in case a **project's technical lifetime is shorter than the assessment period**, then the project's **benefits and costs should be assessed until the end of its lifetime**. Considering the uncertainty related to the technical lifetime of new hydrogen infrastructure, and the fact that the remaining useful life of repurposed assets may vary considerably on a case-by-case basis, information on the technical life of the projects should be provided as input by the project promoters.

Recommendation	ENTSOG should consider using a 25-year assessment period, consistently with the current ENTSO-E approach. For projects with technical lifetimes shorter than the assessment period, perform the economic analysis until the end of their lifetime.
Impact	High – the 40-year assessment period would produce results with significant uncertainties thus limiting their added value for decision makers
Needs for implementation	-
Timeline of implementation	Current CBA methodology

iii. Calculation of economic performance indicators

The economic performance indicators applied in ENTSOG's CBA methodology are the economic net present value and benefit-to-cost ratio in line with the requirements set out in Paragraph (8) of Annex V of the recast TEN-E Regulation. Although the formulas for calculating ENPV and BCR are provided, clarity is necessary for the practical application of these indicators.

The methodology **does not specify the starting year for calculating the assessed project's benefits**. Instead, the formulas for ENPV and BCR appear to allow benefits starting from year "f" that is defined as the first year where costs are incurred. One of the following two approaches could apply to avoid overestimation of benefits for the first year of the project's commissioning:

- To **start counting the benefits one year after the year of the project's commissioning**, to ensure that a full year of operation is taken into account for all years of the project's assessment. **This is the most straightforward and simple way for a starting point** to count benefits, given that the temporal granularity of the analysis is annual and not anything finer, or
- To **estimate the benefits of the year of commissioning proportionately to the timing that the project is expected to be commissioned** within the year. This would require from project promoters to provide information for the month or quarter during which the project is expected to be commissioned.

For clustered projects, the benefits should start from **the next year of commissioning for the whole cluster** (see Section 6.4.4 for considerations with regards to the commissioning year of clustered projects).

ENTSOG should coordinate with ENTSO-E on the approach to be followed concerning the start year of benefits, to ensure consistency in their methodologies.

Recommendation	ENTSOG should consider specifying in the hydrogen CBA methodology the year in which a project's benefits start counting (e.g., one year after commissioning). ENTSOG and ENTSO-E should agree on the approach to be followed, to be consistent in both methodologies.
Impact	Low – the starting year of counting the benefits has a small impact to the overall economic analysis results
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Current CBA methodology

iv. Residual value

ENTSOG proposes the assessment of projects to be carried out without a residual value[63]. This approach provides a conservative view of the project's benefits, as it considers only the benefits' impact during the assessment period. It has the advantage of not requiring longer-term assumptions for the shadow prices of the project, that would increase the uncertainty of the results and decrease their usefulness for the decision makers. This approach is in line with the one followed by ENTSO-E.

However, **it appears that ENTSOG allows the inclusion of the residual value in the calculation of the economic performance indicators, in the form of sensitivity analysis**. Performing such a sensitivity offers limited added value to the analysis, as it examines the impact on the results of a structural element of the CBA methodology itself[64]. This sensitivity analysis may provide mixed and hard to interpret results to decision makers, that can hinder the assessment of the projects. It is therefore **proposed not to perform a sensitivity analysis on the residual value**.

Furthermore, the **current wording in the hydrogen CBA Methodology is not fully clear** in the guidelines provided to the project promoters as to **whether residual value is to be included in the economic analysis** or not. Specifically, the formula calculating ENPV makes a reference to residual value, whereas the document explaining the residual value recommends zero value. It is proposed to explicitly show in the formula that no residual value is considered.

[63] See Annex I to ENTSOG's hydrogen CBA Methodology, p.60. *"In line with this approach and in order to provide a conservative approach, it is recommended as a basis approach that projects are assessed without residual value"*

[64] Assessing a project with and without residual value is similar to estimating the project's economic viability for different assessment periods.

Recommendation	ENTSOG should consider not using residual value in the calculations either in the base approach or as a sensitivity, consistently with the current ENTSO-E approach. The wording in the hydrogen CBA Methodology should explicitly mention that no residual value is considered, throughout the document.
Impact	Medium – it appears that residual value is currently being analysed only as a sensitivity, and that the base case scenario is without residual value
Needs for implementation	-
Timeline of implementation	Current CBA methodology

6.2.2 Application of common rules for clustering

ENTSOG has included in its CBA methodology additional clustering rules (presented as *"additional considerations"*), compared to the ones included in its gas CBA Methodology. These rules follow the same rationale but are not consistent with the clustering rules proposed by ENTSO-E in its CBA Guidelines, as shown in the Table below.

Table 17: Clustering rules by ENTSOG and ENTSO-E

ENTSOG hydrogen CBA Methodology	ENTSO-E 4th Draft CBA Guidelines
Investments can be clustered if they are at maximum **two stages** of maturity[65] apart	Investments can be clustered if they are at maximum **one stage** of maturity apart
Investments can be grouped together if their expected commissioning is **10 years** apart	Significantly delayed investments (over **5 years** apart) cannot be clustered with the main project
N/A	Investments *"under consideration"* **are not clustered** with investments of other statuses
In clusters with enabling project(s), the enabler project(s) must be **commissioned prior to or together** with the enabled project	N/A (investments are not classified as enablers)
If a main investment is enhanced by other project(s), then the main investment is clustered with the enhancer project(s), but also **examined individually**	N/A (investments are not classified as enhancers)
Competing projects are **not clustered** together	Competing projects are **not clustered** together
For project consisting of several phases, each phase should be **assessed separately**	N/A

The clustering rules should be set so as to reduce the risks of investments being stranded or underutilized. ENTSOG has already put safeguards in place, with the rules established for the enhancer

[65] ENTSOG and ENTSO-E use different terminology: advancement status (ENTSOG) and stage of maturity (ENTSO-E). Nevertheless, the stages are the same: under consideration, planned, permitting, under construction.

and enabler projects[66], i.e., projects being enhanced are assessed with and without the enhancer projects, and enabled projects are commissioned together or after the enabler projects.

For **clusters with enhancer projects**, the **existing rule provides to the decision makers sufficient information** to understand the incremental impact of the enhancer projects, and to assess this vis-à-vis the different stage of maturity of the clustered projects.

For **clusters with enabler projects**, the clustering criterion is the maturity of the enabler, without assessing the plausibility of the enabler's timing of implementation. The **overarching rule** that projects up to two stages of implementation apart can be clustered together **may result in enabler projects being in a conceptual phase** (*"under consideration"* stage) to **be clustered with main investments in permitting**, on the basis of the former's commissioning date declared by the project promoter. To address the uncertainties associated with the commissioning of projects being at different stages of development, it is proposed for enabler projects to apply the following rules, in line with ENTSO-E's approach (Figure 14):

- Enabler projects must be **maximum one stage of maturity apart** from the enabled project, and
- Enabler projects in the **"*under consideration*" stage** can only be grouped with enabled projects in the **same stage of maturity**.

Figure 14: Clustering criteria for clusters with enabler projects

Furthermore, the rule grouping together investments with commissioning up to 10 years apart, covering the full span of the 10-year development plan, may result in projects with very different timelines being grouped together. The country analysis discussed in Section 3 has indicated that usually network planning is carried out for 5-year intervals or less (for example in the cases of Germany and Denmark). To limit the uncertainty of projects with long commissioning timelines, it is proposed to **limit the allowed difference between projects' commissioning to 5 years**.

Considering that in the initial implementation of the hydrogen CBA Methodology the majority of assessed projects will be in the *"under consideration"* stage, and to avoid restrictions in clustering that may hinder the projects' appraisal, it is **proposed to allow for more flexibility in the first application**

[66] According to ENTSOG's CBA Methodology: **Enabler** is a project indispensable for the realisation of the assessed investment/project in order for the latter to start operating and show any benefit. The enabler itself might not bring any direct capacity increment at any Interconnection Point (IP). / **Enhancer** (or complementary) is a project that would allow the main project to operate at higher rate or creating synergies compared to the main project operating on its own basis, increasing the benefits stemming from the realisation of the main investment. An enhancer, unlike an enabler, is not conditional for the realisation of the main project.

of the hydrogen CBA Methodology (for the 2024 TYNDP), and then apply stricter clustering rules. In particular, it is recommended to prescribe in the CBA Methodology that:

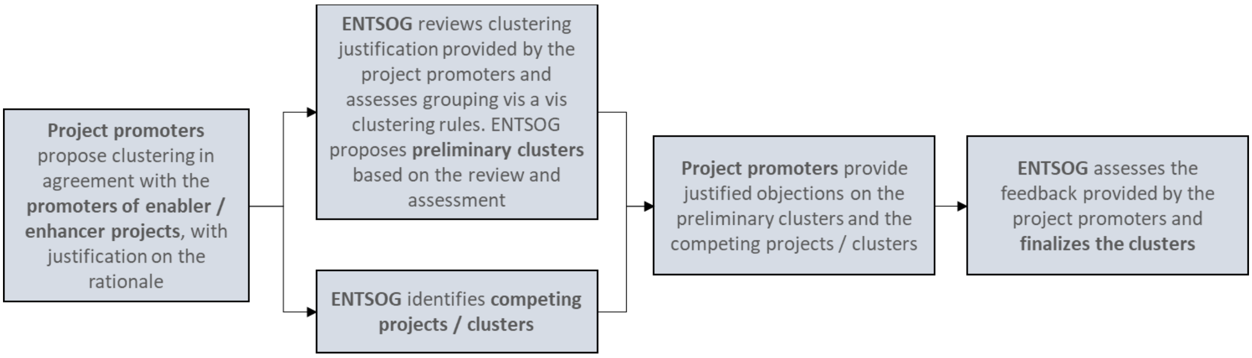
- **For the first TYNDP** for which the hydrogen CBA Methodology applies, to **allow clustering of projects up to two stages of implementation apart** (as proposed by ENTSOG), but group together investments if their expected commissioning years are **up to 5 years apart**.
- **For subsequent applications** of the hydrogen CBA Methodology (i.e., after the maturity of hydrogen infrastructure projects has improved), **to apply the clustering rules indicated in Figure 14**, grouping together investments with commissioning **up to 5 years apart**.

The above clustering rules should form the universe of clustering principles to be shown in the document, and should not be referred to as *"other considerations for grouping"* or *"additional clustering rules"* in the text of the hydrogen CBA Methodology.

To apply the clustering rules, **the definition of enabler projects should provide clear guidance to project promoters**. It is understood that ENTSOG is applying the lesser rule[67] for certain types of investments that have to be grouped together (e.g., the sections of the same cross-border interconnection at each side of the border), without however providing relevant details in the hydrogen CBA Methodology. In this respect, it is proposed that the hydrogen CBA Methodology clarifies the cases of grouped investments for which ENTSOG is applying the lesser rule, and how the lesser rule is applied.

The CBA methodologies of ENTSOG and ENTSO-E do not specify the process, according to which the clustering rules apply, and the roles of different parties. A **high-level process** could be foreseen in the methodologies, **to provide clarity and transparency on how the proposed projects will be grouped into clusters** for the purposes of the TYNDP and subsequently the PCI selection. Such a high-level process could include the steps presented in the Figure below.

Figure 15: Potential high-level project clustering process



Such a **high-level procedure should be agreed with ENTSO-E, and discussed with the European Commission and ACER**, to ensure that clustering rules apply the same way for the hydrogen and electricity infrastructure assessed under the recast TEN-E Regulation. Details on the implementation of clustering procedure could be described by the ENTSOs in the TYNDP implementation guidelines prepared for each TYNDP.

[67] Use of the latest commissioning year and of the lowest capacity for investments grouped together.

Recommendation	ENTSOG should consider revising the project clustering rules: ▪ To group together projects with commissioning up to 5 years apart ▪ After maturity of hydrogen infrastructure projects has improved (for example from the 2nd application of the CBA methodology onwards), to apply stricter clustering rules for clustering in case of enabler projects (enabler and enabled projects maximum one stage of maturity apart, clustering of enabler projects under consideration only with enabled projects in the same stage) It is also proposed to include a high-level clustering process in the hydrogen CBA Methodology, defining the steps followed for project clustering, and the stakeholder roles.
Impact	High – changes in the clustering of projects can affect the CBA results of the assessed projects
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Current CBA methodology (detailing of the implementation procedure can be carried out for each TYNDP)

6.2.3 Consistency of interlinked assessment

ENTSOG is planning to apply joint modelling to capture the interlinkages between electricity – hydrogen and natural gas – hydrogen. To ensure internal consistency in the modelling exercise, the **assumptions that are used to establish the baseline of the simulations should follow the same pathway**. As such, the energy supply and demand and the energy system evolution should be based on the same storyline.

Although the supply and demand evolution is commonly set by the ENTSOs, under the joint scenario process, the rules for setting the reference grids of electricity and natural gas infrastructure are different. This is noted by ENTSOG in its CBA methodology as follows: *"Reference grid: Different methodologies are used within ENTSO-E and ENTSOG, therefore definitions may change slightly."*. Considering that both the electricity and natural gas systems affect the supply and demand of hydrogen, the simulated reference grids will have an impact on the assessment of hydrogen infrastructure projects. Therefore, **the ENTSOs should agree on the same set of rules for defining the electricity and gas reference grids which will be used in the simulations**.

Through the interlinked assessment, **cross-sectoral projects** (characterised by ENTSOG as "*hybrid projects*")[68], may be assessed. Assessment of such projects falls outside the scope of the hydrogen CBA Methodology, which according to the recast TEN-E Regulation should be a "*single-sector*" methodology. Nevertheless, to provide clarity on how the hybrid projects are treated, it is proposed that **ENTSOG describes in the hydrogen CBA Methodology the principles for assessing such projects**, i.e., how ENTSOG and ENTSO-E coordinate, how consistency is ensured, which monetized indicators are applied, how double-counting of benefits is avoided, etc.

[68] For example, a cluster of cross-sectoral projects including interconnections linking off-shore RES generation, electrolysers and a cross-border hydrogen pipeline.

Recommendation	The ENTSOs should agree on the rules for defining the electricity, hydrogen and natural gas reference grids, which will be used in ENTSOG's modelling exercise. ENTSOG could consider including in the hydrogen CBA Methodology a description of how hybrid projects are assessed (in coordination with ENTSO-E).
Impact	High – without common definitions of reference grids simulations lack internal consistency
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Current CBA methodology

6.2.4 Consistency in the CBA methodologies' documents

Although the contents of both ENTSOG's hydrogen CBA methodology and ENTSO-E's CBA Guidelines are based on Annex V of the recast TEN-E Regulation, the structure of the documents and their level of detail on different methodological elements is significantly different. To increase the level of consistency between the two methodologies, the **ENTSOs should coordinate** so that in subsequent versions of their CBA methodologies, the relevant **documents follow at least the same high-level structure, and use the same terminology for identical notions** (see also Section 5.2.1).

Furthermore, the results of the CBA methodologies' application should be presented in the ENTSOG and ENTSO-E TYNDPs in a consistent way and format, presenting similar information for assessed projects. To facilitate consistency, it is proposed to **list in the CBA methodology, the outline contents of the project fiches and the main information to be presented**. The detailed contents of the project fiches can then be described in the implementation guidelines of each TYNDP.

Recommendation	The ENTSOs should agree on a common high-level structure of their CBA methodologies, and on the high-level outline of the project fiches to be included in their TYNDPs.
Impact	Low – consistency in documents will facilitate the consistent use of the methodologies by interested parties
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Future revisions of the CBA methodology

6.3 Assessment of costs and benefits of hydrogen infrastructure

6.3.1 Inclusion of all costs associated with hydrogen infrastructure development

The cost-side of the CBA must include all costs related to the development of the hydrogen infrastructure, which may relate to costs associated directly with the construction, operation and maintenance of the assets, as well as of indirect costs associated with interventions in other infrastructure which are necessary for the project to operate. The hydrogen CBA methodology should describe with clarity all the cost items that the project promoters should take into account. The different costs associated with the types of infrastructure should be highlighted, especially considering that in the case of hydrogen the infrastructure may be either new-built or repurposed from natural gas pipelines, with different cost items for each.

The recommendations for enhancing the detailing of costs in the CBA methodology are discussed below.

i. Treatment of costs for repurposed infrastructure

ENTSOG provides in its hydrogen CBA methodology a classification of investment costs and their description, using the same cost items with its gas CBA methodology. This disaggregation of costs is sufficient for new-built hydrogen infrastructure, the costs items of which are the same with that of developing new natural gas infrastructure. This is **not the case, however, for projects repurposing natural gas pipelines, the costs of which are different**.

Considering that the initial development of hydrogen infrastructure in the EU will be heavily based on utilizing existing natural gas assets, it can be expected that many projects in ENTSOG's TYNDP will concern repurposing for gas infrastructure. To facilitate the assessment of such projects, **the costs that should be accounted for when performing a CBA should be described explicitly in the methodology**, to ensure that assessment of all examined repurposing projects is carried out in a consistent and non-discriminatory manner.

The ACER study on future regulatory decisions on natural gas networks [49] identifies the costs associated with repurposing of gas assets. Apart from the new investment costs for the retrofitted assets (e.g., installation of new compressor stations), repurposing could also entail possible costs for the gas TSO to enhance the remaining natural gas transmission system, and costs for disconnecting existing natural gas consumers.

The value of gas assets transferred to hydrogen infrastructure should not be included in the costs of repurposed projects. As the hydrogen and natural gas systems are being assessed jointly, **it can be considered that the transfer of assets from the gas to the hydrogen operator would result in a zero net sum of costs.** The transferred assets would increase the tariff of hydrogen transmission, and would respectively decrease gas transmission tariffs, which as a result would decrease the social welfare of hydrogen consumers and increase that of gas consumers.

The **economic analysis should consider the full CAPEX and OPEX of the repurposing project** when calculating the economic performance indicators. The CBA methodology should therefore be revised to describe the direct (new CAPEX and OPEX) and indirect (interventions on the remaining gas system) costs of repurposing natural gas infrastructure, to ensure that the costs of such projects will be assessed consistently.

Recommendation	ENTSOG should consider expanding the description of project costs to be provide by promoters, to include the specific cost items for the repurposing of natural gas assets.
Impact	High – cost items for projects repurposing natural gas infrastructure are currently not described
Needs for implementation	Definition by ENTSOG of project costs for repurposing projects
Timeline of implementation	Current CBA methodology

ii. Negative environmental externalities

ENTSOG provides to project promoters a template to present the environmental impact of their project, including the possibility to provide additional expected costs which are not internalized in the project's CAPEX or OPEX. It is understood that these additional costs aim to represent the negative environmental externalities of the project. These externalities are not included in the economic analysis of the project, but are only presented for information purposes.

The negative environmental externalities presented by the project promoters cannot be verified by ENTSOG, and no guidance is provided on how these are defined. Although the additional costs are not used to assess the projects' economic performance, they are included in the project fiche, and therefore form part of the overall project evaluation.

To have monetary values of negative environmental externalities which are consistently assessed for all projects, ENTSOG would have to develop a methodology for monetizing such externalities. However, this would require significant effort from ENTSOG side, potentially with limited added value for the overall project evaluation. In this respect, **it is proposed to require project promoters to qualitatively present the expected negative environmental externalities of their project**. To ensure consistency, **ENTSOG should provide guidelines in the hydrogen CBA methodology** with regards to the type of externalities that should be considered.

Recommendation	The "*additional expected costs*" in the assessment of the projects' environmental impact are proposed to be replaced with a qualitative assessment of negative environmental externalities. Such an assessment should be based on guidelines provided to promoters by ENTSOG.
Impact	Low – additional costs are not included in the economic analysis of projects
Needs for implementation	Development by ENTSOG of qualitative guidelines for the types of negative environmental externalities to be considered
Timeline of implementation	Current CBA methodology

6.3.2 Assessment of benefits in line with the hydrogen sector development

The benefits of implementing hydrogen infrastructure projects can be assessed using monetized, quantitative or qualitative indicators. **Priority should be given to establishing indicators that monetize benefits**, and can be included in the economic analysis of the assessed projects. In cases where benefit monetization is not possible or yields highly uncertain results, a quantitative, normalized and comparable indicator can be applied. Qualitative indicators (using a quantitative scale) should apply only if quantification of a benefit is not possible or may provide results of high uncertainty.

The indicators used to assess benefits resulting from the development of hydrogen infrastructure should be **in line with the evolution of the hydrogen sector development**. The hydrogen market will evolve gradually, starting from existing hydrogen loads and easy-to-switch sectors (high grade temperature heat processes in industry, heavy duty transport), then progressively moving to other sectors, if hydrogen is more competitive than electrification and biomethane. Development of infrastructure will follow demand, evolving from point-to-point transport linking supply with demand, to the development of regional networks, until reaching the stage of a nation-wide hydrogen transmission system with cross-border connections with other systems.

ENTSOG proposes in the hydrogen CBA methodology a set of benefit indicators that cover the main potential impacts of hydrogen infrastructure, namely the improvement of sustainability, increase of social welfare by reducing energy costs and the strengthening of security of supply. Most of the indicators proposed (four out of five) are monetized, allowing their inclusion in the calculation of the economic performance indicators. **The approach to monetizing the benefits has certain limitations, that would merit further refining and improvement**, particularly to factor in the expected evolution of hydrogen markets and infrastructure. Specifically, calculation of the benefit indicators appears to focus to a large extent on the impact of hydrogen infrastructure on the electricity sector, with hydrogen-based generation replacing the use of fossil fuels, whereas sectors that can achieve short-term switching from existing fuels to hydrogen (e.g., heavy industry) are not covered.

Recommendations on enhancing the benefit indicators foreseen in the hydrogen CBA methodology, to mitigate these issues, are discussed below.

i. Assessment of the impact on sustainability

ENTSOG is monetizing the impact of hydrogen infrastructure on sustainability through two indicators, "*B1: Societal benefit due to CO2 emissions variation*", and "*B4: Societal benefit due to non-GHG emissions variation*". ENTSOG's approach, for both indicators, is in line with CBA practices to assess emission reduction, which includes multiplying the project's impact on emission reduction with the economic cost of emissions (shadow cost of carbon for B1 and cost of pollutants for B4).

For the practical application of the indicators B1 and B4, ENTSOG is considering the reduction of CO2 emissions as a result of:

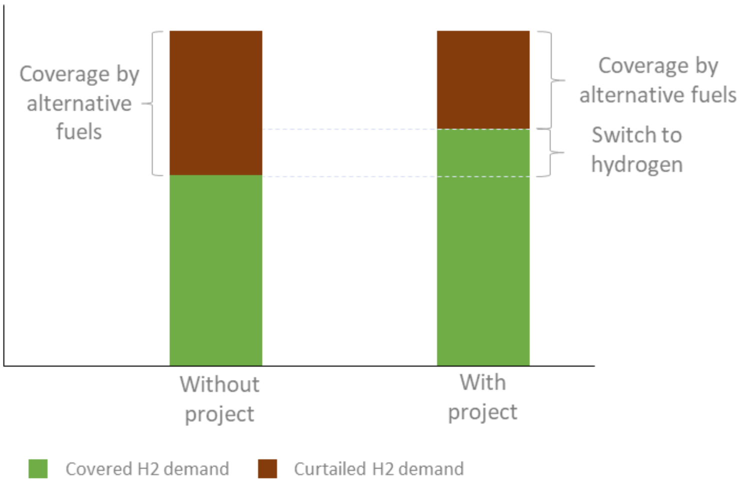
- Changing the generation mix of the electricity sector, and
- Changing the supply sources used to meet hydrogen demand (replacement of low-carbon with green hydrogen).

The approach followed takes into account the potential switching from alternative fuels to hydrogen only for electricity generation, while for all other sectors only H2-to-H2 competition is considered. This way, however, **the benefit of reducing emissions is only partially covered, as the impact of replacing polluting fuels in other sectors**, e.g., industries (for CO2) or heavy-duty transport (for CO2 and non-GHG), **as a result of the assessed project's implementation, is not examined**.

It is therefore proposed to **expand the indicators B1 and B4 to cover at least reduction emission in hard-to-abate sectors**.

A potential approach to estimate emission reduction as a result of the project implementation, without changing the joint modelling approach, is to assume that curtailed hydrogen demand under normal conditions calculated from the model simulations would be covered with alternative fuels. In this case, decrease in curtailed demand due to the project implies switching from the alternative fuels to hydrogen, with the corresponding reduction in emissions (Figure 16).

Figure 16: Potential approach to assess emission reduction from fuel switching



Recommendation	ETNSOG should consider revising the indicators used to monetize sustainability (B1, B4), to capture the impact of projects in switching from alternative fuels to hydrogen in hard-to-abate sectors.
Impact	High – sustainability is currently assessed partially
Needs for implementation	Development by ENTSOG of methodology to assess fuel switching (within or outside the joint model)
Timeline of implementation	Current CBA methodology

ii. Assessment of the impact on socioeconomic welfare

ENTSOG is monetizing the impact of hydrogen infrastructure on the reduction of energy system costs through the indicator *"B2: Cross-Sectoral Social Economic Welfare"*. This indicator is calculated focusing specifically on the economic surpluses of electricity consumers, producers, transmission owners (congestion rent) and cross-sectoral rents.

The focus of this assessment appears to be on the project's impact on the electricity sector and the hydrogen – electricity interlinkage. Although energy cost reduction in the electricity sector has a wide benefit on society, spanning all economic sectors, potentially **there are also societal benefits associated with energy cost reduction in hard-to-abate sectors**, which are expected to account for the majority of hydrogen demand at least in a short to medium term horizon.

With this approach, only projects seeking to supply hydrogen to the electricity sector will have monetized benefits under this indicator, whereas infrastructure that aims to transport hydrogen to cover the needs of other sectors, such as industries, will not be accounted for any benefits. As a result, there is an inherent preference in this indicator for only some projects, based on the targeted end-use.

It is proposed to **revise the approach, so that the projects' impact on the socioeconomic welfare due to the reduction of energy system costs, at least in hard-to-abate sectors, is estimated**. Development of such a new approach from ENTSOG, which may involve changes in the modelling approach, would require time and effort. Until a revised approach is developed it is proposed to **explain the limitations when using the current indicator**.

ENTSOG could also consider **splitting the impact of the assessed project on socioeconomic welfare into consumer and producer surplus**. This will provide to decision makers a better understanding of how the impact of the project is allocated to European energy consumers, and to producers of hydrogen inside and outside the EU.

Recommendation	ENTSOG should consider revising the indicator used to monetize socioeconomic welfare (B2), to include the projects' impact on the socioeconomic welfare due to the reduction of energy system costs, at least, in hard-to-abate sectors. Until the revised approach is developed it is proposed to explain the limitations when using the current indicator.
Impact	High – current indicator has inherent preference to projects targeting supply of electricity generation
Needs for implementation	Development by ENTSOG of a methodology to assess socioeconomic welfare impact in hard-to-abate sectors (including changes in the joint model)
Timeline of implementation	Current CBA methodology (if not possible to develop new indicator for the current methodology, explain the limitations of using current indicator)

iii. Assessment of the impact on energy security of supply

ENTSOG is monetizing the impact of hydrogen infrastructure on the security of supply through the indicator "*B5: Reduction in exposure to curtailed demand*". The analysis is similar to the examination of security of supply for natural gas infrastructure, by estimating the economic cost of demand curtailment under different conditions of climatic stress and supply / infrastructure disruptions in the country.

The characteristics of a future nascent hydrogen market are very different from the characteristics of a mature natural gas market. Hydrogen demand is expected to gradually emerge in a dispersed manner, with initial point-to-point network developments connecting localized demand and consumption in industrial sites, then expanding to the connection of local and regional industrial clusters. As a result, **the approach proposed by ENTSOG does not sufficiently address the security of supply concerns for the hydrogen sector**:

- Assessment of **climatic stress conditions would affect hydrogen demand if it were used for building heating, which is not expected** to be the case at least in the short to mid-term. Indirectly, climatic stress conditions may affect the availability of RES for hydrogen production, since more RES generation would be needed to address increasing heating needs. This condition, however, can be directly captured when assessing potential disruption is electrolyser capacity.
- Assessment of **normal climatic conditions should not be part of security of supply assessment**, considering that, without external factors, supply in a market should be adequate to meet demand. Curtailment of demand without disruption indicates either a physical structural infrastructure limitation (due to technical bottlenecks, lack of infrastructures, etc.),

or a market failure when demand cannot be balanced by available supply. Normally, consumers would continue to use their current energy carriers until there is confidence that hydrogen will be available. The impact of switching to hydrogen should be captured in the indicators assessing emission reduction and socioeconomic welfare increase.

- Assessment of infrastructure stress conditions are considering disruption of the country's largest capacity. This, however, can **provide misleading results if hydrogen infrastructure is point-to-point and the largest capacity in the country is not serving the targeted hydrogen cluster**[69].

To assess security of supply in the hydrogen sector adequately in particular in the short and mid-term, **ENTSOG's model should be able to support demand granularity on a hydrogen cluster level**, instead of the current country level. This would allow examination of disruptions of hydrogen deliveries to the specific demand centres that the hydrogen infrastructure is being developed to supply. Examined stress conditions can include disruption of existing infrastructure and/or disruption of the largest electrolyser supplying the cluster.

To support the assessment, **the topology of the joint model has to expand, increasing the granularity of consumption nodes to cover hydrogen clusters**. Considering that such an update could require significant time and effort by ENTSOG, as a fall-back option **until the model can provide this functionality**, monetization of security of supply can be carried out on a **case-by-case basis with analysis performed by the project promoters, based on ENTSOG's guidelines**. To ensure consistency in the analysis of different projects, ENTSOG should include, in its hydrogen CBA methodology, guidelines for carrying out project-specific security of supply assessment, defining the key elements and assumptions such as the stress conditions analysed, the cost of disrupted hydrogen applied, and the probability of disruption assumed. Nevertheless, comparability will suffer when each promoter is conducting its own assessment (even with a fixed framework provided by ENTSOG), therefore **this can only serve as a transitional solution, until ENTOG's model can depict the grid in adequate granularity**.

In the absence of a harmonised reference value at EU level for CoDH[70], ENTSOG proposes to use as a proxy the cost of disrupted gas. **CoDG is based on a mix of natural gas demand that is very different from the mix of hydrogen demand**, therefore its use would not provide an appropriate indication of hydrogen consumers' willingness to pay for hydrogen supply or to accept compensation in case of disruption of hydrogen supply. Instead, **since hydrogen will mainly be used in the industrial sector, it is proposed that ENTSOG investigates and presents to stakeholders alternative approaches** (e.g., the ratio of each country's industrial gross value added to its natural gas demand in the industrial sector could be considered as a proxy).

Another aspect of energy security of supply that merits further investigation and analysis is the **potential negative impact of repurposing natural gas assets on the security and continuity of supply**

[69] Hydrogen clusters can be considered as local or regional hydrogen demand centres within a country.
[70] ACER's Study on the estimation of the cost of disruption of gas supply in Europe provides an analysis of practices and scientific approaches that may be taken into consideration to calculate the cost of hydrogen disruption.

of gas infrastructure. ENTSOG could assess this negative externality by including in the hydrogen CBA Methodology an approach to expand the security of supply indicator, which may entail:

- Receiving inputs from the project promoter on how the repurposing project will affect the natural gas infrastructure,
- Identifying the gas demand curtailment risks (if any) under different climatic conditions (normal and stress conditions) and supply disruptions, assuming appropriate probabilities of materialization for each examined case, and
- Monetizing the negative externality by applying the CoDG on the curtailed demand.

To perform the analysis described above, **ENTSOG should expand the analysis carried out for security of supply, to cover both hydrogen and gas sectors**.

Recommendation	ETNSOG should consider revising the indicator used to monetize security of supply (B5), to assess disruptions on a cluster and not country-wide level. Until the joint model can support this assessment, the analysis could be carried out by project promoters, on the basis of guidelines provided by ENTSOG. It is proposed not to use CoDG as proxy of CoDH in the calculations. Instead, a factor based on industrial demand could be applied. ENTSOG could also consider including in the assessment the potential negative impact of repurposing projects on the gas sector security of supply (applying a monetization approach similar to that used in ENTSOG's gas CBA Methodology).
Impact	High – the analysis of hydrogen demand curtailment on country level can be misleading as there are no nation-wide transmission networks in place. Assessment of any potential negative impact of repurposing projects on the gas sector should be included in the economic analysis.
Needs for implementation	Update of the joint model to analyse demand on hydrogen cluster level. Development by ENTSOG of methodology to assess project-specific hydrogen security of supply impact, to be applied by project promoters. Development by ENTSOG of methodology for assessing the impact of repurposing projects on natural gas security of supply.
Timeline of implementation	Current CBA methodology (guidelines for assessing security of supply impact) Future revisions of the CBA methodology (use on joint model to assess disruptions at clusters)

iv. Assessment of the impact on market integration

In the initial phases of establishing the European hydrogen transmission systems, the hydrogen networks are mostly being developed locally, within each EU Member State, with only few exceptions particularly of small links between cross-border hydrogen production sites and consumption centres. In this setup, the development of any cross-border hydrogen interconnection between Member States shall contribute to a first step of EU hydrogen market integration, as it connects isolated "*hydrogen islands*" and unlocks the possibility of flows between them.

As such, **the projects' contribution to market integration could be assessed, even at this early phase of market evolution**, as it addresses a clear infrastructure need of establishing cross-border capacity. It is proposed that ENTSOG includes in the analysis of benefits an **indicator that assesses the ending of isolation and/or increases the interconnectivity** between countries in the geographical perimeter of the assessment.

Currently examination of price convergence is not meaningful, as hydrogen markets are yet to be developed. Assessment could be done using a **capacity-based quantitative or even qualitative indicator**, that reflects on the interconnections developed with the realization the examined projects. A more elaborate quantitative indicator can be developed once hydrogen markets are sufficiently mature to consider price convergence as a potential impact of new infrastructure.

Recommendation	ETNSOG should consider introducing a quantitative or qualitative indicator assessing the projects' impact on market integration.
Impact	High – connecting "*hydrogen islands*" is an important benefit as an initial step towards market integration
Needs for implementation	Development of approach for assessing market integration
Timeline of implementation	Current CBA methodology

v. Assessment of the impact on methane emissions

Switching from natural gas to hydrogen at the end use and substituting the production of blue with green hydrogen, will not only reduce carbon emissions but also decrease the methane emitted along the global natural gas supply chain. The impact of projects on carbon emissions is captured using indicator "*B1: Societal benefit due to CO2 emissions variation*", but the impact on methane emissions is not examined with the indicators proposed by ENTSOG.

As methane is a potent greenhouse gas, it could potentially be included in the analysis of benefits an indicator that assesses the **indirect impact of the examined projects on reducing fugitive and vented methane**, by decreasing the need to produce and transport natural gas.

For such an indicator to be complete, however, it should **also take into account the impact to the environment of the hydrogen that is replacing natural gas**. Hydrogen has an indirect impact on greenhouse gas emissions, as leaking hydrogen reacts with hydroxyl radicals, thereby increasing the lifetime of GHGs in the atmosphere [52]. Studies are being carried out to assess the level of impact of hydrogen leaks to the environment, and their extent to which positive benefits from methane emission reduction are netted off [51].

It is proposed that **ENTSOG considers introducing an indicator to assess the impact of hydrogen on methane emissions in subsequent versions of the hydrogen CBA Methodology**, once there is sufficient information and analysis that allows confident quantification of the hydrogen leakage impacts. Such an indicator should examine the net impact of projects, assessing both the upside of switching from natural gas to hydrogen, and the downsides associated with hydrogen emissions.

Recommendation	ETNSOG could introduce an indicator monetizing the impact of the project on methane emissions in later versions of the hydrogen CBA methodology. This indicator should examine the project's impact on both methane and hydrogen emissions.
Impact	Medium – reduction of methane emissions is an additional benefit of hydrogen projects that should examined, together with the impact of hydrogen leaks
Needs for implementation	Development of approach for monetizing the projects' impact on methane emissions
Timeline of implementation	Future revisions of the CBA methodology

6.3.3 Avoidance of correlation between indicators

In principle, **double counting of benefits should be avoided**, in particular for monetized indicators, so as not to overestimate the economic performance of an assessed project. **Correlations between monetized and quantitative indicators should be minimized**, to allow for an independent assessment of the project under the different indicators. In cases where significant correlation is observed, the level of correlation should be highlighted, so that it can be taken into account by the decision makers when performing the project evaluation.

ENTSOG is avoiding double counting of monetized benefits in the hydrogen CBA methodology. The cases that might result in double counting are identified (societal cost of carbon used in indicator B1 should be net of the emission trading scheme price considered to calculate the energy system costs for indicator B2), and measures to ensure that each indicator is independent are described.

On the other hand, the only quantitative indicator used, "*B3: Renewable Energy integration*", appears to be **highly correlated with the monetized indicators**. The use of curtailed RES generation is already captured when measuring the reduction of emissions (indicators B1 and B4), and when assessing the reduction of generation costs (B2). Indicator B3 provides no additional signals as a stand-alone criterion, and this should be clearly stated in the hydrogen CBA Methodology. When projects are being **ranked or quantitatively compared, B3 indicator should not be part of the assessment**, as this would provide a bonus to projects that are also having impact on B1 and B4 indicators.

For any additional quantitative indicators that may be included in the hydrogen CBA methodology in the future, it is proposed that ENTSOG, apart from identifying other indicators with which they are interlinked, also **defines the level of correlation with each other, and if possible, identify ways to decrease the correlation**.

Recommendation	ETNSOG should consider stressing in the hydrogen CBA Methodology that the indicator assessing renewable energy integration (B3) is correlated with monetized indicators, and it should not be aggregated in the overall quantitative evaluation of projects.
Impact	Medium – the indicator is not taken into account in the economic analysis
Needs for implementation	-
Timeline of implementation	Current CBA methodology

6.4 Baseline and assumptions of the analysis

6.4.1 Set-up of reference grid in line with development of hydrogen infrastructure

In the absence of an existing European hydrogen system, ENTSOG proposes the use of a reference grid that is based on the latest list of hydrogen infrastructure projects of common interest (starting from the sixth PCI list), while any non-PCI hydrogen infrastructure projects submitted to TYNDP will be considered as part of an alternative grid the "*hydrogen extended network*". The modelling itself is performed considering one node per country, i.e., considering only capacities to/from the countries and assuming that there are no internal constraints to transport hydrogen to consumption centres within the country.

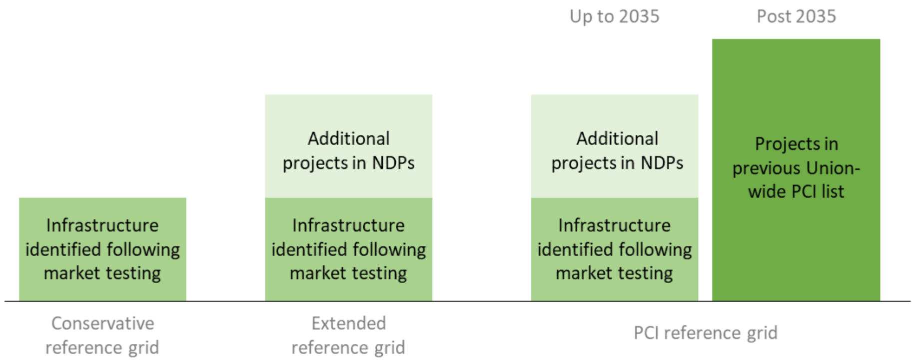
Considering that the evolution of hydrogen markets is now starting from fragmented and localized production and consumption, and that initial infrastructure will be mainly point-to-point or regional linking hydrogen clusters[71], **the approach proposed by ENTSOG is not capturing adequately the characteristics of the hydrogen sector development**. The use of country-level granularity is **omitting the reality of dispersed and localised hydrogen demand** within countries, while the consideration of only PCIs in the reference grid (which by default have cross-border impact) **may not be factoring in the internal constraints** of the hydrogen systems during the early phases of development of hydrogen networks.

It is proposed that an **alternative approach** is applied to set up the reference grid, **which incorporates the ongoing planning of hydrogen transmission systems** by natural gas and hydrogen operators across Europe. This approach should strike a **balance between a conservative and optimistic view of future grid evolution**. To mitigate uncertainties related to network development, three alternative reference grids may be set, ranging from a conservative infrastructure evolution outlook to the availability of unconstrained internal networks to support the pan-European hydrogen system development envisioned in the TEN-E Regulation:

- A **conservative reference grid** can consider infrastructure projects that have been identified following **market testing**.
- An **extended reference grid** can include additional projects **planned in national plans**, without including projects still at concept stage.
- A **PCI reference grid**, assuming developed national transmission networks (i.e., lifting any in-country constraints) **post 2035**, which includes all projects included in the previous Union-wide PCI list.

[71] Such a progressive hydrogen network development is envisioned in the Commission's hydrogen strategy for a climate-neutral Europe

Figure 17: Potential alternative scenarios of reference grids



For this approach to be effective, ENTSOG should also consider **increasing the granularity of its network and market model**, so that each hydrogen cluster (local or regional hydrogen demand centres within a country) can be represented with a node in the model. This will allow for a better representation of the actual (at least) short-term and mid-term development of hydrogen infrastructure and will facilitate a more realistic assessment of projects of the expected development of hydrogen networks.

The proposed changes will **require interactions of ENTSOG with the natural gas and hydrogen operators**, to identify the infrastructures to be included in the reference grid and the timing that these are expected to materialize. The model will also have to be upgraded to support the disaggregation of demand nodes.

It has to be noted that the hydrogen reference grid used will affect the natural gas reference grid. Specifically, the **repurposing of natural gas infrastructure should be reflected in the gas grid**, by removing / adjusting the corresponding assets. Fur purposes of clarity and transparency, it is proposed that this is highlighted in the hydrogen CBA methodology, when describing the modelling approach and reference grids for both hydrogen and methane.

Recommendation	ETNSOG should consider revising the reference grids considered, to take into consideration the current planning of hydrogen infrastructure. Additionally, to better reflect hydrogen market evolution, it is proposed that the granularity of the hydrogen model is increased to represent hydrogen supply and demand in hydrogen clusters instead of countries.
Impact	High – the reference grid is a vital part of assessing the incremental impact of the projects
Needs for implementation	Coordination with gas and hydrogen operators to identify ongoing planning of infrastructure Upgrade of the hydrogen model to increase granularity of supply and demand nodes
Timeline of implementation	Current CBA methodology

6.4.2 Targeted sensitivity analysis on uncertainty parameters

ENTSOG proposes to carry out sensitivity analysis in a number of parameters (excluding the factors that are already captured by the different supply and demand scenarios):

- Project-specific data: commissioning year, CAPEX and OPEX, avoided decommissioning cost of natural gas infrastructure for repurposing hydrogen infrastructure.
- Monetary parameters: social discount rate, residual value.

Sensitivity analysis should be carried out only on selected parameters and assumptions which are uncertain and may deviate from anticipated values and can have a significant impact on a project's economic performance indicators. Monetary parameters, such as the social discount rate and residual value are structural elements of the CBA methodology, and therefore performing sensitivities on them may be seen as a change in the evaluation framework under which the projects are assessed. Additionally, sensitivity analysis on avoided decommissioning costs of gas infrastructure would only affect a subset of projects, that concern repurposing, while analysis of new-built hydrogen infrastructure will remain unchanged.

It is **proposed that the number of parameters on which sensitivities are carried out is limited**, as they will have to be analysed by the decision makers for all examined supply and demand scenarios. Sensitivity analysis could focus on p**arameters, that carry uncertainty and are of high impact to the evaluation of the projects**, such as:

- **Shadow carbon prices:** To assess CO2 emissions, ENTSOG proposes to use shadow carbon prices provided by the EIB, in line with the approach followed for the appraisal of other European infrastructure projects (Commission Notice 2021/C 373/01) [59]. EIB is forecasting a steep increase of shadow prices from 131 EUR/tCO2e in 2023 to 800 EUR/tCO2e in 2050[72], which can have a decisive impact on the economic performance of a project. Sensitivities should be **carried out for moderate trajectories of shadow prices**, to ensure that high shadow prices are not the only driver for the assessed project being economically viable.
- **CAPEX**: The unit investment **costs for new-built hydrogen infrastructure** reported **in literature vary considerably** (as shown in Section 4.1.1). For **repurposing projects** costs are very different as the investment needs **depend heavily on the gas infrastructure** that will be repurposed. Given this uncertainty, sensitivity analysis should be applied on the project's CAPEX, to ensure that its benefits can outweigh its costs even if the investment requirements are higher than initially expected by the project promoter.
- **Commissioning year:** Experience from development of natural gas infrastructure projects has indicated that **there usually are delays in the expected commissioning year**. The risks are even higher in case of project clusters, as delays in a complementary project can prolong the start of operation of the assessed project. To assess the impact of these risks on the benefits of the project, sensitivity analysis on its commissioning date should be carried out.

[72] EIB's forecasts factor in the uncertainties related to costs of technological advancements in the future which can affect the attainment of the target of 1.5°C reduction by 2050.

Cost of disrupted hydrogen is another parameter on which sensitivity analysis could be conducted, **once its value has been defined**, given the uncertainty of the actual impact of hydrogen demand curtailment (with factors such as availability of other energy sourcing, actual economic impact on consumers, etc. affecting the cost of disrupted hydrogen).

Recommendation	ENTSOG should consider performing sensitivity analysis only on selected parameters which are uncertain and can impact the economic results (such as shadow carbon prices, CAPEX, commissioning and CoDH in the future).
Impact	High – the impact of key uncertainty parameters on the project should be assessed
Needs for implementation	-
Timeline of implementation	Current CBA methodology

6.4.3 Validation of project commissioning

The expected commissioning year of a project is provided as input by its promoter during the TYNDP project collection. The **reasonability of the commissioning year put forward by the project promoter should be examined**, as it can have a significant impact on the appraisal of the project, as well as of all other projects clustered with it.

ENTSO-E, in its CBA Guidelines, is proposing a streamlined approach for assessing a project's commissioning, based on statistical analysis of past projects' development. In the case of hydrogen infrastructure, the absence of sufficient historic data on project implementation does not currently allow the use of a validation mechanism like the one proposed by ENTSO-E with an adequate confidence level.

It is proposed that at the **initial stages of the CBA methodology's application, ENTSOG requires from project promoters to provide a justification of the expected commissioning date**, on the basis of the projects' status of development, and the studies carried out so far.

After hydrogen projects have been completed in the EU, ENTSOG can seek to **establish a validation mechanism** based on past experience, similar to that applied by ENTSO-E.

Recommendation	Project promoters should provide justification for the expected commissioning year. Once sufficient historic data on hydrogen infrastructure development is available, ENTSOG can establish a validation mechanism based on statistical analysis.
Impact	Medium – delays in project commissioning can impact the results
Needs for implementation	Collection of past data on commissioning of hydrogen infrastructure
Timeline of implementation	Current CBA methodology (justification of commissioning by promoters) Future revisions of the CBA methodology (validation mechanism)

6.4.4 Appropriate setting of commissioning year in clusters

The hydrogen CBA methodology foresees that for clustered projects the commissioning of the cluster is set by the year of the first project to be commissioned. Sensitivity analysis is carried out using the year of the last project to be commissioned. This approach does not take into consideration the relations and complementarities of projects within the cluster, i.e., the existence of enabler and enhancer projects, for benefits to materialise.

It is proposed that **for the case of clusters the commissioning year of the whole cluster is based on the complementarities** between the grouped projects:

- If the **cluster includes one or more enabler projects**, the commissioning **year of the last enabler** to be implemented is set as the commissioning for the whole cluster.
- If the **cluster includes enhancer projects**, the commissioning year of the enhanced project (or the last enabler project as per the rule above) is set as the commissioning for the whole cluster.
- For **competing projects, the commissioning year of each is set individually**, and does not affect the other.

Recommendation	ENTSOG should consider setting rules for the commissioning year of clustered projects based on their complementarities. In case enabler projects are included in the cluster, the year of the last enabler to be commissioning should be used.
Impact	High – commissioning year for the cluster affects the results of the grouped projects
Needs for implementation	-
Timeline of implementation	Current CBA methodology

6.4.5 Use of long-term shipper commitments in modelling

Decisions of project promoters to proceed with the development of hydrogen infrastructure is in most cases linked with the results of open seasons that will lead to binding commitments of shippers to utilize the infrastructure[73]. It can be therefore expected that in the future, as the hydrogen market will evolve, at least a subset of the projects included in ENTSOG's TYNDP will have part of their capacity already booked via long-term contracts.

Inclusion of these commitments in ENTSOG's modelling, could provide a better reflection of the actual flows of hydrogen from the production sites to the consumption centres. Nevertheless, this is **meaningful only in future updates of the model**, as currently only a few projects have reached the stage of open seasons.

[73] As indicated in Section 3.2.4.

Recommendation	ENTSOG could consider including in its model constraints related to long-term commitments or hydrogen suppliers and consumers to use the assessed infrastructure. This is meaningful in the future, once such commitments are actually in place.
Impact	Medium – Modelling commitments of shippers can impact the economic performance of the project
Needs for implementation	-
Timeline of implementation	Future revisions of the CBA methodology

6.5 Clarity of implementation of the CBA methodology and its results

6.5.1 Clarity on the application of the methodology

ENTSOG's hydrogen CBA methodology provides a description of each indicator used for the assessment of project benefits, including the steps used to calculate it, the quantification / monetization methodology applied, some considerations (e.g., avoidance of double counting, types of projects that can be assessed), and in some cases the monetization formula. Additionally, the formulas used to calculate the economic performance indicators are described.

In the description of the indicators, ENTSOG determines which model is used (dispatch simulations, dual assessment model hydrogen-natural gas), without however describing how the modelling outputs are actually used to calculate the indicator. To provide more clarity on the application of the indicators, **it is proposed that ENTSOG specifies which outputs of the model are used in the calculations** and modify the indicator formulas to explicitly use these outputs.

Additionally, to strengthen the understanding on how the hydrogen CBA methodology is applied, and to facilitate its replicability by third parties, it is **proposed that ENTSOG includes in the methodology**:

- A **numerical example calculating each benefit** for each type of fictional hydrogen infrastructure projects (transmission pipelines, storage facilities and liquid hydrogen terminals).
- A **complete case study** presenting the application of the methodology (inputs provided by the promoter, assessment of costs, estimation of benefits, calculation of economic performance indicators, sensitivity analysis) for a fictional hydrogen infrastructure project, similar to the presentation of case studies in EC DG-Regio to Cost-Benefit Analysis of Investment Projects [63].

In all numerical examples and in the case study ENTSOG should use, to the extent possible, assumptions from actual data sources (e.g., GHG and non-GHG emissions, shadow cost of carbon, etc.).

Recommendation	ENTSOG should consider revising the descriptions of the benefits' indicators, to provide more clarity on how modelling outputs are used, and the indicators are practically calculated. It is also proposed to introduce in the document examples and of the benefit indicators' calculation, and a case study for the full application of the CBA methodology in each main type of hydrogen infrastructure project.
Impact	High – Provides clarity to parties interested in understanding and applying the methodology
Needs for implementation	Formulate fictional hydrogen infrastructure project(s) and perform model runs to assess them
Timeline of implementation	Current CBA methodology

6.5.2 Application span of the CBA methodology

ENTSOG's CBA methodology appears to focus its application on candidate PCIs and PMIs. This continues ENTSOG's application of the gas CBA methodologies exclusively for PCI candidate projects and not for all TYNDP projects.

Considering that candidate PCIs and PMIs will constitute only a subset of ENTSOG's TYNDP infrastructure projects, it is proposed that **ENTSOG applies the hydrogen CBA methodology and publishes project fiches with the CBA results for all projects included in the TYNDP and for all assessed scenarios**[74]. Expanding the span of the CBA methodology's application will provide a better understanding of how the projects constituting the TYNDP address the identified infrastructure gaps and will allow direct comparison of the expected impact of all infrastructure projects under common scenarios and framework of analysis. This is consistent with the approach followed by ENTSO-E that is performing the CBA for all projects in its TYNDP.

The scope of the methodology, and particularly its application for the assessment of infrastructure projects within the frame of ENTSOG's TYNDP, should be explicitly described in the hydrogen CBA methodology document.

Recommendation	ENTSOG should seek to apply the hydrogen CBA methodology and publish the results for all projects in the TYNDP and all examined scenarios.
Impact	High – Provides assessment for all projects in the TYNDP
Needs for implementation	Model runs and CBA need to be performed for all projects included in the TYNDP
Timeline of implementation	Development of next Union-wide TYNDP

6.5.3 Transparency of project information and analysis assumptions

The analysis performed using the CBA methodology, and the underlying assumptions, should be transparent. The **project fiches** published for the infrastructure projects included in the TYNDP should

[74] ENTSO-E is already applying its CBA methodology for all projects in the TYNDP, but only for a selected subset of scenarios.

include the results of the CBA, as well as **information and project-specific assumptions** that affect the economic analysis. The project fiches could be complemented with spreadsheet files providing transparency on the calculations, formulas and values of assumptions and indicators and for different scenarios and study years. It is proposed that the published information in the project fiche includes at least:

- **Results** of the analysis:
  - The calculated economic performance indicators per scenario
  - Results of each benefit indicator (at least for EU-wide aggregated results of the indicators)
- Information on the project's **maturity**:
  - Current stage of the project's development
  - Market consultations and open season processes carried out for the project and their outcomes
  - Expected commissioning date and its justification
  - Inclusion in previous TYNDP and in previous/current National Development Plans
  - Inclusion in previous/current PCI lists
- **Complementarities** with other projects:
  - Project clustering with enables and enhancers
  - Rationale for clustering the specific projects
  - Maturity information for enablers and enhancers
  - Competing projects
- Project-specific **inputs and assumptions** used in the assessment:
  - Project CAPEX and OPEX, including cost range and relevant justification
  - Commissioning year (for project clusters) considered for the assessment
  - Assumed start of benefits (for the calculation of the Economic Performance Indicators)

The above information to be presented could be included in the outline contents of the project fiches, presented in the hydrogen CBA methodology document, proposed in Section 6.2.4.

Recommendation	It is proposed that the published project fiches provide complete information for the assessed projects, including all CBA results and project-specific assumptions.
Impact	Medium – Transparency of the projects' assessment is enhanced
Needs for implementation	-
Timeline of implementation	Development of next Union-wide TYNDP

6.5.4 Transparency of the model features

ENTSOG is providing in its CBA methodology an overview of the modelling assumptions and how interlinkages of hydrogen with electricity and natural gas networks are modelled.

To facilitate replicability of the CBA results, **it is proposed that details on the model applied are published**. Such information should not be part of the CBA methodology document, but should constitute a separate document exclusively focusing on the model, that can be revised each time the model's features change (e.g., if simulation of cross-sectoral interlinkages is further refined). The document presenting the model should include at least:

- Model characteristics (modelling approach, system and solvers used, granularity, etc.)
- Model structure
- Modelling assumptions
- Data input requirements
- Model outputs
- Modelling of interlinkages between electricity – hydrogen – natural gas sectors (general and mathematic description of the interlinkages)

Considering that the joint modelling requires interlinkages with the electricity model of ENTSO-E, **it is proposed that the document presenting the model is jointly prepared, published and revised by ENTSOG and ENTSO-E**.

Recommendation	The ENTSOs should consider jointly publishing and maintaining a document describing the joint model used for simulating the hydrogen – electricity – natural gas sectors.
Impact	Medium – Transparency of the model used for the CBA, facilitating its replicability
Needs for implementation	Coordination with ENTSO-E
Timeline of implementation	Development of next Union-wide TYNDP

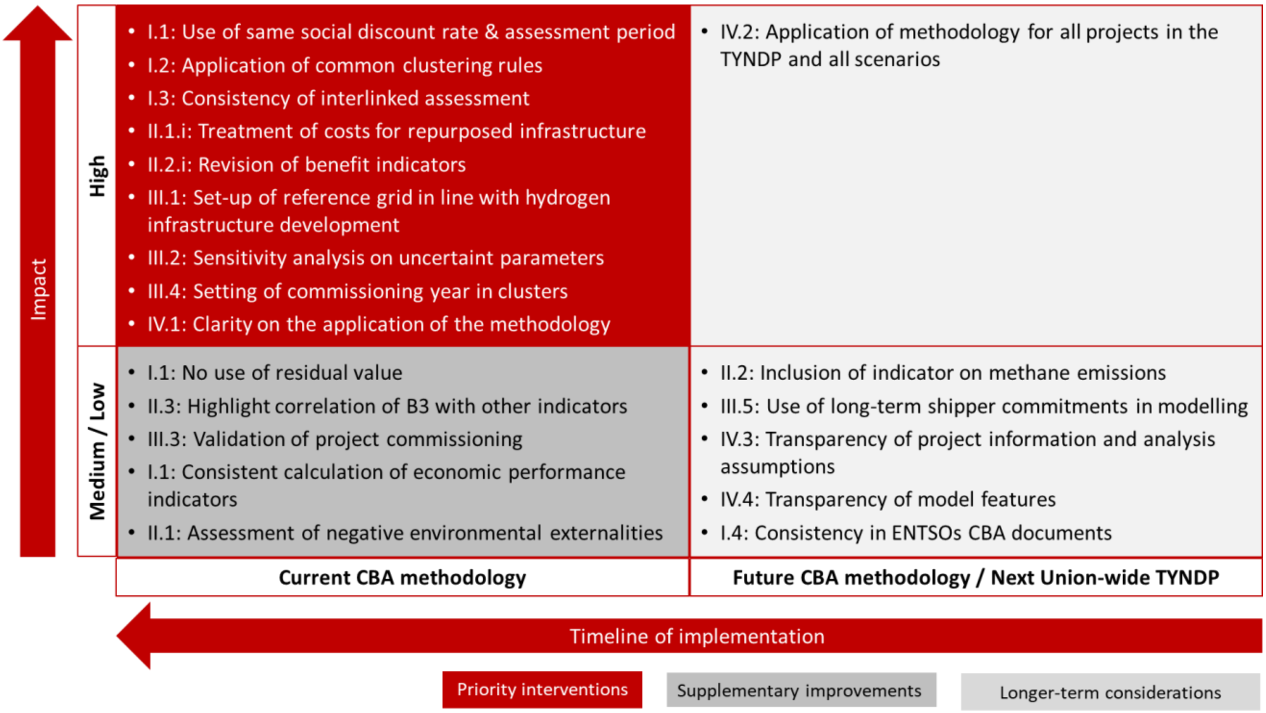
6.6 Priorities for enhancing the CBA methodology

The recommendations analysed in Sections 6.2 - 6.5 have been assessed with regards to their impact on the application of the hydrogen CBA Methodology to assess infrastructure projects (high, medium, low impact), and their timeline of implementation (in the current CBA Methodology, its future revisions, or the Union-wide TYNDP). On the basis of this assessment, the identified recommendations can be classified into different levels of priority (Figure 18):

- **Priority interventions**: Recommendations with high impact, that should be implemented in the current version of the CBA methodology.

- **Supplementary improvements**: Recommendations with medium or low impact, that could be addressed in the current version of the CBA methodology, in addition to the priority interventions.
- **Longer-term considerations**: Recommendations to be considered for future revisions of the CBA methodology or when developing the TYNDP, as subsequent steps for introducing new elements in the methodology.

Figure 18: Prioritization of identified recommendations



The proposed priority interventions, identified in the Figure above, include:

- Application of common key CBA **methodological elements**:
  - Coordination with ENTSO-E to use a **common social discount rate**, allowing comparability of energy infrastructure proposed within the frame of the recast TEN-E Regulation.
  - Use of a **25-year assessment period**, consistent with the current ENTSO-E approach, to allow the assessment to be carried out for a reasonably forecastable time frame.
- **Enhancement of the clustering rules**, to the extent possible consistent with those applied by ENTSO-E:
  - Revision of the grouping rule, to allow clustering of projects with commissioning **up to 5 years apart.**
  - Inclusion of stricter clustering rules after maturity of hydrogen projects improves, to **reduce uncertainties related to implementation of enabler projects**.
  - Inclusion, in both ENTSOG and ENTSO-E methodologies, of a **high-level clustering process** in the CBAM, defining the steps followed for project clustering, and the stakeholder roles.

- **Consistent interlinked assessment** of hydrogen – electricity – gas infrastructure. The assumptions and inputs used for the modelling exercise should be consistent, including the rules for setting the electricity and natural gas reference grids. Additionally, inclusion of the **principles for assessing hybrid projects** in the methodology, to provide clarity on how such cross-sectoral projects can be examined.
- Expansion of the description of project costs to be provided by promoters, to include the **cost items for the repurposing** of natural gas assets, covering both direct (new CAPEX and OPEX) and indirect (interventions on the remaining gas system) costs of repurposing.
- **Enhancement of benefit indicators**:
  - Revision of the indicators used to monetize sustainability (B1, B4), to capture the impact of projects in **reduction of emissions due to switching** from alternative fuels to hydrogen in **hard-to-abate sectors**.
  - Revision of the indicator used to monetize socioeconomic welfare (B2), to include the projects' impact on the welfare due to the **reduction of energy system costs in hard-to-abate sectors**. Until a revised approach is developed, the methodology should clarify the limitations of the proposed indicator.
  - Revision of the indicator used to monetize security of supply (B5), to assess **disruptions on a hydrogen cluster** and not on country-wide level. Until the joint model can support this assessment, the analysis could be carried out by project promoters, according to guidelines provided by ENTSOG.
  - Expansion of the indicator used to monetize security of supply (B5), to include the **potential impact of repurposing natural gas infrastructure** on the continuity and supply of natural gas consumers.
  - Inclusion of an indicator (quantitative or qualitative) to assess the projects' **impact on market integration**.
- Revision of the rules setting up the **reference grid**, to **balance between a conservative** (e.g., implementation only of infrastructure confirmed through market testing) **and an optimistic** (e.g., implementation of PCI projects) **view of future grid evolution**. Additionally, to better reflect the gradual network evolution, **increase of the hydrogen model granularity** to represent hydrogen clusters instead of countries.
- **Sensitivity analysis** only on **selected parameters which are uncertain** and can impact the results, such as shadow carbon prices, CAPEX, commissioning of projects, cost of disrupted hydrogen.
- Setting the **commissioning year** of a cluster with enabler projects according to the **year of the last enabler** to be commissioned (with or without enhancers in the cluster).
- Revision of the **descriptions provided for the benefits' indicators**, to clarify the use of modelling outputs and calculation of indicators. Inclusion of **examples** of the benefit indicators' calculation, and a case study for the full application of the CBA methodology.

These priorities enhance the effectiveness and applicability of the CBA methodology in assessing hydrogen infrastructure projects. It is therefore proposed to be considered by ENTSOG as potential revisions, when preparing the current draft CBA Methodology.

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Annex I – Selected countries' hydrogen sector planning

Belgium

The first version of the Belgian Vision and Strategy-Hydrogen (hereafter Hydrogen Strategy) was published in October 2021. An updated version[75] was released in October 2022 which enriched the country's hydrogen-related targets, documented the status of the several actions that have been put in place in the first version and announced new ones. The Hydrogen Strategy reveals the country's ambition to become an import and transit hub for green hydrogen in Europe.

Apart from the Hydrogen Strategy, publications from the so-called "*Hydrogen Import Coalition*" and the Belgian gas TSO, Fluxys, were reviewed, which complement and reinforce the Federal Government's plans for building out the country's hydrogen infrastructure.

Targets set for hydrogen demand

The **hydrogen demand targets** set by the Belgian Hydrogen Strategy are based on the Federal Government's position that electrification is the most effective way to use renewable electricity and should, thus, remain the priority where technically feasible and economically realistic. However, the Hydrogen Strategy states that the domestic renewable energy production potential is not enough to cover the country's demand. As a result, hydrogen and its derivatives (including ammonia[76], e-methane, e-methanol or e-kerosine) will also be employed to achieve the country's decarbonization targets and meet its energy needs. Another driver for the expected hydrogen demand is the volumes of green hydrogen that Belgium expects to import from shipping routes and export to neighbouring countries.

According to the Hydrogen Strategy, the **total domestic demand** in Belgium by **2050** for both hydrogen and its derivatives is expected to amount to **125 – 200 TWh/year (bunkering fuels included)**. However, the country's aspiration to become a **transit country** for hydrogen transmission, could **double the volumes of green hydrogen (and hydrogen derivatives) forecasted imports, totalling to an amount of 20 TWh in 2030 and 200 – 350 TWh in 2050**, about half of which will be available for transit to neighbouring countries and the other half for domestic consumption.

Regarding the **end-uses** that could be fuelled by hydrogen by 2050, the Hydrogen Strategy identifies **four sectors (industry, heavy transport, power sector and buildings)**:

- **Industry** and the **heavy transport** will drive the initial increase in demand for hydrogen and its derivatives.
    - Regarding the industry sector, hydrogen is a feedstock in various chemical processes such as the production of methanol, aromatics, ammonia or alkenes. Hydrogen may be also used for high-temperatures processes for instance for the production of steel, cement, aluminium, ceramics and glass.

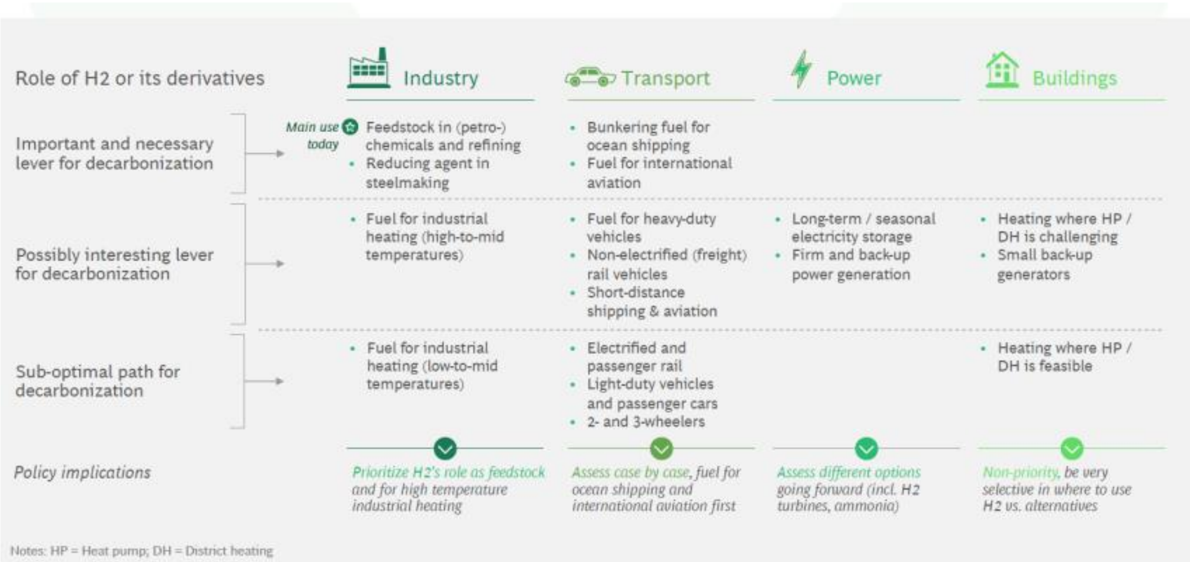
[75] Federal Belgian Government, October 2022, Vision and Strategy-Hydrogen
[76] In this report reference is made only to ammonia produced by using green hydrogen as feedstock (also referred to as e-ammonia).

  - Regarding the transportation sector, the Federal Government promotes electrification as the primary means for decarbonization. However, the use of hydrogen and its derivatives will be considered in the cases that the energy losses and higher costs associated with hydrogen technologies are outweighed by their advantages in terms of charging time, autonomy or weight and volume for energy storage in a vehicle. For aviation, fuels, such as e-kerosene produced based on renewable hydrogen show great promises. Inland navigation is expected to use both electricity and fuels, such as ammonia or methanol produced based on renewable hydrogen. The use of hydrogen for trains (particularly freight transport), is foreseen to be limited. For the road transport of goods both battery-electric and hydrogen can complement each other in order to meet the sector's needs. According to the Hydrogen Strategy, the market will find the optimum balance between these two technologies. Lastly, for cars currently fuelled with gasoline or diesel, the use of hydrogen is not a priority for the Federal Government, because battery-electric vehicles are considered to be more cost-efficient than hydrogen-fuelled ones.

- The **power sector** will follow, where hydrogen will be used to increase the sector's flexibility by storing renewable electricity in the form of hydrogen and using it to cope with time periods characterized by low wind and solar production. Nevertheless, the use of hydrogen to store excess capacity is viewed as supplementary to the use of batteries and the market is expected to determine the optimum between the two storage options.
- The **building sector** could partially rely on hydrogen and its derivatives on the longer run. However, the Hydrogen Strategy states that this sector is not seen as a priority application, due to the fact that heating and cooling needs can be met with electric heat pumps which exhibit very high efficiencies and can use renewable electricity directly.

Figure 19 summarizes the potential role of hydrogen per end-user sectors, as described in the Belgian Hydrogen Strategy.

Figure 19: Role of hydrogen and its derivatives[75]



Hydrogen supply options considered

According to the Hydrogen Strategy, the **supply options for hydrogen and its derivatives** are identified by the Federal Government based on the country's ambition to serve as an import and transit hub for renewable molecules in Western Europe, in a similar way as Belgium today transits natural gas from Norway, the UK and via LNG ships to its neighbouring countries. The Federal Government estimates that the transit of hydrogen and its derivatives through Belgium to other EU Member States could double the forecasted volumes of imports, totalling to an amount of **20 TWh in 2030 and 200 – 350 TWh in 2050, with half of these volumes intended for transit to other countries**.

Regarding domestic production of hydrogen, the Hydrogen Strategy outlines that the **electrolysis capacity is limited** in Belgium because of the **limited local RES potential**. As already mentioned, the country prefers to use the available RES capacity to decarbonize the electricity supply and to further electrify other energy needs, for instance for road transport and building heating. However, the Federal Government considers the deployment of a **minimum domestic electrolysis capacity of strategic importance**, in order to gain the relevant technological expertise and thus support the Belgian companies active in the field. To this end, the country has set a target within the National Recovery and Resilience plan to **reach at least 150 MW of electrolysis capacity into operation by 2026**. Local production is expected to materialize at the ports of Zeebrugge and Antwerp (Zeebrugge is located close to wind plants and natural gas infrastructure, while Antwerp is near Europe's largest chemical cluster[77]).

As regards the type of hydrogen to be used in Belgium, **only green hydrogen (from RES electricity and maybe from processing biomethane in the future) is envisioned to be included in the final energy mix by 2050**. Nevertheless, a transitional phase is also foreseen, during which blue hydrogen, produced by ATR and SMR installations coupled with carbon capture and storage[78] or via pyrolysis, will be used in order to kickstart the market. However, no specific future production and consumption volumes are mentioned for blue hydrogen. The Strategy states that blue hydrogen producers should limit their exposure to the natural gas price and manage their risk of stranded asset if renewables become competitive faster than expected.

Focusing on the supply of hydrogen and its derivatives via imports, the Federal Government has identified **three potential routes**:

North Sea route (pipeline):

The North Sea is one of the **major offshore wind resources located close to Belgium**, which, according to the Federal Government, could deliver hydrogen production via pipelines from 2030 onwards,

[77] Website of the Port of Antwerp Bruges, [Revision of Belgium's federal hydrogen strategy proposed at Port of Antwerp-Bruges]

[78] For example, in 2021, energy groups ENGIE and Equinor [announce the 1 GW H2BE project] which aims to producing hydrogen from natural gas using ATR technology combined with CCS. The captured CO_2 is planned to be transported in liquid form and to be permanently and safely stored at a site in the sub-surface of the Norwegian North Sea. In 2022, [more than 20 potential hydrogen offtakers expressed interest in H2BE], which has also received letters of support from investment funds and authorities in Belgium. In early 2023, the feasibility study of the project was completed.

without conversion costs for producing derivatives and for turning them back into hydrogen. The collaboration with neighbouring countries is a prerequisite for the exploitation of this potential supply route. Initiatives have already been taken towards this goal:

- In the Esbjerg Offshore Wind Declaration[79] that took place in May 2022, Belgium, Denmark, Germany and the Netherlands committed themselves to develop 65 GW of offshore wind, 20 GW of renewable hydrogen in the North Sea by 2030 and 150 GW of offshore wind by 2050.
- In September 2022, the nine North Seas Energy Cooperation (NSEC)[80] countries announced a target of 260 GW of offshore wind capacity by 2050.
- The Federal Government launched a study to investigate how the development of both electricity and hydrogen networks can complement each other in the North Sea, with specific attention to the connection with the UK and Norway, where Belgium already has its natural gas interconnectors.

Southern route (pipeline):

The Southern route concerns the **import of hydrogen from the south (mainly Iberia and North Africa)**, where there is abundance of RES capacity which may compensate for the longer distance compared to the North Sea route. However, the usefulness of this route for Belgium depends on the development of hydrogen transport networks in the Iberia peninsula and through France. Therefore, the Federal Government considers this route as a long-term solution, while in the short to mid-term --until the necessary hydrogen network is in place- shipping routes can be used for these regions.

Shipping route:

This route concerns the shipping of hydrogen derivatives from locations in the **Middle East, Africa, or the America's**, using highly mature and proven technologies. These derivatives can either be directly used as-is or be converted back to hydrogen (and injected in the hydrogen transport network if needed). The Belgian Hydrogen Strategy considers this route to be become the most competitive and thus the preferred solution for supplying hydrogen derivatives to Belgium. Actions taken to secure this route are MoUs already signed with some key partners (Oman and Namibia), while new ones could be concluded in the future.

In order to build a robust hydrogen import strategy, Fluxys, Deme, Engie, Exmar, Port of Antwerp, Port of Zeebrugge and WaterstofNet joined forces under the so-called "*Hydrogen Import Coalition*" and conducted a feasibility study[81] to explore the global importing opportunities of renewable energy in Belgium by means of hydrogen carriers. The analysis covered all steps of the value chain from renewable energy production, electrolysis and synthesis into a hydrogen carrier molecule, to shipping, terminals and end-use in Belgium. Figure 20 presents a representative **sample of possible sourcing regions** together with the considered seaport facilities and shipping routes identified by the Hydrogen

[79] This Declaration was the outcome of the Offshore Wind Summit that took place in May 2022 at the port of Esbjerg (Denmark). Officials from Belgium, Denmark, Germany and The Netherlands signed a joint declaration that highlighted the role of home-grown North Sea offshore wind in strengthening the EU's energy security.
[80] Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden.
[81] Hydrogen Import Coalition, 2021, Shipping sun and wind to Belgium is key in climate neutral economy

Import Coalition. The outcomes of this study will be employed to put forward concrete plans on specific import projects.

Figure 20: Representative sample of possible sourcing regions identified by the Hydrogen Import Coalition[81]

Measures for promoting hydrogen market development

The **measures** for promoting hydrogen market development in the Belgian Hydrogen Strategy are listed below:

R&D support:

In order to support the Belgium based companies and research institutions active in the hydrogen field, the Federal Government plans to employ the following instruments:

- The Energy Transition Fund
- The call for projects Clean Hydrogen for Clean Industry, organized within the frame of Belgium's National Recovery and Resilience Plan. A first call was launched in April 2022 for a total support of maximum 50 mil. €. A second one will be launched in 2023 for a total support of 10 mil. €.
- The H2 Import Call, to be launched in early 2023, with an envelope of 10 mil. €. This call will focus on the development and demonstration of technologies that enable the import of hydrogen (in any form, hydrogen derivatives included) and its injection in a hydrogen transport network.
- The development of the VKHyLab, a test infrastructure which will be operational by 2025 in order to help research institutes and companies to scale up their hydrogen technologies.
- The first electrolysis capacities in Belgium will be exempted from the excise duty on electricity.

Robust hydrogen market:

In order to support the creation of a robust hydrogen market, the Federal Government plans to investigate, together with the regions[82] and/or the European Commission, measures to unlock

[82] The Flemish Region (Flanders) in the north, the Walloon Region (Wallonia) in the south, and the Brussels-Capital Region

hydrogen demand, such as operational support, guarantees or quotas to create the demand for the right vector (hydrogen and hydrogen derivatives) in the appropriate sector.

Moreover, to connect suppliers/producers with end-users, the Federal Government will engage in the necessary actions to develop the framework for the construction of domestic hydrogen transport network which should operate under non-discriminatory third-party access conditions. To this end, in January 2022, the Federal Minister of Energy described the regulatory principles and choices she intends to make to regulate the transport of hydrogen by pipeline in a consultation paper[83] that she submitted to the sector. The public consultation has since closed, and the responses received will be taken into account in the development of the draft Law for the regulation for the transport of hydrogen by pipeline.

Lastly, Belgium supports the emergence of a European hydrogen market and to this end the Federal Government will make available 300 mil. € in order to interconnect its hydrogen transport network with Germany by 2028. In February 2023, the two countries signed a Joint Declaration on Bilateral Cooperation on the Transition to Sustainable Carbon Neutral Economies[84], in which they called for the cooperation between the competent gas TSOs for the development of a hydrogen transmission interconnection between the two countries and invited them to concretize the plans for the connection between the two hydrogen networks.

Planning for hydrogen transportation and storage

A hydrogen transport network is already present in Belgium, developed by a private company (Air Liquide) to supply various industrial customers spread across Belgium, France and the Netherlands.

The Federal Government is looking into the development of a hydrogen transport network, understood as a **pipeline network dedicated to the transport of high-quality grade hydrogen**. The blending of hydrogen in the natural gas network is not considered as a viable solution as it does not enable for a complete transition to renewable energies (risk of lock-in effect). According to the Hydrogen Strategy, even though pipeline transport is the most efficient and secure solution, it requires significant initial investments. Therefore, **the repurposing of existing natural gas pipelines** can help reduce the initial CAPEX.

The development of the hydrogen network will take place in phases[75,85]:

- By **2026**, develop **100 to 160 km of additional hydrogen pipelines** (new and/or repurposed) to be operated under non-discriminatory third-party access conditions, supported by a budget of 95 mil. € from Belgium's National Recovery and Resilience Plan. Maximum advantage will be taken of existing pipelines, such as natural gas pipelines and pipelines used for the

[83] Federal Minister of Energy, 2022, Public consultation on the envisaged regulatory model for hydrogen transport by pipeline

[84] Federal Government of the Federal Republic of Germany and Federal Government of the Kingdom of Belgium, 2023, Belgian-German Joint Declaration on Bilateral Cooperation on the Transition to Sustainable Carbon Neutral Economies

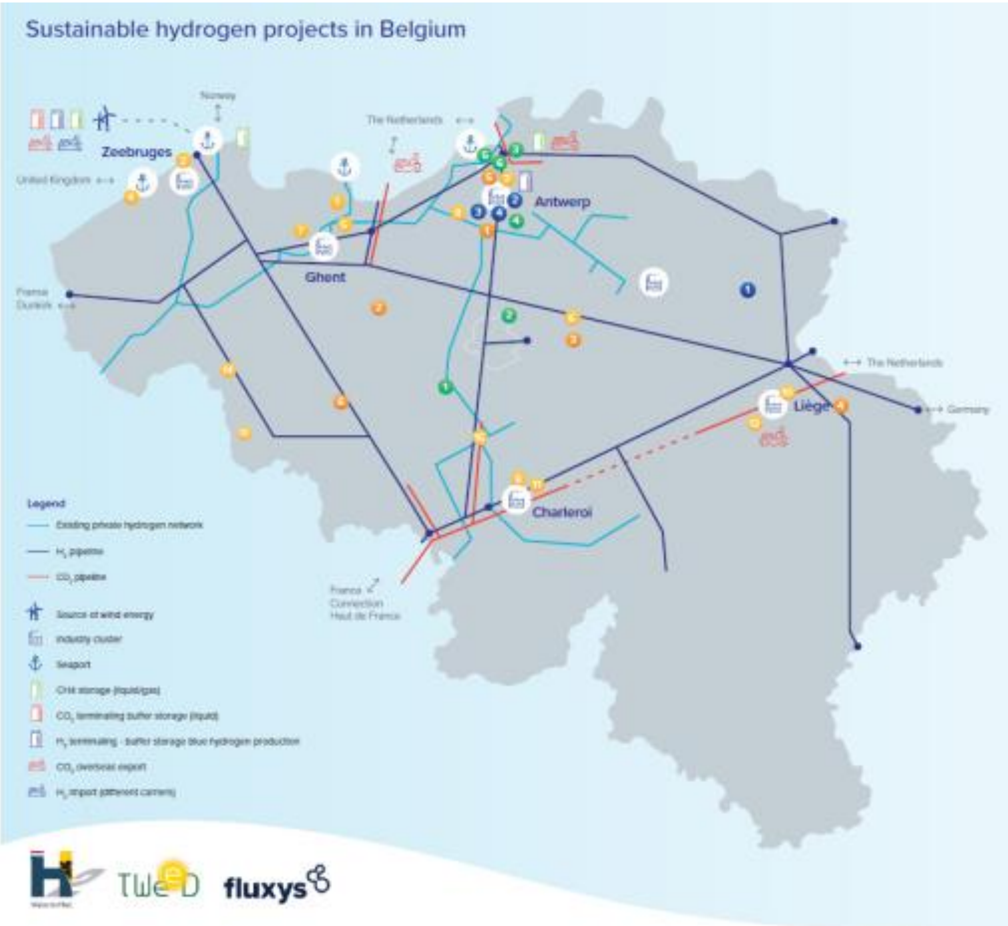
[85] Fluxys Belgium, September 2022, Information Memorandum for H2 infrastructure

transportation of low-calorific gas which will be shut down as a result of the complete conversion of Belgian consumers to high-calorific gas.

- By **2028**, Belgium aspires to **interconnect its hydrogen network with at least Germany, France and the Netherlands**.
- By **2030,** the Federal Government wants an **open access backbone** for hydrogen connecting the ports (Zeebrugge, Ghent, Antwerpen) to the industrial zones and with neighbouring countries.

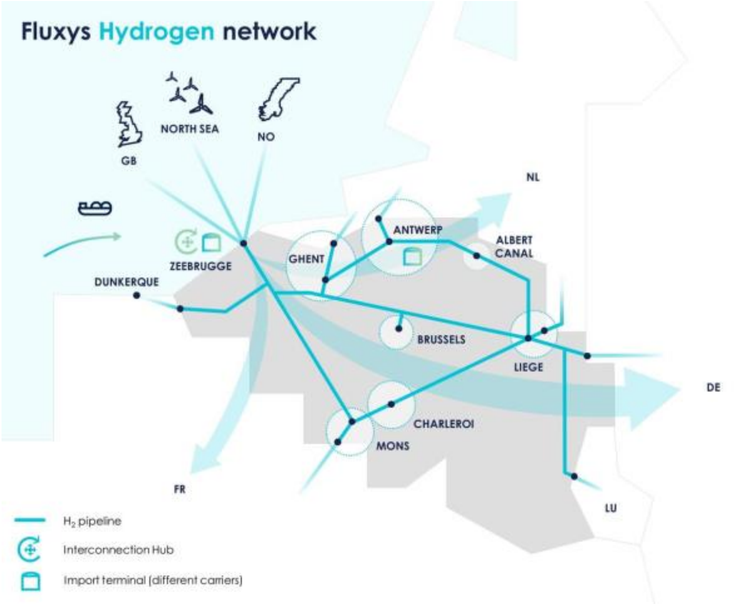
Figure 21 presents the geographical distribution of hydrogen projects in Belgium including current and future infrastructure of hydrogen pipelines, as envisioned in the Belgian Hydrogen Strategy.

Figure 21: Current and future hydrogen infrastructure in Belgium[75]



Following the Federal Government's ambitions, Fluxys, proposed to begin the deployment of the hydrogen infrastructure by **first offering hydrogen transmission services within industrial clusters**. Progressively, **inter-cluster connections** will be added which will be later **complemented with cross-border interconnections** with neighbouring systems (Figure 22)[85].

Figure 22: Fluxys Hydrogen Network[85]



For the realization of the hydrogen network (transportation of hydrogen between the import locations such as Zeebrugge, the different industrial clusters and with neighbouring countries), Fluxys engaged in several activities. In more detail, Fluxys invited interested parties[85]:

- to participate in a **market consultation** (**"*RFI*" – Request for Information)[86],** and
- to express their **interest for specific infrastructure proposals (open season)**

The market consultation consisted of a webinar that took place in January 2021, where potential users of the future hydrogen network were invited to participate at an **informative market consultation and to fill out an RFI**. The information gathered through the RFI provided Fluxys with a clear overview on **how market needs develop geographically and over time**, hence demonstrating interest for hydrogen network infrastructure. The (publicly available) outcomes are summarized below:

- Overall hydrogen **demand in Belgium is already strong**. Aggregated demand over the 2025-2030 period doubles or even triples. Aggregated demand over the 2030-2035 period sees another significant uptake (but participants have limited forward visibility on hydrogen, electricity and CO2 prices).
- Aggregated **supply evolution exhibits a similar stepwise trend**. Across the supply and demand ranges, however, there are scenarios indicating the need for additional supply through increased local production and imports.
- Demand and supply balance shows great variety between industrial clusters.

Also, Fluxys proceeded with a "***matchmaking/matching process"*** and approached participants that participated at the RFI, to facilitate mutual exchanges between offtakers and suppliers in order to match their hydrogen demand and supply needs. This process gave Fluxys the indication to **move forward with an open season phase** (call for subscriptions allowing transparent and non-

[86] On-going process

discriminatory allocation of access capacity to infrastructures) for hydrogen transmission, consisting of **three steps**:

- Non-binding Expression of Interest,
- Bilateral Iterations and
- Binding Commitment

To facilitate the process Fluxys develops **specific infrastructure proposals** -based on market demand and maturity level-within a cluster. With growing market maturity in different regions, several Open Seasons will hence be triggered for separate geographical proposals: industrial clusters, inter cluster connections, border crossings and import locations. The **current status of the Open Season** is depicted in Table 18.

Table 18: Current Status of Fluxy's Open Season[87]

Area*	Status	Closure Date
Antwerp	Closed**	15/07/2022
Ghent	Closed	15/07/2022
Liège	Open	will be published
Mons	Closed	16/09/2022
Charleroi	Open	will be published

** Fluxys is also looking into a specific import infrastructure proposal within the port of Zeebrugge.*
*** Even after the closure date for a Specific Infrastructure Proposal, interested parties may still fill the RFI and Fluxys will keep finetuning their infrastructure mapping.*

Fluxys proposes for the network to be operated under a **commercial model which will be based on the natural gas model**. Consequently, Fluxys will apply the following key principles for the transmission of hydrogen[85]:

- Unbundling of transmission services and marketing of the commodity.
- Non-discriminatory open access to the network to ensure a level playing field for participation in the emerging hydrogen market.
- Cost-effectiveness pursued to maximum extent, based on Fluxys' operational pipeline expertise and with optimal reuse of existing natural gas network for the development of the hydrogen network.

This model may be updated based on future regulation. As a matter of fact, the first Belgian hydrogen law for regulating hydrogen transportation was voted in January 2023. With this law, Belgium wants to ensure that hydrogen can be brought in the country from abroad just as the country is currently receiving LNG in the port of Zeebrugge. The law also introduces the function of the grid operator to manage the hydrogen transportation network. This entity, yet to be appointed, will be a regulated

[87] Website of Fuxys, Hydrogen: Preparing to build the network

company overseen by the Belgian Commission for the Regulation of Electricity and Gas (CREG) and must guarantee free and non-discriminatory access to the hydrogen network and ensure the quality of hydrogen[88,89].

Concerning **storage of hydrogen**, the Hydrogen Strategy briefly examines the different storage options for hydrogen and it derivates, to conclude that **a European approach is needed** to ensure sufficient gaseous storage capacities, as the Belgian subsurface offers limited opportunities for the storage of hydrogen molecules.

Denmark

The Danish Power-to-X Strategy (hereafter the Strategy) was published in late 2021[90]. PtX refers to a number of technologies that are all based on using electricity to produce hydrogen which can subsequently be used directly as a fuel for road transport or for industrial purposes or further converted into other fuels, chemicals and materials.

The Strategy also differentiates among:

- **Non-carbonaceous PtX fuels**, which include pure green hydrogen produced from electrolysis powered by RES which can be used directly as a fuel for road transport or industrial purposes and e-ammonia produced using green hydrogen which can be used as fuel in diesel-like engines on ships.
- **Carbonaceous PtX fuels**, for example e-kerosene (aircraft fuel) which will be composed from green hydrogen and biogenic or sustainable carbon sourced from biogas plants, biomass-fuelled combined heat and power (CHP) plants or via incineration of biological waste or non-biogenic/sustainable carbon. The overall CO2 footprint of such fuels depends on the carbon source.
- **PtX products**, such as fertilisers and plastics that could use green hydrogen as feedstock material (basically, ammonia produced by using green hydrogen).

Apart from the Hydrogen strategy, publications from the EU and the gas TSO were also reviewed.

Targets set for hydrogen demand

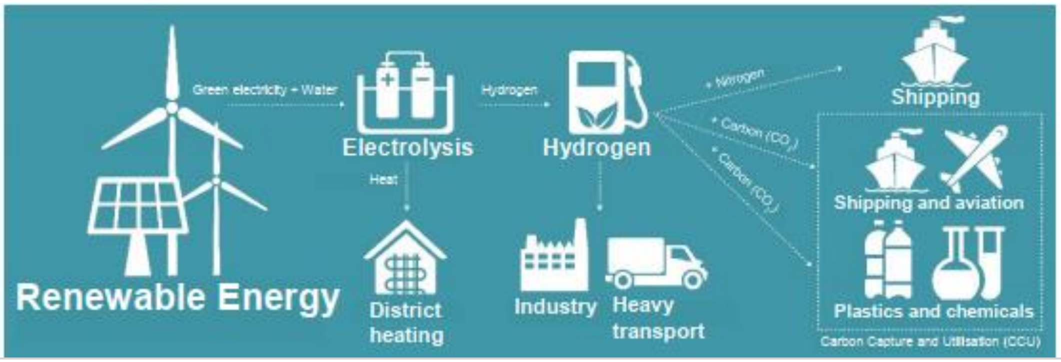
Today, Denmark's consumption of hydrogen is limited to refineries and all hydrogen production is based on fossil fuels such as coal and natural gas. Based on the Strategy, the country's focus is exclusively on producing green hydrogen.

According to Strategy, PtX should primarily be considered for sectors where direct electrification is not feasible and cost-effective, such as parts of the industrial and heavy road transport sectors as well as the shipping and aviation sectors. In more detail, the Danish Government expects that up to **2050**, it is possible for PtX to play a significant role in **aviation**, **most of shipping**, in the **industrial sector's internal heavy road transport** and **high temperature processes**, **parts of heavy road transport**,

[88] WaterstofNet website, 2023, Belgium pioneering with very first Hydrogen Law
[89] BELGA news agency, 2023, Will Belgium become the first country in the world with a hydrogen law?
[90] Danish Ministry of Climate, Energy and Utilities, 2021, The Government's Strategy for Power-to-X

refineries and **a portion of the Danish Defence's emissions**. Another possible application is the use of the surplus heat from the PtX plants in the local district heating grids. It is also noted that in the short-term for all the aforementioned sectors the **PtX fuels will be competing with biofuels**, while it is expected that in the long-term PtX will become more affordable than 2nd generation biofuels. Figure 23 shows how PtX can be used in Denmark.

Figure 23: How PtX can be used in Denmark: Renewable energy can be used to produce fuels and other products used for transport and industry[90]



Below are presented the sectors for which the use of PtX fuels and products are forecasted to eventually become cost-effective (vs electrification) in Denmark:

Sectors with robust potential, which is defined as areas of application where direct electrification is not possible or expected to be more expensive than adopting PtX fuels:

- Power-to-X for shipping (domestic and refuelling in Denmark)
- Power-to-X for aviation (refuelling in Denmark)

Sectors with robust potential of indeterminate extent, where 'indeterminate extent' is defined as the degree of PtX adoption within the area of application being indeterminate/uncertain. This includes segments with significant electrification potential but where the use of PtX fuels will be the most cost-effective and practical solution in parts of the segment:

- Hydrogen for light road transport
- Hydrogen for trucks and buses
- Hydrogen for industry, direct firing
- Hydrogen or e-diesel for industry, internal transport
- E-fuels for the Danish Defence (aircraft, ships, vehicles)
- Hydrogen for biofuel production, etc. at refineries
- Production of chemicals (fertiliser, plastics, etc.)

Sectors with uncertain potential for transitional solutions, where 'transitional' refers to the fact that the use of PtX may be considered before moving on to electrification or the use of biofuels, for example for the transportation sector the heady duty transport is the most PtX compatible sector today. However, for other vehicles that run on gasoline and diesel burnt in internal combustion engines the use of PtX fuels such as methanol, e-gasoline and e-diesel could be seen as transitional solutions before being substituted by electric vehicles. For example:

- By mixing ethanol with gasoline or
- By mixing e-fuels into diesel/gasoline

The Danish **demand targets are set in the form of CO2 avoided** due to the use of PtX fuels and products. However, this depends on the source for carbon that is needed for the composition of certain PtX fuels and products. Potential **reduction for 2030 is set at 0.5 – 1.9 mil. tonnes/year of CO2** and **for 2050**, **1.1 – 3.5 mil. tonnes/year of CO2**.

Hydrogen supply options considered

Regarding the supply routes for PtX fuels and products, the Strategy set the target for Denmark to **build 4 – 6 GW of electrolysis capacity by 2030**. This supply is indented to **cover both domestic needs and support Denmark's aspiration to export PtX fuels** in neighbouring countries.

The already announced projects -from private actors up to 2030- add up to a collective electrolysis capacity of 7 GW.

Denmark's **ability to produce and export large volumes of PtX fuels and products** is based on the following:

- Denmark has considerable **offshore wind resources**, particularly in the North Sea. Previous analyses have determined a capacity of 40 GW of offshore wind energy in the Danish maritime territory.
- Regarding the production of PtX products that require the use of carbon, Denmark has the option to **make use of biogas plants and biomass-fuelled CHP plants to produce biogenic CO2**.
- Denmark has a **well-developed gas infrastructure** and a **strategic geographical position** in terms of exporting PtX products and technologies to countries such as Germany.

Measures for promoting hydrogen market development

Below are listed the **measures** that the Danish government has in place or considers adopting to support the development of a PtX market:

- The Government notified the EU of its intention to invest 170 mil. € through a PtX tender for operational support of the production of hydrogen and other PtX products. In February 2023, the EU approved -under EU State aid rules- the Danish scheme which will support the construction of up to 100 – 200 MW of electrolysis capacity. The aid will take the form of a direct grant for a ten-year period, and it will be awarded through a competitive bidding process to be concluded in 2023. The tender will be open to all companies planning to construct new electrolysers in Denmark[91].

[91] European Commission, 2023, State aid: Commission approves €170 million Danish scheme to support renewable hydrogen production

- The Government will earmark 46.8 mil. € for innovative green technologies, including PtX, via funds from the REACT-EU initiative and the Just Transition Fund.
- The Government will support R&D for PtX solutions through the national “*Green solutions of the future*” strategy for investments in green research (total budget Just under 136 mil. € has been earmarked for the four missions of the strategy)
- The Government has funded the Danish value chain projects for hydrogen (Important Projects of Common European Interest/IPCEI) with 115.6 mil. €.
- The Government has allocated roughly 54.4 mil. € to the development of PtX via the national Energy Technology Development and Demonstration Programme (EUDP) and Danish Energy Agency’s energy storage funding pool
- The Government has allocated 68 mil. € from REACT-EU for green energy activities (including PtX) and another 68 mil. € will be made available towards 2027.
- The Government will grant major electricity consumers, such as PtX plants:
    - The option for Energinet (gas TSO) and the grid companies to use geographically differentiated consumption tariffs. This can provide a financial incentive to choose appropriate locations in the electricity grid for PtX plants and thereby contribute to more efficient use of the electricity grid.
    - The application-based opportunity to establish direct links between electricity producers and consumers, e.g., between a wind farm and PtX plant, when deemed socio-economically appropriate.

Planning for hydrogen transportation and storage

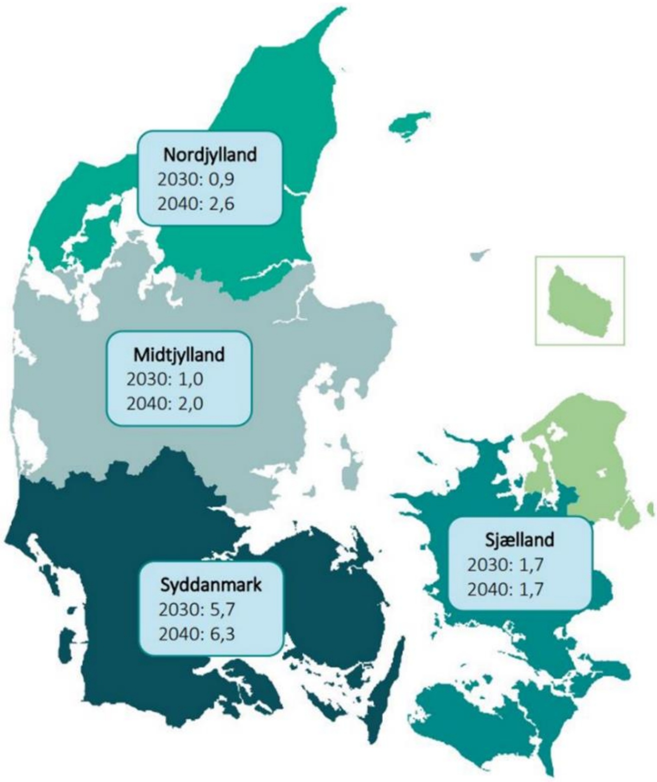
According to the Strategy, hydrogen infrastructure is seen as a prerequisite to Danish exports of hydrogen and other PtX products. In this sense**, the Strategy identifies the region of South Jutland as the one with the largest potential to kick-start the deployment of PtX plants** due to the region’s good infrastructural conditions with large gas pipelines going from west to east - and **towards Germany**. Parts of the existing infrastructure for gas transport in South Jutland may potentially be able to be used as a Danish export pipeline. Other countries to which Denmark could **export PtX fuels** are the **Netherlands, Sweden and Belgium**, as they already have a large consumption of fossil-derived hydrogen in their industrial sectors, which can be replaced by green hydrogen. The Strategy states that in the short term it would be more affordable for Germany, Belgium and the Netherlands to source green hydrogen from Denmark rather than from Morocco, considering both production and transportation costs.

Moreover, the Government aims to give **Energinet and Evida (gas Distribution System Operator/DSO)** the possibility to **own and operate hydrogen infrastructure**. In this context, even before the publication of the Strategy, Energinet and the Danish Energy Agency entered into a **market dialogue** (non-binding expression of interest) with a total of **19 market actors** based in Denmark and abroad who had expressed interest in the future Danish hydrogen infrastructure. The dialogue revealed the following[92]:

- the need for transport was found to be closely correlated with the need for large-scale storage of hydrogen and exports to other countries
- the majority of the actors see the need for hydrogen infrastructure already before 2030
- hydrogen infrastructure will initially be of most interest in Jutland, with a connection to hydrogen storage and exports to Germany

Figure 24 presents the needs -stated in TWh per year and region- indicated by the market players to feed hydrogen into any upcoming hydrogen infrastructure.

Figure 24: Results of the 2021 market dialogue in TWh of hydrogen per year and region to be fed into the future hydrogen grid[92]

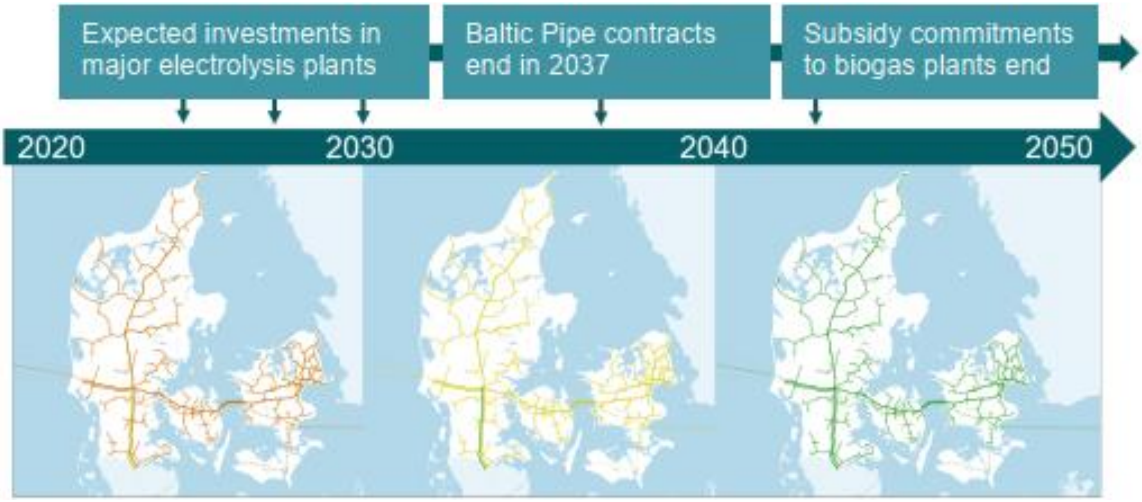


According to the Strategy, following the first market dialogue, Energinet determined that **one of the two gas pipelines currently connecting the Danish and German gas systems** between Egtved and Ellund can be **converted to export pure hydrogen**, thereby contributing to linking Danish PtX producers to a European hydrogen infrastructure. Similarly, parts of the gas distribution system could potentially be reused as gas boilers for home heating are gradually phased out. However, due to political decisions **the majority of the natural gas grid for at least the next 20 years will be used to transport and store biogas**. Also, the Baltic Pipe connection will transport large quantities of gas

[92] Energinet website, 2021, Market dialogue showed broad interest in hydrogen infrastructure

through Denmark to Poland until at least up to 2038. Taking into consideration all the above, the Strategy identified the possibilities for repurposing existing gas infrastructure to hydrogen over time.

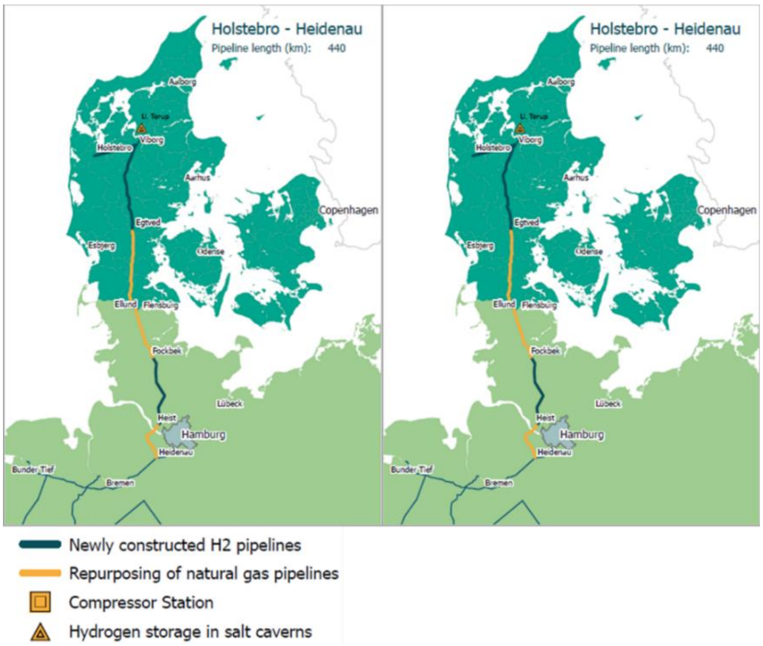
Figure 25: Overview of the Danish gas system and conversion possibilities over time[90]



Red: No possibility for conversion, yellow: Some possibility for conversion, green: Good possibilities for conversion. Note the pipeline in South Jutland which can potentially be converted to hydrogen export in the medium term

As the connection of Denmark with Germany appeared to be a feasible project for the medium-term, in 2021, **Energinet and Gasunie Deutschland (German gas TSO) published a technical pre-feasibility study** for transporting hydrogen via a 350 – 450 km pipeline from Esbjerg or Holstebro in Denmark to Hamburg in Germany, in order to take advantage of the export potential for green hydrogen from Denmark to demand centres in Germany (see Figure 26)[93].

Figure 26: Result of the feasibility study for interconnecting Denmark with Germany[93]

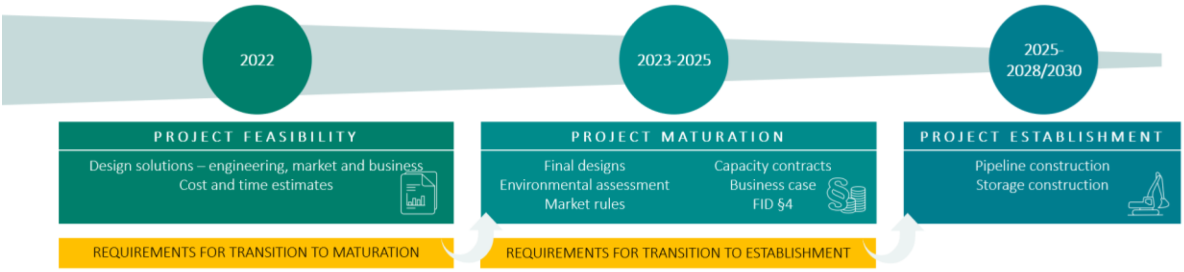


[93] Energinet, 2021, Energinet and Gasunie publish pre-feasibility study on hydrogen infrastructure

In 2022, the Danish Energy Agency, Evida and Energinet launched another **market dialogue** addressed to collect information from promoters with projects (i) producing hydrogen, (ii) expect to use hydrogen, (iii) both will be a producer and a consumer of hydrogen, in order to understand their needs for hydrogen infrastructure[94].

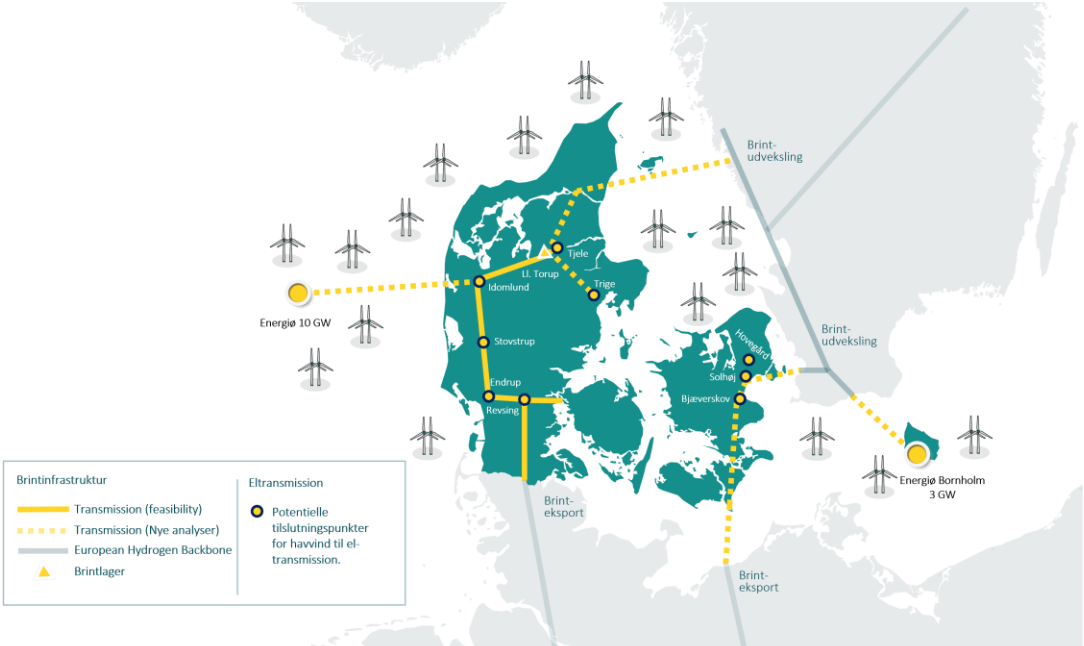
Also in 2022, Energinet already begun work on a **feasibility study** for hydrogen infrastructure in **Jutland with connection to the future German hydrogen grid** and a hydrogen storage facility in Ll. Torup in North Jutland[95]. The preliminary timeline for the delivery of the infrastructure is depicted in Figure 27.

Figure 27: Preliminary timeline for establishing hydrogen infrastructure[95]



The same feasibility study will also investigate a **proposal of a Danish hydrogen backbone**. One proposal for a routing is presented in Figure 28, while other alternatives will be also analysed in the study.

Figure 28: Proposal for the Danish hydrogen backbone[95]



[94] Evida website, 2022, Invitation to market dialogue about hydrogen infrastructure
[95] Energinet, 2022, FEASIBILITY STUDY OF HYDROGEN TRANSMISSION INFRASTRUCTURE

France

In 2018, the French Government published its Multi-Annual Energy Plan (known by its French acronym PPE) for 2019 – 2023 & 2024 – 2028[96], which included targets for hydrogen use. In 2020, the National Hydrogen Strategy (hereafter the Strategy)[97] was published, which was drafted after a broad consultation with relevant stakeholders. The consultation was in the form of a nationwide call for expressions of interest which took place in 2020 and 160 projects were submitted by companies, local authorities and R&D centres representing a total investment of 32.5 bil. €.

Apart from the aforementioned documents, the French legislation (i.e., the Energy Code) was consulted especially with regards to the public support for hydrogen technologies and publications from gas transmission and storage operators were also reviewed as they are involved in the development of the hydrogen infrastructure in France.

It should be noted that as part of "*France 2030*"[98], the Government launched a Hydrogen acceleration strategy: "*Accelerating the deployment of hydrogen, the keystone of the decarbonization of industry*"[99]. This will evolve into a new national hydrogen strategy, with the aim to deploy hydrogen hubs on all the major industrial platforms in a logic of pooling the production for industrial uses in mass production centres. The strategy should be developed by June 2023 and allow rapid implementation so as to ensure the deployment of abundant and competitive hydrogen on all major industrial basins in the country after 2030. It should provide a response to the technological, economic and regulatory issues raised by the development of these hydrogen hubs. It will also study the competitiveness of hydrogen production on the basis of electricity from the national grid, whether through the use of long-term contracts for the electricity supply of the electrolysers or by price support to help deploy production capacities. An envelope of more than 4 bil. € is provided for this purpose, in addition to Important Projects of European Common Interest (IPCEIs) funding.

Targets set for hydrogen demand

The overarching **target** set by the French Government with regards to hydrogen demand is for the **20 to 40% of the total hydrogen consumption, as well as for the 20 to 40% of the industrial hydrogen consumption** to be covered by low-carbon and renewable hydrogen by 2030. This statement is made in the Strategy, but it also enacted by Law (Energy Code-Article L100-4)[100].

Based on the PPE and the Strategy, the following targets are set per sector:

Industry:

Focusing on the industrial usage, the Strategy, identifies opportunities for the use of hydrogen in the refining industry, the chemicals industry (in particular for the production of ammonia and methanol)

[96] Ministry of Ecological Transition, 2018, Multi-Annual Energy Plan 2019- 2023 2024-2028
[97] French Government, 2020, Stratégie nationale pour le développement de l'hydrogène décarboné en France
[98] Investment plan -announced by the Prime Minister of France in 2021-aiming to sustainably transform the key sectors of the French economy (energy, automotive, aeronautics or space) through research, innovation and industrial investment.
[99] Ministre de l'Économie, des Finances et de la Souveraineté industrielle et numérique, 2023, Dossier de presse : Accélérer le déploiement de l'hydrogène, clé de voûte de la décarbonation de l'industrie
[100] Code de l'énergie, Article L100-4

and in certain sectors such as electronics or food processing, which use hydrogen in smaller quantities. According to the PPE, the target for industrial usage is to reach a rate of 10% carbon-free hydrogen by 31 December 2023 and then between 20 – 40% by 31 December 2028[101].

Transportation:

Regarding the transportation sector, the Strategy highlights that hydrogen is suited to heavy-duty vehicles, particularly for captive fleets travelling long distances with tight deadlines, such as light commercial vehicles, heavy goods vehicles, buses, Refuse Collection Vehicles and regional or interregional trains in non-electrified areas. The respective targets set in the PPE are to deploy 100 charging stations by 31 December 2023 and 400 – 1,000 by 31 December 2028 and to have approximately 5,000 light commercial vehicles and 200 heavy vehicles (buses, trucks, regional trains, boats) by 2023 and 20,000 to 50,000 light commercial vehicles, as well as 800 – 2,000 heavy vehicles by 2028[101].

Hydrogen supply options considered

Regarding the supply options, the French Strategy refers exclusively to **domestic production** and sets the target of **6.5 GW of electrolysers to be installed by 2030**[102]. Expected import and export activities are however revealed in the gas TSOs' (GRTgaz and Teréga) publications. As seen in Figure 29, which depicts the potential consumption and production centres in the country and the interactions with neighbouring countries as mapped by GRTgaz and Teréga in a report documenting their findings after a national consultation[103], potential **imports are expected from Spain and Belgium** and potential **exports to Belgium and Germany**.

Figure 29: Hydrogen production - consumption sites and imports - exports (Source: GRTgaz / Teréga [103])

[101] Quantitative data in terms of hydrogen volumes is not available.
[102] On the 14th of February 2023, it was announced that the European Commission intends to allow hydrogen derived from electricity grids with high levels of nuclear power to be considered green. This development will provide one more green hydrogen supply option for the country.
[103] GRTgaz and Teréga, 2022, NATIONAL CONSULTATION OF LOW-CARBON AND RENEWABLE HYDROGEN MARKET STAKEHOLDERS

Measures for promoting hydrogen market development

To encourage investments in the production of renewable and low-carbon hydrogen, the French State plans to implement an **aid mechanism for producers**. The State support may take the form of **operating aid or a combination of investment and operating aid**. The selection of facilities or projects eligible to benefit from this support is carried out according to a competitive bidding procedure[104]. This procedure includes a phase of selecting eligible candidates, according to criteria and conditions defined in the call for projects by the administrative authority. Only eligible candidates participate in the next phase which consists of the individual examination of the eligible projects, taking into account their economic profitability (price of the hydrogen produced), with regard to the overall assessment in terms of GHG emissions from the operation of the installation and its contribution to the achievement of the national objectives. The State support will have to be formalized by an agreement for a maximum period of 20 years concluded between the operator and the State.

According to the Strategy, 7 bil. € in public support, including 2 bil. € from the recovery and resilience package will be made available between 2020 and 2030 for hydrogen technologies. This amount will be invested according to three priorities: decarbonising industry, developing the use of hydrogen for heavy-duty mobility and supporting research and developing training programmes.

Calls for proposal have already been launched, such as the "*Hydrogen Territorial Ecosystems*", which aimed to support investments in ecosystems that combine production and/or distribution of hydrogen on the one hand, and hydrogen uses (industrial, mobility or power) on the other. This call for proposals will be endowed with 275 mil. € by 2023. Another call for proposals, the "*Technological bricks and hydrogen demonstrators*" aims to support innovation that will develop or improve components and systems used for the production and transportation of hydrogen, as well as its uses. This call for proposals is endowed with 350 mil € by 2023[105].

Planning for hydrogen transportation and storage

The French gas transmission and storage operators have already involved in a number of activities for the transportation and storage of hydrogen.

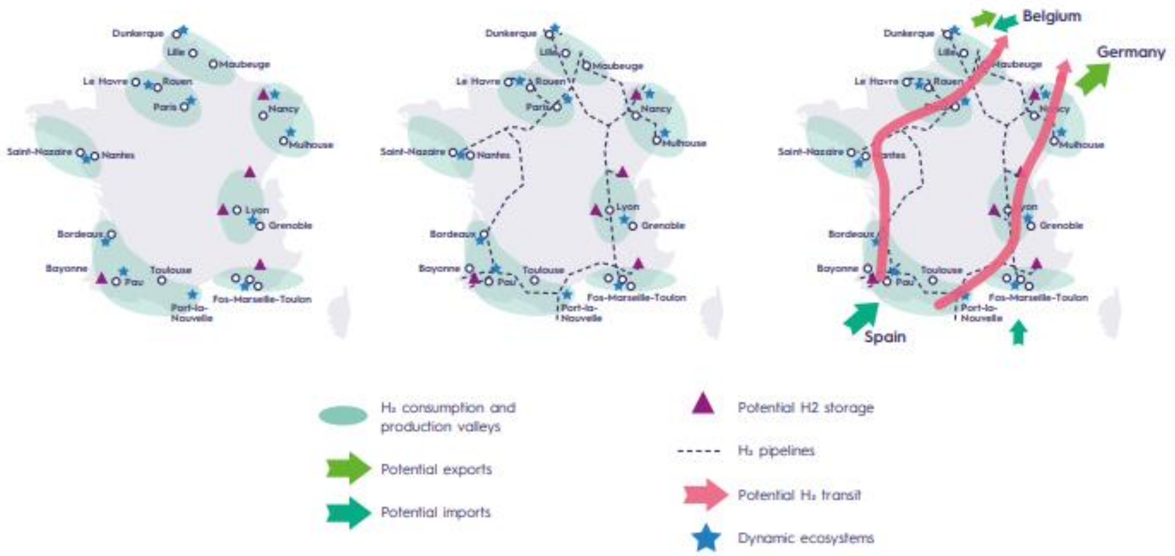
To begin with, in June 2021, **GRTgaz and Teréga launched the first national consultation** for the low-carbon and renewable hydrogen market, to identify the needs of market actors. The consultation was addressed to all stakeholders in the hydrogen market – industry, energy suppliers, producers and shippers, public and institutional stakeholders, associations, infrastructure operators and academic experts. The two gas TSOs received 133 contributions enabling them to identify 90 production and/or consumption sites. The consultation also confirmed the TSOs' idea of a three-stage development of the French hydrogen infrastructure[103]:

- In the short term (from today up to 2030), to build infrastructure within local ecosystems favourable to its production and consumption, particularly for industrial and transport uses.

[104] Code de l'énergie, Articles L. 812-1 to 10
[105] WFW, 2021, THE FRENCH HYDROGEN STRATEGY

- In the medium term (from 2030 up to 2035), to create hydrogen valleys interlinking local ecosystems via a regional pipeline-based transport grid, integrating hydrogen storage infrastructures.
- In the long term (from 2035 up to 2050), to structure an interconnected grid at European level for pipeline-based transport, incorporating storage infrastructures and ensuring transit into neighbouring EU Member States.

Figure 30: Three-stage development of the French Hydrogen infrastructure (Source: GRTgaz / Teréga [103])

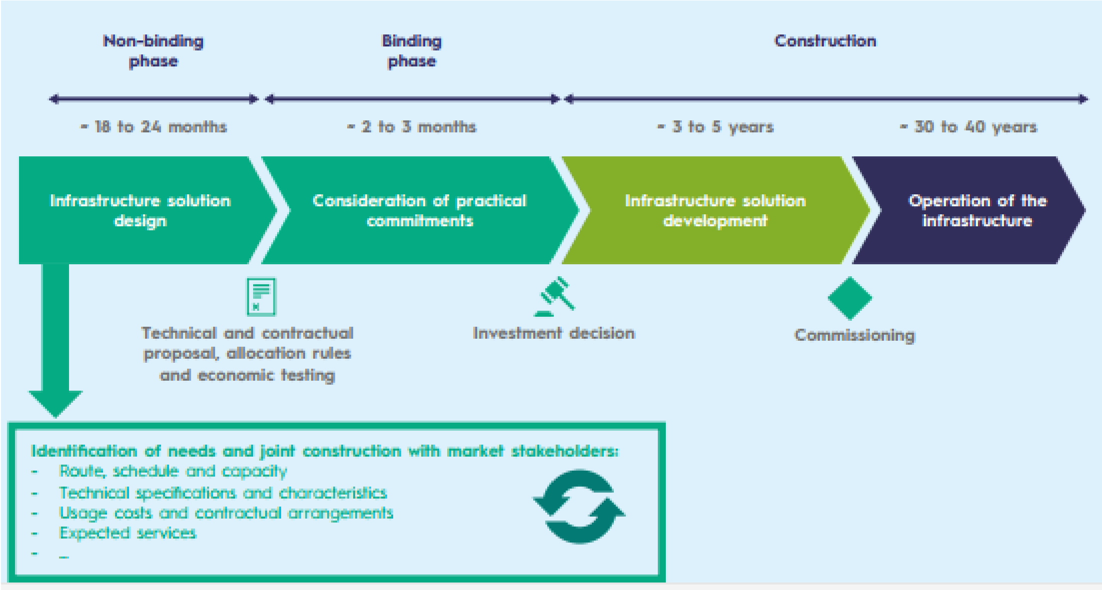


The two gas TSOs intend to repeat the process of market consultation on an annual or bi-annual basis to continuously receive feedback on the market participants' infrastructure needs.

The market consultation results were enriched by discussions with stakeholders and interested parties from the hydrogen market, by organizing **three "*territorial workshops*"** (the industrial port zone of Dunkirk on 16 November 2021, the Fos-Marseille hydrogen valley workshops on 17 November 2021, and the region of Lyon in June 2022) during which the TSOs elicited the precise needs of local stakeholders and understood more accurately their expectations in terms of infrastructure type, geographical scale and timescale[103,106]. In the context of the workshops, the two TSOs presented their envisaged **hydrogen pipeline transport planning methodology**, based on their natural gas planning experience, as depicted in Figure 31.

[106] GRTgaz website, Regional workshops

Figure 31: Transport grid planning process (Source: GRTgaz / Teréga [103])



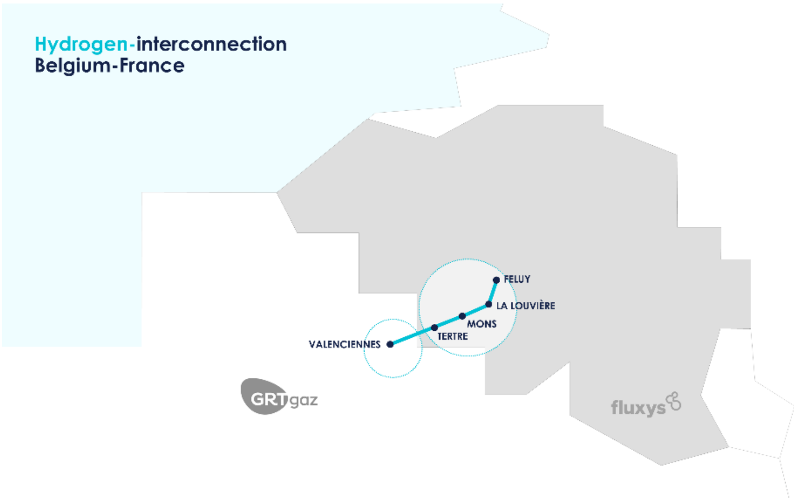
In the first non-binding phase (considered to be completed for the regions that participated in the territorial workshops) the TSOs identify and qualify transport requirements, including particularly the predicted consumption, production, import and export locations. In the second binding phase, future users of the grid submit and commit themselves to volumes and capacities, over a stated period of time, in accordance with the rules defined during the non-binding phase. The last phase concerns the construction of the infrastructure identified in the second phase.

Following the market consultation, from June to September 2022, **GRTgaz launched its first Hydrogen Call for Expression of Interest**, calling on regional stakeholders to express their interest in a cross-border low-carbon hydrogen transport network linking Valenciennes in France and Mons in Belgium's Hainault region. During the first non-binding phase, respondents were invited to express their interest based on the details provided in an "*Information Memorandum*", supplemented by the "*Infrastructure Proposal*" and the "*Hydrogen Specifications Proposal*". This non-binding expression-of-interest phase will also include bilateral or group exchanges with participants to gradually fine-tune the infrastructure design and come up with an economic and contractual model that supports the transport of hydrogen. Provided that the non-binding phase confirms the market interest, GRTgaz will define the conditions of access to the structures (capacity allocation, indicative price). Next, the binding phase will be launched, and will entail booking of capacities which may give rise to the construction of the infrastructure. GRTgaz highlighted that the entire open season process is **coordinated with an open season led by Fluxys Belgium**, to take place at the same time, in particular in terms of the design of the border interconnection point and the schedule of the different phases[107]. According to Fluxys Belgium, there was a successful response to this call for interest by GRTgaz and Fluxys, as 17 companies confirmed needs for a cross-border pipeline to connect the hydrogen valleys in France and Belgium. The results of the feasibility study aimed at designing the infrastructure depicted in Figure

[107] GRTgas, 2022, Open Season for a Hydrogen transport infrastructure

32 and making an initial evaluation of its cost, that is currently being developed by the two TSOs, will be disclosed in the first quarter of 2023[108,109].

Figure 32: Interconnection between France and Belgium (Source: GRTgaz[108])



From September to November 2022, **GRTgaz launched its second Hydrogen Call for Expressions of Interest** for the Port of Dunkirk. The proposed hydrogen transmission network crosses various sections of the Port of Dunkirk: to the west, the network passes through the commune of Gravelines, it then runs near to the Atlantic basin and the "*Sustainable Chemistry*" (Chimie Verte) zone, and it joins the central Port and the area east of the port, up to the site of a former refinery. The open season process, phases and supported documents followed the example set during the first open season[110].

In the same manner, on January 12, 2023, **GRTgaz launched its third call for Expressions of Interest** for a low-carbon hydrogen transport network to be developed between the industrial areas of Fos-sur-Mer and Manosque. The hydrogen transportation network infrastructure proposed by GRTgaz will include a loop linking the production, consumption and storage projects at Fos-sur-Mer and Lavera. This future network will also connect up the Manosque storage site[111].

Moreover, on January 31, 2023, **Géométhane**, owner of the Manosque underground natural gas storage site, called on all local stakeholders (hydrogen producers and hydrogen suppliers) to **express their interest in a hydrogen storage project** in salt caverns on the Manosque site. Provided that market interest is confirmed, Géométhane will define the conditions of access to the works and the decision conditions for its realization, in consultation with the interested parties, to launch a second, binding phase[112].

Lastly, in December 2022, the **French, Spanish and Portuguese TSOs signed a MoU** to collaborate on the development of the proposed H2Med project. In more detail, the agreement includes a

[108] Fuxys website, 2022, Belgium-France cross-border hydrogen transmission: successful response to call for interest by GRTgaz and Fluxys
[109] H2 Bulletin website, 2022, Fluxys Belgium and GRTgaz start feasibility study of hydrogen transmission
[110] GRTgaz website, Launch of a Call for Expression of Interest for Dunkirk market stakeholders
[111] GRTgaz website, Launch of the call for interest for Fos-sur-Mer market players
[112] Storengy website, Launch of a call for expressions of interest-"Open Season" for the creation of an underground hydrogen storage facility in Manosque

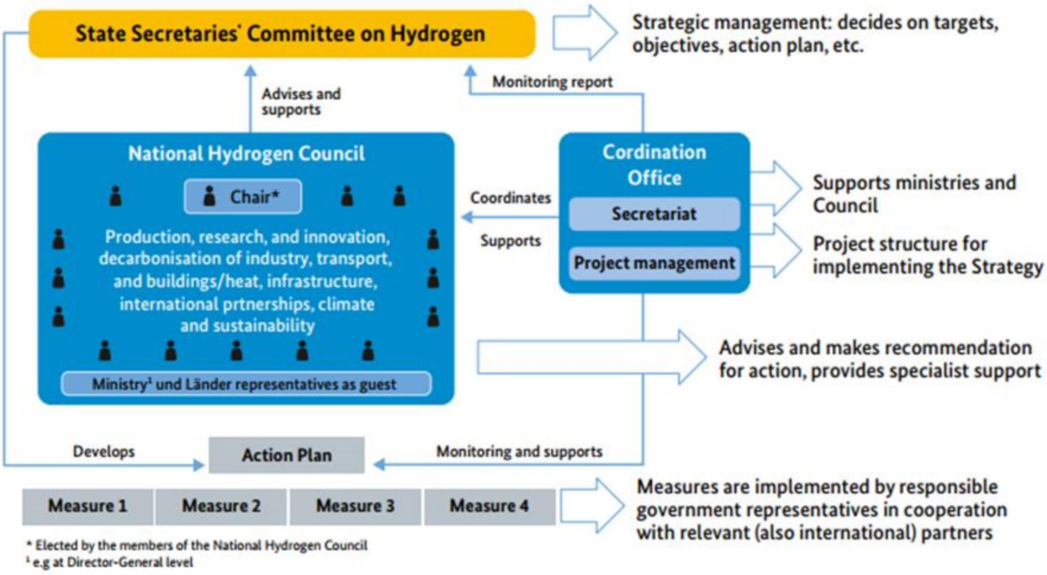
commitment to complete the renewable gas interconnections between Spain and Portugal, linking Zamora with Celourico da Beira; to develop a maritime pipeline connecting Barcelona with Marseille; and to technically adapt these hydrogen infrastructures to transport other renewable gases, as well as a limited proportion of natural gas as a temporary and transitory energy source[113,114].

Germany

The National Hydrogen Strategy (hereafter the Strategy)[115] was introduced in 2020 and is due for revision every three years, on the basis of the findings and indications of annual monitoring reports. The first update is expected to be released by the Federal Ministry for Economic Cooperation and Development (BMZ) in early 2023[116]. Aside from the measures taken at Federal level, several of Germany's 16 State Governments also have defined hydrogen strategies or roadmaps (e.g., Baden-Württemberg, Bavaria, five north German coastal states together, North Rhine-Westphalia)[117].

The implementation of the Strategy is monitored by the State Secretaries' Committee on Hydrogen, which is in turn supported and advised by a National Hydrogen Council with high-level experts from science, business and civil society (Figure 33).

Figure 33: Governance structure of the National Hydrogen Strategy[115]



In Germany, the current hydrogen consumption amounts to approximately 55 TWh/year and is needed for material production processes in the basic chemicals industry (production of ammonia, methanol, etc.) and in the petrochemicals sector (production of conventional fuels). The bulk of the hydrogen being used in these processes is grey hydrogen.

[113] La Moncloa, 2022, Sánchez, Macron and Costa agree to create the Green Energy Corridor linking the Iberian Peninsula with Europe
[114] Offshore Energy, 2022, TSOs formalise intention to develop H2Med subsea hydrogen link
[115] The Federal Government, 2020, The National Hydrogen Strategy
[116] Clean Energy Wire, 2022, German hydrogen strategy revision aims to solidify target to double electrolysis capacity by 2030 - media
[117] CSIS, 2022, Germany's Hydrogen Industrial Strategy

The focus of the Strategy is primarily on the production and use of green hydrogen, as the Federal Government considers only hydrogen that has been produced using renewable energy to be sustainable in the long term. However, Germany expects that in the hydrogen market which will emerge in the coming ten years, carbon-free (for example blue or turquoise) hydrogen will be also traded and, in this case, the country will temporarily use it.

Targets set for hydrogen demand

According to the Strategy, **90 – 110 TWh of green hydrogen will be needed by 2030**. This is planned to be **partially covered by establishing up to 5 GW of generation capacity** including offshore and onshore energy generation facilities. The 5 GW capacity corresponds to about 14 TWh of green hydrogen production (assuming: 4,000 hours full-load hours of electrolyser operation and an efficiency ratio of 70%) and thus only covers about a seventh of the projected German hydrogen demand by 2030[117]. The **gap between production and demand** will be covered by **imports**. Another 5 GW of capacity are to be added, if possible, by 2035 and no later than 2040.

With regard to **end-use**, priority will be given to sectors that are already close to commercial viability and to sectors that cannot be decarbonized in other ways, including **the process-related emissions in the steel or chemicals industry** and **certain parts of the transport sector**. The potential use of hydrogen in the heating sector will be examined in the longer term.

Focusing on the use of hydrogen in the **industry**, Germany's industrial sector already has demand for hydrogen, which is expected to grow heavily in the future. In particular, the steel and chemicals industry will require roughly 77 TWh of hydrogen in 2035 and 93 TWh in 2040. The target is for 50% of this demand[118] to be met with green hydrogen. Currently, approximately 55 TWh/year of hydrogen – most of it being grey hydrogen – are used for industrial applications in Germany and the country aspires to progressively serve this demand with green hydrogen. Consequently, the Federal Government considers the industry as a crucial sector which is expected to speed up the hydrogen market roll-out. The Strategy highlights the fact that in refineries and parts of the chemical industry, it is already possible today to substitute green hydrogen for grey hydrogen without any adjustments being necessary. Additionally, existing infrastructures of the chemical industry, e.g., hydrogen networks, can continue to be used and possibly be expanded or optimized for other applications such as in the steel sector.

Regarding the use of hydrogen in the **transport sector**, the Federal Government recognizes that hydrogen-based or PtX-based mobility can be an alternative option for applications where using electricity directly is not reasonable or technically feasible. For certain modes of transportation, including local public passenger transport (buses, trains), parts of heavy-duty road transport (trucks), commercial vehicles (e.g., for use in construction work or agriculture and forestry) or logistics (delivery traffic and other commercial vehicles such as forklift trucks), the Strategy recognizes that both fuel cell and battery-powered electric vehicles could be employed in a complementary manner. However, the Strategy also stresses that especially for air and maritime transport further technological advances

[118] The remaining 50% is planned to be covered from natural gas (as a transitional fuel) and non-green hydrogen.

are needed to decide on the most optimal decarbonization pathway[119]. The following Table summarizes the future hydrogen demand expected in the land and air transport sectors, as elaborated by the National Hydrogen Council in their *Hydrogen Action Plan Germany 2021 – 2025* (hereafter the Hydrogen Council's Action Plan).

Table 19: Future hydrogen demand in the transport sectors[120]

	Total demand of transport		of which e-fuels for land transport		of which e-fuels for air transport	
	million t H_2	TWh	million t H_2	TWh	million t H_2	TWh
2030	0.8	25	0.17	5.7	0.1	2.7
2035	2.0	67	0.24	8	0.2	6.3
2035*	2.8	92	0.9	30	0.2	6.3
2040	3.8	128	0.3	11	0.4	12.1
2050*	6.1	203	2.2	72	0.4	12.1

* Scenario with high e-fuels production (internal data).

As regards the **heat market**, the Federal Government foresees that the electrification and energy efficiency measures will lead the sector's decarbonization. Nonetheless, for both process heat generation in the industrial sector and residential heating purposes, there will always be demand for gaseous fuels, which in the long run could be met by biogas, biomethane, hydrogen and its derivatives. Projects are currently underway on the use of hydrogen in the heating market, which are investigating and demonstrating the compatibility of hydrogen with heating appliances and the pipeline infrastructure in various blends in the distribution network (blends of up to ten per cent are already possible with existing appliances, and up to 20% with new appliances). In this regard the National Hydrogen Council expects that the initial blending or first conversions of sub-grids can already begin in the period up to 2030.

Hydrogen supply options considered

Concerning the supply of hydrogen, the Strategy states that the first step should be the establishment of a strong and sustainable domestic market for the production and use of hydrogen. To this end the country will design the incentives for speeding up the roll-out of hydrogen technology in Germany and particularly for increasing the capacities for generating electricity from RES (particularly wind power and photovoltaics) and establishing and operating electrolysers.

Nevertheless, the Federal Government underlines the fact that the **domestic generation of green hydrogen will not be sufficient to cover all new demand due to Germany's limited renewable energy generation capacity**, and as a result **most of the hydrogen needed will have to be imported**. According to the Strategy, in order to secure volumes of hydrogen from abroad, the country plans to intensify its cooperation with other EU Member States, particularly those bordering the North and

[119] In May 2021, the German federal and state governments and industrial leaders have agreed on a roadmap aimed at establishing climate-friendly power-to-liquid (PtL) aviation fuel production. The target is set at an annual production of at least 200,000 tonnes of sustainable kerosene for German air traffic by 2030 which corresponds to a third of the current fuel requirement for domestic German air traffic.
[120] National Hydrogen Council, 2021, Hydrogen Action Plan Germany 2021 – 2025

Baltic Sea[121], but also with the countries of Southern Europe, where untapped renewable potential is available. Particularly for the cooperation with the North and Baltic Sea border States, Germany plans to push forward hydrogen production by establishing a reliable regulatory framework for offshore wind energy. Moreover, the country is prepared to systematically **develop hydrogen production sites in other partner countries**, for example as part of development cooperation. In the long term (after 2050) Germany foresees to engage in **international trade** and thus import hydrogen from beyond the (envisaged) European internal market. Below are listed selected bilateral agreements between Germany and other countries to co-operate on hydrogen development[122]:

- Germany – Australia: Formulate new initiatives to accelerate development of a hydrogen industry, including a hydrogen supply chain between the two countries. Focus on technology research and identification of barriers.
- Germany – Canada: Form a partnership to integrate renewable energy sources, technological innovation and co-operation, with a focus on hydrogen.
- Germany – Chile: Strengthen co-operation in renewable hydrogen and identify viable projects.
- Germany – Morocco: Develop clean hydrogen production, research projects and investments across the entire supply chain (two projects have already been announced by the Moroccan agencies MASEN and IRESEN).
- Germany – Saudi Arabia: Co-operate on the production, processing and transport of hydrogen from renewable energy sources.
- Germany – Norway: The Norwegian and German governments published a joint declaration to explore the feasibility of an offshore hydrogen pipeline between the two countries[123]

In the Hydrogen Council's Action Plan[120], published in mid-2021, the envisioned **sources of climate-neutral hydrogen for Germany**, were further solidified as follows:

- Domestic production of green hydrogen of at least 5 GW targeted in the NW for 2030. Significantly higher electrolysis capacity should be targeted, unpinned by the expansion of additional renewable energies.
- Import of green hydrogen from other European countries, which can be carried out via cost-effective infrastructure connections that can be used at short notice (time frame: 2030/2035).
- Imports of green hydrogen beyond the 2030 time horizon from supply regions that require greater technical and economic investment for infrastructural development.
- Generation or import of blue hydrogen as a bridge option.

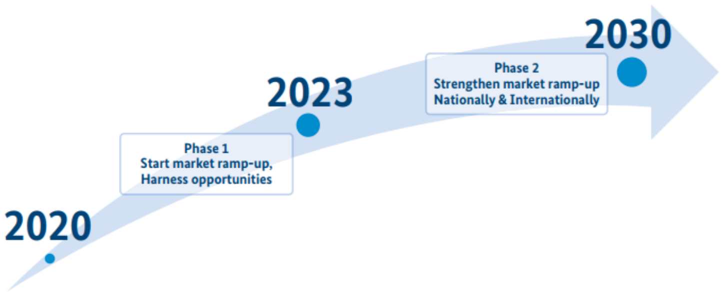
[121] In January 2023, Germany's gas TSO Gascade and its Belgian counterpart Fluxys jointly declared that they intend to build a green hydrogen pipeline, the so-called "*AquaDuctus*", in the North Sea. The offshore pipeline will be over 400 kilometers long and it is envisaged to collect hydrogen from multiple offshore wind production sites. By 2035, the subsea pipeline should carry up to one million tonnes of hydrogen a year into Germany. The two gas TSO have applied to the European Commission for their project to obtain the status of PCI.
[122] IEA, 2021, Global Hydrogen Review
[123] Federal Ministry for Economic Affairs and Climate Action, 2022, Joint Statement Germany - Norway

- Generation or import turquoise hydrogen for the market ramp-up phase beyond 2030.
- Import of hydrogen derivatives for energy and material use from supply regions with favourable production conditions for renewable electricity and climate-neutral CO2, which could become possible on an increasing scale from around 2030.

Measures for promoting hydrogen market development

The specific measures for promoting hydrogen market development are laid out in an Action Plan, which is an integral part of the Strategy. The Plan consists of **38 measures** targeting hydrogen production, fields of application (industrial sector transport, heat), infrastructure/supply, research, education, innovation, need for action at European level and international hydrogen market and external economic partnerships. It should be noted that these **measures concern the first phase of the Strategy, i.e., the phase up to 2023**, by which time the Federal Government expects to establish the basis for a well-functioning domestic market. The second phase, to begin in 2024, concerns stabilizing the domestic market and exploring the European and international dimension of hydrogen (Figure 34).

Figure 34: Action plan for hydrogen market development[115]



The measures relevant to the current study are listed below:

Hydrogen production:

- Introduction of CO2 pricing for fossil fuels used in transport and the heating sector.
- Examining the possibility to largely exempt electricity used for the production of green hydrogen from taxes, levies, and surcharges.
- Supporting the switchover to hydrogen in the industrial sector by providing funding for investments in electrolysers.
- Exploring the possibility of potential tendering schemes for the production of green hydrogen, e.g., to help decarbonize the steel and chemical industries and the potential for additional auction rounds for the production of renewables.
- Designation of additional areas that can be used for offshore production of hydrogen/PtX.

Fields of application:

Transport:

- Provision of clear incentives for investments in electrolysers to allow for the use of green hydrogen for the production of other transportation fuels.
- For air traffic, imposition of a requirement on suppliers to use electricity-based jet fuel, for the production of which green hydrogen is needed.
- Numerous funding measures for transport (For instance, the Federal Ministry of Transport and Digital Infrastructure provides funding under the National Innovation Programme for Hydrogen and Fuel Cell Technology (1.4 billion euros from 2016 to 2026) for a growing number of so-called HyLand regions that focus on green hydrogen to decarbonize transportation):
    - to boost investments in hydrogen-powered vehicles (light and heavy-duty vehicles, buses, trains, inland and coastal navigation, car fleets),
    - for the construction of a needs-based refuelling infrastructure for vehicles, including heavy-duty road haulage vehicles, vehicles for public transport and in local passenger rail services, and
    - for the establishment of a competitive supply industry for fuel-cell systems (fuel cells and related components) including an industrial basis for large-scale fuel-cell stack production for vehicle applications.

Industrial sector:

- Launch several programmes that reward the switchover from conventional fossil-fuel based technologies to technologies low in greenhouse gas emissions or even climate neutral.
- Launch a new pilot programme entitled 'Carbon Contracts for Difference (CfD)', to target the process-related emissions produced by the steel and chemical industries. Under this programme, the Federal Government will guarantee that it will provide funding amounting to the difference between the actual cost of avoiding emissions/a project-based contractually agreed carbon price per amount of greenhouse gas emissions avoided, and the ETS prices for the construction and operation of decarbonization technologies to achieve greenhouse gas neutrality.
- Establishment of a demand quota for climate-friendly base substances, e.g., green steel.
- Development of hydrogen-based long-term decarbonization strategies together with stakeholders particularly from the energy-intensive industries, within sector-specific dialogue formats (beginning in 2020 for the chemical, steel, logistics, and aviation sectors, with others to follow step-by-step).

Heat:

- Continuation of the Energy Efficiency Incentive Programme (in place since 2016) for highly efficient fuel-cell heating systems in the building sector (residential and non-residential property)[124]
- Examining ways of providing funding for 'hydrogen readiness' installations on the end-use side.

Infrastructure/supply:

- Preparation of the necessary regulatory framework for repurposing existing natural gas networks and constructing dedicated hydrogen pipelines. In this context, a market exploration procedure is to take place shortly.
- Linking the electricity, heat, and gas infrastructure will continue and coordinating the relevant planning, financing of these different parts of the energy in order to develop them as required in line with the needs of the energy transition and in a cost-efficient way.
- Establishment of the network for hydrogen refuelling stations in road transport[125], at suitable locations within the railway network[126], and for the waterways.

In terms of **budgets dedicated to support the Strategy**, the public investment committed amounts to approximately 9 bil. € by 2030, under multiple programmes, such as Germany's Decarbonization Programme, which provides funding for investment in technologies and largescale industrial facilities which use hydrogen to decarbonize their manufacturing processes. Of the 7 bil. € earmarked for national projects and funding, 2 bil. € will go towards building up electrolysis capacity, 2.5 bil. € towards converting the steel and chemical industries to hydrogen-based processes, 1.5 bil. € towards transport and 1 bil. € towards setting up a hydrogen infrastructure. To put this amount in perspective, according to the International Energy Agency's Global Hydrogen Review 2021[127], countries that have adopted hydrogen strategies have committed at least 35 bil. €. Hence, Germany provides approximately a quarter of global state aid under its national hydrogen strategy[117,120].

Planning for hydrogen transportation and storage

Regarding hydrogen infrastructure, the Federal Government recognizes the fact that in order to be able to import and develop sales markets for hydrogen and its downstream products, the right infrastructure, especially as regards transmission systems, must be in place. The following **two options** are mentioned in the Strategy:

- Part of Germany's gas infrastructure consisting of a natural gas network and gas storage units is to be usable for hydrogen as well. In particular, the Federal Government will:

[124] With >15 000 of fuel cell-based heating units operating, Germany has been the most successful market for stationary fuel cell installations in Europe.
[125] At the end of 2020, over 2,600 FCEVs were operating in Europe, with more than 1,000 in Germany.
[126] In 2018, the first commercial service of a hydrogen fuel cell passenger train (developed by Alstom) began a 100-km route in Germany. Two Alstom trains in Germany have since driven >180 000 km.
[127] IEA, November 2021, Global Hydrogen Review 2021

- examine whether natural gas pipelines which are no longer needed to transport natural gas (for example L gas) can be **converted into hydrogen infrastructure**, and
- investigate whether the **compatibility of existing or upgraded gas infrastructure** with hydrogen can be ensured.

- Further networks are to be **created exclusively for the transport of hydrogen**.

Specifically for the case of international trade, an option for transporting hydrogen over **long distances** is in the form of **PtL/PtX downstream products or Liquid Organic Hydrogen Carriers (LOHCs)**. In this case, existing transport capacities and the relevant infrastructure may be used, and new capacities may be created (e.g., pipelines, methanol and ammonium tankers).

On the end-use side of hydrogen applications, there are technical challenges for certain devices and installations to be hydrogen-compatible and operate safely. According to the Strategy, the necessary transformations will take place as soon as possible, to avoid misallocated investments.

Concerning the initiatives and plans undertaken by gas TSOs, following the first-time inclusion of hydrogen and other green gases (synthetic methane) in the Gas Network Development Plan (NDP) 2020 (for the period 2020 – 2030), in 2021, the **FNB Gas**[128] conducted their **Hydrogen Generation and Demand Market Survey**[129] for the Scenario Framework of the NDP 2022 – 2032 to collect information on the planned generation and future demand of hydrogen and other green gases in Germany. The market survey respondents reported almost 500 projects, including 488 hydrogen projects with a total demand of 231 TWh in 2032, 427 TWh in 2040 and 598 TWh in 2050. The reported **electrolysis capacity** of around 29 GW in 2032 is **significantly higher than the capacity predicted in the National Hydrogen Strategy** (5 GW by 2030) and in the Electricity NDP 2035 (up to 8,5 GW by 2035). The electrolysis capacity reported for 2040 is around 40 GW, and for 2050 it is around 56 GW[130,131]. As a result, by October 2021, the promoters of more than **250 projects** with a total demand of 165 TWh had concluded **MoUs with the corresponding gas TSOs**. The signing of an MoU was as a prerequisite for the projects to be considered as inputs in the 2022 – 2032 Gas NDP. The MoUs contain, inter alia, information on the specific capacity requirements and the planned commissioning[132].

On January 24, 2023, a **consultation workshop on the Scenario Framework for the Gas NDP 2022 – 2032** took place. The Scenario Framework, to be confirmed by the NRA, will form the basis for

[128] The Berlin-based association Vereinigung der Fernleitungsnetzbetreiber Gas e.V. (FNB Gas) was founded in 2012 by the German gas transmission system operators, i.e., the network companies operating the major supra-regional and cross-border gas transportation pipelines. One key focus of the association's activities is the Gas Network Development Plan, which has been drawn up annually by the TSOs since 2012. The association also acts as a central point of contact for policymakers, the media and the general public on behalf of its members.
[129] FNB Gas, 2021, Press release: Gas Network Development Plan becomes German transparency platform for hydrogen market ramp-up
[130] FNB Gas website, 2021, Market partners report strong increase in demand for hydrogen and green gases
[131] FNB Gas, 2020, Press release: Gas TSOs start to prepare Scenario Framework for the Gas NDP 2022-2032 with the aim of developing new gas infrastructure for hydrogen and methane in line with demand
[132] FNB Gas website, 2021, Large hydrogen demand confirmed by MoU

modelling the Gas NDP 2022 – 2032[133]. During the workshop, FNB gas presented their **plan for the development of the hydrogen infrastructure in Germany**, as follows[134]:

- By 2027, subnetworks will be in place, as depicted in Figure 35. The largest coherent subnetworks will be located in the East, Schleswig-Holstein and the North-West.
- By 2032, the network will consist of 7,600 – 8,500 km length of pipelines, as illustrated in Figure 36. The natural gas repurposed pipelines are estimated between 4,900 – 5,900 km and the new-dedicated ones will range from 2,300 – 2,900 km. The final assessment as to which pipelines would specifically have to be newly built or converted is currently not possible due to the highly dynamic developments in the gas market and it will be decided during the development of the next NDP 2024 – 2034. Moreover, by 2032, the gas TSOs expect that the hydrogen network will cover more than 230 MoU projects (about 90%) and that electrolysis projects with a capacity of about 20.5 GW will be in place.

Figure 35: FNB Gas Modelling result for hydrogen transmission development by 2027 (Source: FNB Gas[134])

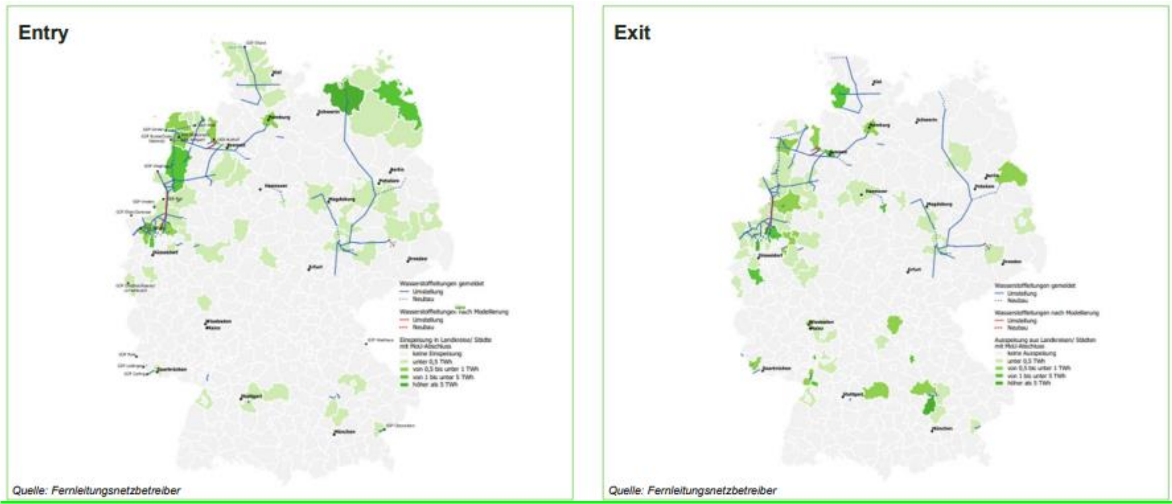
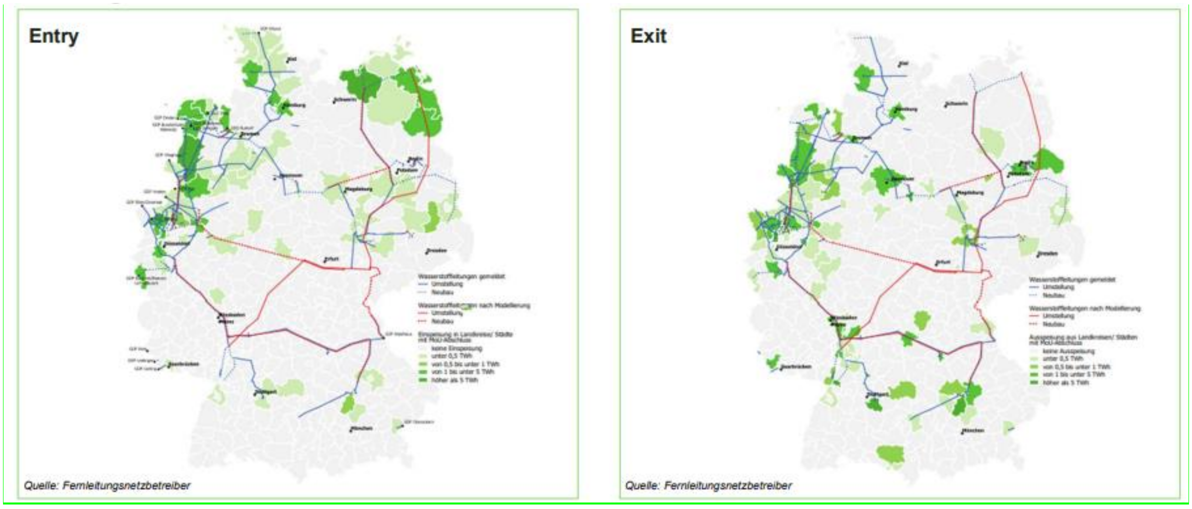


Figure 36: FNB Gas Modelling result for hydrogen transmission development by 2032 (Source: FNB Gas[134])



[133] FNB Gas website, 2023, [Network Development Plan 2022]
[134] FNB Gas, 2023, [Network Development Plan Gas 2022-2032 Hydrogen Variant]

Italy

In November 2020, the Ministry for Business and Made in Italy (MIMIT)[135] published the "*Guidelines for the National Hydrogen Strategy*" ("*Linee Guida per la Strategia nazionale sull'idrogeno*", hereafter the Strategy)[136]. According to MIMIT this document was an introduction aimed at framing the discussion that will lead to a detailed Italian Strategy for Hydrogen, to be released in early 2021. However, no other official document has been made publicly available yet.

Apart from the Strategy, the reviewed documents include the Italian gas TSO's (Snam) development plans and Italy's National Recovery and Resilience Plan. It should be noted that the Strategy is a high-level document focusing on hydrogen demand targets, without providing any concrete plans for hydrogen infrastructure. Snam's infrastructure development plans provide more information on the so-called Italian "*Hydrogen Backbone*".

Targets set for hydrogen demand

The Strategy refers to the **expected hydrogen demand up to 2030 and up to 2050**. The demand by 2030 is expected to predominantly concern applications of hydrogen in the **transport sector**, especially heavy-duty vehicles (e.g., long-haul trucks) and rail, and in the **industry**, with specific reference to those segments in which hydrogen is already used as a raw material, for example in the chemical sector and in oil refining. In more detail:

- **Long haul trucks:** Italy can achieve a penetration of at least 2% of fuel cell long-haul trucks by 2030, out of a total national fleet of approximately 200,000 vehicles. To support such market growth, both a comprehensive expansion of fuel cell technology and relevant infrastructure investments should be undertaken.
- **Trains:** In Italy, up to half of non-electrifiable national routes could be converted to hydrogen by 2030: in some regions, diesel trains have a high average age and are expected to be replaced in the coming years, creating the ideal opportunity for the transition to hydrogen. The first regions to initiate a potential implementation are those with a high number of diesel trains and a large number of passengers who use them, such as Sardinia, Sicily and Piedmont, or regions where there is a common consensus on the use of hydrogen to start decarbonization and improve local rail transport.
- **Chemicals industry and refining:** Hydrogen can support the decarbonization of "*hard-to-abate*" sectors characterised by high energy intensity and the lack of scalable electrification solutions. Two of these are the chemicals industry and refining sectors, where hydrogen is already used as a feedstock both in the production of basic chemicals such as ammonia and methanol and in a number of refining processes. The concentration of refineries and chemical plants in Italy mainly affects the centre-north of the country and the islands, with large differences not only in terms of size of the plants and emissions but also in physical characteristics (for example proximity to the sea, RES potential, etc.). Therefore, the transition

[135] Formerly Ministry of Economic Development (MISE)
[136] MISE, 2020, Strategia Nazionale Idrogeno Linee Guida Preliminari

to low carbon hydrogen will require careful evaluation of each individual plant to establish technical feasibility.

- **Hydrogen valleys**, i.e., ecosystems that include both hydrogen production and consumption, may also provide areas for hydrogen deployment by 2030, leading to possible application of hydrogen in other sectors.
- Finally, some **small-scale pilot projects** are also planned in other sectors, for example in local public transport, biological methanation or secondary steel sites:
    - In the steel industry, hydrogen represents the only zero-carbon alternative in the production of pre-reduced iron (DRI), which can be progressively used to avoid the high-emission production of pig iron in the blast furnace. Currently, DRI technology uses natural gas as the feedstock of choice: as the cost of hydrogen versus natural gas falls, steel mills may consider blending hydrogen for DRI production.
    - The long-haul truck segment could experience more significant penetration and grow 5 – 7% versus the aforementioned 2%. This may in part be due to specific regulations regarding Original Equipment Manufacturers (OEMs) requiring additional efforts regarding climate impact (15% and 30% reduction of emissions on new vehicles sold, respectively by 2025 and 2030).
    - Some industrial clusters could consume blended hydrogen, exploiting their proximity to other industrial consumption poles or the availability of supply and logistics.

Based on the above, the Government expects a growth in the penetration of hydrogen on final uses from the current ~1% (grey hydrogen) to around **2% by 2030** (additional opportunities could lead to a higher penetration). This 2% is referred to as domestically produced green hydrogen in the Strategy, even though the use of imported green and blue hydrogen is mentioned, if needed.

By **2050** the demand for hydrogen in the already mentioned sectors is expected to increase: for example, in a scenario of complete decarbonization the penetration of long-haul fuel cell trucks could reach up to 80% by 2050 compared to ~2% by 2030. In addition, several **other sectors will be able to use hydrogen and its derivatives** for various purposes, from the progressive replacement of methane in residential heating to the development of synthetic fuels to provide alternatives to zero carbon emissions to the aviation and maritime sectors.

In the industrial sector, in addition to the production of chemical products, oil refining and steelmaking, hydrogen can potentially also be used for industrial heating, in particular for processes that require a high temperature (>1,000°C, for example in the steel or cement industry) and where electrification may not be the most effective or feasible alternative due to the necessary modernization of the existing infrastructure.

In the transport sector, hydrogen is expected to become an option for the decarbonization of passenger cars, especially for fleet / long-distance consumption. The aviation and shipping sectors can also be important applications for hydrogen, in the form of e-fuels based on hydrogen such as e-kerosene in the aviation sector and e-ammonia in the maritime industry.

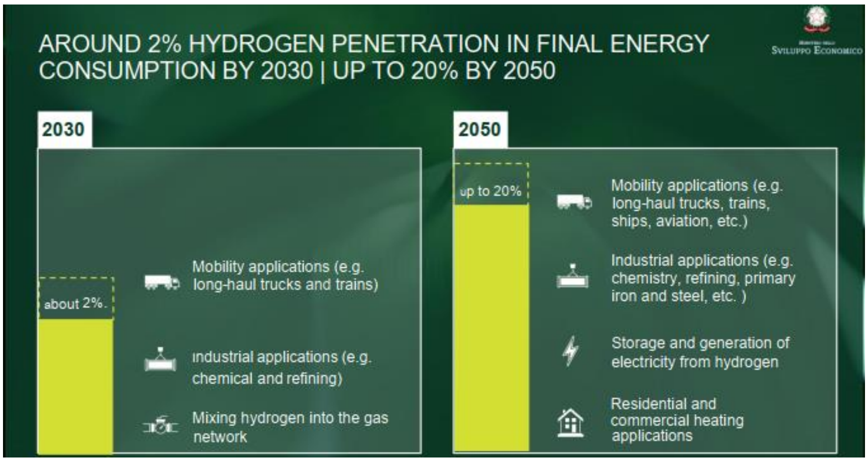
In the civil sector, with particular reference to residential and commercial heating, hydrogen can equally contribute to decarbonization, as a competitor to heat pumps and other low-carbon technologies in replacement of methane and petroleum products.

Finally, hydrogen will be able to play a role in electricity generation, given that it will allow better integration of intermittent energy sources such as renewable ones: excess renewable electricity can be converted into hydrogen to then be used as fuel in the generation of electricity backup with turbines (albeit with low efficiency), or on site to produce electricity with fuel cells for industrial uses.

According to the Strategy, in terms of penetration into the final energy demand, hydrogen could account for up to **20% by 2050**[137]; should further opportunities be identified and the cost of hydrogen become more competitive than forecasted today, higher penetration could occur.

The Italian targets set for hydrogen demand in 2030 and 2050 are depicted in Figure 37.

Figure 37: Italy's targets for hydrogen demand by 2030 and 2050[136]



Hydrogen supply options considered

According to the Strategy, to meet a hydrogen demand of about 2% by 2030, corresponding to about **23 TWh/yr**[138] (0.7 MTons/yr), the most favourable conditions to ensure the feasibility of production and a low cost of the raw materials will have to be identified. The Strategy identifies **three theoretical production/transport models** and elaborates on their pros and cons, without prioritizing them. In brief, the three models are:

- Fully on-site production: Renewable electricity generation and electrolysis capacity is located next to the point of consumption to minimize transportation costs.
- On-site production with transport of electricity: Renewable electricity is generated in areas with a high availability of natural resources, and transported through the electricity grid to the point of consumption where it is then converted into hydrogen by electrolysis.

[137] According to Snam (2019), the hydrogen demand in 2030 will be 26 TWh (= 2% of the total energy demand of 1,283 TWh) and equal to 220 TWh in 2050 (= 23% of the total energy demand of 955 TWh).
[138] Conversion from tons to MWh throughout this document is done using an NCV of 33 kWh/kg hydrogen (according to ENTSOG TYNDP).

- Centralized production with hydrogen transport: the renewable electricity generation and electrolysis capacity are located in areas with a high availability of natural resources (for example wind or sunlight) to exploit higher load factors. The hydrogen produced is then transported to the point of consumption through a dedicated facility that could exploit the existing gas network, or through other methods of transport (e.g., trucks).

According to the Strategy, to produce 23 TWh of green hydrogen per year, a considerable amount of renewable electricity generation, both solar and wind, will be needed in addition to the amount of renewables needed to meet the targets set by the National Energy and Climate Plan (NECP). To kick-start the development of the hydrogen market, the Government plans to **install around 5 GW of electrolysis capacity by 2030** to meet part of the demand described above. Domestic production of green hydrogen could be **complemented with imports**, where the country's location could be exploited as a **hub for hydrogen trading**, or with other forms of low-carbon hydrogen, such as blue hydrogen.

Measures for promoting hydrogen market development

The **measures** for promoting hydrogen market development outlined in the Strategy mostly concern the potential use of EU and National Funds:

- **EU funds**: Recovery and Resilience Facility, ReactEU, Horizon Europe, Innovation Fund, the National Operational Plan 2021-2027, Important Projects of European Common Interest (IPCEIs)
- **National funds**: Sustainable Growth Fund (FRI), DL Agosto, and Mission Innovation, National Electricity System Research, CleanTech Fund, Development and Cohesion Fund

From the Recovery and Resilience Facility, 3.19 bil. € were dedicated to hydrogen technologies: support of hydrogen production, distribution, research, use in industry and transport (5 GW electrolyzation capacity up to 2030), use of hydrogen in "*hard-to-abate*" sectors (steel, refining, chemicals), hydrogen valleys and reconversion of decommissioned industrial areas (capacity up to 1-5 MW for each site), deployment of 40 filling stations for heavy-duty transport (Brenner Green Corridor; Turin-Trieste motorway), hydrogen testing along six regional railways, creation of a research network on production, storage and transport, fuel cells, resilience of infrastructure, streamlining authorization procedures[139].

For boosting **hydrogen production**, the Italian Government is expected to support hydrogen both with incentive schemes and with the simplification of RES regulation. Electrolyser capacity can rely on new or existing dedicated renewable capacity to fully exploit and complement existing renewable power plants.

Similarly, from the **demand side**, the Strategy states that some type of support will have to be designed to accelerate the diffusion of hydrogen applications and the adoption of hydrogen-based mobility, i.e., long-haul trucks and trains or other new applications.

[139] Italian Trade Agency (government agency), Italian Recovery and Resilience Plan

Special attention is also given to the **R&D sector**, with the establishment of a national R&D program to address priority areas such as the development of electrolysers and fuel cells and exploit the opportunity to develop competitive SMEs in these fields.

Planning for hydrogen transportation and storage

The Strategy refers to **hydrogen blending in the existing gas infrastructure** as an effective way to contribute to the country's decarbonization goals and stimulate the hydrogen market while investing in the development of the production and transportation chain. Although an official technical limit has yet to be defined in Italy, according to the Strategy it is plausible to think that by 2030 an average of up to 2% of the natural gas distributed can be replaced with hydrogen.

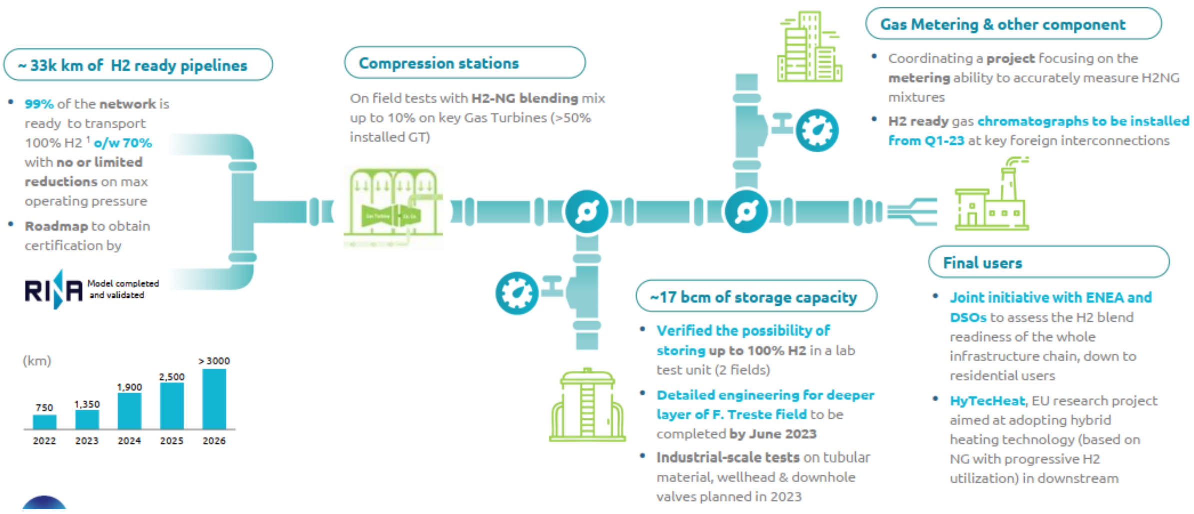
In April 2019, Snam was the first company in Europe to successfully introduce a mix of 5% hydrogen and natural gas in its transmission network, in a trial in Contursi Terme, in the province of Salerno which involved supplying a hydrogen-natural gas mixture for a month to two industrial companies in the area. The Contursi experiment was replicated in December 2019, doubling the percentage of hydrogen by volume to 10%. At present, Snam is committed to verifying the full compatibility of its infrastructure with increasing amounts of hydrogen mixed with natural gas[140,141].

According to Snam, the 50% of the company's 2020 – 2024 business plan was dedicated for the replacement and development of assets to standards that are also compatible with hydrogen. Snam has also adopted new internal regulations for procurement to ensure that **all materials for the new sections of the grid can transport, without cost increases, not only natural gas and biomethane, but also, increasing hydrogen percentages up to 100%**[142].

In its 2022 – 2026 Strategy Plan, published in January 2023, Snam refers to "*the development of the "Italian Hydrogen Backbone" by repurposing infrastructure (networks and storage) to support green gas domestic demand and import/export excess domestic capacity*". Figure 38 presents **Snam's hydrogen asset readiness** and notes that the plan for assets repurposing is on track. Regarding the pipelines, "hydrogen ready"[143], means ready to accept increasing percentages of hydrogen[144,145].

[140] Snam website, THE EXPERIMENTATION AT CONTURSI TERME
[141] WFW, 2021, THE ITALIAN HYDROGEN STRATEGY
[142] Snam website, SNAM AND HYDROGEN
[143] Snam, 2020, INFRASTRUCTURE FOR CHANGE
[144] Snam, 2023, Press release for the 2022-2026 STRATEGY PLAN
[145] Snam, 2023, 2022-26 Strategic Plan Building a Secure and Sustainable Energy System

Figure 38: Snam's status on assets' repurposing to transport hydrogen[145]

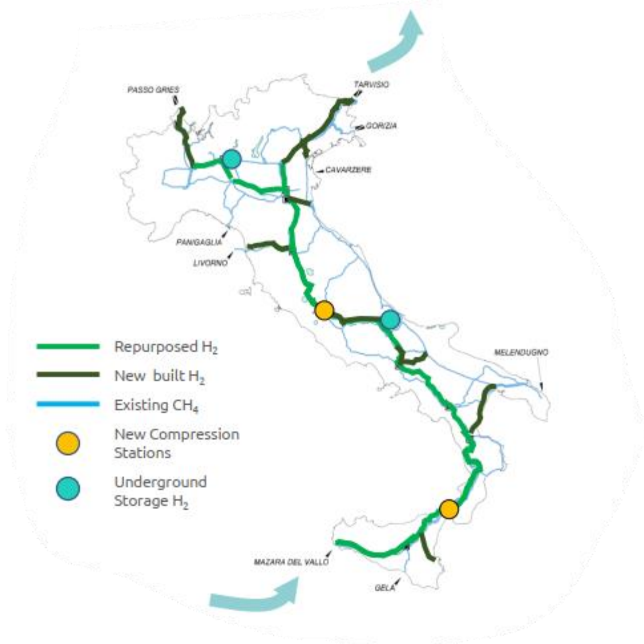


1. Based on Option A of ASME B31.12 (H2 >10% by Volume Blended with Dry Natural Gas, see also here)

In the 2022 – 2026 Strategy Plan, Snam refers to the Italian hydrogen backbone, as depicted in Figure 39. According to the 2022 – 2026 Strategy Plan and Snam's 2030 vision[146] published in late 2021, **the backbone will consist of**:

- 2,300 km of hydrogen network to bring production from north Africa and Southern Italy to consumption areas of which 70% will be repurposed from natural gas
- Up to 500 MW compression stations to enable hydrogen export
- 1.5 bcm of storage capacity (One new site and reconversion of one existing field)

Figure 39: The Italian hydrogen backbone[145]



[146] Snam, 2021, Snam 2030 vision and 2021-2025 plan

According to Snam's 2030 Vision, **the first tranche of the Italian hydrogen backbone will be to connect Italy to countries with higher demand like Germany**[147]. On January 25, 2023, Snam announced that Italy and Algeria are considering the construction of a new pipeline between the two countries that will transport gas and hydrogen, based on a joint announcement of the Italian Prime Minister and the Algerian President. According to the Italian Prime Minister, "*Facing the great energy crisis that Europe in particular is experiencing, Algeria could become a leader in production, certainly African but probably global. […] Italy is inevitably the gateway for access for this energy* (referring to natural gas, hydrogen and electricity) *and for Europe's supply.*" for natural gas, hydrogen and electricity[148]. This development follows Algeria's and Germany's agreement in late 2022 to transport gas in the first phase and green hydrogen in the future from the North African country to the German grid via Sardinia and mainland Italy[149].

Netherlands

In June 2019, the Dutch Government published the National Climate Agreement of the Netherlands[150], which is an agreement between many organizations and companies in the Netherlands to combat climate change, recognizing the potential use of hydrogen among other carriers. Subsequently, in April 2020, the Dutch Government delivered the National Strategy on hydrogen (hereafter the Strategy) as well as the corresponding policy agenda[151]. Apart from the above, publications from the National Hydrogen Programme[152], set up to support the development of the whole hydrogen supply chain, as well as publications from Gasunie and TenneT, who are being involved in the development of the respective infrastructure, were also reviewed.

According to the aforementioned documents, the country aspires to be able **to own hydrogen production facilities for domestic consumption and to get involved in hydrogen import and export activities**. The above could materialize due to the country's proximity with the North Sea (suitable for offshore wind power), its favourable location, international ports and the existing gas grids and storage capacity which can be repurposed to accommodate the hydrogen supply chain.

Targets set for hydrogen demand

The Strategy states that the demand for hydrogen will be concentrated in the existing industrial clusters, to provide flexibility to the electricity system, and in refuelling stations for transport. Especially for the industrial sector, according to the National Climate Agreement, by 2030, on the coast alone, there will be a large potential demand for hydrogen for industrial applications (approximately 35 – 59 TWh), while additional demand may emerge on the coast for hydrogen for electricity production. However, the Agreement highlights that the actual demand in 2030 will partly depend on the development of incentives for industry to become more sustainable and on incentives for

[147] Snam, November 2021, Press release for increased investments in the 2021-2025 plan with significant growth opportunities to 2030 thanks to acceleration of the transition towards net zero
[148] Voaafrica website, January 2023, Italy's Meloni Visits Algeria Over Energy
[149] Hydrogen Today website, 2023, ALGERIA AND ITALY SIGN AN AGREEMENT ON HYDROGEN
[150] The Dutch Government, 2019, National Climate Agreement
[151] The Dutch Government, 2020, Government Strategy on Hydrogen
[152] Nationaal Waterstof Programma website (homepage)

sustainable and carbon-free electricity production. The targets set in the Strategy per end-use sector for the mid (2030) to long (2050) term, are outlined below[150,151,153]:

- **Industry:**
  - Installation of 3 – 4 GW electrolysis in 2030 (500 MW in 2025), to support carbon-free feedstock for the process industry, and carbon-free energy carriers for high temperature heat for the process industry
  - Reduction in investment costs for electrolysis by 65% between now and 2030
- **Electricity generation:**
  - For flexibility of electricity system, development of CO2-free dispatchable production, potentially up to 17 TWh in 2030, for which carbon-free hydrogen is an option
  - Development of Green Powerhouse North Sea (up to 60 GW in 2050) with partial conversion to hydrogen
- **Mobility and Transport:**
  - In 2025 50 refuelling stations, 15,000 fuel cell cars and 3,000 heavy vehicles; in 2030 300,000 fuel cell cars
  - Reduction in investment costs for filling stations by average 10% per year
  - Hydrogen contributing to at least 150 emissions-free inland waterway vessels in 2030
- **Built Environment:**
  - By 2030, clear picture of how hydrogen can contribute to achievement of 2050 goal, including for buildings and communities that are difficult to make sustainable otherwise

The Strategy clarifies that "*for various forms of final consumption, zero-carbon hydrogen is one of the options that can lead to sustainability improvements. [...] **The development of zero-carbon hydrogen production and demand should ideally progress more or less in tandem**. Strong demand from end users will stimulate the rapid development of the market for hydrogen. Once there are clear rules for the market and successful steps have been taken in scaling up production, resulting in cost reductions, this will lead to a clearer picture for potential customers as to what extent hydrogen could be beneficial to them as a tool to achieve sustainability improvements.*" And "*Improved insights among major potential customers into the cost effectiveness of sustainable hydrogen in reducing CO2 emissions compared to other measures, such as electrification, will in turn provide a better picture of the total potential demand for hydrogen.*"

Looking into the end-use sectors in more detail, the Hydrogen Strategy refers to initiatives and projects, some of which have already started to materialize:

[153] Jörg Gigler, Marcel Weeda, Remco Hoogma, Jort de Boer, Hydrogen for the energy transition

Ports and industry clusters: The ports and industry clusters consider clean hydrogen as an essential part of achieving a climate-neutral industry sector by 2050. Until 2030, sustainability projects will be predominantly local in nature. Pilot-demo projects are already underway and receive funding support through several schemes.

- The Porthos project in Rotterdam focuses on the capture of CO2 in existing hydrogen production within the port. The objective of the associated H-Vision project is to achieve large-scale blue hydrogen production aimed at reducing emissions for 2030.
- The port of Amsterdam is interested in making the necessary preparations for a more significant role for hydrogen in the short term.
- In the run up to 2030, industry has expressed a desire for clusters to be connected with hydrogen infrastructure.

Hydrogen (including synthetic fuels) for transport: The Dutch Government recognizes that agreements with the sectors for transportation of specific groups (e.g., disabled), waste collection vehicles, zero emissions urban logistics and a strategy for long-distance transport for hinterland connections should provide further support for the roll-out of hydrogen, meaning that the national government and local and regional authorities will act as launching customers. Subsidy schemes for zero emissions urban logistics and heavy-duty transport will also be developed and the use of hydrogen in the shipping industry (maritime transport and inland waterways) and in the ports and further roll-out of refuelling stations will be encouraged. Regarding aviation, even though the Dutch government recognizes that making aviation more sustainable is a complex challenge, the country is firmly committed to a European blending obligation. In case that this commitment will not be adopted on European level, the Government will pursue a national obligation as of 2023. So far, the (draft) Sustainable Aviation Agreement with the sector included the commitment to reach 14% blending of sustainable fuels by 2030 and 100% by 2050. Due to the limited availability of biomass, the sustainable fuels will largely synthetic fuels produced from blue (in the mid-term) and green (in the long-term) hydrogen.

Building sector: The Dutch government recognizes that there is potential for the use of hydrogen for heating purposes but there are still uncertainties with regards to hydrogen’s applicability, safety, availability, sustainability and affordability. The country aims to investigate these uncertainties and determine the way in which hydrogen can strengthen other options, such as hybrid heat pumps and heat grids, primarily with regard to peak demand. In order to achieve the above, a number of targeted pilots in buildings will be realized in the 2020 – 2025 period.

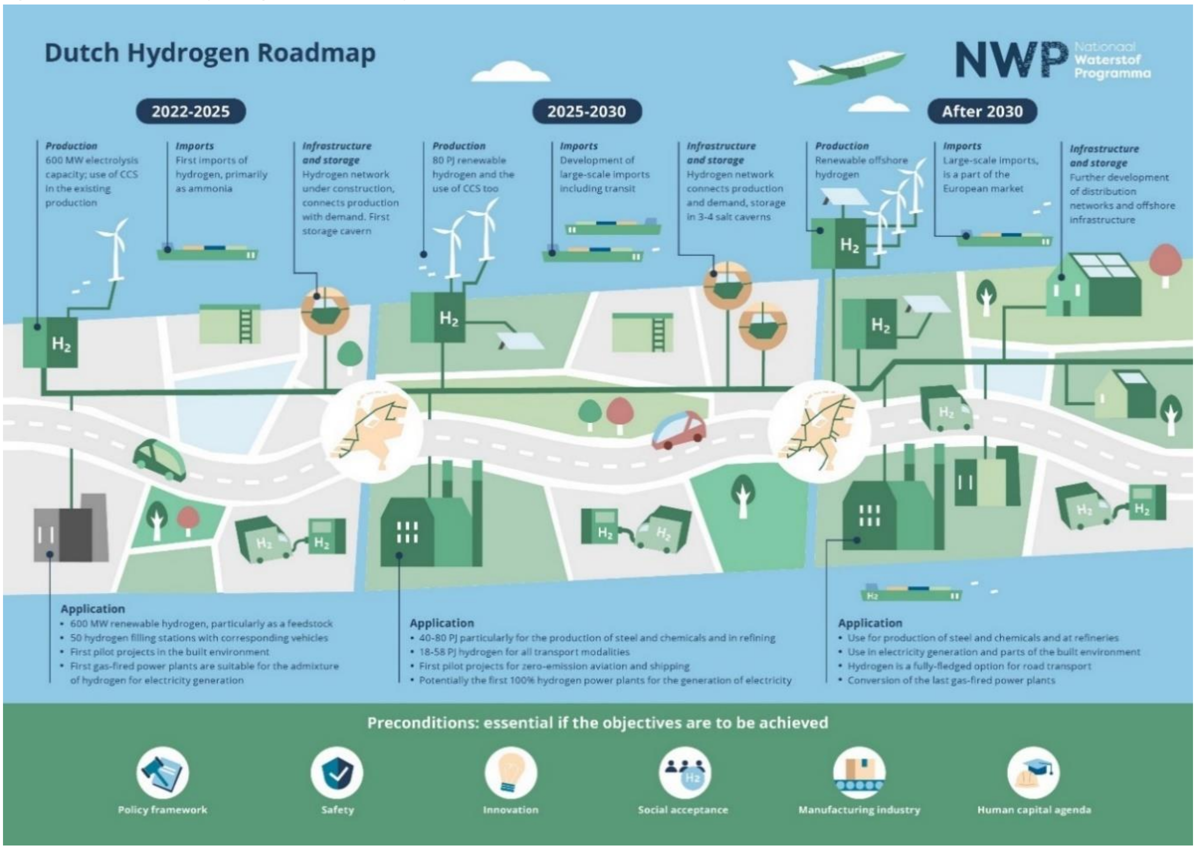
Electricity sector: The use of carbon-free hydrogen in the electricity sector is considered by the Dutch government for the long term and especially for enabling increased penetration of renewable energy sources. Pilot projects are underway to investigate the combination of local RES generation with hydrogen production, usage and storage, in order to address congestion problems in the electricity transmission network and increase the possibilities for integration of renewable energy in a decentralized manner.

Agricultural sector: For the agricultural sector, the Strategy states that the use of decentralized generation of RES (wind and solar on agricultural establishments, such as stables and commercial buildings) could be used for the production of green hydrogen which could in turn be used for agricultural machinery, tractors and heavy-duty agro-logistics. In the short-term, the country in such small-scale pilot and demonstration projects.

In the National Climate Agreement, the establishment of a Hydrogen Programme was mentioned, which would focus on unlocking the supply of green hydrogen, the development of the necessary infrastructure and collaboration with various sectoral programmes, as well as the facilitation of ongoing initiatives and projects. This programme would also allow the synergy between infrastructure and the use of hydrogen to be advanced[150].

The Hydrogen Programme was indeed initiated in January 2022[154] by both public and private stakeholders and delivered a Roadmap[155] which proposes targets for renewable hydrogen in 2030 and describes what actions are needed to achieve those targets. The main milestones of this Roadmap are depicted in Figure 40. Based on the Roadmap, the solidified targets for 2030 concern the use of 11 – 22 TWh of green hydrogen for the production of steel and chemicals and for the refining sector and of 5 – 16 TWh for all transport modalities.

Figure 40: Dutch Hydrogen Roadmap[155]



[154] Nationaal Waterstof Programma (NWP) website (about us page)
[155] Ministry of Economic Affairs and Climate - Nationaal Waterstof Programma, 2022, Hydrogen Roadmap of the Netherlands

Hydrogen supply options considered

In the "*Excelling in Hydrogen Dutch technology for a climate-neutral world*" report, a new guide on hydrogen technology, issued by government and industry backed organizations in mid-2022, it is clarified that since largescale production of carbon-neutral (green) hydrogen will take time, **blue hydrogen is an important intermediate step**[156]. This statement reflects the National Climate Agreement's position on the possible sources of hydrogen:

- Focus on green hydrogen as much as possible, primarily based on electrolysis using sustainable electricity, but also based on biogenic feedstocks, provided they have been produced sustainably.
- Use of blue hydrogen – produced from natural gas with capture of CO2 emissions, without impeding the growth of green hydrogen.

The above are based on the fact that the Dutch government expects that a global hydrogen market will emerge including both blue and green hydrogen, whose carbon footprint will be differentiated via the use of certifications of origin.

Regarding the hydrogen **supply options** envisioned by the Strategy, these include:

- **Domestic production** in the Netherlands which can take place with the use of large electrolysers or production plants with CCS in the coastal regions. Regarding green hydrogen, the National Climate Agreement includes an ambition to scale up electrolysis to approximately **500 MW of installed capacity by 2025 and to 3 – 4 GW by 2030**.
- Domestic smaller-scale production sites may also be set up.
- **Imports from countries with cheap solar energy** which will enable the Netherlands to continue to act as an energy hub due to its favourable location, its ports and its extensive gas grid and storage capacity.

Regarding imports, the Hydrogen Programme stakeholders express the opinion that **initial imports (up to 2025)** will probably come from countries from which fossil fuels are currently imported, such as the **Middle East and North America**, as they have great potential for renewable electricity and existing infrastructure and expertise can be exploited. They also identify the possibility of hydrogen imports, initially in **small volumes**, from other EU Member States, such as **Portugal and Spain**. **After 2025**, they expect the Netherlands to import hydrogen from **several countries inside and outside Europe**. The initial imports will be realized via tools such as the Important Project of Common European Interest framework, via setting up bilateral MoUs with other countries and by collaborating on an import strategy with other countries with similar import interests, such as Germany and Belgium.

[156] Government and industry stakeholders, 2022, [Excelling in Hydrogen Dutch technology for a climate-neutral world]

Measures for promoting hydrogen market development

According to the National Climate Agreement, although the costs of green hydrogen are expected to fall, at present there is a significant operating cost gap vs other energy carriers. Taking into consideration that the costs of green hydrogen primarily depend on the cost for developing RES used and that the costs of blue hydrogen largely depend on the price of natural gas and CO2, the Dutch government established the following **support measures**:

Support schemes for research, scaling up and rolling out:

1. Applied research and innovative pilot projects:

- Applied research and development of hydrogen production is supported by various Mission-oriented Research, Development and Innovation (MOOI) tenders.
- Innovative pilots in the field of hydrogen -principally at research and development in an industrial environment- are encouraged through the DEI+ (Energy Innovation Demonstration Scheme). These will be projects aimed principally at research and development in an industrial environment. Within the DEI+, these projects will be eligible to receive a subsidy for 25% of the eligible costs and depending on the type of company, this amount may be up to 45%, up to a maximum of 15 mil. € per project.

2. Scaling up through new, temporary operating cost support

- The government aims to facilitate the scaling-up process by making use of the existing Climate Budget funds available for temporary operating cost support as of 2021.
- Projects will be able to rely on existing subsidy schemes. The relevant possibilities within the state aid framework will be considered. In this context, the possible extension of the state aid for IPCEIs.

3. Roll-out: SDE++

- The projects producing hydrogen via electrolysis will be included in the SDE++. The subsidy will equal 1,064 € per avoided tonne of CO2.
- The projects producing blue hydrogen, will also be able to compete in the SDE++ through a dedicated CCS category.

Linking hydrogen to offshore wind energy:

In order to support the production of green hydrogen, the Government will conduct a study to investigate the advantages and disadvantages of linking hydrogen production to offshore wind energy via integrated tenders.

Blending obligation:

The Dutch Government will explore the option of imposing an obligation for blending green hydrogen in the natural gas grid (either physically or through certificates) to increase demand for green hydrogen. Physical blending up to 2% is already achievable with minor adjustments, and with further adjustments, the percentage could gradually be increased to approximately 10 – 20%. This measure is particularly examined for converting RES produced regionally and locally into hydrogen and blending it into the gas grid to promote decentralized production of green energy in places where the electricity grid has insufficient capacity.

Planning for hydrogen transportation and storage

As far as transportation of hydrogen is concerned, the Hydrogen Strategy foresees the following:

- The transport of hydrogen **across the country and across Europe through pipeline** would be the cheapest option.
- **Intercontinental transport** will take place **by sea**.

Focusing on pipelines, according to the National Climate Agreement, since the hydrogen projects in the Netherlands **up to 2025 are expected to be primarily local in scope**, the produced hydrogen will be **transported by regional infrastructure within the various industrial clusters and energy clusters**. **After 2025**, the electrolysis projects will be larger (in GW scale) and thus the need will arise for the **storage of hydrogen and the connection of various clusters**, which can largely be achieved **using existing natural gas infrastructure**.

In June 2020, the Dutch Ministry of Economic Affairs and Climate Policy along with Gasunie and TenneT, kicked-off a study, known as **HyWay 27**, to evaluate the conditions under which part of the existing gas grid can be used to transport hydrogen[157]. The project's final report[158], published in June 2021, concluded that by 2030 Gasunie will be able to free up existing natural gas transmission pipelines between the country's five major industrial clusters and on multiple connections to neighbouring countries. In the long run, existing pipelines can serve as a transport ring that enables suppliers to feed in hydrogen for high-volume users to use. In certain areas, new pipelines will have to be laid to fill gaps in stretches of pipeline or create connections to industrial clusters (Figure 41). The proposed infrastructure consists of approximately 200 km new pipelines, and 1,000 km of existing repurposed natural gas pipelines which create a hydrogen pipeline system connecting industrial clusters, import/export routes and storage facilities. The study also concluded that in theory, there is sufficient space under Dutch soil for the development of around 320 onshore salt caverns for hydrogen storage (Figure 42).

[157] Government of the Netherlands, 2020, HyWay 27 kick-off: The Dutch Ministry of Economic Affairs and Climate Policy, Gasunie and TenneT look into using national gas grid to develop hydrogen infrastructure
[158] Hyway 27 website, 2021, HyWay 27: realization of a national hydrogen network

Figure 41: Technically possible hydrogen network based on existing natural gas by 2030 (Source: HyWay27[158])

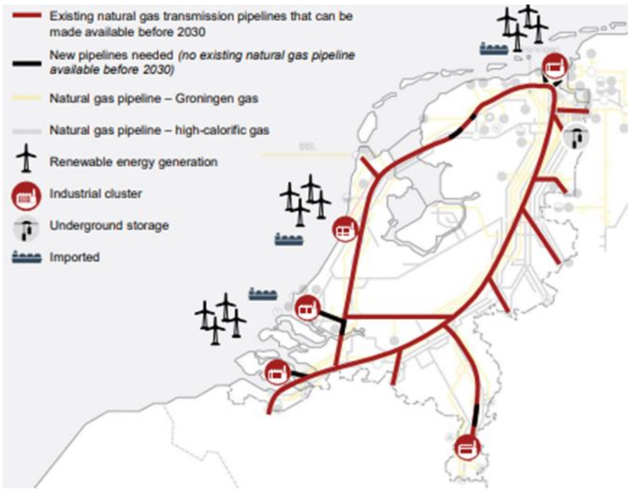
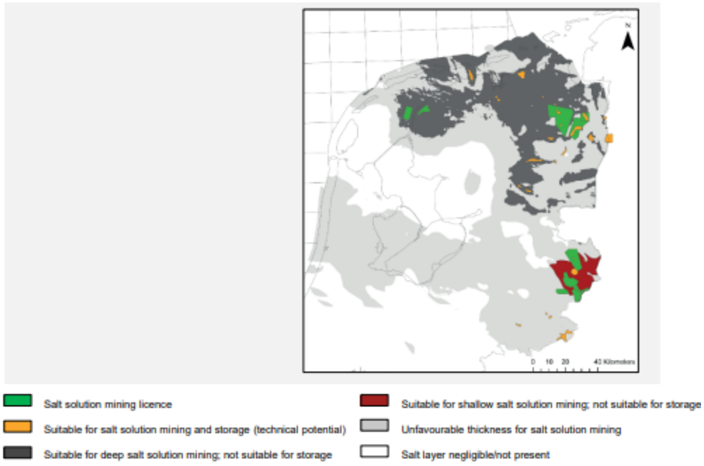


Figure 42: Overview of suitability of salt caverns for hydrogen storage (Source: HyWay27[158])



Following the conclusion of the HyWay study, in June 2021, **Gasunie was asked to develop the "*Dutch hydrogen backbone*"** via a letter by the State Secretary for Economic Affairs and Climate to the President of the House of Representatives, stating that "*Gasunie can quickly start preparations for the development of the transmission network, such as mapping supply and demand in more detail and obtaining commitment from the demand side, as well as by making suggestions for phasing the roll-out of the hydrogen network*"[159].

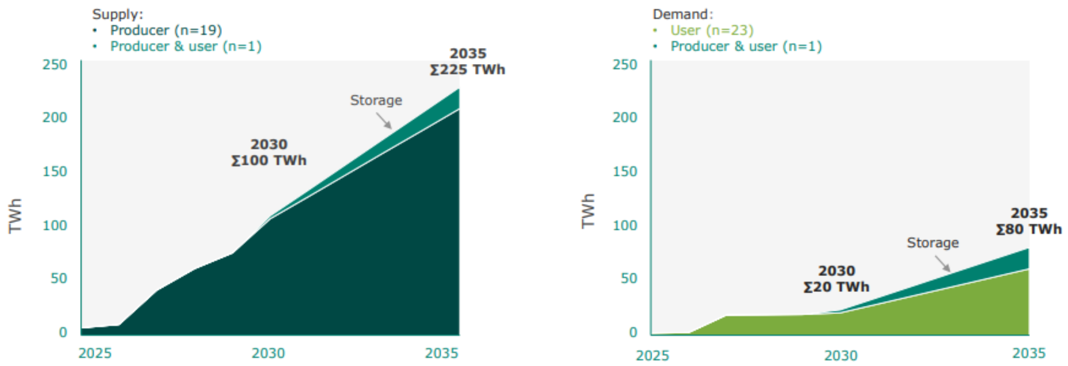
The construction of a 'hydrogen backbone' will be executed by **Hynetwork Services (100% subsidiary of Gasunie)**. In that respect, the Hynetwork Services have already engaged in several activities.

In October 2020, Hynetwork Services conducted a **Market Consultation** in order to understand the preferences of market parties for the technical specifications of the Dutch national hydrogen transport network. The participants were potential hydrogen producers, industrial users and companies that could act as both producers and users. As per Figure 43 below, the results indicated that in 2030,

[159] State Secretary for Economic Affairs and Climate, 2021, Ontwikkeling transportnet voor waterstof

producers expect to produce and transport roughly 100 TWh of hydrogen and users expect to use roughly 20 TWh. By 2035 these amounts increase to 225 and 80 TWh, respectively[160].

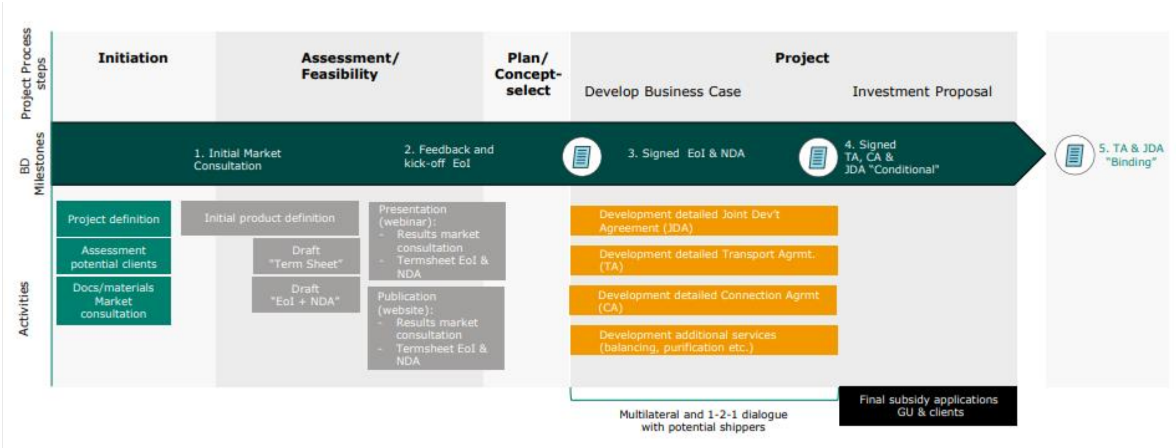
Figure 43: Non-binding indication of hydrogen to be transported between 2026 – 2035[160]



Regarding the end-uses, heating was the most-mentioned use for hydrogen and as far as production is concerned, the production of green hydrogen via electrolysis with electricity from offshore wind was the most preferred production route.

Following the market consultation, Hynetwork Services communicated during a **workshop** held in October 2021, their **business development process for the construction of the Dutch Hydrogen Backbone**. As shown in Figure 44, at the time, the company was already in the "*Assessment/ Feasibility*" phase. The market consultation results were presented during this workshop and participants were asked to express their interest to contract in future hydrogen pipeline infrastructure in the Netherlands.

Figure 44: Hynetwork Services business development process[160]



The **expression of interest** concerned the following services:

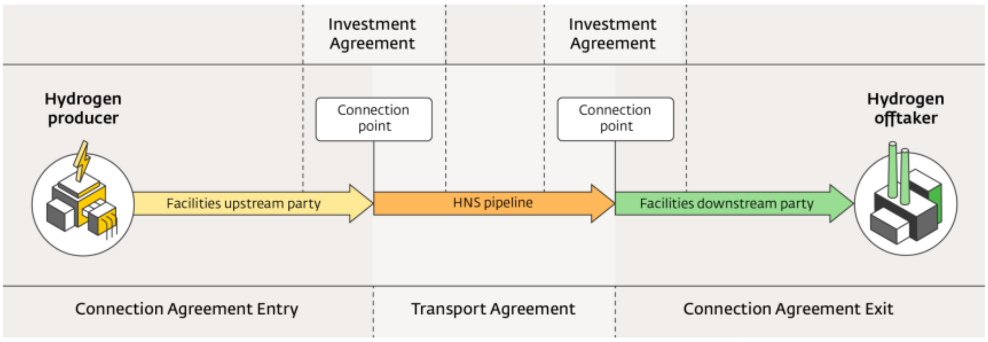
- Services considered to be included in the tariff: transport from client's nominated entry point and delivery to clients' nominated delivery point, management of system balance.
- Mandatory services subject to additional cost/fee: connection, correction of imbalance.

[160] Hynetwork services website, 2021, HyWay 27 webinar recording available and call for Expression of Interest

- Additional optional services (subject of separate cost-plus based fee): linepack flexibility service, purification, compression.

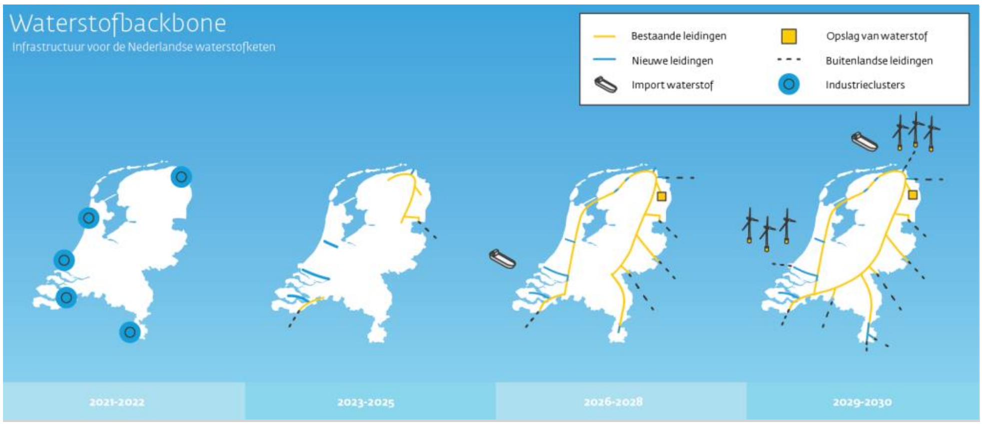
Next, from April to May 2022, Hynetwork Services proceeded with a **consultation process** about the general terms and conditions for hydrogen transport and connection services (contractual framework), as per Figure 45[161].

Figure 45: Hynetwork Services hydrogen transmission contractual framework[161]



Based on the HyWay 27 study and the above activities, Hynetwork Services aims to **build the Dutch hydrogen backbone in phases**, as shown in Figure 46. Progressively, industrial clusters will be connected to each other, to other countries[162] and to hydrogen storage and import locations. This will primarily (85%) be done using existing infrastructure and partly using newly constructed infrastructure. Gasunie has decided to modify the pipeline so it can deliver 100% hydrogen rather than blend hydrogen with natural gas[160].

Figure 46: The Dutch hydrogen backbone[160]



Apart from the Dutch hydrogen backbone investigated by the gas TSOs, the following infrastructure will be also examined:

[161] Hynetwork Services website, 2022, [Transport and connection agreements]
[162] In February 2023, it was announced that [Gasunie plans to build a hydrogen network crossing the German part of the North Sea] to transport green hydrogen from future offshore wind farms and enable large-scale hydrogen imports from Norway to Germany.

- regional infrastructure which will accommodate heating needs and
- commercial networks operated by private parties provided that these networks are either existing geographically demarcated networks or are eligible for third party access exemption.

The development of storage and import facilities, will be undertaken by private parties. However, until there will be sufficient competition in the field of hydrogen storage and import facilities, Gasunie subsidiaries will be allowed to participate in projects for the development of large-scale storage facilities and import terminals[163].

United States

The U.S. Department of Energy (DOE) published the "*Hydrogen Program Plan*"[164] and the "*Hydrogen Strategy*"[165] in 2020, which aimed to build a strategic framework to turn hydrogen into an *"affordable, widely available and reliable"* technology and "*an integral part of multiple sectors of the economy across the country"*. In September 2022, DOE released a draft National Clean Hydrogen Strategy and Roadmap (hereafter the Roadmap)[166]. The Roadmap provides an overview of the potential for hydrogen production, transport, storage, and use in the United States and outlines how clean hydrogen can contribute to national decarbonization and economic development goals. The main priorities outlined in the Roadmap are to identify and target **strategic, high-impact uses** of hydrogen, to **reduce the cost of clean hydrogen to 1 $/kg by 2031** and to focus on the **deployment of at least four regional clean hydrogen hubs**.

A final version of the strategy and roadmap is pending to be released, while the document will be updated at least every three years.

The context in which the U.S. Roadmap is developed includes the following policy goals:

- The U.S. aims to tackle the climate crisis: 100% pollution-free electricity by 2035 and net-zero GHG emissions by 2050.
- U.S. ambition is to take a leadership role in supporting the global transition from fossil fuels, by building a robust domestic market for clean hydrogen supported by domestic supply chains and by exporting clean hydrogen.

Targets set for hydrogen demand

The Roadmap considers as end-use sectors for clean hydrogen use, these **sectors for which there are fewer decarbonization alternatives (such as direct electrification or use of biofuels)**. The identified potential end-uses include the **industrial sector, the transportation sector, and the long-duration energy storage**. In the long-term opportunities include the **potential for exporting clean hydrogen** or hydrogen carriers to partner countries.

[163] CMS Law Now, 2022, Netherlands to develop national legislation for the Dutch hydrogen market
[164] DOE, 2020, Hydrogen Program Plan
[165] DOE, 2020, Hydrogen Strategy
[166] DOE, 2022, Draft National Clean Hydrogen and Roadmap

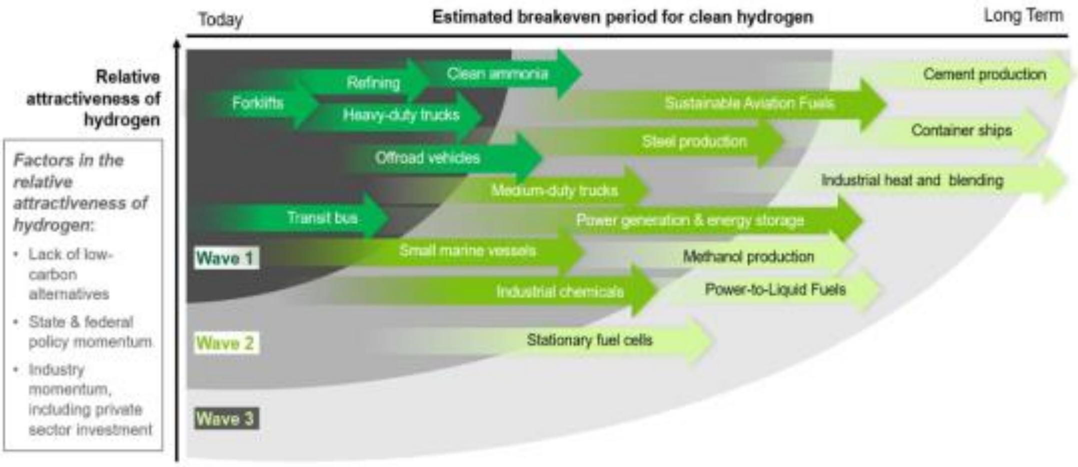
As "*clean hydrogen*", the Roadmap considers decarbonized[167] hydrogen produced from natural gas, coal, renewable energy sources, nuclear energy, and biomass. It is also clarified that **a mix of hydrogen production from water electrolysis, hydrogen production from fossil fuels with CCS, and hydrogen production from biomass and waste feedstocks** is likely to be used in the U.S. **through at least 2050**.

Figure 47 presents DOE's views on **possible emerging demand** for the use of clean hydrogen and Figure 48 shows DOE's vision of a **phased roll-out of hydrogen use in specific end-use sectors**. It is highlighted that this phased market penetration of clean hydrogen will depend on several factors including technical maturity, cost, infrastructure availability, manufacturing and supply chain capacities, the cost of other low-carbon solutions, the policy and regulatory landscape, regional and state initiatives, industry momentum and commitments, and unlocking private capital and investment.

Figure 47: Current and emerging demands for hydrogen[166]

	Industrial feedstocks	Transportation	Power generation & energy storage	Hydrogen blending in natural gas
Existing demands at limited current scales	• Oil refining • Ammonia • Methanol	• Forklifts and other material-handling equipment • Buses • Light-duty vehicles	• Distributed generation: primary and backup power • Renewable grid integration with storage and other ancillary services	• Low percentage hydrogen blending
Emerging demands and potential new opportunities	• Steel and cement manufacturing • Industrial heat • Bio/Synthetic fuels	• Medium- and heavy-duty vehicles • Rail • Maritime • Aviation • Offroad equipment (mining, construction, agriculture)	• Hydrogen low NOx combustion • Long-duration energy storage • Direct/reversible fuel cells • Nuclear/hydrogen hybrids • Fossil/waste/biomass hydrogen hybrids with CCUS	• High percentage hydrogen blending • Industry, building or district heating for hard to electrify or limited options

Figure 48: Roll-out of clean hydrogen in the U.S. in waves[166]



[167] By "*decarbonized*", the Roadmap refers to hydrogen produced with a carbon intensity equal to or less than 2 kg CO2-eq produced at the site of production per kilogram of hydrogen produced.

As technologies and markets develop, more detailed analyses will be conducted for the updated versions of the Roadmap, including the optimal use of hydrogen in "*no regrets*" sectors, avoiding stranded assets by creating demand certainty, and prioritizing energy and environmental justice. However, initial deployments using clean hydrogen are expected to emerge in industries (refining, ammonia and methanol, metals) that currently use grey hydrogen produced by reforming natural gas without CCS.

The Roadmap also clarifies that in order to build demand per end-use sector, **a specific production cost threshold** (Figure 49) should be achieved to make hydrogen competitive against other technologies.

Figure 49: Threshold price for clean hydrogen to be competitive[166,168]

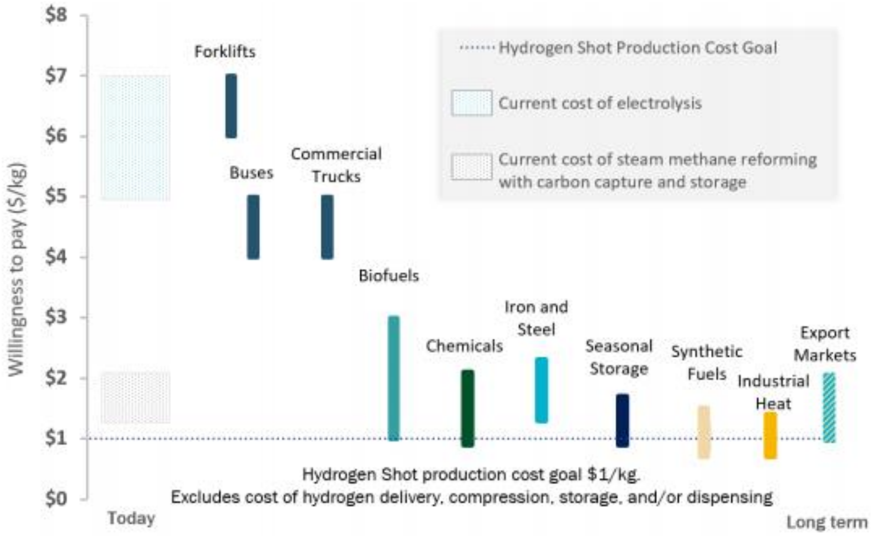
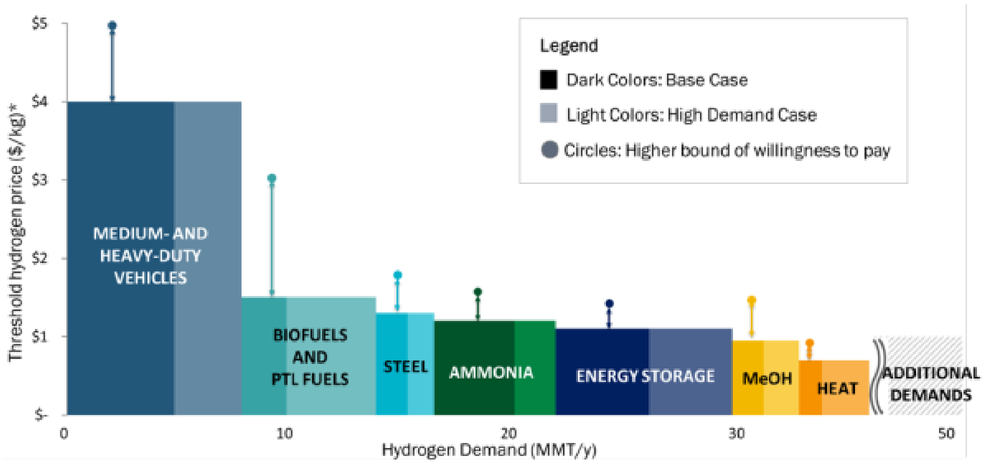


Figure 50 depicts DOE's scenarios for the expected demand in different sectors provided that clean hydrogen is available (produced, delivered, and dispensed) at the threshold price shown above.

Figure 50: Scenarios of potential clean hydrogen demand[166]



[168] The "*Hydrogen Shot production cost of $1/kg*" refers to DOE's "*Hydrogen Energy EarthShot (Hydrogen Shot)*" launched in June 2021 which set the target of reducing the cost of clean hydrogen production to $1 per 1 kilogram in one decade (Office of Energy Efficiency and Renewable Energy, 2021, [Hydrogen Shot)](Hydrogen Shot)

According to the Roadmap if the above demand scenarios were to materialize then **330 TWh/yr (10 Mtons/yr) of clean hydrogen would be needed by 2030, 660 TWh/yr (20 Mtons/yr) by 2040, and 1650 TWh/yr (50 Mtons/yr) by 2050**.

The Roadmap points out that other emerging, and future markets with higher ranges of uncertainty today, such as hydrogen exports and petroleum refining could generate additional demand.

Hydrogen supply options considered

The Roadmap states that for the domestic production of hydrogen, there are several technologies that can produce clean hydrogen, including electrolysers powered by the U.S. growing share of clean energy, methane reformation with CCS, gasification or thermal conversion of biomass and/or solid wastes with carbon capture and storage, and many other emerging technologies. The envisioned supply of clean hydrogen in quantitative terms, matches the envisioned demand for hydrogen and is illustrated in Figure 51.

Figure 51: DOE's goals to progressively increase clean hydrogen production[166]

DOE estimated the technical potential for producing hydrogen from domestic renewable energy sources and outlined that the lowest-cost production methods should be selected, based on regional resource availability, as during the early market developments production needs to be located near end-users to reduce the costs of hydrogen delivery.

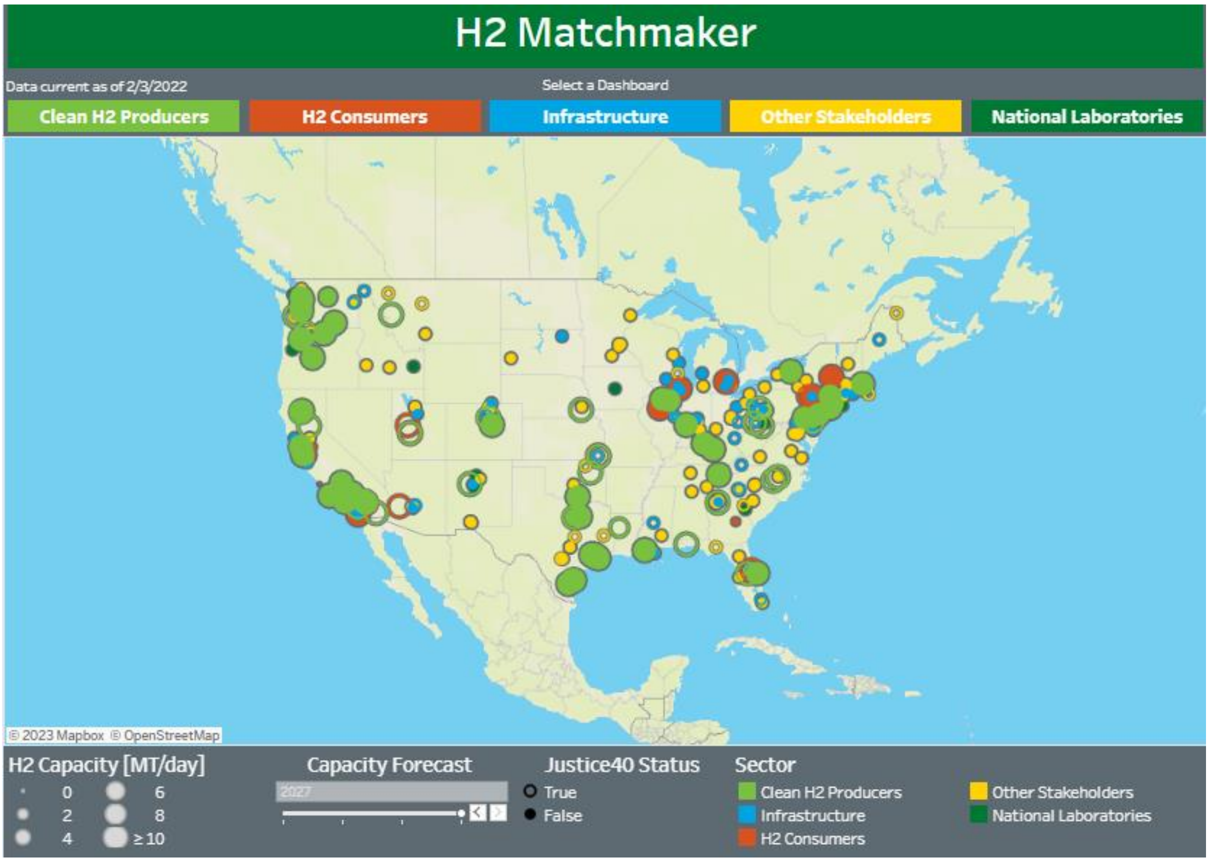
The **focus will primarily be on regional clean hydrogen hubs**, defined as a network of clean hydrogen producers, clean hydrogen consumers, and connective infrastructure located "*in close proximity*" to each other.

To this end, in January 2020, DOE set up the ***"H2 Matchmaker"***[169] which is an online portal aimed to assist hydrogen suppliers and users to align potential needs in specific geographic areas within the U.S. and explore opportunities towards realizing regional hydrogen hubs. The online tool requests information only from companies that already are, or are planning to be, a significant hydrogen producer, end-user, infrastructure provider, or other key stakeholder within the next 5 years. DOE's

[169] Office of Energy Efficiency and Renewable Energy, 2022, H2 Matchmaker

goal by setting up this tool is to match suppliers with offtakers and thus unlock private capital and avoid stranded assets. The current and future hydrogen supply and demand centres and infrastructure are demonstrated on a map (Figure 52) that is continuously updated based on stakeholders' expressed interests.

Figure 52: H2 Matchmaker map[169]



Measures for promoting hydrogen market development

In November 2021, the Congress passed the Investment and Jobs Act (Public Law 117-58), also known as the Bipartisan Infrastructure Law (BIL). This legislation authorizes for DOE **9.5 bil. $ for clean hydrogen**, as follows [166,170]:

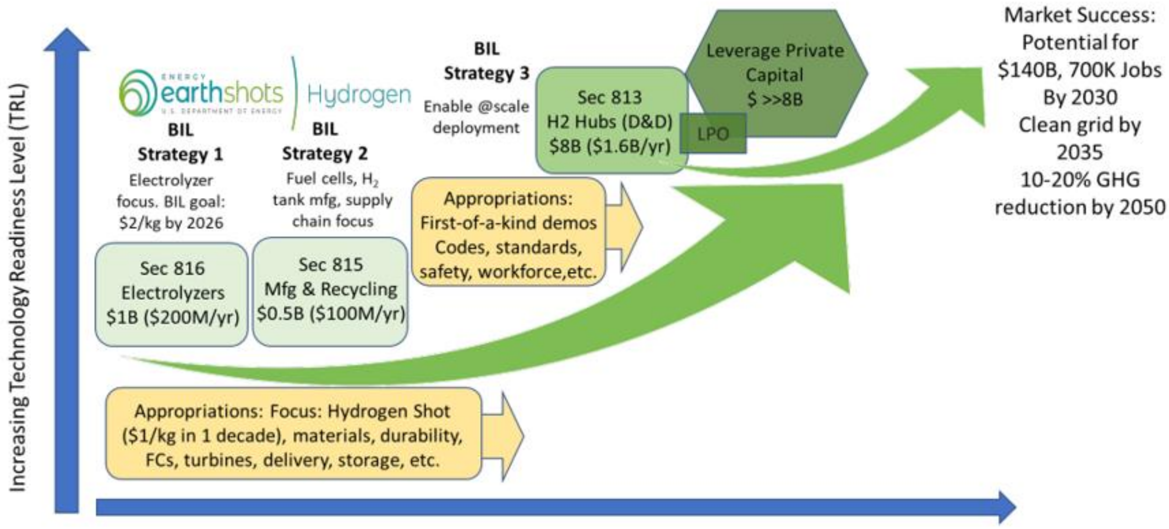
- 1 bil. $ for electrolysis research, development and demonstration.
- 500 mil. $ for clean hydrogen technology manufacturing and recycling R&D.
- 8 bil. $ for at least four regional clean hydrogen hubs which should demonstrate balanced hydrogen supply and demand, connective infrastructure, and a plan to be financially viable after the DOE funding has ended.

According to DOE, the above funding opportunities are aligned with Hydrogen Shot priorities by directing work to **reduce the cost of clean hydrogen to 2 $/kg by 2026 (and 1 $/kg by 2031)**. Following the BIL enactment, in February 2022, DOE launched a "*Requests for Information Supporting Hydrogen*

[170] DOE, 2022, Notice of Intent No.: DE-FOA-0002768

Bipartisan Infrastructure Law Provisions, Environmental Justice, and Workforce Priorities"[171]. As shown in Figure 53, during the webinar kick-starting the RFI, DOE presented how the BIL in conjunction with the Loan Programs Office (LPO), could lead to a successful hydrogen market by 2030.

Figure 53: BIL support to reach hydrogen market success[171]



Two RFIs concluded in March 2022:

- Hydrogen Hubs Implementation Strategy RFI, which requested public input on the provisions, requirements, implementation strategy, etc. for the creation of the hubs.
- Clean Hydrogen Manufacturing, Recycling, and Electrolysis RFI, which requested public input on priority areas that would advance domestic manufacturing and recycling of clean hydrogen technologies, including fuel cells, storage equipment, and other hydrogen related components.

Based on the information collected through the RFI's, in October 2022, DOE announced a 7 bil. $ funding opportunity for Regional Clean Hydrogen Hubs[172]. Moreover, in December 2022, DOE announced its intent to issue 750 mil. $ in funding from the BIL to dramatically reduce the cost of clean-hydrogen technologies[173,].

Apart from the funding that stems from the BIL, in January 2023, DOE announced additional funding of 47 mil. $, for hydrogen carrier development, onboard storage systems for liquid hydrogen, liquid hydrogen transfer/fuelling components and systems and high performing, durable membrane electrode assemblies for medium and heavy-duty applications[174].

[171] DOE, 2020, The #H2IQ Hour, Today's Topic: Overview of DOE Requests for Information Supporting Hydrogen Bipartisan Infrastructure Law Provisions, Environmental Justice, and Workforce Priorities

[172] Latham & Watkins Environment, Land & Resources Practice, 2022, DOE Releases Draft Clean Hydrogen Production Standard, Draft Roadmap, and Hydrogen Hub Funding Opportunity

[173] DOE, 2022, Biden-Harris Administration Announces $750 Million To Accelerate Clean Hydrogen Technologies

[174] DOE, 2023, Biden-Harris Administration Announces $47 Million to Develop Affordable Clean Hydrogen Technologies

Additionally, In August 2022, the U.S. President signed the Inflation Reduction Act (IRA) into law (Public Law 117-169), which provides additional policies and incentives for hydrogen including a production tax credit. The tax credit for clean hydrogen will pay producers up to 3 $/kg of hydrogen from 2023[166,175].

Planning for hydrogen transportation and storage

The Roadmap refers to "*opportunities to use, and barriers to using, existing infrastructure, including all components of the natural gas infrastructure system, the carbon dioxide pipeline infrastructure system, end-use local distribution networks, end-use power generators and LNG terminals*". It also identifies, as **scope of future work**, to enable the development of **injection standards for blending hydrogen into natural gas pipelines**, assessing opportunities to repurpose natural gas infrastructure for hydrogen and identifying conditions under which deployment of new infrastructure would be necessary to enable the use of high concentrations of blends.

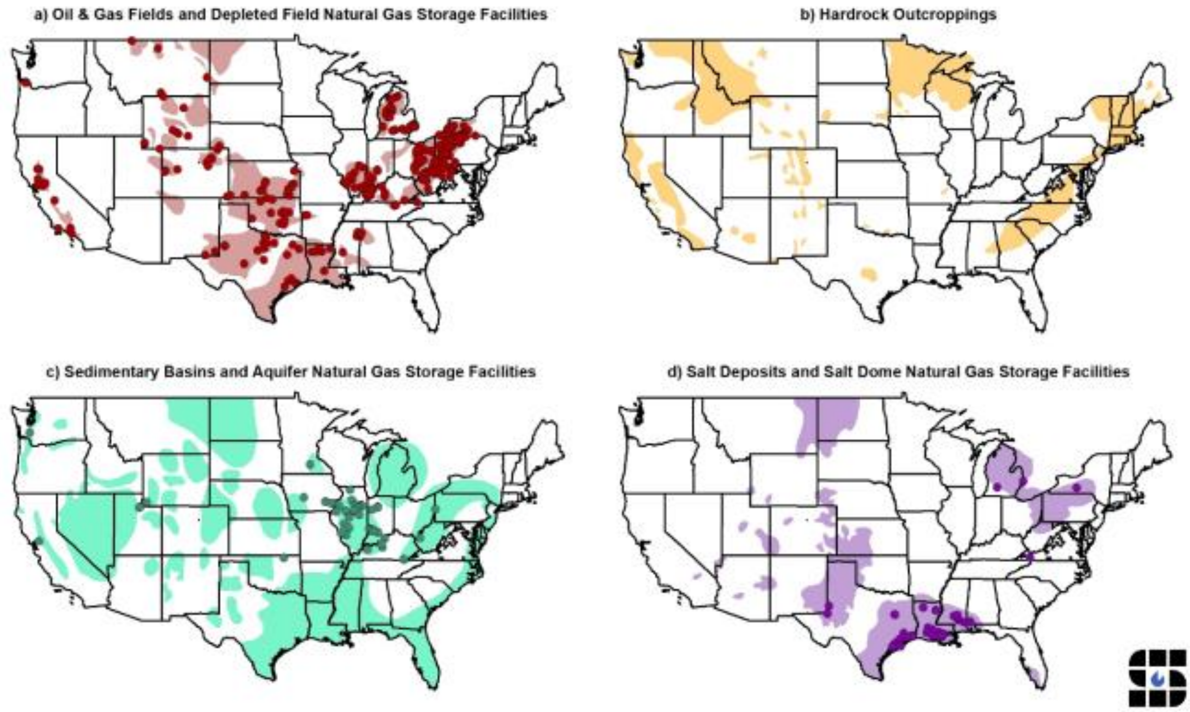
To this end, DOE's Hydrogen and Fuel Cell Technologies Office (HFTO) launched the HyBlend program in 2021. The objective is to test pipeline materials in varying concentrations of hydrogen to assess their susceptibility to hydrogen effects[176]. More R&D activities are underway and discussions on regulatory and technical obstacles for an extensive pipeline network in the U.S. In 2020, the majority staff of the House Select Committee on the Climate Crisis called for legislation to facilitate hydrogen infrastructure development[177,178]. Also, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is working with DOE's Office of Energy Efficiency & Renewable Energy (EERE) to lower the cost and energy use of the hydrogen delivery infrastructure. This includes developing improved, lower cost materials for pipelines, breakthrough approaches to hydrogen liquefaction, lighter weight and stronger materials and structures for high pressure hydrogen storage and transport, and novel low-pressure solid and liquid carrier systems for hydrogen delivery and storage[179]. Nevertheless, "*developments in both hydrogen supply and demand will be key determinants of how much hydrogen pipeline capacity will be needed, when it will be needed, and where*"[178] and as outlined in the BIL, "*the purpose is to establish a program to support the development of at least 4 regional clean hydrogen hubs that […]* ***can be developed into a national clean hydrogen network*** *to facilitate a clean hydrogen economy.*[171]"

Regarding **storage** of clean hydrogen, the Roadmap examines the country's potential for regional storage. The options listed include storage in gaseous or liquid vessels, in underground formations, in materials, such as hydrogen carriers. According to DOE, each approach has both advantages and disadvantages that also depend on the end-use application. As regards, large scale storage, the U.S. has three geological hydrogen storage caverns including the world's largest in Beaumont, TX, storing over 7,000 tonnes underground. These storage facilities have been excavated in salt deposits near the

[175] Green Hydrogen Organization, 2022, United States: Tax credits for green hydrogen under the US Inflation Reduction Act 2022
[176] DOE, 2021, HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines
[177] ENERGY BAR ASSOCIATION, 2021, FERC'S AUTHORITY TO REGULATE HYDROGEN PIPELINES UNDER THE INTERSTATE COMMERCE ACT
[178] Congressional Research Service, 2021, Pipeline Transportation of Hydrogen: Regulation, Research, and Policy
[179] PHMSA website, Hydrogen

point of hydrogen use. According to the Roadmap, additional geologies used for natural gas storage, such as depleted oil and gas reservoirs and aquifers (Figure 54), could potentially be used for hydrogen in the future since in many cases regions with storage capacity also have significant clean hydrogen production potentials.

Figure 54: Underground storage opportunities in the U.S.[166]



Annex II – Webinar results

The preliminary findings of Tasks 1 – 5 were presented during an on-line public webinar held on 13 April 2023, organised and conducted, with the support of the Agency.

The webinar entitled "*ACER webinar on a consultancy study on hydrogen networks*" received 430 registrations for attendance and the number of attendees amounted to 204. The webinar's agenda included a short presentation from ENTSOG on its Preliminary Draft CBA Methodology and three presentations from VIS on hydrogen transportation plans and supply/demand targets in selected EU MSs, market and network conditions justifying building hydrogen infrastructure and recommendations to ENTSOG for a CBA methodology for Hydrogen Infrastructure

After the presentations, the attendees were invited to participate in a poll to collect their feedback on the key VIS recommendations for improving ENTSOG's hydrogen CBA Methodology. The (single choice) questions and the received answers are presented below.

1. What should be the length of economic assessment period for H2 projects? (Total votes: 88)

25-years, to consider a timeframe where uncertainty is reasonably acceptable	61%
40 years, as proposed in ENTSOG preliminary methodology for H2 projects	23%
Other	6%
I do not have a view	10%

2. How consistent should be ENTSOs' CBA methodologies? (Total votes: 86)

As consistent as possible, in line with these recommendations	65%
Current ENTSOs methodologies are already sufficiently consistent	12%
I do not have a view	23%

3. Should the reference network consider a minimum level of infrastructure development closer to an "existing" grid? (Total votes: 82)

Yes, by including only projects at the stage of market test will be built	9%
Yes, by including both projects at the stage of market test will be built and projects included in National Development Plans	10%
Yes, by including both projects at the stage of market test will be built and projects included in National Development Plans	48%
No, the PCI reference network indicated in ENTSOG CBA Methodology is adequate to assess H2 infrastructure gaps and H2 projects	16%
I do not have a view	18%

4. Considering the limited level of H2 infrastructure developed within a country today, should the ENTSOG CBA Methodology consider internal H2 infrastructures in the H2 topology? (Total votes: 79)

Yes, to properly assess a gradual development of the H2 network (point to point, cluster to cluster, cross border)	75%
No, to focus only on cross-border capacities is enough to capture H2 benefits at EU level	11%
I do not have a view	14%

Answers to the poll revealed that the majority of the respondents widely supported the recommendations presented by VIS in its Study, which differ from the approach proposed by ENTSOG in its preliminary draft CBAM.

The webinar was recorded and its material has been published here.