european network
of transmission system operators
for gas

TEN-YEAR NETWORK DEVELOPMENT PLAN

2024

ANNEX D1

Implementation Guidelines
for Project-specific Cost-Benefit Analyses
of Hydrogen Projects

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Cover picture Courtesy of Gas Connect Austria

Contents

Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulations
AF	Alternative Fuel(s)
ATR	Autothermal Reforming
B1	GHG Emissions Variation Indicator
B2	Non-GHG Emissions Variation Indicator
B3.1	Integration of Renewable Electricity Indicator
B3.2	Integration of Renewable and Low Carbon Hydrogen Indicator
B4	Increase of Market Rents Indicator
B5	Reduction in Exposure to Curtailed Demand Indicator
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CO_2-eq	CO_2 equivalent
CODG	Cost of Disrupted Natural Gas
CODH	Cost of Disrupted Hydrogen
DC	Demand Curtailment
DGM	Dual Gas Model, also Dual Hydrogen/Natural gas Model
DHEM	Dual Hydrogen/Electricity Model
DRES	Dedicated Renewable Energy Sources
DSR	Demand Side Response

DSO	Distribution System Operator
EBCR	Economic Benefit-to-Cost Ratio
EC	European Commission
EE1st	Energy Efficiency First
EEA	European Environmental Agency
EEA27	European Economic Area
EHB	European Hydrogen Backbone
EIB	European Investment Bank
ETS	Emission Trading Scheme
ENPV	Economic Net Present Value
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ENTSOs	ENTSO-E and ENTSOG
EU	European Union
FEED	Front-End Engineering Design
FID	Final Investment Decision
GCV	Gross Calorific Value, also Higher Heating Value
GHG	Greenhouse Gas
GJ	Gigajoule
GWh	Gigawatt Hour
GWh_{H2}	Gigawatt Hour in terms of thermal energy of hydrogen
HCR	Hydrogen Curtailment Rate

HDC	Hydrogen Demand Curtailment
IGI	Infrastructure Gaps Identification
IPCC	Intergovernmental Panel on Climate Change
LOR	Lesser-of-Rule
MCA	Multi-Criteria Analysis
MWh	Megawatt Hour
MWh_{H2}	Megawatt Hour in terms of thermal energy of hydrogen
NCV	Net Calorific Value, also Lower Heating Value
NECP	National Energy and Climate Plan
NH_3	Ammonia
Non-GHG	Non-Greenhouse Gas
NOx	Nitrogen Oxide
NMVOC	Non-Methane Volatile Organic Compounds
NT+	National Trends+ Scenario
OPEX	Operational Expenditure
PCI	Project of Common Interest
PINT	Put One In at a Time
PLEXOS	PLEXOS Energy Modeling Software
PM 10	Particulate Matter with a Diameter of 10 Micrometers or less
PM 2.5	Particulate Matter with a Diameter of 2.5 Micrometers or less
PMI	Project of Mutual Interest
PS-CBA	Project-Specific Cost-Benefit Analysis, also Project Assessment

P2G	Power-To-Gas
PV	Photovoltaic
RES	Renewable Energy Sources
SMR	Steam Methane Reformer(s)
SO_2	Sulphur Dioxides
SRES	Shared Renewable Energy Sources
t	Ton
TEN-E Regulation	Regulation (EU) 2022/869
TOOT	Take Out One at a Time
TSO	Transmission System Operator
TYNDP	Union-wide Ten-Year Network Development Plan
VoLL	Value of Lost Load of Electricity
VOLY	Value of a Life Year
VO&M	Variable Operations and Maintenance Cost
VSL	Value of Statistical Life
WTP	Willingness To Pay
y	Year
YOLL	Years of Life Lost

1. Introduction

The objective of the ENTSOG TYNDP 2024 Implementation Guidelines is to provide detailed guidance on the different elements of relevance for the project-specific cost-benefit analysis, or *PS-CBA*, as part of the 2024 TYNDP cycle.

Namely, the elements of the multi-criteria cost-benefit analysis applied by ENTSOG to perform project-specific CBAs in the TYNDP 2024 process and referred to in this document are:

- Modelling tools
- Topology for hydrogen, electricity and natural gas
- Infrastructure levels used in modelling
- Supply and demand inputs used in modelling
- Other market assumptions used in modelling
- Project grouping principles
- Project status
- Benefit indicators for PS-CBA
- Monetisation elements used for benefit indicators
- Economic performance indicators

Summary of TYNDP 2024 / PS-CBA process

An important change in the 2024 TYNDP cycle is that its timeline prioritizes deliverables related to hydrogen. The reason is that such projects are submitted in time to the PCI/PMI selection process, currently expected in the third quarter of 2024. Natural gas-related projects will still be taken into account in the TYNDP system-level assessment, yet will no longer be covered by individual cost-benefit analyses, as in previous editions.

While priority deliverables are foreseen to be made available in majority during 2024, the rest of the TYNDP documentation – additional simulations, selected maps and annexes – are planned to be published in 2025, after extended stakeholder consultations are conducted and opinions from regulatory bodies are received.

The PS-CBA or *Project Assessment* phase is expected to start as soon as the system-level assessment is completed. This latter analysis will result in the identification of infrastructure gaps compared to European energy and climate goals[1]. In line with Art. 4[2] of the "TEN-E"[3] Regulation, for each project which promoters intend to submit for PCI/PMI status attribution, a PS-CBA will be conducted in order to determine the degree to which the project contribute(s) to the criteria of sustainability, market integration, security of supply, and competition and to assess whether these benefits outweigh the associated costs. Such requirement is also referred to in the Annex III[4] of the TEN-E Regulation.

For wider context, the system-wide assessment itself starts as soon as the 2024 Scenarios report is available. Scenarios start from the existing infrastructure and draw out possible future energy system evolutions for the following decades; these provide a quantitative basis for the assessment, to which projects from the TYNDP are added to perform the system-wide assessment. In the image below, the three main phases of the TYNDP cycle are framed in connection to the generic steps of the PCI/PMI selection process.

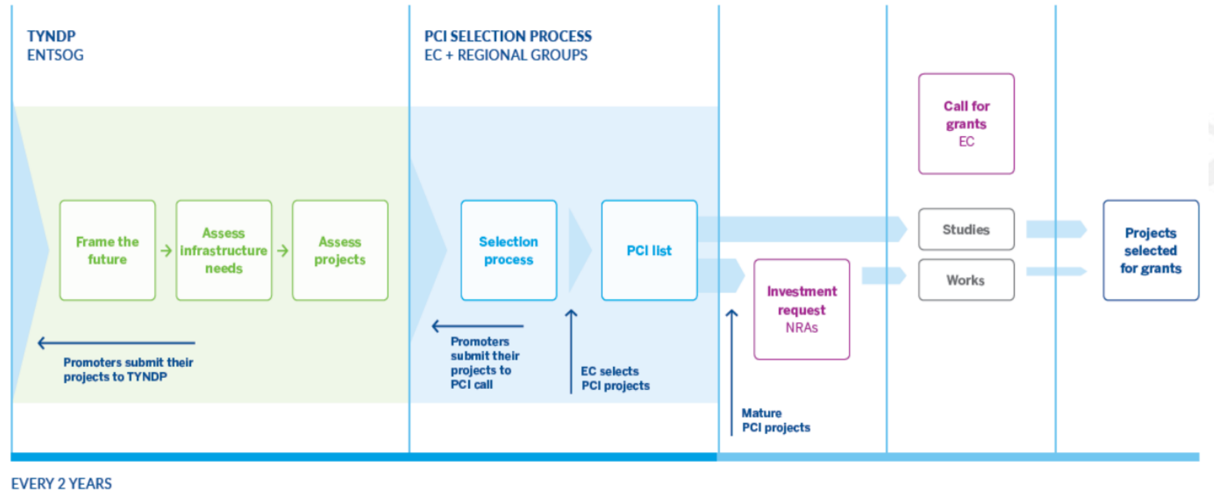

Figure 1 - TYNDP and PCI/PMI process overview

In line with the requirements of the TEN-E Regulation, public consultations are held to validate the methodological approach and results from the above-mentioned assessments, in line with Art. 11[5], 12[6], and 13[7] of the TEN-E Regulation. The schematic below illustrates the main steps of the outstanding TYNDP 2024 phases.

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[1] 2030 targets for energy and climate and 2050 climate neutrality objective – see paragraph 1 of Art. 1 – Subject matter, objectives and scope

[2] Art. 4 – Criteria for the assessment of projects by the Group

[3] Reg. (EU) 2022/869, on guidelines for trans-European energy infrastructure, accessible online at https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32022R0869

[4] Section 2, point (1)(d) of Annex III

[5] Paragraph 2 of Art. 11 – Energy system wide cost-benefit analysis

[6] Paragraph 1 of Art. 12 – Scenarios for the ten-year network development plans

[7] Paragraph 1 of Art. 13 – Infrastructure Gaps Identification

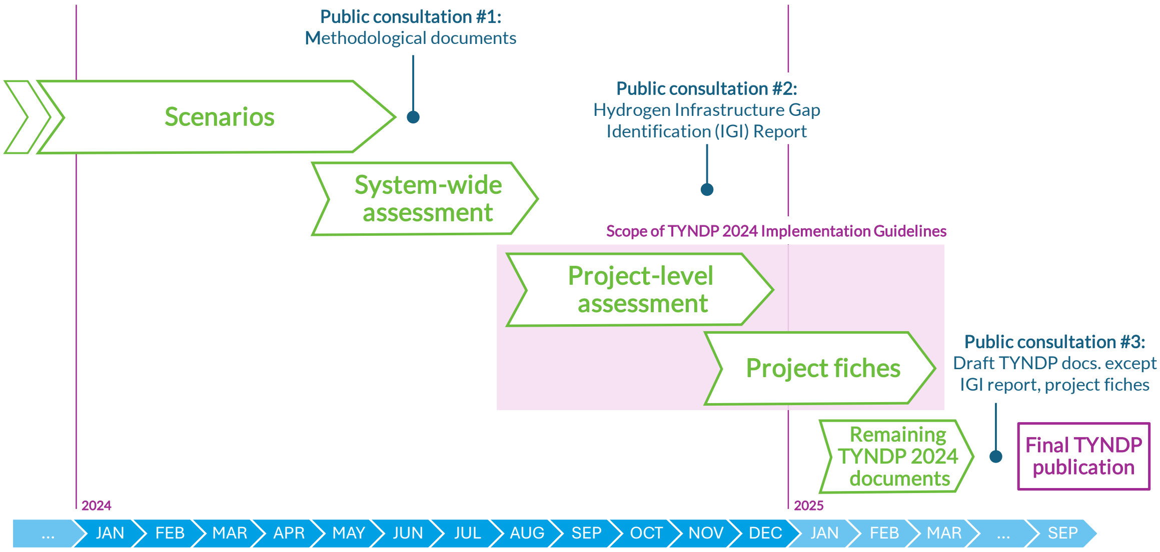


Figure 2 – Main outstanding TYNDP 2024 phases (updated June 2024)

Interaction between TYNDP 2024 and 7th PCI/PMI Selection process

The 7th PCI/PMI selection process, under the responsibility of the TEN-E Regional Groups led by the European Commission, is a separate process from the TYNDP 2024 project collection process[8]. As part of the 7th PCI/PMI project collection process, promoters will be asked to actively confirm their intention to apply to PCI/PMI status.

Following the TYNDP 2024 project collection and system-wide assessment ENTSOG will only run the project-specific assessment on hydrogen projects which:

(1) are eligible for the upcoming PCI/PMI selection process and

(2) for which promoters will have expressed their intention to participate to the PCI/PMI selection during the TYNDP 2024 project collection phase.

ENTSOG will provide PS-CBA results to promoters ahead of the publication of corresponding project fiches. Promoters will at this stage have the option to maintain or withdraw the project from the PCI/PMI selection process.

The process can be graphically summarized as follows:

[8] TYNDP 2024 Guidelines for Project Inclusion: https://www.entsog.eu/sites/default/files/2023-10/TYNDP%202024%20Guidelines%20for%20Project%20Inclusion_for%20Publication_0.pdf

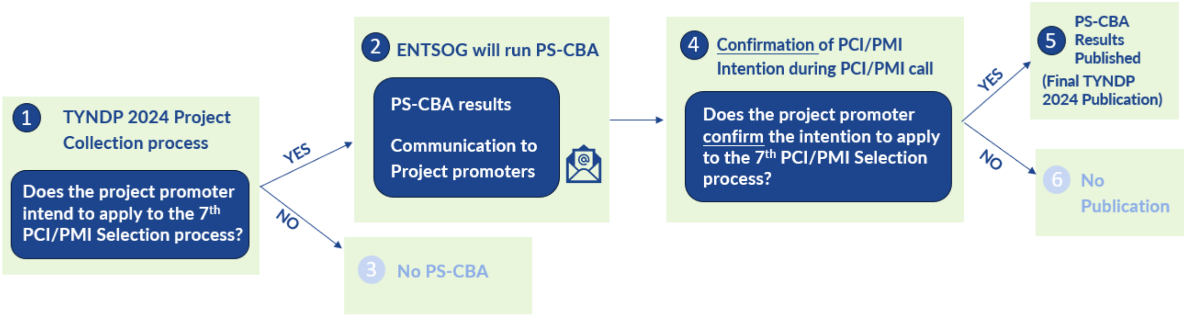


Figure 3: Interactions between TYNDP 2024 and 2nd PCI/PMI selection process under revised TEN-E

TYNDP 2024 Scenario Report

The ENTSOs have to use scenarios established in line with Art. 12 of the TEN-E Regulation as the basis for the TYNDPs and the calculation of the PS-CBAs used in PCI/PMI selection process. The draft scenario documents for the TYNDP 2024 are publicly available[9] and currently await opinions from ACER, Member States, and the European Advisory Board on Climate Change as well as approval or a request for amendments by the European Commission.

The following scenario inputs are used for the TYNDP 2024 PS-CBA:

- Selection of scenario: National Trends+ (NT+)[10]
- Timeframes: 2030, 2040

[9] https://2024.entsos-tyndp-scenarios.eu/

2. Model description

This section of the TYNDP 2024 Implementation Guidelines provides a detailed description of the market and network modelling tools used for the TYNDP 2024 PS-CBA.

2.1 General description of the modelling approach for TYNDP 2024

Modelling of hydrogen infrastructure requires market and/or network modelling of different energy carriers such as natural gas and electricity, given the foreseen interlinkages between the energy carriers.

Figure 4: Description of the interactions between Electricity, Hydrogen and Natural gas systems in TYNDP 2024 PS-CBA process.

As described in the **Figure 4**, the TYNDP 2024 PS-CBA process consists of a two-step approach:

- The first step that intends to capture the interlinkages between hydrogen and electricity through a network and market modelling of the joint hydrogen/electricity systems (i.e., Dual Hydrogen-Electricity Model, DHEM). This model and its objective function are used for the benefit indicators capturing GHG emissions variations (B1), non-GHG emissions variations (B2), integration of renewable electricity (B3.1), integration of renewable and low-carbon hydrogen (B3.2), increase of market rents (B4), and the reduction in exposure to curtailed hydrogen demand (B5).
- Interlinkages between hydrogen and natural gas networks (i.e., the Dual Gas Model, DGM). This model is used for the benefit indicator capturing reduction in exposure to curtailed hydrogen demand (B5).

With minor adaptations detailed in sections 2.3.3 and 2.4.2, the hydrogen network data (i.e., topology) used for both dual models (DHEM and DGM) are essentially identical.

The level of detail to represent the infrastructure strikes a balance between the accuracy and complexity of the modelling and the availability and complexity of the underlying network information. The topology refers to both existing and planned infrastructure.

2.2 General modelling principles

Hydrogen, electricity and natural gas systems are represented in the DHEM and the DGM through a simplified topology. The basic modelling topology for both dual models is composed of nodes and arcs.

Node

The basic block of the topology is the node at which level demand and supply is balanced. A node can be thought of as a circle representing a modelling area within a country. This area can be dedicated to either:

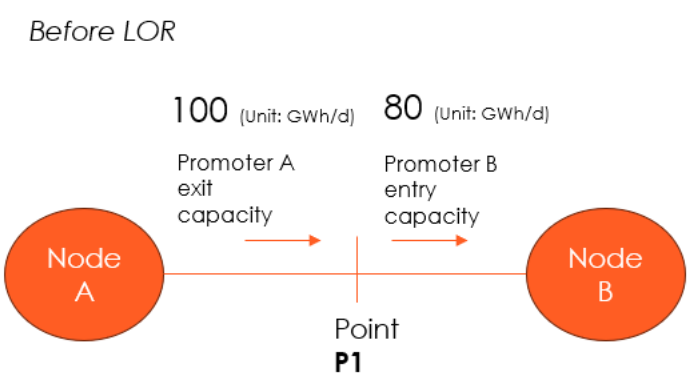
> A specific geographic part of the country (e.g., to represent bottlenecks within the country) or
> A specific functional part of the country like imports, aggregation of storages, aggregation of demand, etc.

Arc

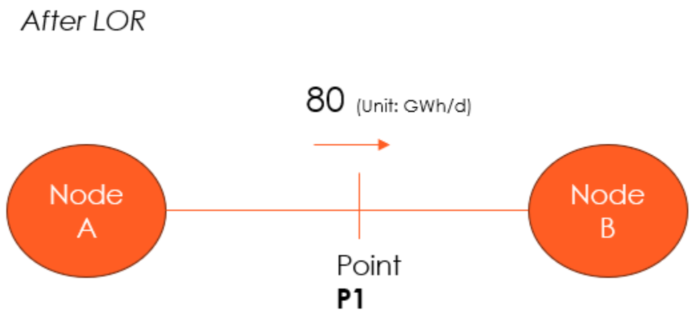
An arc represents a connection between two nodes. It allows for transfer of some energy between these two nodes. This transfer is thereby limited to the sum of the capacity of all interconnection points between these two nodes that the arc is representing after application of the lesser-of-rule. According to the lesser-of-rule, when two opposite operators provide a different capacity on the same point, the lower of the two is considered. In this process capacities are computed for the model. This can be either related to natural gas, or hydrogen, or electricity, depending on the grid considered.

Example for the application of lesser-of-rule (LOR)

> Case: Point P1 is attached to the arc linking node A and node B, Promoter A submits an exit capacity out of node A in the direction of node B at P1 of 100 and Promoter B submits an entry capacity from node A into node B at P1 of 80.



> Resulting modelling capacity after lesser of rule application (LOR) from node A into node B via P1 is defined as the minimum value between promoter's submissions (i.e., MIN(100,80)= 80).



The supply and demand balance in a node depends on the incoming flow from other nodes or direct imports from a supply source. Hydrogen, natural gas, and electricity may also come from sources connected to the node itself, e.g., storages, import, or production facilities of the respective energy carrier. The sum of all these entering flows must match the demand of the node, plus the need for storage filling (e.g., injection into hydrogen storages or charging of batteries) and the exit flows to adjacent nodes. In case the balance is not possible, a disruption of demand is used as a last resort. In the model, as supply and demand must be balanced, this is achieved through a virtual supply representing disrupted demand. This approach enables an efficient analysis of the disrupted demand.

For the supply and the demand of the different sectors to interact, conversion assets are required. These enable a transfer of energy from one sector to another sector, subject to an efficiency factor. Conversion thereby acts as a demand in a node of the delivering sector and as a supply in a node of the receiving sector.

Supply potentials

For countries or regions that are supplier of an energy carrier while their internal infrastructure assets are not known in detail and therefore not modelled explicitly, the supply potential approach is used. This means that assumptions are made about the amounts of the specific energy carrier that can be supplied from this source and at which marginal cost. Additional assumptions about the properties of this supply can be made (e.g., emission factors).

Infrastructure levels

Infrastructure levels are defined as the potential level of development of the European hydrogen network, electricity network, or natural gas network. An infrastructure level

represents the complete set of infrastructure elements assumed to be in place along the considered analysis time horizon. Since infrastructure levels thereby represent counterfactual[11] situations against which projects are assessed, the PS-CBA results are strictly dependent on the definition of the infrastructure level(s).
The following rules were considered when defining the infrastructure levels:

- When building the infrastructure levels, the lesser-of-rule is consistently applied to all submitted projects (i.e., a project only effectively creates capacity at an interconnection point if there is also sufficient capacity at the other side of the interconnection point).
- When projects are found to be competing (see section 3.1) when establishing the infrastructure levels, the infrastructure levels will reflect this situation by including only one of the (group of) competing projects' capacities (e.g., by only including the capacity of the (group of) competing project(s) with the highest capacities).
- If an enabling project is not part of an infrastructure level, the project it enables cannot be part of this infrastructure level of the same energy sector.

Objective function

An objective function is a function that is either maximised or minimized depending upon identified constraints. This function is used in linear programming to find the optimal solution to a problem with some constraints. The objective function sets the objective of the problem and focuses on decision-making, based on constraints.

The models are working with constraints that can be understood as the conditional equations governing the linear function:

- Hard constraints: constraints that the model must respect whatever the consequences (even if it leads to the absence of a solution). Some examples of hard constraints are capacities, working gas volumes of underground storages, the maximum supply potentials, etc.
- Soft constraints: parameters that the model incorporates to find the optimum solution. They are constraints because they put restrictions on the optimum solution. However, they are also considered to be soft because the model can still use the related quantity, even if it increases the cost of the solution. These soft constraints are price/cost related. Examples of soft constraints are cost of curtailment, and fuel prices.

The optimum solution is the best possible solution that satisfies all constraints and achieves the highest or lowest objective. The optimum solution is identified through the mathematical maximisation or minimisation of the objective function under constraints, in other words: maximise or minimise (objective function) subject to (hard constraints). There is no closed-form

[11] Situation against which the project group is assessed.

formula that gives the solution. It is found through an optimisation programme. Often, there is no best solution, but one best solution, among many.

Geographical perimeter

The geographical perimeter for TYNDP 2024 PS-CBA will cover EU countries, as well as the countries from the Energy Community or other third countries in which TYNDP 2024 projects[12] are located.

2.3 Dual Hydrogen/Electricity Model (DHEM)

2.3.1 Introduction

Considering the strong interlinkages between the electricity and hydrogen systems, the best way to capture all potential variations of benefits provided by hydrogen infrastructure is through joint modelling of at least these two energy carriers. This is achieved through a dispatch modelling at hourly granularity. The DHEM is used for this purpose.

The DHEM contains one node per electricity bidding zone and by default two hydrogen nodes per country. Some countries have dedicated RES which will be modelled as an additional zone. This topology, with an additional modification in the number of nodes in Zone 2, is represented in **Figure 5** below.

[12] TYNDP 2024 Hydrogen projects that indicated intention to apply for the second PCI/PMI selection process under the revised TEN-E Regulation (Hydrogen infrastructure subcategories defined in section 3.3.1.I to 3.3.1.IV of ENTSOG TYNDP 2024 Guidelines for projects inclusion https://www.entsog.eu/sites/default/files/2023-10/TYNDP%202024%20Guidelines%20for%20Project%20Inclusion_for%20Publication_0.pdf).

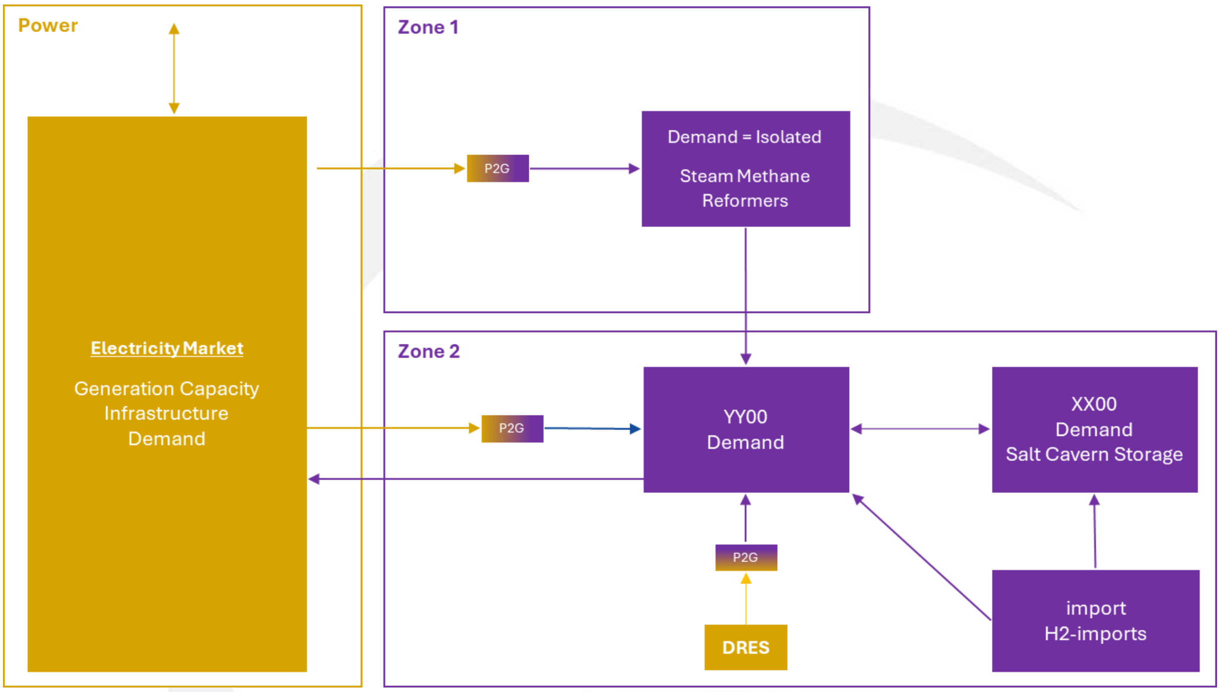


Figure 5: TYNDP 2024 DHEM Topology for a country (source: ENTSOG).

The default hydrogen topology at country-level represented in **Figure 5** can be refined based on TYNDP 2024 project submissions in a given country.

The two sides of the DHEM (i.e., hydrogen and electricity) are interlinked by connections between hydrogen nodes and electricity nodes that enable energy conversion, and thereby implicitly also storage, demand shifting, and transport across sectors:

- **Electrolysers:** An electrolyser acts as a load in the electricity system and as supply in the hydrogen system.
- **Electricity production from hydrogen:** A hydrogen-fired power plant (or hydrogen-fired engine) acts as a load in the hydrogen system and as supply in the electricity system.

2.3.2 Electricity topology and infrastructure level (DHEM)

The electricity infrastructure level in the DHEM reflects the reference grid including generation and storage assets used in the NT+ scenario. Depending on time horizon (i.e., 2030 or 2040) different electricity projects will be considered to be part of the reference grid.

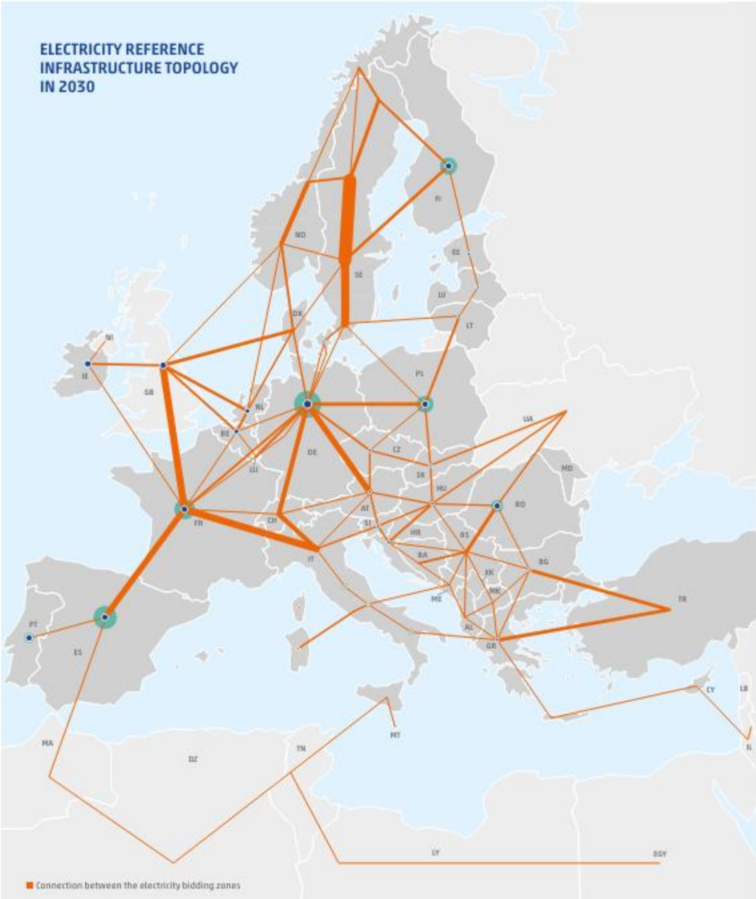


Figure 6: Electricity topology for 2030 time horizon.

As shown in Figure 6, most countries use one bidding zone and, therefore, one node per country, whereas, seven countries[13] have multiple bidding zones and, therefore, multiple nodes per country. Within the model, arcs between nodes are used to establish capacities[14] between the connected nodes.

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[13] List of countries with multiple bidding zones: Italy (7), Sweden (4), Denmark (2), Norway (3), Greece (2), Luxemburg (4), United Kingdom (2). Any countries outside of the EU27 countries, with the exception of Norway, are represented as 1 node.

[14] Electricity topology is included.

2.3.3 Hydrogen topology (DHEM)

The hydrogen topology represented in **Figure 5** represents existing hydrogen infrastructure as well as certain hydrogen projects submitted by project promoters during the TYDNP 2024 project data collection. The hydrogen topology is developed from the NT+ scenario model. However, as the NT+ scenario model is based on projects from ENTSOG's TYNDP 2022, when transforming the NT+ scenario model into the DHEM, updates are required that reflect the submitted projects.

Hydrogen Zone 1 represents hydrogen supply, storage, and demand that can be linked with each other without requiring the main national hydrogen transmission infrastructure system. Zone 1 may contain:

- Electrolysers with properties including capacities defined in the NT+ scenario, connected to
  - the electricity market;
  - dedicated RES that has no access to the electricity market (DRES);
  - shared RES that also has access to the electricity market (SRES).[15]
- Facilities for hydrogen production from natural gas which exist today, with properties including capacities defined in the NT+ scenario;
- A share of the national hydrogen demand which is defined in the NT+ scenario (see **Table 5** in Annex III).

To reflect the presence of bottlenecks, Zone 1 can be further split into different nodes based on the input of project promoters, eventually being connected to different Zone 2 nodes. However, to ensure consistency with the NT+ scenario, the total country values assigned to Zone 1 as defined in the NT+ scenario must remain unchanged for the following items:

- Inelastic hydrogen demand (i.e., hydrogen demand that is not price-sensitive);
- Hydrogen-based power plant capacities (i.e., 0);
- Hydrogen production capacities from natural gas;

Hydrogen Zone 2 represents the national main hydrogen transmission infrastructure system. Here, the linkage of supply, storage, and demand may require transmission capacity. Zone 2 may contain:

- Electrolysers with properties including capacities defined in the scenarios, connected to
  - the electricity market;
  - dedicated RES that has no access to the electricity market;
  - shared RES that also has access to the electricity market.

[15] The differentiation of electrolysers' access to RES in the DHEM may be reflecting a physical relationship between RES producer and the electrolyser or a relationship established by power purchase agreements (PPA) directly between corporate companies and electricity suppliers.

- Internal hydrogen infrastructures, either existing or from submitted projects.
- Cross-border capacities to/from other Member States or third countries from submitted projects.
- Hydrogen reception facilities from submitted projects.
- Hydrogen underground storages (e.g., salt cavern storages) from submitted projects[16].
- The share of the national hydrogen demand assumed to be connected to the main hydrogen infrastructure system as defined in the NT+ scenario (see Table 5 in Annex III).
- A capacity to/from Zone 1:
    - Default case 1 for countries in which it is assumed that hydrogen produced from natural gas is coupled with CCS in the NT+ scenario: Hydrogen can be transported from Zone 1 to Zone 2. The connection capacities are taken from the TYNDP 2024 scenarios. This connection provides additional flexibility in managing hydrogen supply and ensures that hydrogen produced by electrolysers as well as from natural gas in Zone 1 can help meet demand in Zone 2. Through cross-border connections in Zone 2, also other countries can be supplied in principle.
    - Default case 2 for countries in which it is assumed that hydrogen produced from natural gas is not coupled with CCS in the NT+ scenario: There is no capacity from Zone 1 to Zone 2. This is to safeguard that cross-border hydrogen capacity is not used for unabated hydrogen produced from natural gas.
    - More complex capacities including between sub-zones with values deviating from the default solution can be established based on project promoters inputs. More complex capacities including between sub-zones of Zone 1 and sub-zones of Zone 2 with values deviating from the default solution can be established based on project promoters inputs.

To reflect the presence of bottlenecks and introduce further granularity within a country, Zone 2 can be further split into different nodes based on the input of project promoters, eventually being connected to different Zone 1 nodes. Between such nodes, hydrogen transmission projects may be required to create capacities, for modelling purposes. However, to maintain consistency with the NT+ scenario, the total country values assigned to Zone 2 as defined in the scenarios must remain unchanged for the following items:

- Inelastic hydrogen demand (i.e., hydrogen demand that is not price-sensitive: all other hydrogen demand than hydrogen demand for power generation);
- Hydrogen-based power plant capacities;
- Hydrogen production capacities from natural gas (i.e., 0).

[16] Hydrogen underground storages are assumed to start the year with a filling level of 50% of their working gas volume and must end the year with the same filling level.

Electrolyser redistribution methodology

The electrolyser redistribution methodology is used to make the NT+ scenario information match the requirements of the DHEM of the TYNDP 2024.

The NT+ scenario is linked to a hydrogen demand split between Zone 1 and Zone 2, but the NT+ scenario model does not include such split. Also, the NT+ scenario contains country-specific electrolyser capacities but no allocation of this total amount to Zone 1 and Zone 2 is established therein. Furthermore, in case Zone 1 and/or Zone 2 are split based on project submissions during the TYNDP 2024 project submission phase, the allocation of electrolyser capacities to these sub-zones needs to be established.

To address these challenges, the following redistribution methodology is implemented in a version of the DHEM which does not yet contain a fixed allocation of electrolyser capacities to the (sub-)Zones:

- Inputs:
    - Model updates in PLEXOS: The NT+ scenario model is updated to reflect the nuanced structure of multiple hydrogen nodes and zones, as described above.
    - Constraint on total electrolyser deployment: This constraint aggregates the country-based electrolyser capacities from the NT+ scenario into a flexible allocation system, allowing capacities to be distributed between Zone 1 and Zone 2, whereas the sum of the deployed electrolysers in all zones (and sub-zones) exactly matches the country-specific NT+ scenario value.
    - Variable Operation and Maintenance (VO&M) Cost: Incorporates water pricing to influence electrolyser marginal costs which can affect how the system manages it flexibilities.
    - Stakeholder collaboration: Project promoters' inputs on expected capacity splits in Zones and sub-zones are considered, ensuring the model aligns with practical and operational realities (e.g., if a known part of the country-specific electrolyser capacities are expected to be located on an island). Adjustments based on this feedback are communicated and refined to ensure optimal deployment.
- Redistribution objective:
    - Under consideration of the listed restrictions, an optimisation run in PLEXOS deploys the electrolyser capacity in a way that the result of the DHEM's objective function (see section 2.3.4) is minimised. As curtailed hydrogen demand is adding to the total system cost due to the CODH, it is considered within this optimisation.
- Result: An allocation of the exact country-specific electrolyser capacity from the NT+ scenario to the model's zones and sub-zones. This allocation is neither amended by

alternative fuel approach (see section 3.2.5) nor by the incremental approach (see section 3.2.2).

2.3.4 Objective function (DHEM)

The objective function of the DHEM aims at minimising the overall cost of the system. This is equivalent to the maximisation of the market rents if the market rents contain all system costs (see the description of the total surplus approach in Annex VI). This objective function is based on an hourly dispatch modelling that assumes perfect competition with the exception of constraints from infrastructure limitations.

The dispatch of the electricity system is based on the costs of generation plants, storage options, import and export options, electrolyser options and electricity demand. Electricity market prices are then determined endogenously in the model. For each electricity bidding zone, a market clearing price is established where the willingness of electricity consumers to buy meets the willingness of electricity producers to sell in terms of price and quantity.

The dispatch of the hydrogen system is based on costs of the relevant hydrogen production types and hydrogen import options, hydrogen-based power plant options, and other types of hydrogen demand. Hydrogen market prices are then determined endogenously in the model. For each hydrogen market area, a market clearing price is established where the willingness of hydrogen consumers to buy meets the willingness of hydrogen producers to sell in terms of price and quantity.

An overview of the relevant market assumptions is provided in section 3.2.4 and in Annex III.

2.4 Dual Hydrogen/Natural Gas Model (DGM)

2.4.1 Introduction

The Dual Hydrogen/Natural Gas Model (Dual Gas Model, DGM) represents the hydrogen and natural gas infrastructure within the geographical scope of the TYNDP 2024. It is used for the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5). This is achieved through a dispatch modelling at monthly granularity which uses a reference day per calendar month.

The two sides (i.e., hydrogen and natural gas) of the DGM are joined by connections between hydrogen nodes and natural gas nodes (see section 2.2 concerning the definition of a node) that enable energy conversion, and thereby also storage, demand shifting, and transport across sectors:

> **Hydrogen production from natural gas:** Hydrogen production facilities using natural gas (i.e., SMR or ATR units) act as a load in the natural gas system and as supply in the hydrogen system.

Hydrogen infrastructure can be composed of newly built infrastructure dedicated to hydrogen or hydrogen infrastructure repurposed from natural gas infrastructure. It is necessary for the natural gas infrastructure level to consider the potential impact of repurposing of natural gas infrastructure to hydrogen infrastructure in the context of security of supply.

Electricity-related data is represented in the model as fixed supply (e.g., for electrolysis expressed in the DGM as hydrogen supply) and fixed demand (e.g., for gas- or hydrogen-fired power plants expressed in the DGM as natural gas and hydrogen demand respectively) included in the relevant nodes of the DGM.

2.4.2 Hydrogen topology (DGM)

The DGM contains hydrogen topology and natural gas topology. Therefore, both must be defined. The hydrogen topology in the DGM is essentially identical to the hydrogen topology in the DHEM. Only one change may be introduced to the hydrogen topology in the DGM in comparison to the hydrogen topology in the DHEM:

> Since electricity bidding zones are not included in the DGM, the hydrogen topology may be simplified in the DGM in comparison to the DHEM if functionally not affecting the computations.[17]

2.4.3 Natural gas topology (DGM)

The natural gas topology defined by ENTSOG for TYNDP 2024 contains transmission, storage, and LNG infrastructure.

There are two natural gas infrastructure level options for the TYNDP 2024 PS-CBA (see Figure 7):

> A **Low natural gas infrastructure level** containing existing natural gas infrastructure and FID natural gas projects.

> An **Advanced natural gas infrastructure level** containing the existing natural gas infrastructure, FID natural gas projects, as well as advanced natural gas projects.

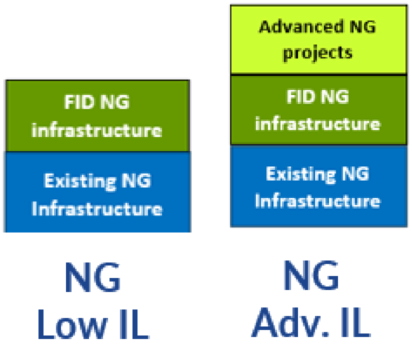

Figure 7: Natural gas infrastructure levels as potential basis for TYNDP 2024 PS-CBA process

Whereas:

> **Existing natural gas infrastructure** refers to natural gas infrastructure that is operational at the time of the TYNDP 2024 data collection as well as natural projects with the final investment decision taken (FID) and expected commissioning year before 31st December 2024.

> **FID[18] natural gas projects** refers to projects having taken the final investment decision ahead of the TYNDP 2024 project data collection. The FID status was defined in Art. 2(3) of Regulation (EC) 256/2014 as follows: "*final investment decision means the decision*

[17] Example: Country A consists of 2 electricity bidding zones and one hydrogen market area. In the DHEM, the hydrogen market area needs to be connected to electrolysers in both electricity bidding zones separately to properly capture the market dynamics. The supply from those electrolysers can be merged in the DGM as the electricity market is not modelled in the DGM.

[18] FID: Final investment decision

taken at the level of an undertaking to definitively earmark funds for the investment phase of a project (…)".

- **Advanced natural gas project** refers to projects with an expected commissioning date no later than 31 December of 2029 and that fulfil at least one of the following criteria:
  - Permitting phase has started ahead of the data collection from TYNDP 2024.
  - Project has completed FEED[19] ahead of the data collection from TYNDP 2024.

When combined with hydrogen infrastructure levels in the DGM, the natural gas infrastructure considers the impact of the relevant hydrogen repurposed infrastructure (from repurposed projects included in the PCI/PMI hydrogen infrastructure level or in the Advanced hydrogen infrastructure level).

Biomethane production and synthetic methane production is by default connected to a country's natural gas demand node only and it is therefore not possible to export biomethane in the model unless there are projects submitted to TYNDP clearly indicating the purpose to enable the exportability of biomethane.

The list of TYNDP 2024 projects conforming the proposed natural gas infrastructure levels (i.e., Low natural gas infrastructure level and Advanced natural gas infrastructure level) can be found in Annex I.

The natural gas cross-border, import and storage capacities at country/zone level can be found in Annex II.

For the TYNDP 2024 PS-CBA process, the natural gas topology will be limited to only one natural gas infrastructure level (i.e., Low natural gas infrastructure level or Advanced natural gas infrastructure level) **to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines.**

2.4.4 Objective function (DGM)

The objective function is defined, for a given simulation, as the sum of all costs in the system (**Figure 8**). The mathematical solver used for the simulations tries to minimise this sum. The parameters' values known before the simulation are represented in blue. The variables, or values that will be known after the simulation, are represented in purple. "SUM" represents the sum for all concerned objects and for all periods. Therefore, there is not one objective function per period (i.e., a month), but only one objective function for the full simulation horizon (i.e., a year).

[19] FEED: Front-End engineering design

OBJECTIVE FUNCTION = ***SUM for all supplies (unitary cost of supply × related supply quantity)***
+ SUM for all arcs (unitary residual cost × related flow)
+ unitary CO_2 cost × CO_2 emissions
+ SUM for all countries (unitary curtailment cost × related curtailed quantity)
+ SUM for all storage (unitary target penalty × quantity below target)

Figure 8: Objective function of the DGM

The DGM has the following costs categories (represented in blue), listed from highest to lowest:

1. Curtailment: As the highest cost, to avoid curtailment is prioritised. By differentiating between curtailment costs of hydrogen and natural gas demand, the DGM can enforce i) preferred supply of natural gas, ii) preferred supply of hydrogen, or iii) an approach that aims at equal curtailment rates in both sectors.
   For the TYNDP 2024 PS-CBA process, the DGM prioritizes the supply of natural gas (i.e., option i) above). This means that the hydrogen production from natural gas will be curtailed by the model before any other natural gas consumer.
2. Storage target penalty. The storage target penalty is a property used to shape the use of storages' supply compared to other supplies. This is a cost incurred by the system when a storage does not reach its pre-defined fill rate target at the end of a given period. In the objective function, this cost is multiplied by the amount by which the target was missed. For instance, if set above the other supply prices, storages will be used as last resort. This is in contrast to what might happen in reality for a sudden stress case, but it allows to answer the question "what is the minimum amount of withdrawal needed to face the event", or alternatively "what is the minimum amount of gas needed in the storages". In yearly simulations, the target is mandatory by setting the target penalty at an infinite value; this is to start and end at the same level for a steady-state assessment. This target can be subject of country-specific strategic storages or strategic reserves.
3. GHG emissions price: CO_2 equivalent emissions are third in the order. The only intention is to have curtailment cost and storage target penalty ranked higher, and residual costs (supply, infrastructure etc.) ranked lower. Therefore, the DGM prioritises renewable hydrogen over low carbon hydrogen and over unabated hydrogen. At the same time, it will use low carbon and unabated hydrogen if needed to minimise curtailment (cost category 1) and honour certain storage requirements (cost category 2).
4. Residual incremental costs:

- Supply: import and national production prices. This can be used to favour national production over imports or to minimise or maximise the usage of certain sources. [20] For the TYNDP 2024, LNG is set as a more expensive source than all pipeline supplies except those from Russia, so that LNG is used after the less expensive pipeline supplies. Natural gas supplied from Russia by pipeline are set as the most expensive source to minimise its usage. This will not influence the result of the benefit indicators but allows additional insights if Russian pipeline supply is needed or not. Amongst the renewable and the low-carbon supply options for hydrogen, production within the EU is favoured over imports of the same emissions intensity.
- Infrastructure: incremental residual costs. Pipeline supplies are all treated the same way with residual incremental costs to induce an average use of equivalent routes.
- Costs for hydrogen production from natural gas: residual incremental cost to induce harmonised/cooperative behaviours between such hydrogen production facilities along the different periods and with hydrogen imports of the same emissions intensity.

2.4.5 Demand input (DGM)

The demand for the DGM is derived from the TYNDP 2024 draft Scenario Report demand data for the NT+ scenario with the DHEM, as described in this section. This is to increase consistency between DHEM-based and DGM-based calculations.

Hydrogen demand input (DGM)

Through the following strictly consecutive steps, monthly hydrogen demand profiles can be derived for the DGM per assessed hydrogen infrastructure level. In the TYNDP 2024 draft Scenario Report, inelastic hourly hydrogen demand is defined for NT+ scenario.

0. All scenario parameters of relevance for the DHEM (see section 3.2.4) including those of hydrogen demand are inserted in the DHEM. This requires an allocation of scenario parameters to the updated DHEM topology (see section 2.3 and section 3.2.4). The DHEM simulations are executed with the DHEM's objective function (see section 2.3.4) and under consideration of the alternative fuel approach (see section 3.2.5).[21]

[20] For example, a pre-defined import source of gas from country A could be attributed with the highest costs of all sources, resulting in a minimized usage.
[21] For the PS-CBAs, this simulation is run with and without the assessed (group of) project(s) to implement the incremental approach.

1. The DHEM simulations described in step 0 provide per node and hour:
   - Amount of inelastic hydrogen demand that could be satisfied. On country (or zone) level, it is identical to the inelastic hydrogen demand of the NT+ scenario if sufficient hydrogen is available.
   - Amount of hydrogen demand for power generation per electricity bidding zone. As the DGM does not simulate the electricity system, this output is used in the next step.
2. As the DHEM and the DGM are based on the same hydrogen topology, the satisfied inelastic hydrogen demand and hydrogen demand for power generation from the DHEM is directly transferrable from the DHEM results for a hydrogen node into the DGM inputs for the same hydrogen node. As the DHEM and the DGM are however based on different timestep durations, the hourly hydrogen demand from the DHEM is transformed into monthly profiles by summing up the hourly hydrogen demand values per node of each calendar month and dividing it by the number of days of the respective calendar month. This produces the monthly reference day hydrogen demand per node that is simulated in the DGM.

Natural gas demand input (DGM)

0. This step is identical to step 0 for the hydrogen demand input calculation described above.
1. The DHEM simulations described in step 0 provide per node and hour following natural gas-related outputs:
   - Amount of natural gas demand for power generation per electricity bidding zone. As the DGM does not simulate the electricity system, this output is used in the next steps.
   - Amount of natural gas demand due to alternative fuel usage (see section 3.2.5).
   - Amount of natural gas demand for hydrogen production per hydrogen node. As the DGM simulates both involved systems, this output is not used in the next steps. Instead, it is a variable of the DGM's objective function.
2. The amount of natural gas demand for power generation per electricity bidding zone from the DHEM outputs is transferred into the DGM as a natural gas demand in the main natural gas demand node of each country. As the DHEM and the DGM are however based on different timestep durations, the hourly natural gas demand from the DHEM is transformed into monthly profiles by summing up the hourly natural gas demand values per node of each calendar month and dividing it by the number of days of the respective calendar month.

This produces the relevant part of the monthly reference day natural gas demand per node that is simulated in the DGM.

3. The natural gas demand for other use cases than power generation (described above) and hydrogen production (variable of the DGM's objective function) is sourced directly from the NT+ scenario.
4. The monthly natural gas demand values for power generation of step 2 and for other consumers except hydrogen production of step 3 are summed up.

2.4.6 Supply input (DGM)

Hydrogen supply input (DGM)

0. All scenario parameters of relevance for the DHEM (see section 3.2.4) including those of hydrogen demand are inserted in the DHEM. This requires an allocation of scenario parameters to the updated DHEM topology (see section 2.3 and section 3.2.4). The DHEM simulations are executed with the DHEM's objective function (see section 2.3.4) and under consideration of the alternative fuel approach (see section 3.2.5).[22]
1. The DHEM simulations described in step 0 provide per node and hour:
   - Amount of electrolytic hydrogen production per hydrogen node.
2. As the DHEM and the DGM are based on the same hydrogen topology, the electrolytic hydrogen production from the DHEM is directly transferrable from the DHEM results for a hydrogen node into the DGM inputs for the same hydrogen node. As the DHEM and the DGM are however based on different timestep durations, the hourly electrolytic hydrogen production from the DHEM is transformed into monthly profiles by summing up the hourly electrolytic hydrogen production values per node of each calendar month and dividing it by the number of days of the respective calendar month. This produces the monthly reference day electrolytic hydrogen production per node that is simulated in the DGM.

The DGM itself calculates the values for hydrogen production from natural gas and hydrogen imports as they are variables of the DGM's objective function. The usage of hydrogen import capacities and hydrogen production from natural gas are therefore only transferred implicitly as a supply gap of hydrogen that the DGM aims at satisfying in an optimised way. Therefore, the DGM can use the hydrogen import capacities differently than the DHEM in order to optimise the satisfaction of hydrogen demand. This might be necessary, since the additional restrictions from the natural gas system that are only

[22] For the PS-CBAs, this simulation is run with and without the assessed (group of) project(s) to implement the incremental approach.

available in the DGM and potentially limit the hydrogen production from natural gas may require adaptions in the hydrogen flow patterns.

For hydrogen import from some third countries (both through pipelines and terminals), the concept of a supply potential is used (see section 2.2 and Annex III). The actual use of a supply source is a result of the model taking into account the source-specific constraints of the NT+ scenario.

Natural gas supply input (DGM)

There is no need to source natural gas supply figures from the DHEM as it is not included in it.

For natural gas import from some third countries (both through pipelines and terminals), the concept of a supply potential is used (see section 2.2). The actual use of a supply source is a result of the model taking into account the source-specific constraints of the NT+ scenario (see Annex III).

Other natural gas supply (i.e., biomethane production, synthetic methane production, and natural gas production) for the DGM is directly derived from the NT+ scenario data for each country.

2.5 Hydrogen infrastructure level(s)

There are two default hydrogen infrastructure levels (see Figure 9):

> A **PCI/PMI hydrogen infrastructure level** containing existing hydrogen infrastructure, FID hydrogen projects, and hydrogen projects on the PCI/PMI list in force[23] at the time of the definition of infrastructure levels.

> An **Advanced hydrogen infrastructure level** containing the existing hydrogen infrastructure, FID hydrogen projects, PCI/PMI hydrogen infrastructure level as well as advanced hydrogen projects.

[23] As defined by in section B. (HI West, HI East and BEMIP Hydrogen) of the Annex VII to Regulation (EU) No 2022/869 https://energy.ec.europa.eu/system/files/2023-11/Annex%20PCI%20PMI%20list.pdf

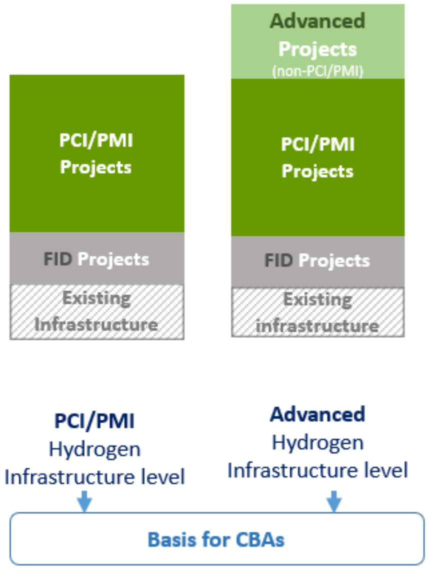

Figure 9: Hydrogen infrastructure levels as potential basis for TYNDP 2024 PS-CBA process

Whereas:

- **Existing hydrogen infrastructure** refers to hydrogen infrastructure that is operational at the time of the TYNDP 2024 data collection as well as projects that acquired the final investment decision (FID) ahead of the relevant TYNDP project data collection and that are expected to be commissioned no later than 31 December 2023. The FID status was defined in Art. 2(3) of Regulation (EC) 256/2014 as follows: "*final investment decision' means the decision taken at the level of an undertaking to definitively earmark funds for the investment phase of a project (...)*".
- **FID hydrogen project** refers to projects having taken the final investment decision ahead of the TYNDP 2024 project data collection.
- **Advanced hydrogen project** refers to projects with an expected commissioning date no later than 31 December of 2029 and that fulfil at least one of the following criteria:
  - The project is included in the latest published national network development plan(s) of the respective country(ies) or in the national law(s).
  - The project was successfully consulted through a market test (including non-binding processes), which delivered positive results.
- **PCI/PMI hydrogen project** refers to hydrogen projects that are on the 6th PCI/PMI Union list as detailed in section B of the Annex VII to the TEN-E Regulation.

For the TYNDP 2024 PS-CBA process, the assessment will be limited to only one hydrogen infrastructure level (i.e., PCI/PMI hydrogen infrastructure level or Advanced hydrogen infrastructure level) with the choice **to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines**.

The list of TYNDP 2024 projects conforming the proposed hydrogen infrastructure levels (i.e., PCI/PMI hydrogen infrastructure level and Advanced hydrogen infrastructure level) can be found in Annex I.

The hydrogen cross-border, import, and storage capacities at country/zone level can be found in Annex II.

3. Project Assessment

3.1 Project Grouping

A project can be assessed individually or in a group, in the case where a set of functionally-related projects need to be implemented together for their benefits to materialise.

Introduction and definitions:

> *Project advancement status*

The **project advancement status** describes the current phase of a project's implementation. The options for this status are:

i) under consideration;
ii) planned;
iii) permitting;
iv) under construction.

The project advancement status is derived from the information provided by the project promoter during the TYNDP 2024 project submission process.

> *Enabling projects and enabled projects*

An enabling project (or enabler) is a project which is indispensable for the realisation of an enabled project, in order for the latter to start operation and to show any benefit. The enabler itself might not bring any direct capacity increment.

If an enabling project's advancement status is "under consideration", the enabled project's advancement status is also considered as "under consideration".

Example : enabling project - enabled project

> Description: Project A connects a supply source with Point 1. Project B connects Point 1 with demand. Without Project A, Project B would have no connected supply source. Also, it relies on Project A's pressure provision to create its own transport capacity. Thus, Project A is indispensable for the realisation of Project B. Project A is enabler of Project B.

> *Enhancing projects and enhanced projects*

An enhancing project (or enhancer) is a complementary project that would allow another project (i.e., the enhanced project) to get improved. This could mean that synergies are created compared to the enhanced project operating on its own basis, increasing the benefits arising from the realisation of the enhanced project. An enhancer, unlike an enabler, is not strictly required for the realisation of the enhanced project.

Example: enhancing project - enhanced project

Case: Project A connects a supply source with Point 1. Project B connects Point 1 with demand. While Project B creates sufficient capacity to satisfy the demand, the supply source connected by Project A is not sufficient. Project C connects another supply source with Point 1, increasing the benefits that can be provided with Project B. Project C is not strictly required for the realisation of Project B but increases its benefits. Project C is enhancer of Project B.

Grouping principles

To avoid overclustering of investments when grouping them together, it is important to analyse projects' interlinkages (i.e., enabler/enabled relationships, enhancer/enhanced relationship) and take into consideration other factors such as their maturity status and/or project advancement. Therefore, the following **grouping principles** are applied:

- Projects should be grouped together when there is a functional relationship between them:
  - As a minimum, the transmission projects on both sides of a boarder that jointly form an interconnector must be grouped together.
  - As a minimum, a hydrogen reception terminal and its connecting pipeline to the hydrogen grid must be grouped together.
  - As a minimum, a hydrogen storage and its connecting pipeline to the hydrogen grid must be grouped together.
- Projects can only be grouped together if they are at maximum one project advancement status apart from each other.
- Projects can only be grouped together if their commissioning dates are not more than five years apart from each other.
- Projects that are enabled projects can only be grouped together with their enabling project.

- Projects that are enabling projects under consideration can only be grouped with enabled projects of the same project advancement status.
- An enabled project can only be grouped with an enabling project if the enabling project's commissioning year is equal to or before the commission year of the enabled project.
- **Competing projects** need to be assessed separately and as many groups as projects in competition should be established, with only the competing project amended while the rest of the group stays unchanged. There are several possible sources of information about the competing nature of certain projects:
  - Competition identified by the involved project promoters.
  - Competition between projects connecting an outside-EU supply source with a specific Member State. It is derived by comparing the NT+ scenario's supply potential for this outside-EU supply source with the import capacities into this Member State provided by projects. There is competition if a reduced set of projects would provide sufficient capacity to import the supply source's full supply potential (e.g., if a supply source has a supply potential of 50 and there are two projects submitted to connect this supply source to the same country with a capacity of 60 and 70 respectively).
  - Competition as an observation from the intermediate CBA results. In line with ACER's Recommendation No 02/2023 of 22 June 2023 *on good practices for the treatment of the investment requests, including Cross Border Cost Allocation requests, for Projects of Common Interest*[24], projects may be considered competing if the added value of one project is significantly reduced by the presence of the other project, e.g., the realisation of both of them would result in a lower overall ENPV[25] than implementing only one.
- **Enhancing project(s)** need to be grouped with and without the enhanced project. The benefit indicators and economic performance indicators that can be calculated for the groups with and without the enhancing project(s) allow the determination if the benefits related to the enhancement are justifying the additional investments related to the enhancing project(s).
- In case of a project consisting of **multiple phases**[26], each phase should be assessed separately in order to evaluate the incremental impact of all phases (e.g., in case of a

[24] https://acer.europa.eu/Recommendations/ACER_Recommendation_02-2023_CBCA.pdf
[25] ACER in its Recommendation No 02/2023 refers to the "net impact" which is the equivalent of the ENPV of this CBA methodology.
[26] Multi-phase investments projects are composed of two or more sequential phases, where the first phase is required for the realization of the following phases (e.g., extension and capacity increase of reception terminal, capacity increase of import route, extension and capacity increase of an hydrogen storage, etc.).

project composed of two different phases, one group considers only phase 1 while a second group considers phase 1 and phase 2).

> Projects that are connecting outside-EU supply sources with demand along a hydrogen corridor should be grouped together. Pipelines connecting extra-EU hydrogen supplies (i.e., extra-EU hydrogen supply corridor) should be grouped with the directly or indirectly connected EU-countries or European demand centre(s).

3.2 Project-Specific Cost-Benefit Analysis (PS-CBA)

3.2.1 *Quantification and monetisation principles*

The TYNDP 2024 PS-CBA combines monetary elements pertaining to the CBA approach, as well as non-monetary and/or qualitative elements based on a multi-Criteria Analysis (MCA) Its scope is wider than the pure monetary assessment, as the reality of the energy markets and its effect for the European economy and society generally require that non-monetary effects are also considered. Quantitative indicators provide detailed, comprehensible, and comparable information independently from their potential monetary value.

For monetisation, it is important to identify all possible double-counting of benefits in the assessment. Each benefit indicator measures the contribution of the project to the specific criteria independently from the others and is considered as non-overlapping with the others. This is safeguarded by removing potentially overlapping parts of the different indicators as described per benefit indicator.

Monetisation should only be performed when reliable monetisation is ensured, to avoid non-robust conclusions when comparing monetised benefits to project costs. Without it, (non-monetised) quantitative benefits should be maintained.

3.2.2 *The incremental approach*

Estimating benefits associated with projects require comparison of the two situations "*with project*" and "*without project*". This is the incremental approach. It is at the core of the cost-benefit analysis, and it is based on the differences in benefit indicators and monetary values between the situation "*with the project*" and the situation "*without the project*".

The counterfactual situation is the level of development of the infrastructure against which the project is assessed. It should be consistent across the different projects assessed.

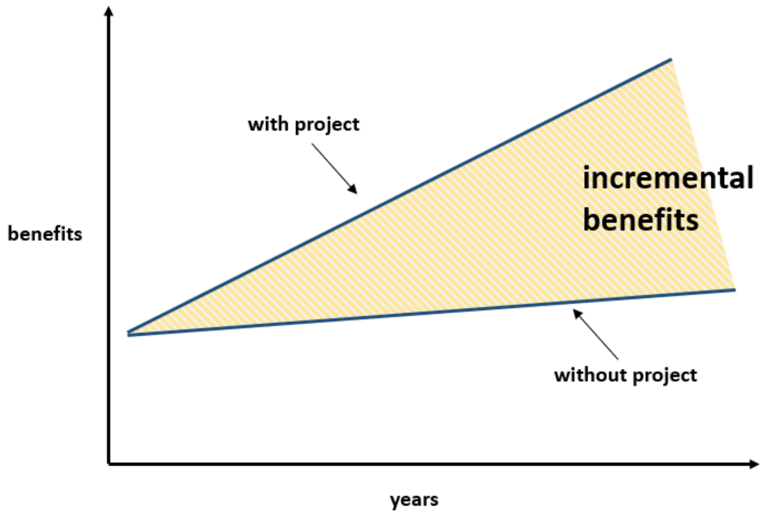

Figure 10 Incremental approach for benefits from the implementation of an assessed project.

The counterfactual situation against which the project is assessed impacts the value given to the project.

According to the counterfactual situation against which the project is assessed, the literature makes available two methods for the application of the incremental approach:

> **Put in one at a time** (PINT) implies that the incremental benefit is calculated by **adding** the project compared to the considered counterfactual situation (i.e. the infrastructure level without the implementation of the project), in order to measure the impact of implementing the project. Following this approach, each project is assessed as if it was the subsequent one to be commissioned.

> **Take out one at a time** (TOOT) implies that the incremental benefit is calculated by **removing** the project compared to the counterfactual situation (i.e. the infrastructure level with the implementation of the project), in order to measure the impact of implementing the project. Following this approach, each project is assessed as if it was the final one to be implemented.

Within the PS-CBA, a (group of) project(s) will be assessed with the PINT approach if it was not part of the concerned infrastructure level, and it will be assessed with the TOOT approach if it was already part of the infrastructure level. This is shown in the example below. If a group of projects contains projects that are in the infrastructure level and projects that are not, a mixed approach will be used. A mixed approach means that the incremental benefit is calculated by removing the project that is part of the infrastructure level for the *"without the project"* situation and then adding all projects of the group for the *"with the project"* situation.

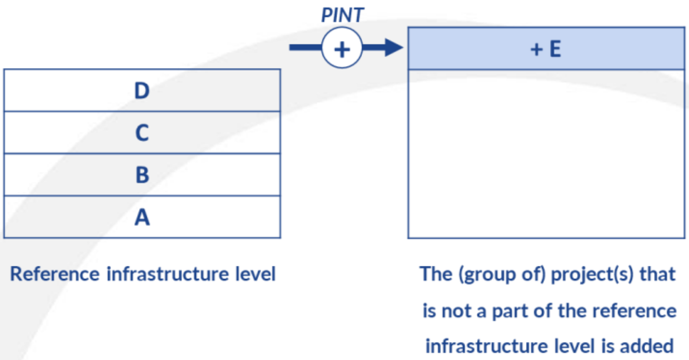

Figure 11: Incremental approach with PINT of project E.

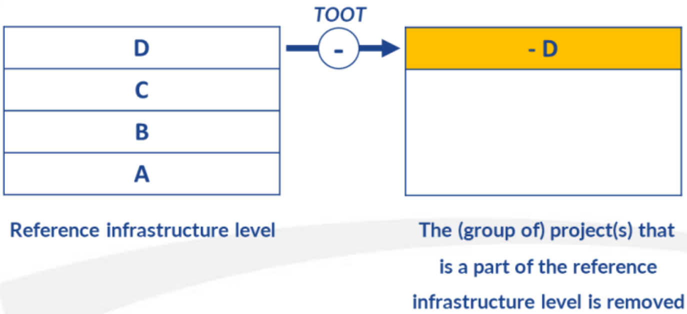

Figure 12: Incremental approach with TOOT of project D.

3.2.3 Introduction and overview of benefit indicators

The TEN-E Regulation has identified four main criteria for the assessment of hydrogen projects: sustainability, security of supply and flexibility, competition, and market integration. In line with those criteria, hydrogen infrastructure projects' potential benefits will be measured in the PS-CBA process through the variation of the following benefit indicators:

- B1: Societal benefit due to GHG emissions variations
- B2: Societal benefit due to non-GHG emissions variations
- B3.1: Integration of renewable electricity generation
- B3.2: Integration of renewable and low-carbon hydrogen
- B4: Increase of market rents
- B5: Reduction in exposure to curtailed hydrogen demand

This is summarised in the Figure below.

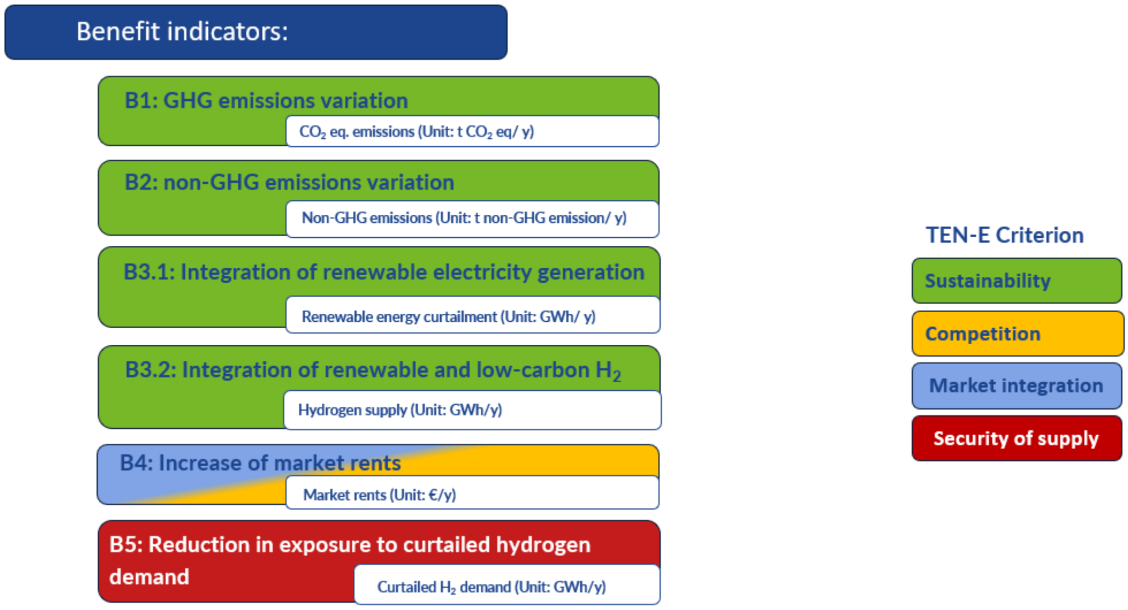

Figure 13: Proposed benefit indicators under TYNDP 2024 PS-CBA process

All benefit indicators are calculated through the incremental approach (as described in 3.2.2) in order to evaluate the EU-related contribution of a (group of) project(s).

For all categories of hydrogen projects falling under Annex II(3) of the TEN-E Regulation, all benefit indicators will be calculated.

The benefit indicators GHG emissions variations (B1), non-GHG emissions variations (B2), integration of renewable electricity generation (B3.1), integration of renewable and low-carbon

hydrogen (B3.2) and increase of market rents (B4) are based on the same DHEM base-case simulation, while different simulation output parameters are used for their calculations.
The reduction in exposure to curtailed hydrogen demand indicator (B5) is based on a different DHEM simulation case, that captures the restrictions of the electricity and hydrogen systems under a more stressful climate year than the reference year used for the other indicators, followed by a DGM simulation run that additionally captures the restrictions of the natural gas system. The DGM simulation run thereby tests whether sufficient natural gas is available to enable the required hydrogen production from natural gas.

3.2.4 Market assumptions in the DHEM

Table 1: Summary of the market assumptions considered by DHEM for TYNDP 2024 PS-CBA process.

Market assumption		2030	2040	Description	Source
Assumed ETS price (unit: €/t $CO_{2\ eq}$)		113.4	147.0	Costs for covered GHG emissions under the ETS.	TYNDP 2024 draft Scenario Methodology Report[27]
Fuel prices (unit: €/gross GJ)	Nuclear	1.7	1.7	EU-price per fuel	
	Natural gas	6.8	8.1		
	Light oil	12.4	12.1		
	Heavy oil	10.2	9.9		
	Hard coal	1.9	1.7		
	Lignite (G1[28])	1.4	1.4	Lignite price per region	
	Lignite (G2[29])	1.8	1.8		
	Lignite (G3[30])	2.4	2.4		
	Lignite (G4[31])	2.9	2.9		
	Liquid imports	116.5	91.6	Assumed liquid imports in form of ammonia	

[27] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/05/TYNDP_2024_Scenarios_Methodology_Report_240522.pdf
[28] Lignite group 1: Bulgaria, North Macedonia, and Czech Republic.
[29] Lignite group 2: Slovakia, Germany, Serbia, Poland, Montenegro, UK, Ireland, and Bosnia and Herzegovina.
[30] Lignite group 3: Slovenia, Romania, and Hungary.
[31] Lignite group 4: Greece and Turkey.

Hydrogen import prices (unit: €/MWh_{H2})	North Africa	53.2	35.5	Estimated base price per import source	
	Ukraine	65.9	43.1		
	Norway	40.6	40.6		
Hydrogen production prices (unit: €/MWh_{H2})	Unabated Hydrogen production from natural gas	56.6	64.4	Hydrogen produced by SMR or ATR without CCS, releasing CO_2 into the atmosphere.	
	Hydrogen production from natural gas with CCS	53.7	46.1	Hydrogen produced by SMR or ATR with CCS to capture and store 90% of the CO_2.	
	Hydrogen production from nuclear	Minimum: 28.16	Minimum: 28.16	Hydrogen produced by water electrolysis using electricity from nuclear energy. If the electricity price is higher in the relevant bidding zone, also the hydrogen production cost will be higher.	
	Hydrogen production from renewables	Minimum: 0.82	Minimum: 0.82	Hydrogen produced by water electrolysis using electricity from renewable energy sources. If the electricity price is higher in the relevant bidding zone, also the hydrogen production cost will be higher.	
Seasonality		Same curve description for 2030 and 2040, but different natural gas fuel price and ETS price		**A seasonality of the fuel price of natural gas is proposed for public consultation.** As there is a general tendency for higher natural gas prices in winter than in summer, while every year shows very specific behavior, the following generic approach is proposed: A sine wave with an amplitude that captures fluctuations around the	ENTSOG

		natural gas fuel price described above with its absolute maximum in the first hour of 1 February and its absolute minimum 6 months thereafter. The maximum is 10% higher and the minimum is 10% lower than the natural gas fuel price described above. As the cost of the production of hydrogen from natural gas is depending on the price of natural gas, the natural gas price fluctuation also influences the price of hydrogen production from natural gas with and without CCS.	
SMR and ATR capacities at country level	Technical parameters, economic parameters, capacities and their localisation.	The production capacities of SMR and ATR plants in each country and differentiation into those that are coupled with CCS and those that are not.	TYNDP 2024 Draft Scenario Methodology Report[32]
Electrolysers		Assets that use electricity to split water into hydrogen and oxygen.	TYNDP 2024 Draft Scenario Methodology Report
Water Prices		Used to assign a VO&M value to Electrolysis based on country specific water prices.	The International Benchmarking Network for Water and Sanitation Utilities (IBNET)

[32] Exception for the electricity generation profiles of RES: While the reference year (i.e., 2009) is included in the TYNDP 2024 NT+ scenario model, the required data for the stressful weather year (i.e., 2012), must be sourced from outside of the scenario process.

			database[33] (see Annex III)
Thermal power plants		Power plants that generate electricity by converting heat energy, typically from fossil fuels.	TYNDP 2024 Draft Scenario Methodology Report
Demand-side response		Adjustments in electricity consumption by end-users in response to supply conditions or price signals.	TYNDP 2024 Draft Scenario Methodology Report
Hydro storages		Facilities that store energy in the form of water in reservoirs, used for hydroelectric power generation.	TYNDP 2024 Draft Scenario Methodology Report
Battery storages		Systems that store electrical energy in batteries for later use.	TYNDP 2024 Draft Scenario Methodology Report

[33] Water prices are taken from The International Benchmarking Network for Water and Sanitation Utilities (IBNET) database. The data compares tap water prices in the cities up to 15m³ per month. https://www.waternewseurope.com/water-prices-compared-in-36-eu-cities/

RES plants			Renewable Energy Source plants that generate electricity from renewable resources like wind, solar, or hydro.	TYNDP 2024 Draft Scenario Methodology Report
Electricity generation profiles of RES	Per type (e.g., onshore wind, offshore wind, photovoltaic solar, concentrated solar power, other RES) and per country.		Patterns of electricity generation over time from renewable energy sources.	ENTSO-E Seasonal Outlooks website [34]
VoLL (unit: €/MWh_{el})	3000		Value of Lost Load, representing the cost of unserved electricity to consumers.	TYNDP 2024 draft Scenario Methodology Report
WTP_{H2} (unit: €/MWh_{H2})	154	157	Estimated Willingness to pay	ENTSOG based on European Hydrogen Bank auction information (see Annex III)
Electricity demand	Elastic (i.e., this demand is price-sensitive) and inelastic (i.e., this demand is only interrupted if insufficient supply is available at		The total amount of electricity required by all users at bidding-zone level.	TYNDP 2024 draft Scenario Methodology Report

[34] Exception for the electricity generation profiles of RES: While the reference year (i.e., 2009) is included in the TYNDP 2024 NT+ scenario model, the required data for the stressful weather year (i.e., 2012), data can be obtained from ENTSO-E through the downloads section of their winter outlooks website. https://www.entsoe.eu/outlooks/seasonal/

	costs below the VoLL) electricity demand.		Climate stress case data requested from ENTSO-E
Hydrogen demand	Elastic (i.e., this demand is price-sensitive) and inelastic (i.e., this demand is only interrupted if insufficient supply is available at costs below the Cost of Disrupted Hydrogen) hydrogen demand.	The total amount of hydrogen required by all users at country level. In addition, total hydrogen demand at country level is assigned to the different hydrogen zones within the country (i.e., by default Zone 1 and Zone 2). For countries with two hydrogen zones the shares of demand are listed in Annex III. For countries with hydrogen topology composed by 3 or more zones, shares of hydrogen demand were considered as provided by project promoters.	TYNDP 2024 draft Scenario Methodology Report for hydrogen demand per country. ENTSOG based on project promoters for shares of hydrogen demand assigned per zone within a country.
Cooperation mode	Introduction of a hurdle cost for cross-border flows and a WTP differentiation to formalize the intended limitations of the cooperation mode.	A small hurdle cost is implemented for cross-border flows to limit the cooperation between countries. This way, a country with a hydrogen supply surplus will only supply an amount of hydrogen with its neighboring countries that does not result in curtailment of its own hydrogen demand. First, it would help to satisfy the hydrogen demand of its direct neighbors. By being a small hurdle cost, this hurdle cost will not distort the benefits indicators. If a country with a hydrogen supply surplus has several direct neighbors and it cannot help to mitigate all	ENTSOG

		hydrogen demand curtailment in all of them, they will be helped equally in terms of the resulting hydrogen curtailment rates. This can be achieved by defining the WTP_{H2} value being slightly increasing with the curtailment rate in a country, with the value stated above in the center. This differentiation must be smaller than the hurdle cost to not distort the limitation of the cooperation. This extra rule is needed as otherwise the allocation of hydrogen supply to neighboring countries could be a random output of the model and cause issues with the alternative fuel approach, which is highly depending on the localization of hydrogen demand curtailments.	
Alternative fuel(s)	Shares of alternative fuels are country- and year-specific based on the NT+ scenario (see section 3.2.5).	For the alternative fuel, constituted of natural gas and light oil (see section 3.2.5): > Marginal supply costs: Additional natural gas demand compared to the NT+ scenario is assumed to be imported. The producer rent is therefore located outside of the EU. It is therefore not to be counted as a relevant benefit. The marginal supply cost is thus set at the market clearing price, so no producer rent is considered. > Emission factors: see Annex IV and Annex V.	ENTSOG

		> Methodology to assess which part of the hydrogen demand from the scenarios that cannot be satisfied in the DHEM is curtailed and which part is instead supplied by which alternative fuel: see section 3.2.5. > Maximum price consumers would be willing to pay for natural gas and light oil respectively: below the WTP_{H2} as hydrogen is considered more valuable. **The exact value is to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines.** > Market clearing price: Fuel price of natural gas and fuel price of light oil respectively (see above).	

3.2.5 Alternative fuel approach

Introduction

Since the infrastructure levels used for the PS-CBAs may be insufficient to satisfy all hydrogen demand, an approach using alternative fuel(s) should be applied. Another option would be to assume unsatisfied hydrogen demand as fully curtailed (no alternative fuel approach), which would:

- Describe a situation where certain end users would eventually not receive any energy over a sustained period of time. If deindustrialisation was assumed to result from hydrogen curtailment, this would be a correct representation. If not, the energy would need to be supplied with alternative fuel(s).
- Result in an issue for the GHG emissions variations indicator (B1) and the non-GHG emissions variations indicator (B2) since curtailed energy demand has no emissions in the model. Energy demand curtailment can therefore not be overachieved in terms of emissions reduction. Improving the security of supply situation or the market rents with a project might therefore lead to a negative sustainability indicator if hydrogen demand curtailment was reduced.

Meanwhile, assuming unsatisfied hydrogen demand to be partially curtailed will:

- Describe a situation where certain end users that prefer to switch to hydrogen but structurally cannot receive it would stay with their incumbent fuel to prevent their own deindustrialization. At the same time, a certain share of hydrogen might still be considered as fully disrupted.
- Solve the issue for the GHG emissions variations indicator (B1) and the non-GHG emissions variations indicator (B2) described above. The curtailed hydrogen demand share that is supplied with an alternative fuel has the emission factors of the alternative fuel, being higher than the emissions linked to renewable and low-carbon hydrogen. Improving the hydrogen security of supply situation can therefore enable positive sustainability benefit indicators if hydrogen demand curtailment was reduced.

The alternative fuel(s) approach can be used to split unsatisfied hydrogen demand into i) a share that is satisfied with an alternative fuel and ii) a share that is completely curtailed.

Proposed application in the TYNDP 2024 PS-CBA process

In the DHEM, there is an hourly matching of hydrogen demand and hydrogen supply. **Figure 14** displays an example of this relationship along a year that does not apply an alternative fuel approach and for a reference simulation without the assessed (group of) project(s). Whenever the hydrogen demand is higher than the potential hydrogen supply (here, meaning all available means of hydrogen production and import) in a given hour, their difference is quantifying the unsatisfied hydrogen demand.

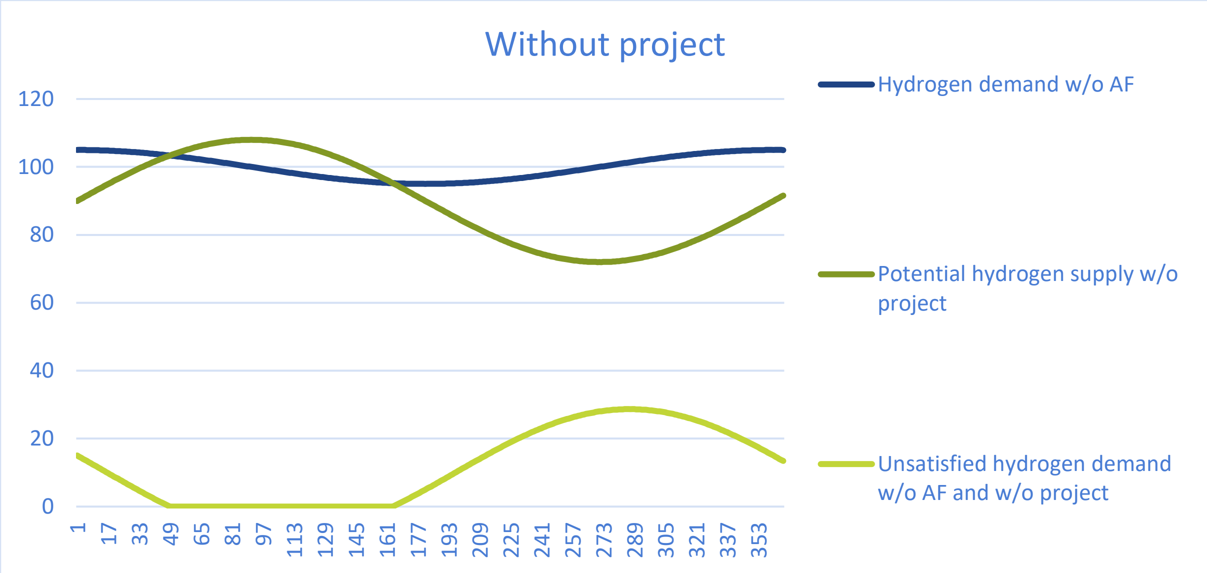

Figure 14: Example of hydrogen demand, hydrogen supply potential without the assessed project, and resulting unsatisfied hydrogen demand (simplification: no storages).

The alternative fuel approach does not accept the disruption of demand shares with a frequency above a certain value. In this example, a frequency of 33.33% is used. **The frequency to be applied for the TYNDP PS-CBA will depend on the public consultation. The proposed pattern of hydrogen demand to be shifted to the alternative fuel is a constant value for the whole year. The alternative fuel approach is applied for each hydrogen node.** This results in the situation displayed in Figure 15, where a certain share of the hydrogen demand is assumed to remain with their incumbent fuel (red line). Thereby, the hydrogen demand is reduced and this reduced hydrogen demand can be satisfied to a higher extent with the given hydrogen supply potential. Thus, the unsatisfied hydrogen demand is also reduced. The example situation does not consider infrastructure bottlenecks and storages.

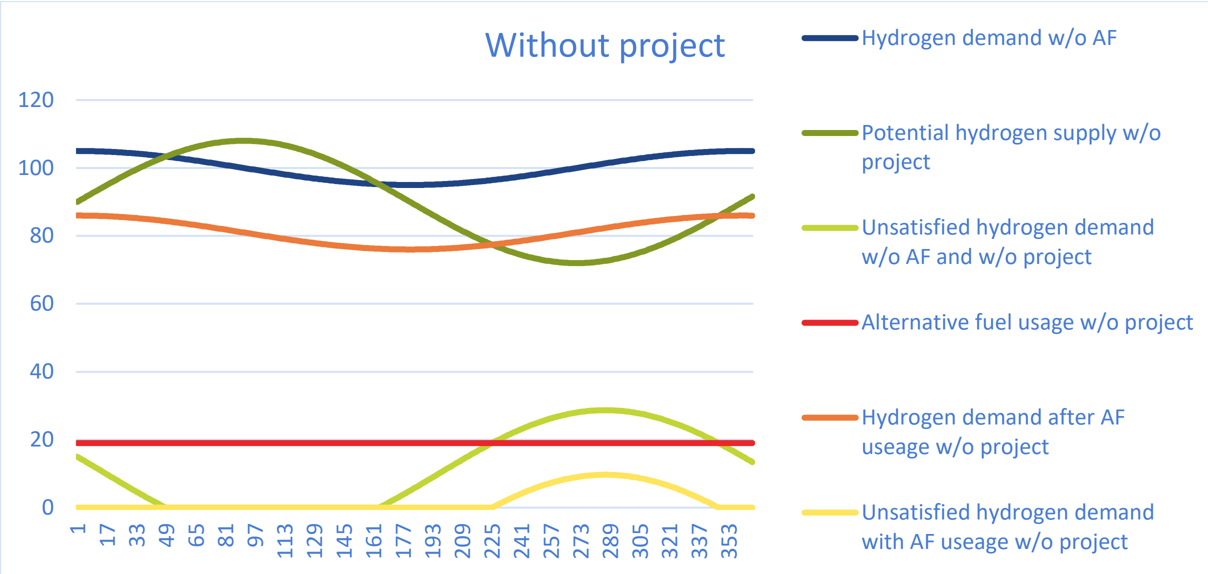

Figure 15: Example of hydrogen demand, hydrogen supply potential without the assessed project, and resulting unsatisfied hydrogen demand as well as the resulting alternative fuel usage, reduced hydrogen demand, and reduced unsatisfied hydrogen demand (simplification: no storages).

As the hydrogen topology of the DHEM is more complex than in the given example and includes storage options, the reference case requires two DHEM runs: A first run to determine the alternative fuel usage and a second run with a hydrogen demand that is reduced accordingly.

In Figure 16, the effect of adding the assessed project is displayed. In the example, the project increases the supply potential in each day by 5 GWh. This means that in comparison with the situation without the project, the alternative fuel share of the initial hydrogen demand can be reduced as the initial hydrogen demand is curtailed less often. In the given example that does not include storages, the reduction of alternative fuel usage is also 5 GWh for each day. Then, along the whole year, the (group of) project(s) reduces the alternative fuel usage in the whole year by 1825 GWh. The unsatisfied hydrogen demand after the dimensioning of the alternative fuel (i.e., area under the yellow lines in both Figures) would however stay constant with the (group of) project(s) in the example. As the hydrogen topology of the DHEM is more complex than in the given example and includes storage options, the incremental case requires two DHEM runs if the (group of) project(s) alters the unsatisfied hydrogen demand: A first run to determine the alternative fuel usage and a second run with a hydrogen demand that is reduced accordingly. The effect of the (group of) project(s) can then be determined by comparing the second run of the reference case with the second run of the incremental case. If the (group of) project(s) does not alter the unsatisfied hydrogen demand, the first run of the incremental case is sufficient and its outputs can be compared with the second run of the reference case.

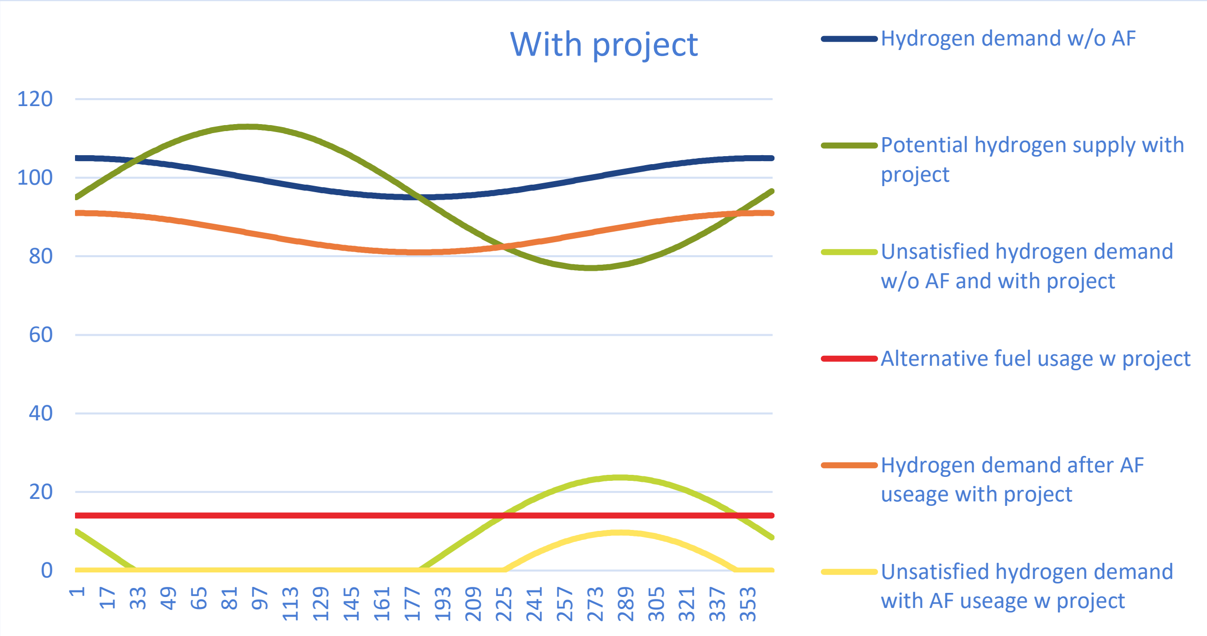

Figure 16: Example of a hydrogen demand pattern, hydrogen supply potential with the assessed project, and resulting unsatisfied hydrogen demand as well as the resulting alternative fuel usage, reduced hydrogen demand, and reduced unsatisfied hydrogen.

Next, the effect of the (group of) project(s) on the benefit indicators within the example can be estimated (see following sections). For this purpose, it is assumed in the example that the (group of) project(s) would allow for renewable hydrogen supply by ship, which is the most expensive supply source of hydrogen.

Then, the 1825 GWh of alternative fuel usage would be replaced with a fuel with a GHG emissions factor of 0. Considering an alternative fuel consisting of 100% natural gas in this example, this translates into a GHG emissions reduction of 1825 GWh multiplied by 180 tCO_2 equivalent/GWh (see Annex IV), i.e. 328,500 tCO_2 equivalent, per year. For the monetisation, a societal cost of carbon of 250 € per tCO_2 equivalent as well as the inclusion of an ETS price of 113.4 € per tCO_2 equivalent in the alternative fuel(s)' market rents are assumed. The 328,500 tCO_2 equivalent can be monetised by multiplying this value with the difference between 250 €per tCO_2 equivalent and 113.4 € per tCO_2 equivalent. The benefit of GHG emissions reduction by the (group of) project(s) is then monetised as 44.9 M€ per year. In this simple example, this would be the result of the GHG emissions variation indicator (B1).

At the same time, the market rents would be influenced. While the EU-internal producer rent of the alternative fuel is considered as 0, the consumer rent is the difference between the alternative fuel's market clearing price (i.e., the natural gas fuel price) and the willingness to pay of the consumers. Assuming a natural gas fuel price of 22.8 €/MWh and a willingness to pay of 70 €/MWh, the alternative fuel consumer rent is 47.2 €/MWh. For the 1825 GWh of reduced alternative fuel usage per year, the alternative fuel consumer rent is decreased by 86.1 M€. On the other hand, additional hydrogen market rents are enabled. Considering a price of hydrogen imports by ship of 116.5 €/MWh and a willingness to pay of hydrogen consumers of

154 €/MWh, the hydrogen market rents are 37.5 €/MWh. In the example without storages and infrastructure bottlenecks, the hydrogen market clearing price only determines the allocation of this hydrogen market rent to hydrogen consumer rent and hydrogen producer rent, so it does not influence their sum. For the 1825 GWh of increased hydrogen usage per year, the hydrogen market rents are increased by 58.1 M€. Thus, the increase of market rents indicator (B4) would in fact be negative by 28.1 M€ per year when factoring in the negative change of the alternative fuel market rents as well as the positive change of the hydrogen market rents enabled by the (group of) project(s).

Combining the monetised benefits of the GHG emissions variation indicator (B1) and the increase of market rents indicator (B4), the (group of) project(s) in the example would result in a joint benefit of 16.8 M€ per year.

The alternative fuel is proposed to be depending on the year and country. It is assumed that all hydrogen demand sectors are affected proportionally to their share of the total country-specific hydrogen demand in the given year of the NT+ scenario. The share of hydrogen demand of the transport sector that is shifted to an alternative fuel is considered with light oil as alternative fuel. All other hydrogen demand sectors are considered with natural gas as alternative fuel. The reason is that the typical incumbent fuels of future hydrogen consumers are coal, oil, and natural gas. The consideration of oil or coal as alternative fuel would result in higher joint benefits of the project in the example if the same willingness to pay would be assumed. Therefore, the consideration of natural gas as the dominant alternative fuel is considered as conservative regarding the monetised benefits.

The alternative fuel that is considered as natural gas is added to the natural gas demand in the DGM (see section 2.4.5).

3.2.6 B1: GHG emissions variation

DEFINITION	This benefit indicator (B1) measures the variations in GHG emissions as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B1) > Considers the change of GHG emissions as a result of changing the generation mix of the electricity sector and the supply sources used to meet hydrogen demand; > Calculates the GHG emissions by multiplying the usage of electricity generation type (e.g., coal-fired power plant), hydrogen production type (e.g., unabated SMR), hydrogen import options (e.g., low-carbon hydrogen from Norway), and alternative fuel (e.g., natural gas) with respective CO_2 equivalent emission factors capturing direct emissions; > Is first expressed in quantitative terms in tons of CO_2 equivalent emissions savings per year (tCO_2-eq/y); > Can be expressed in monetary terms (€/y) by multiplying the CO_2 equivalent emissions savings (tCO_2-eq/y) by the societal cost of carbon (€/tCO_2-eq) of the corresponding simulated year, additionally considering double-counting with the increase of market rents indicator (B4).
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B1) is interlinked with the integration of renewable electricity generation indicator (B3.1), the integration of renewable and low carbon hydrogen indicator (B3.2), and the increase of market rents indicator (B4). Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied. The simulation outputs thereby cover all elements of the formula except the GHG emission factors.

$$\Delta GHG\ emissions\ enabled\ by\ (group\ of)project(s)$$
$$= ((\sum_{i}^{n}(power\ generation_{i,with\ (group\ of)project(s)} * CO_{2-eq} emission\ factor_i)$$
$$+ \sum_{j}^{m}(hydrogen\ production_{j,with\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_j)$$
$$+ \sum_{k}^{p}(alternative\ fuel\ usage_{k,with\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_k)$$
$$+ \sum_{i}^{n}(hydrogen\ import\ from\ supply\ potential_{l,with\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_l))$$
$$- ((\sum_{i}^{n}(power\ generation_{i,without\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_i)$$
$$+ \sum_{j}^{m}(hydrogen\ production_{j,without\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_j)$$
$$+ \sum_{k}^{p}(alternative\ fuel\ usage_{k,without\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_k)$$
$$+ \sum_{i}^{n}(hydrogen\ import\ from\ supply\ potential_{l,without\ (group\ of)project(s)}$$
$$* CO_{2-eq} emission\ factor_l))$$

On the basis of:

> n: number of different types of electricity generation.

> m: number of different types of hydrogen production.

> p: number of different alternatives fuels.

> r: number of different supply sources that are considered with the supply potential approach.

> All CO_2 equivalent emission factors proposed for the TYNDP 2024 PS-CBA process capture direct GHG emissions as detailed in Annex IV.

> Power generation$_i$: Amount of electricity produced by power generation of type ‘i' (e.g., coal-fired power plant, etc.). Variations with and without the (group of) project(s) are resulting from changing the generation mix and total generation of the electricity sector.

- CO_2-eq emission factor$_i$: GHG emission factor expressed in CO_2 equivalence of power generation of type 'i' per unit of energy generated in form of electricity.

- Hydrogen production$_j$: Amount of hydrogen produced by hydrogen production from natural gas of type 'j' (e.g., unabated hydrogen production from natural gas with SMR, low-carbon hydrogen production from natural gas with SMR and CCS, etc.). Variations with and without the (group of) project(s) are resulting from changing the usage of supply sources and the total production and imports of hydrogen if the country is not considered with the supply potential approach. Electrolytic hydrogen production is already addressed by the power generation term of the formula as the electrolyser usage itself is not causing additional GHG emissions.

- CO_2-eq emission factor$_i$: GHG emission factor expressed in CO_2 equivalence of hydrogen production of type 'j' per unit of energy produced in form of hydrogen.

- Alternative fuel usage$_k$: Amount of usage of alternative fuel of type 'k'. Variations with and without the (group of) project(s) are resulting from changing amounts of hydrogen demand that can be satisfied with hydrogen, reducing the need to use an alternative fuel.

- CO_2-eq emission factor$_k$: GHG emission factor expressed in CO_2 equivalence of alternative fuel usage of type 'k' per unit of energy used.

- Hydrogen import from supply potential$_l$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'l'. It is used to capture the changes of imports from supply sources that are considered with the supply potential approach.

- CO_2-eq emission factor$_l$: GHG emission factor expressed in CO_2 equivalence of hydrogen source that is considered with the supply potential approach of type 'l' per unit of energy used.

The resulting amount of variation of GHG emissions in tons of CO_2-eq shall be valued in monetary terms. The unit is €/y.

There are different approaches to monetise GHG emissions:

- To simulate an expected market behaviour, it is prudent to include those costs of GHG emissions that must be paid by market participants, as those will influence their decision making. These costs are related to the Emission Trading Scheme (ETS). They are internalised into the increase of market rents indicator (B4) through the producer rent, as the marginal costs of each production asset is defined as the sum of the fuel cost, variable operation and maintenance costs, as well as the ETS price (as forecasted in the scenarios). Therefore, the increase of market rents indicator (B4) already considers a certain monetisation of GHG emissions.

- However, also a societal cost of carbon can be established based on two concepts that typically consider higher cost of carbon than the ETS[35]:
    - The social cost (or social cost of carbon) that represents the total net damage of an extra metric ton of CO_2 emissions due to the associated climate change; and
    - The shadow price (or shadow cost of carbon) that is determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint.
- This benefit indicator (B1) aims to monetise the GHG emissions variations resulting from the implementation of a (group of) project(s) with societal cost of carbon. These costs do not influence the market behaviour as it is not paid by a market participant as a direct consequence of its actions. Therefore, the assessment of this benefit indicator (B1) is based on the same market behaviour as the increase of market rents indicator (B4). Since latter benefit indicator (B4) already captures the ETS-related costs, they are removed from this benefit indicator (B1) to avoid a double-counting of benefits.

The societal cost of carbon used for this benefit indicator (B1) should be based on reputable scientific investigations and international studies. In line with the EC technical guidance on the climate proofing of infrastructure in 2021–2027[36] and EC Economic Appraisal Vademecum 2021-2027 General Principles and Sector Applications[37], the reference values proposed for the monetisation of the B1 indicator for the TYNDP 2024 PS-CBA process are societal cost of carbon that are based on the shadow cost of carbon as detailed in Table 2 below.

Table 2: Proposed societal cost of carbon for TYNDP 2024 PS-CBA process for simulated years (source: EIB[38]).

Monetization factor (B1)[39]	2030	2040	2050
Proposed societal cost of carbon (unit: € /t CO_2-eq)	250	525	800

[35] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2.
[36] Commission Notice Technical guidance on the climate proofing of infrastructure in the period 2021-2027 (link).
[37] Economic Appraisal Vademecum 2021-2027 General Principles and Sector Applications (link).
[38] EIB Group Climate Bank Roadmap 2021-2025 (https://www.eib.org/en/publications/the-eib-group-climate-bank-roadmap) and EIB Climate Bank Roadmap Progress Report 2022 (https://www.eib.org/en/publications/20230002-climate-bank-roadmap-progress-report-2022).
[39] Monetization factor of B1 indicator for non-simulated years will be based on linear interpolation

3.2.7 B2: Non-GHG emissions variation

DEFINITION	This benefit indicator (B2) measures the reduction in non-GHG emissions as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B2) > Considers the change of non-GHG emissions as a result of changing the generation mix of the electricity sector and the supply source used to meet hydrogen demand; > Calculates the non-GHG emissions for each assessed pollutant by multiplying the usage of electricity generation type (e.g., coal-fired power plant), hydrogen production type (e.g., unabated SMR), hydrogen import options (e.g., low-carbon hydrogen from Norway), and alternative fuel (e.g., natural gas) with respective emission factors reflecting direct emissions; > Is first expressed in quantitative terms in variations of tons of pollutant emitted per year (e.g., tNOx/y, tSO2/y, tPM/y, etc.); > Can be further expressed in monetary terms (€/y) by multiplying the non-GHG emission variations (t[Pollutant]/y) by the damage cost of air pollutants (€/t[Pollutant]) of the simulated year.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B2) is interlinked with the integration of renewable electricity generation indicator (B3.1) and the integration of renewable and low carbon hydrogen indicator (B3.2). Since the interlinked benefit indicators are not monetised, double-counting is avoided.

In the EU, the Directive (EU) 2016/2284 sets national emissions reduction commitments for five different air pollutants: nitrogen oxides (NO_x), sulphur dioxides (SO_2), coarse and fine particulate matter (i.e., PM 10 and PM 2.5), non-methane volatile organic compounds (i.e., NMVOC), and ammonia (NH_3). Also, the European Commission has set in the European Green Deal the zero-pollution ambition for a toxic-free environment[40], in addition to 2030 targets for the reduction of air pollution set in the zero-pollution Action Plan[41].

These pollutants contribute to poor air quality, leading to significant negative impacts on human health and the environment. Energy use in transport, industry and in power sectors, as well as in heat generation, are major sources of emissions especially for NO_x and SO_2.

[40] EC Communication: Pathway to a Healthy Planet for All (https://eur-lex.europa.eu/resource.html?uri=cellar:a1c34a56-b314-11eb-8aca-01aa75ed71a1.0001.02/DOC_1&format=PDF).
[41] EU Action Plan: '(Towards Zero Pollution for Air, Water and Soil' (https://eur-lex.europa.eu/resource.html?uri=cellar:a1c34a56-b314-11eb-8aca-01aa75ed71a1.0001.02/ DOC_1&format=PDF).

In this context, hydrogen infrastructure could significantly contribute to the fulfilment of the above-mentioned targets, as hydrogen causes almost no air pollution when used.
The emissions factors greatly differ depending on the use of the fuel, and in particular depending on the combustion techniques and abatement techniques. Ideally, each fuel user in the model would have a different emission factor for each air pollutant considered in the assessment. To simplify the calculation of the indicator, it is recommended to consider one emission factor per pollutant and technology type.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied. The simulation outputs thereby cover all elements of the formula except the GHG emission factors.

$$\begin{aligned}
&\Delta Non - GHG\ emissions\ enabled\ by\ (group\ of)project(s)_y \\
&= \Big(\Big(\sum_i^n \big(power\ generation_{i,with\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{i,y}\big) \\
&+ \sum_j^m \big(hydrogen\ production_{j,with\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{j,y}\big) \\
&+ \sum_k^p \big(alternative\ fuel\ usage_{k,with\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{k,y}\big) \\
&+ \sum_i^n \big(hydrogen\ import\ from\ supply\ potential_{l,with\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{l,y}\big)\Big) \\
&- \Big(\Big(\sum_i^n \big(power\ generation_{i,without\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{i,y}\big) \\
&+ \sum_j^m \big(hydrogen\ production_{j,without\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{j,y}\big) \\
&+ \sum_k^p \big(alternative\ fuel\ usage_{k,without\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{k,y}\big) \\
&+ \sum_i^n \big(hydrogen\ import\ from\ supply\ potential_{l,without\ (group\ of)project(s)} \cdot Non - GHG\ emission\ factor_{l}, y)\big)\Big)
\end{aligned}$$

On the basis of:

- n: number of different types of electricity generation.
- m: number of different types of hydrogen production.
- p: number of different alternatives fuels.

- r: number of different supply sources that are considered with the supply potential approach.
- All non-GHG emissions factors proposed for TYNDP 2024 PS-CBA process captures direct non-GHG emissions variation from nitrogen oxides (NO_x), sulphur dioxide (S_2O) and particulate matter (fine particles and coarse particles) from stationary fuel combustion (as described in Annex V).
- Power generation$_i$: Amount of electricity produced by power generation of type 'i'. Variations with and without the (group of) project(s) are resulting from changing the generation mix and total generation of the electricity sector.
- Non-GHG emission factor$_{i,y}$: non-GHG emission factor for pollutant 'y' of power generation of type 'i' per unit of energy generated in form of electricity.
- Hydrogen production$_j$: Amount of hydrogen produced from natural gas by hydrogen production of type 'j' (e.g., unabated hydrogen production from natural gas with SMR, low-carbon hydrogen production from natural gas with SMR and CCS, etc.). Variations with and without the (group of) project(s) are resulting from changing the usage of supply sources and the total production and imports of hydrogen if the country is not considered with the supply potential approach. Electrolytic hydrogen production is already addressed by the power generation term of the formula as the electrolyser usage itself is not causing additional non-GHG emissions.
- Non-GHG emission factor$_{i,y}$: non-GHG emission factor for pollutant 'y' of hydrogen production of type 'i' per unit of energy produced in the form of hydrogen. Variations with and without the (group of) project(s) are resulting from changing the supply sources used to meet the hydrogen demand (e.g., unabated hydrogen production from natural gas, low carbon, or electrolytic hydrogen) and the total production and imports of hydrogen.
- Alternative fuel usage$_k$: Amount of usage of alternative fuel of type 'k'. Variations with and without the (group of) project(s) are resulting from changing amounts of hydrogen demand that can be satisfied with hydrogen, reducing the need to use an alternative fuel.
- Non-GHG emission factor$_{k,y}$: non-GHG emission factor for pollutant 'y' of alternative fuel usage of type 'k' per unit of energy used.
- Hydrogen import from supply potential$_l$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'l'.
- Non-GHG emission factor$_{l,y}$: GHG emission factor for pollutant 'y' of hydrogen source that is considered with the supply potential approach of type 'l' per unit of energy used.

The formula is applied to each assessed non-GHG pollutant individually. The set of the resulting quantitative non-GHG emission reductions is the non-monetised non-GHG emissions variation indicator (B2).

The monetisation of the variations of emissions from the considered air pollutants is described as follows:

$$B2_{monetised} = \sum_{y} (Non - GHG\ emissions\ variation\ by\ (group\ of)\ project(s)_y * Damage\ cost_y)$$

On the basis of:

- Non-GHG emission variation by (group of) project(s)$_y$: Result for non-GHG emissions variation for pollutant 'y' (t[Pollutant]/y).
- Damage cost$_y$: Cost of the emission of pollutant 'y' (€/t[Pollutant]).

The proposed damage cost for the TYNDP 2024 PS-CBA process are:

Table 3: Average EU damage cost per tonne of pollutant (source: European Environment Agency[42]).

Pollutant	Average EU damage cost (unit: € (2021)/t pollutant)	
	VOLY	VSL
NO_x	15.353	42.953
SO_2	16.212	38.345
PM 10	51.482	141.145
PM 2.5	86.490	237.123
NH_3	18.991	52.268
NMVOC	1.844	4.480

Damage costs per ton of each pollutant were quantified as EU average by the European Environment Agency (EEA). A sensitivity analysis has been performed using two commonly applied methods for valuing mortality, i.e., the value of statistical life (VSL) and the value of a life year (VOLY). The former is based on the number of deaths associated with air pollution, while the latter is based upon the loss of life expectancy (expressed as years of life lost, or YOLLs). The ranges of external costs (low – high) included in the **Table 3** correspond to the values estimated by EEA[27] using these two methods.

For the monetisation of this benefit indicator (B2) in the TYNDP 2024 PS-CBA process, ENTSOG proposes to consider the average (EU) damage costs based on the value of a life year (VOLY) or value of statistical life (VSL) (see Table 3), **to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines**.

[42] European Environment Agency: Estimating the external costs of industrial air pollution: Trends 2012-2021, Technical note on the methodology and additional results from the EEA briefing 24/2023, Table 3.1.

Example for a hypothetical hydrogen import terminal project

- Case: The hydrogen import terminal project allows increased usage of renewable hydrogen which replaces unabated hydrogen production from natural gas. Pollutant y and pollutant x are assessed.
- Assumed damage cost of pollutant y in the assessed year: 100 €/t pollutant y
- Assumed damage cost of pollutant x in the assessed year: 200 €/t pollutant x
- Non-monetised results of this benefit indicator (B2):
    - Reduction of emissions of pollutant y: 0.1 Mt pollutant y/y
    - Reduction of emissions of pollutant x: 0.05 Mt pollutant x/y
    - Non-GHG emissions variations monetised in this benefit indicator (B2): 100*0.1M€/y + 200*0.05M€/y = 20 M€/y

This benefit indicator (B2) is interlinked with

- The integration of renewable electricity generation indicator (B3.1) as using more renewable electricity generation reduces non-GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The integration of renewable and low carbon hydrogen indicator (B3.2) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher emission factors, which reduces non-GHG emissions;

Since the interlinked benefit indicators are not monetised, double-counting is avoided.

3.2.8 B3.1: Integration of renewable electricity generation

DEFINITION	This benefit indicator (B3.1) measures the reduction of renewable electricity generation curtailment as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B3.1) > Considers the amount of electricity that is provided by RES; > Calculates the sum of all non-curtailed renewable electricity production within the EU; > Is expressed quantitatively in terms of energy (MWh/y); > Is not monetised, since it is already monetised as part of other benefit indicators.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B3.1) is interlinked with the GHG emissions variations indicator (B1), the non-GHG emissions variations indicator (B2), the integration of renewable electricity indicator (B3.2), the increase of market rents indicator (B4), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since this benefit indicator (B3.1) is not monetised, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied.

$$B3.1 = \sum_{i}^{n}\left(uncurtailed\ renewable\ electricity\ generation_{i,with\ (group\ of)\ project(s)}\right) - \sum_{i}^{n}\left(uncurtailed\ renewable\ electricity\ generation_{i,without\ (group\ of)\ project(s)}\right)$$

On the basis of:

> n: number of types of renewable generation.

> Uncurtailed renewable electricity generation: amount of uncurtailed electricity produced by RES of type i (MWh/y).

Example for a hypothetical hydrogen storage project

> - Case: The hydrogen storage project allows increased usage of renewable electricity production by providing a storage option for renewable energy in the form of hydrogen.
> - Non-monetised results of this benefit indicator (B3.1):
>   - Variation of renewable electricity generation: +1 TWh/y

This benefit indicator (B3.1) is interlinked with

- The GHG emissions variations indicator (B1) as using more renewable electricity generation reduces GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The non-GHG emissions variations indicator (B2) as using more renewable electricity generation reduces non-GHG emissions in electricity generation, replacing more emitting alternatives that would otherwise be used;
- The integration of renewable and low carbon hydrogen indicator (B3.2) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources that are not renewable or low carbon;
- The increase of market rents indicator (B4) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors;
- The reduction in exposure to curtailed hydrogen demand indicator (B5) in case the integration of renewable electricity is also improved for the more stressful weather year used for the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5) and the additional renewable electricity can be used to produce electrolytic hydrogen that reduces hydrogen demand curtailment.

Therefore, this benefit indicator (B3.1) is not monetised to avoid double-counting.

3.2.9 B3.2: Integration of renewable and low carbon hydrogen

DEFINITION	This benefit indicator (B3.2) measures the increase of the production of electrolytic and low carbon hydrogen as well as the increase in the import of renewable and low carbon hydrogen as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B3.2) > Considers the production of electrolytic and low carbon hydrogen as well as the increase in the import of renewable and low carbon hydrogen; > Is expressed quantitatively in terms of energy (MWh/y); > Is not monetised, since it is already monetised as part of other benefit indicators.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B3.2) is interlinked with the GHG emissions variations indicator (B1), the non-GHG emissions variations indicator (B2), the integration of renewable electricity generation indicator (B3.1), the increase of market rents indicator (B4), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since this benefit indicator (B3.2) is not monetised, double-counting is avoided.

Using the simulation outputs of the objective function of the DHEM under consideration of the alternative fuel approach, the following formula is applied.

On the basis of:

- Electrolytic hydrogen production: Hydrogen produced by electrolysers (MWh/y).
- Low carbon hydrogen production: Hydrogen produced from natural gas in combination with CCS (MWh/y).
- Renewable hydrogen imports: Hydrogen imported from supply sources that are considered to supply renewable hydrogen in the NT+ scenario (MWh/y), i.e., North Afrika, Ukraine, and imports by ship.
- Low carbon hydrogen imports: Hydrogen imported from supply sources that are considered to supply low carbon hydrogen in the NT+ scenario (MWh/y), i.e., Norway.

Example for a hypothetical hydrogen transmission project

> Case: Country A's domestic hydrogen market is already is fully satisfied. As it is not connected to other countries, this is limiting further usage of electrolytic hydrogen production. Country B's hydrogen demand is satisfied with unabated hydrogen production from natural gas. The hydrogen transmission project allows for exports from country A to country B. Thereby, it allows for increased usage of electrolytic hydrogen production in country A. In the importing country B, this reduces the usage of unabated hydrogen production from natural gas.

> Non-monetised results of this benefit indicator (B3.2):
  - Variation of relevant hydrogen production: +10 TWh/y

This benefit indicator (B3.2) is interlinked with

- The GHG emissions variations indicator (B1) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher CO_2 equivalent emission factors, which reduces GHG emissions;
- The non-GHG emissions variations indicator (B2) since a higher usage of renewable and low carbon hydrogen can allow to replace alternatives that have higher emission factors, which reduces non-GHG emissions;
- The integration of renewable electricity generation indicator (B3.1) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources that are not renewable or low carbon;
- The increase of market rents indicator (B4) through reduced curtailment of renewable electricity generation which can then replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors;
- The reduction in exposure to curtailed hydrogen demand indicator (B5) in case the integration of renewable and low-carbon hydrogen is also improved for the more stressful weather year used for the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5) and can be used to reduce hydrogen demand curtailment.

Therefore, this benefit indicator (B3.2) is not monetised to avoid double-counting.

3.2.10 B4: Increase of market rents

DEFINITION	This benefit indicator captures the change in market rents as a result of implementing a (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B4) > Is defined as the change of the sum of the consumer rent, the producer rent, the congestion rent, the cross-sectoral rent, and the storage rent. It considers both the electricity and the hydrogen sector; > Can be displayed in different granularities, for example for only one sector; > Is directly expressed in monetised terms (€/y).
MODEL USED	Dual Hydrogen/Electricity Model (DHEM)
INTERLINKAGE WITH OTHER INDICATORS	This benefit indicator (B4) is interlinked with the GHG emissions variations indicator (B1), the integration of renewable electricity generation indicator (B3.1), the integration of renewable and low carbon hydrogen indicator (B3.2), and the reduction in exposure to curtailed hydrogen demand indicator (B5). Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

In the DEHM, the sum of the market rents is defined with the total surplus[43] approach that is further detailed in Annex VI. Investments in production capacities, transmission capacities, import capacities, and storage solutions typically increase the sum of these surpluses as they enable to match the demand with cheaper supply sources.

The sum of all market rents along the sectors S ϵ {electricity, hydrogen, alternative fuel(s)} is calculated as follows based on the outputs of the objective function of the DHEM and under consideration of the alternative fuel approach:

$$Market\ rents_{global} = \sum_{j \epsilon S} R^{j}_{consumer} + \sum_{j \epsilon S} R^{j}_{producer} + \sum_{j \epsilon S} R^{j}_{storage} + \sum_{j \epsilon S} R^{j}_{congestion} + R^{electricity \leftrightarrow hydrogen}_{cross-sector}$$

[43] 'Surplus' and 'rent' are used interchangeably.

On the basis of:

- $R^{j}_{consumer}$ is the consumer rent of sector j ϵ S.
- $R^{j}_{producer}$ is the producer rent of sector j ϵ S.
- $R^{j}_{storage}$ is the storage rent of sector j ϵ S.
- $R^{j}_{congestion}$ is the congestion rent of sector j ϵ S.
- $R^{electricity\leftrightarrow hydrogen}_{cross-sector}$ is the cross-sector rent stemming from the interlinkage between electricity and hydrogen sector.

Any component c ϵ C of the energy system that introduces a coupling between the electricity and the hydrogen sector (i.e., electrolysers and hydrogen-based power plants) belongs to a certain electricity bidding zone with a timestep-specific market clearing price for electricity and to a certain hydrogen market area with a timestep-specific market clearing price for hydrogen. The cross-sector rent is dependent on the price difference and is summed up over all timesteps t ϵ T (e.g., each hour of a year) by applying the following formula:

$$R^{electricity\leftrightarrow hydrogen}_{cross-sector} = \sum_{t\epsilon T}\sum_{c\epsilon C}\left|mcp^{c,t}_{hydrogen} * p^{c,t}_{cross-sector,hydrogen} - mcp^{c,t}_{electrictiy} * p^{c,t}_{cross-sector,electricity}\right|$$

On the basis of:

- $mcp^{c,t}_{hydrogen}$ is the market clearing price of hydrogen in the hydrogen market area of component c at timestep t.
- $mcp^{c,t}_{electricity}$ is the market clearing price of electricity in the electricity bidding zone of component c at timestep t.
- $p^{c,t}_{cross-sector,hydrogen}$ and $p^{c,t}_{cross-sector,electricity}$ denote the component's output or input power reference to the hydrogen and electricity side, respectively. These powers are different as they are coupled with the component's efficiency for the conversion from one energy carrier into another.

The producer rent for sector j ϵ S is composed of the contributions of the production components c ϵ P (e.g., coal fired-power plants generating electricity, or SMR producing hydrogen) and is described by the following formula:

$$R^{j}_{producer} = \sum_{t\epsilon T}\sum_{c\epsilon G}\left(mcp^{c,t}_{j} - marginalCost^{c}\right) * p^{c,t}_{generation,j}$$

On the basis of:

> $marginalCost^{c}$ is the marginal cost of the production asset type associated with component c ϵ P. The marginal cost includes the ETS-related costs of associated direct GHG emissions based on the ETS price forecast used in the NT+ scenario.
> $mcp_{j}^{c,t}$ is the market clearing price at time step t ϵ T at the corresponding market area of sector j ϵ S.
> $p_{production,j}^{c,t}$ is the energy output of component c ϵ G of sector j ϵ S at timestep t ϵ T.

The storage rent for sector j ϵ S is composed of the contributions from the storage components c ϵ ST (e.g., batteries storing electricity, or hydrogen underground storages storing hydrogen) that contains the benefits of arbitrage and is described by the following formula:

$$R_{storage}^{j} = \sum_{t\epsilon T}\sum_{c\epsilon ST}(mcp_{j}^{c,t} * p_{from\ storage,j}^{c,t} - mcp_{j}^{c,t} * p_{into\ storage,j}^{c,t})$$

On the basis of:
> $p_{into\ storage,j}^{c,t}$ is the energy flow that is sent into the storage component c ϵ ST of sector j ϵ S at timestep t ϵ T. Its sum over all timesteps T is typically bigger than the sum of $p_{from\ storage,j}^{c,t}$ over all timesteps T, as the storage component c ϵ ST is coupled with the efficiency of its storage asset type.

The consumer rent is determined by the following formula:

$$R_{consumer}^{j} = \sum_{t\epsilon T}\sum_{c\epsilon L}(elasticity^{c} - mcp_{j}^{c,t}) * p_{consumption,j}^{c,t}$$

On the basis of:
> $elasticity^{c}$ is the strike price level for which a consumer or a demand side response (DSR) component c ϵ L is willing to buy energy from the markets.

The congestion rent for sector j ϵ S is summed up over i) all components c ϵ TR that provide capacity between two market areas of the same sector and ii) all timesteps t ϵ T by the following formula:

$$R_{congestion}^{j} = \sum_{t\epsilon T}\sum_{c\epsilon TR}\left|(mcp_{j}^{side\ 1,t} - mcp_{j}^{side\ 2,t}) * p_{exchange,j}^{c,t}\right|$$

On the basis of:
> $mcp_{j}^{side\ 1,t} - mcp_{j}^{side\ 2,t}$ is the difference between the market clearing prices of the two market areas of sector j ϵ S linked my component c ϵ TR at timestep t ϵ T.
> $p_{exchange,j}^{c,t}$ is the energy flow between the two market areas of sector j ϵ S linked by component c ϵ TR at timestep t ϵ T.

The market rents are derived from the results of the objective function of the DHEM under consideration of the alternative fuel approach. The market rents approach allows for a decomposition in order to consider the cross-sectoral links between the electricity and hydrogen systems and to be able to, in principle, allocate benefits to individual countries or to a group of countries.

$$B4 = Market\ rents_{global,with\ (group\ of)project(s)} - Market\ rents_{global,without\ (group\ of)project(s)}$$

For the alternative fuel(s) used, the related energy quantities are attributed with consumer rents based on the alternative fuel(s)' specifications, while congestion rents, cross-sector rents, and storage rents for alternative fuel(s) will not be considered as they would require detailed modelling of the alternative fuel(s)' infrastructure and the producer rent is not considered as it is assumed that the alternative fuel(s) would be imported from outside of the EU (see section 3.2.4 and section 3.2.5).

The distribution of benefits and costs between the sectors resulting from the implementation of a (group of) project(s) is thereby not symmetric:

- For the cross-sector rent representing a part of the surplus of electrolysers and hydrogen-based power plants, an attribution to one or the other sector risks being arbitrary.
- As the electricity system requires additional electricity generation to be used for the production of hydrogen, the electricity market clearing price might be increased if at least one more expensive source of electricity must be used. This translates into a variation of rents related to the electricity market like electricity producers' surplus and/or electricity consumer surplus and/or electricity congestion rent. In other cases, the storage and transport options of the hydrogen system and/or hydrogen-based power plant options could lead to the availability of additional electricity generation options with marginal costs that reduce the electricity market clearing price.
- In the hydrogen system, the hydrogen market clearing price might be reduced if at least the most expensive source of hydrogen is not needed anymore. This translates into a variation of rents related to the hydrogen market like hydrogen producers' rents and/or hydrogen consumers' rents and/or hydrogen congestion rent. In other cases, the storage and transport options of the hydrogen system and/or hydrogen-based power plant options could lead to increased hydrogen usage. This could require the usage of hydrogen supply with higher marginal costs, increasing the hydrogen market clearing price.
- Therefore, the producer rent and consumer rent are often attributed to different sectors.
- The TYNDP 2024 Implementation Guidelines for PS-CBA approach acknowledge the described interdependencies by considering **market rents within this benefit indicator**

(B4) that cover the hydrogen sector as well as the electricity sector[44]. This also makes it redundant to allocate the cross-sector rent to any of the sectors.

This benefit indicator (B4) is interlinked with:

- The GHG emissions variations indicator (B1) which also includes a monetisation of the GHG emissions (see section 3.2.6**Error! Reference source not found.**). Therefore, the GHG emissions costs that are monetised in this benefit indicator (B4) are removed from the GHG emissions variations indicator (B1) to avoid double-counting;
- The integration of renewable electricity generation indicator (B3.1) and the integration of renewable and low carbon hydrogen indicator (B3.2) as reduced curtailment of renewable electricity generation is acting on all three indicators. This is because reduced curtailment of renewable electricity generation can replace more expensive electricity generation and may allow for the production of more electrolytic hydrogen that can replace more expensive hydrogen sources which changes the market rents in the sectors.

Since the interlinked benefit indicators are either not monetised or the potentially mutual benefits are removed, double-counting is avoided.

[44] See also Recommendation 1 in section 8.1 of ENTSO-E's and ENTSOG's Interlinked Model Progress Report 2024: https://www.entsog.eu/sites/default/files/2024-05/entsos_ILM_progress_report_240430.pdf

3.2.11 B5: Reduction in exposure to curtailed hydrogen demand

DEFINITION	This benefit indicator (B5) measures the reduction of curtailed hydrogen demand in a given area due to the implementation of the (group of) project(s).
INDICATOR CALCULATION	This benefit indicator (B5) > Is calculated under consideration of a more stressful weather year than the reference weather year used for the other benefit indicators; > In a first step, the DHEM is used to calculate the curtailed hydrogen demand (HDC) in energetic terms (MWh) for the stressful weather year; > In a second step, the DGM is used to calculate the HDC in energetic terms (MWh) for the stressful weather year; > In a third step, the DHEM is used to calculate the HDC in energetic terms (MWh) for the reference weather year; > In a fourth step, the HDC value provided by the third step is removed from the higher HDC value as provided by the first two steps to remove double-counting with other benefit indicators that use the reference weather year; > Can also be expressed in monetised terms (€/y), by applying assumptions on the CODH, and an assumed frequency of the occurrence of such stressful weather years.
MODEL USED	Dual Hydrogen/Electricity Model (DHEM) and Dual Hydrogen/Natural Gas Model (DGM)
INTERLINKAGE WITH OTHER INDICATORS	No interlinkage, as other benefit indicators are calculated based on the reference weather year and the HDC of the reference weather year is removed from this benefit indicator (B5).

In contrast to the natural gas sector, currently no dedicated EU law exists for the security of hydrogen supply which would set infrastructure standards or prescribe solidarity mechanisms between Member States. This benefit indicator (B5) is therefore less strict than the security of supply assessments that are performed for natural gas and that consider the prolonged unavailability of major supply sources or infrastructures.

While the climate year used for the calculation of the other benefit indicators is supposed to be a representative one, this benefit indicator (B5) is calculated on the basis of another weather year which is more stressful due to

- Lower renewable electricity production (limiting the possibility to produce electrolytic hydrogen) including
  - Onshore and offshore wind profiles,

- PV profiles,
- Water-based profiles; or

> Higher electricity consumption (limiting the availability of electricity for electrolytic hydrogen production), e.g. for heat pumps or air conditioning; or

> A combination of cases described above.

Thereby, the supply and demand stress tests the availability of alternatives like SMR capacities, hydrogen storage capacities, hydrogen import capacities through terminals and pipelines, and inner-EU hydrogen interconnection capacities.

This benefit indicator captures the mitigation of additional hydrogen demand curtailment introduced by the (group of) project(s) for the stressful weather year compared to the reference weather year.

In a first step, the **Hydrogen Demand Curtailment (HDC)** is calculated for the whole assessed duration in energetic terms (MWh) with the DHEM. It can be displayed on node level, country level, EU level, or European level. It can also be displayed in relative terms (%) as **Hydrogen Curtailment Rate (HCR)** for the mentioned levels, representing the share of total demand that is curtailed. The HDC is calculated for the stressful weather year as well as for the reference weather year. For each of the two weather years, the HDC is calculated with and without the (group of) project(s). From this, a reduction of HDC due to the implementation of the (group of) project(s) can be calculated.

$$\begin{aligned}\Delta HDC_{DHEM,stress\ year} &= HDC_{DHEM,European\ Union,stress\ year,with\ (group\ of)\ project(s)} \\ &- HDC_{DHEM,European\ Union,stress\ year,without\ (group\ of)\ project(s)}\end{aligned}$$

Next, the DGM input data is prepared in line with section 2.4.5 and section 2.4.6. Thereby, the input data of the DGM is sourced from the DHEM simulation for the stressful weather year. The only exception is additional natural gas demand that would result from the alternative fuel(s) approach (see section 2.4.5 and section 3.2.5) which is sourced from the DHEM simulation for the reference weather year. This is the case as the alternative fuel(s) approach is based on the reference weather year and end users being supplied with the alternative fuel(s) are not expected to flexibly shift to or away from hydrogen during a stressful weather year. From this data, a reduction of HDC due to the implementation of the (group of) project(s) can be calculated in the DGM.

$$\begin{aligned}\Delta HDC_{DGM,stress\ year} &= (HDC_{DGM,European\ Union,stress\ year,with\ (group\ of)\ project(s)} \\ &- HDC_{DGM,European\ Union,stress\ year,without\ (group\ of)\ project(s)})\end{aligned}$$

When comparing the DHEM and the DGM, both have certain restraints that the other model does not have. The DHEM is using hourly timesteps compared to the monthly timesteps of the DGM. Therefore, peaks of production and consumption show more effect in the DHEM. On the other hand, the DGM includes the restraints of the natural gas system. Thereby, it captures whether sufficient natural gas is available at the desired location(s) to produce hydrogen from it. In the DHEM, the availability of natural gas for this purpose is just assumed to be given. Therefore, depending on the relevance of the described restrains for a given case, one or the other model can show higher benefits from the implementation of a (group of) project(s). Therefore, only the additional benefits provided by the DGM compared to the benefits provided by the DHEM should be considered. This is equivalent to using the maximum of the HDC values provided by the DGM and the DHEM.

Furthermore, a double-counting of HDC reductions that were already considered in the other benefit indicators should be avoided by considering only the additional HDC arising from the stressful weather year. This can be achieved by removing the following HDC reduction that is enabled for the reference weather year.

$$\Delta HDC_{DHEM,reference\ year} = (HDC_{DHEM,European\ Union,reference\ year,with\ (group\ of)\ project(s)} - HDC_{DHEM,European\ Union,reference\ year,without\ (group\ of)\ project(s)})$$

The none-monetised benefit indicator is therefore defined as follows:

$$\Delta HDC_{B5} = MAX(\Delta HDC_{DHEM,stress\ year}; \Delta HDC_{DGM,stress\ year}) - \Delta HDC_{DHEM,reference\ year}$$

This benefit indicator can then be monetised as follows:

$$B5_{monetised} = CODH * \Delta HDC_{B5} * Probability\ of\ occurence$$

On the basis of:

> CODH: Cost of Disrupted Hydrogen (€/MWh).

> Probability of occurrence: Probability of the occurrence of a stressful weather year.

Cost of Disrupted Hydrogen (CODH)

CODH should reflect the potential economic impacts of disruptions in hydrogen supply across Europe, in contrast to the Willingness to Pay (see section 3.2.10), CODH should leave room for an actual producer surplus, the CODH is the price that users would pay to prevent damage to their appliances and/or the price that a user would pay in exceptional situations.

For the TYNDP 2024 PS-CBA process, ENTSOG proposes to assume CODH value as an approximation equal to the electricity prices in a context of tight energy supply and demand balance. CODH will be defined as the maximum value of daily average wholesale electricity prices from 2022 (i.e. 598,1 (€/MWh), for more details see Annex III). **The final value will be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines**.

Stressful weather year and probability of occurrence

For the TYNDP 2024 PS-CBA process, ENTSOG proposes to consider 2012 as the stressful weather year. The related probability of occurrence for the proposed climatic year is estimated as 10% **to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines**.

3.2.12 Environmental impact

Similarly to other energy infrastructure categories, each hydrogen infrastructure has an impact on its surroundings. This impact is of particular relevance when crossing some environmentally sensitive areas, such as Natura 2000[45], namely on biodiversity.

Mitigation measures are taken by the promoters to reduce or even fully mitigate this impact and comply with the EU EIA Directive [46] and European Commission Biodiversity Strategy.

In order to give a comparable measure of project effects, the fields described in the table are to be filled in by the promoter as an obligatory requirement.

Table 4: Minimum set of information to be included in the TYNDP 2024 PS-CBA assessment phase regarding the environmental impact of a hydrogen projects.

Project	Type of infrastructure	Surface of impact	Environment-ally sensitive area	Potential impact	Mitigation measures	Related costs included in project CAPEX and OPEX per year	Justification of costs
Section 1							
Section 2							

Where:

- The section of the project may be used to geographically identify the concerned part of the project (e.g., section point A to point B of the project routing)
- Type of infrastructure identifies the nature of the section (e.g., compressor station, hydrogen transmission pipeline, etc.)
- Surface of impact is the area covered by the section in linear meters and nominal diameter for pipe, as well as in square meters. This last value should not be used for comparison as it may depend on the national framework
- Environmentally sensitive area(s) in which the project is built, such as Natura 2000, as described in the relevant legislations (including where possible the quantification of the concerned surface)
- Potential impact, as the potential consequence on the environmentally sensitive area arising from the realisation of the concerned project

[45] https://ec.europa.eu/environment/nature/natura2000/index_en.htm
[46] EIA Directive (Council Directive 2011/92/CE)

- Mitigation measures, that are the actions undertaken by the promoter to compensate or reduce the impact of the section (e.g., as referred to in the Environmental Impact Assessment prepared by the promoter or National Competent Authority)
- Related costs: Expected related CAPEX and OPEX per year which must be part of the CAPEX and OPEX used for the calculation of the economic performance indicators. Promoters are required to also provide adequate justification of these costs (see Table 4).
- Residual costs: Qualitative or quantitative description, in case the submitted project CAPEX and OPEX do not include the cost of mitigation measures required for the project implementation.
- Qualitative or quantitative information about any other environmental impact not listed above.

3.2.13 Climate adaption measures

Hydrogen infrastructure is usually long-lasting and may be exposed for many years to a changing climate with increasingly adverse and frequent extreme weather and climate impacts. For this reason, in the TYNDP 2024 PS-CBA process, ENTSOG recommends project promoters to assess climate vulnerability and identify the related climate risks as part of the project assessment. In line with the European Commission 'Technical Guidance on the climate proofing of infrastructure in the period 2021-2027', ENTSOG recommends that promoters integrate the assessment of climate vulnerability and related risk assessment from the beginning of the project development process.

Figure 17: Overview of the climate adaptation-related process (source: Technical guidance on the climate proofing of infrastructure in the period 2021-2027, European Commission)

As described in the figure above, project promoters are asked to identify potential climate risks may impact the project and evaluate the related risks based on the sensitivity, exposure and vulnerability analysis. If promoters identified significant climate risk, they should provide a climate risk assessment and impact analysis, including the identification of climate adaptation measures that will be included in the project cycle. Climate adaptation measures are defined as *"a process that ensures that resilience to the potential adverse impacts of climate change of energy infrastructure is achieved through a climate vulnerability and risk assessment, including through relevant adaptation measures"* in the TEN-E Regulation. Climate adaptation measures include all adaptations to an investment to cope with possible (predicted) future extreme weather events due to climate change. This could include flooding, extreme heat or extreme cold, hurricanes, thunderstorms, etc.

3.2.14 Project costs

Costs represent an inherent element of a PS-CBA analysis. According to Annex V (8) of the TEN-E Regulation, the CBA "*shall, at least, take into account the following costs: capital expenditure, operational and maintenance expenditure costs, as well as the costs induced for the related system over the technical lifecycle of the project as a whole, such as decommissioning and waste management costs, including external costs*".

Investment costs are therefore classified[47] by:

> Capital expenditure (CAPEX)
- **Initial investment cost**, that corresponds to the cost effectively incurred by the promoter to build and start operation of the concerned infrastructure. CAPEX should consider the costs related to obtaining permits, feasibility studies, obtaining rights-of-

[47] This classification is in line with the EC Guide to Cost-Benefit Analysis of Investment Projects (https://jaspers.eib.org/LibraryNP/EC%20Reports/Economic%20Appraisal%20Vademecum%202021-2027%20-%20General%20Principles%20and%20Sector%20Applications.pdf).

way, groundwork, preparatory work, designing, equipment purchase, equipment installation and decommissioning.

- **Replacement costs** are the costs borne to ensure that the infrastructure remains operational, over the project assessment period, by changing specific parts of it.
- Costs already incurred at the time of running the project cost-benefit analysis should be generally considered in the assessment, while in case of expansion projects only the costs related to the expansion should be taken into account since the costs incurred before already allowed the project to be functional.

> **Operational and maintenance expenditure** (OPEX) corresponds to costs that are incurred after the commissioning of an asset and which are not of an investment nature, such as direct operating and maintenance costs, administrative and general expenditures, etc.

Where a part of the OPEX is calculated by the model, e.g., energy costs[48], it is already included in the calculated benefits. When calculating the economic performance indicators, to avoid double-counting of these costs, either i) the respective part of the OPEX included in the model must be removed from the benefits, or ii) the respective part of the OPEX as submitted directly by the project promoter must be excluded from the costs. **This choice is to be made following the results of the TYNDP 2024 Implementation Guidelines public consultation.**

All cost data should be considered at constant (real) prices. As part of the TYNDP 2024, constant (real) prices shall refer to 2024.

Unit investment costs for hydrogen infrastructure may be used for comparison. ACER is required to establish such unit investment costs based on Article 11(9) of the TEN-E Regulation.

[48] Example: In the DHEM, the injection into hydrogen storages is associated with a consumption of energy. For the consumed energy, the actual market clearing price is assumed in the model. Thereby, these energy costs are already included in the benefit indicators.

4. Economic performance indicators

4.1 Introduction and general rules

Economic performance indicators are based on project costs as well as the part of the benefits that are monetised. Economic performance indicators are sensitive to the assessment period, residual value, and the retained socio-economic discount rate and therefore to the distribution of benefits and costs over the assessment period. In order to ensure consistent and comparable results, it is important to use consistent economic parameters for each PS-CBA.

For the TYNDP 2024 PS-CBA process, ENTSOG proposes two different economic performance indicators: The Economic Net Present Value (ENPV) and the Economic Benefit-to-Cost Ratio (EBCR).

As described in the section 3, the TYNDP 2024 PS-CBA is using a multi-criteria analysis, on the basis that not all benefits of projects can be monetised. For this reason, the economic performance indicators only represent a part of the balance between project costs and benefits.

For the calculation of economic performance indicators, costs and benefits for each investment are to be represented annually.

The year of commissioning is the year that the investment is expected to come into first operation. The benefits are accounted for from the first full operational year after commissioning.

To evaluate projects on a common basis, benefits should be aggregated across the years as detailed in section 4.2. Since not every year is modelled, benefits and costs must thereby be interpolated. Concerning the interpolation of benefits, the interpolation should be performed on the basis of the quantified benefits that are not yet monetised. The monetisation should then be performed based on yearly monetisation factors that may be based on interpolations between years for which a monetisation factor is available.

To assess a project that is comprised of multi-phase investments[49], the annualised benefits and OPEX for the project are accounted for from the commissioning of the first investment.

For any group of projects, also if consisting of different infrastructure categories, the economic performance indicators should be jointly calculated with the full cost and monetised benefits

[49] Multi-phase investments projects are composed of two or more sequential phases, where the first phase is required for the realization of the following phases (e.g., extension and capacity increase of reception terminal, capacity increase of import route, extension and capacity increase of an hydrogen storage, etc.).

of the whole group. This means that the monetised benefits calculated for the group will be coupled with the sum of costs of all grouped projects. The resulting economic performance indicator is then valid for the whole group of projects.

4.2 Economic parameters

Constant (real) prices

In order to ensure transparency and comparability, the analysis of socio-economic benefits and costs will be carried out at **constant (real) prices**, i.e., considering fixed prices at a base year[50]. By doing so, one neutralises the effect of inflation for all projects.

For the TYNDP 2024 PS-CBA process, constant prices shall refer to 2024.

Social discount rate

The concept of a social discount rate corresponds to the rate that ensures the comparability of benefits and costs incurred at different points in time. The social discount rate is applied to economic benefits and costs of the project (both CAPEX and OPEX). It allows the consideration of the time value of money.

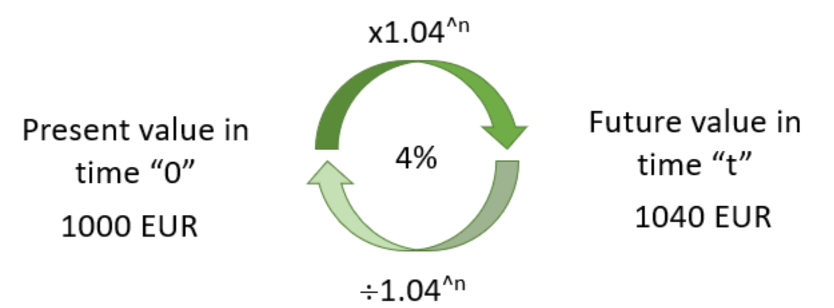

Figure 18: Example of how the social discount rate works.

The social discount rate can be interpreted as the minimum profitability that should be reached by an infrastructure project to achieve net economic benefits. This discount rate thereby represents the weight that society attributes to benefits, with future benefits having a lower value than present ones.

To provide a fair basis for the comparison of projects, unbiased by the location of the projects, **a singular social discount rate of 4% is used for all PS-CBA.**

[50] In order to ensure consistency throughout the time horizon, the already incurred costs (investment) shall be considered as constant prices for the year of occurrence.

Assessment period

It is important to consider when estimating the reference period for hydrogen projects, that these projects are expected to produce benefits in the long term, as hydrogen infrastructure is currently at early stages of implementation.

A project's economic life is defined as the expected time during which the project remains useful (i.e., capable of providing goods/services) to the promoter, and it could be different than the physical or technical life of the project.

For the TYNDP 2024 PS-CBA an **assessment period of 25 years as a default case**. This reference assessment period is in principle retained for all projects assessed to ensure comparability in the analysis of the results. In addition, in the case that the technical lifetime of the asset is shorter than 25 years, the economic analysis will be performed based on the technical lifetime of the asset.

Residual value

For the TYNDP 2024 PS-CBA process, ENTSOG proposes to assess projects **without residual value**.

Cash flow interpolation

For the economic performance indicators and based on project-specific benefit indicator results for simulated years, the economic cash flow for each year will be calculated in the following way:

- From the first full year of operation until the next simulated year the monetised benefits are considered equal to the monetised benefits of the simulated year
- The monetised results as coming from the simulations and used to build the economic performance indicators will be **linearly interpolated** between two simulated years (e.g., n+10 and n+20)
- The monetised benefits will be kept constant until the 24th year of life of the project after the last simulated year (or less if the technical lifetime of the asset is less than 25 years)
- The assessment of all the projects considers the same year of analysis (*n*) and takes into consideration an assessment period of 25 years (or less if the technical lifetime of the asset is less than 25 years). For example, projects may be commissioned in 2029 or 2033, and their benefits and costs will be considered for the following 25 years but all projects are discounted in the same year (i.e., 2024) as follows:

Figure 19: Representation of economic cash flow assessment in case of projects to be commissioned between two assessed years (here: reference case of 25 years assessment period).

For multi-phase projects or a group of projects the benefits will be counted according to the year of the first phase (of the first project) to be commissioned. This allows consideration of projects or a group of projects where the implementation of the first phase (of the first project) already brings benefits and contributes as enhancer to the other phases/projects of the group.

4.3 Economic performance indicator 1: Economic Net Present Value (ENPV)

The Economic Net Present Value (ENPV) is the difference between the discounted monetised benefits and the discounted costs expressed in constant (real) terms for the basis year (i.e., 2024) of the analysis (i.e., discounted economic cash-flow of the project). The ENPV reflects the performance of a project in absolute values.

If the ENPV is positive the project generates a net monetary benefit and it is favourable from a socio-economic perspective.

$$\mathrm{ENPV} = \sum_{t=f}^{c+24} \frac{B_t - C_t}{(1+r)^{t-n}}$$

Whereas:

- *t:* Overall appraisal period.
- *f:* First year where costs are incurred.
- *c:* First full year of operation.
- B_t: Sum of all monetised benefits induced by the (group of) project(s) on year *t*.
- C_t: Sum of CAPEX and OPEX on the year *t.*
- *n:* Year of analysis (i.e., 2024).
- *r*: Social Discount Rate (i.e., 4%)

4.4 Economic performance indicator 2: Economic Benefit-to-Cost Ratio (EBCR)

The Economic Benefit-to-Cost Ratio (EBCR) represents the ratio between the discounted monetised benefits and the discounted costs. It is the present value of project benefits divided by the present value of project costs.

$$\mathrm{EBCR} = \frac{\sum_{t=f}^{c+24} \frac{B_t}{(1+r)^{t-n}}}{\sum_{t=f}^{c+24} \frac{C_t}{(1+r)^{t-n}}}$$

Whereas:

- *t*: Overall appraisal period.
- *f*: First year where costs are incurred.
- *c*: First full year of operation.
- B_t: Monetised benefits induced by the (group of) project(s) on year t.
- C_t: Sum of CAPEX and OPEX on the year t.
- *n*: Year of analysis (i.e., 2024).
- *r*: Social Discount Rate (i.e., 4%)

If the EBCR exceeds 1, the (group of) project(s) is considered as economically efficient as the monetised benefits outweigh the costs over the assessment period. This indicator has the advantage of not being influenced by the size of projects, not disadvantaging small ones. This economic performance indicator should therefore be seen as complementary to the ENPV and as a way to compare projects of different sizes with different levels of costs and benefits.

This economic performance indicator allows the comparison of projects even in case of an EBCR lower than 1. It is not appropriate for mutually exclusive projects. Being a ratio, the indicator does not consider the total amount of net benefits and therefore a comparison of (groups of) project(s) can reward more (groups of) project(s) that contribute less to the overall increase in public welfare as described in the example below.

Example: Comparison of the EBCR for two project groups:	
Project group A (higher ENPV): Total discounted benefits: 9.863 (M€) Total discounted costs: -6.865 (M€) EBCR: 1,44	Project group B (lower ENPV): Total discounted benefits: 1.146 (M€) Total discounted costs: -796 (M€) EBCR: 1,44

5. Sensitivity analyses

Sensitivity analyses can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the PS-CBA results. This provides a deeper understanding of the system's behaviour with respect to the chosen parameter or interlinked parameters.

The following list is not exhaustive and provides some examples of parameters proposed for potential sensitivities that could be implemented for TYNDP 2024 PS-CBA process.

- Societal cost of carbon: A sensitivity study could be performed in which the societal cost of carbon is varied.
  - No new simulations are required. Instead, the GHG emissions variations indicator (B1) can be monetised with the alternative societal cost of carbon. This can also influence the economic performance indicators.
- Damage cost of non-GHG emissions: A sensitivity study could be performed in which the damaged cost is varied between the consideration of VSL damage cost and the VOLY damage cost of non-GHG emissions.
  - No new simulations are required. Instead, the non-GHG emissions variations indicator (B2) can be monetised with the alternative damage cost of non-GHG emissions. This can also influence the economic performance indicators.
- Sensitivities on project-specific data should be reflected in the CBA. This relates to
  - CAPEX and OPEX:
    - Sensitivities on costs will be calculated considering the higher and lower CAPEX and OPEX ranges provided by project promoters during the TYNDP 2024 project submission.
    - No new simulations are required. Such sensitivity will not influence the benefit indicators, but the economic performance indicators can be influenced.
  - Inclusion of avoided decommissioning cost of natural gas infrastructure for repurposing to hydrogen infrastructure:
    - No new simulations are required. Such sensitivity will not influence the benefit indicators, but the economic performance indicators can be influenced.
  - 40 years of assessment period instead of 25 years:
    - No new simulations are required. Such sensitivity would extend the benefit indicators as well as the project costs in time. This can influence the economic performance indicators.

- For the cash flow interpolation of (groups of) project(s) for which 2030 and 2040 is modelled, i) the trend of the interpolated benefit development between the two modelled years is continued after 2024, and ii) the benefit is considered at the 2040 value for all assessed years after 2030.[51]
    - No new simulations are required. Such sensitivity would influence the benefit indicators for non-modelled years and thereby can influence the economic performance indicators.

[51] As for projects that are planned to be commissioned after 2029 only 2040 is modelled, these sensitivities may make such projects' benefits and economic performance indicators more comparable with projects that are planned to be commissioned by 2029.

6. Implementation of the energy efficiency first principle

In the energy efficiency first principle guidelines that are annexed to the European Commission Recommendation (EU) 2021/1749 of 28 September 2021[52], the principle's application in the TYNDP is detailed as follows:

- *"The TEN-E [Regulation] includes the EE1st principle in all the stages of the European ten-Year Network Development Plans development, more specifically in the scenario development, infrastructure gaps identification and projects assessment. […] The practical implication of the EE1st principle in the planning means that the infrastructure development must include within the decisional process options to better utilise the existing infrastructure (by operational mechanisms), implement more energy-efficient technologies, and make better use of the market mechanisms such as, but not exclusive to, demand-side response. […] When implementing the EE1st principle, one must strive to reach the balance between secure and reliable energy supply, quality of energy supplied and overall associated costs […]."*

Annex III.2(12) of the TEN-E Regulation thereby lists four priority solutions for the application of the energy efficiency first principle that should be considered instead of the construction of new supply side infrastructure, if considered more cost-efficient from a system wide perspective: i) Demand-side management; ii) market arrangement solutions; iii) implementation of digital solutions; iv) renovation of buildings.

The mentioned concepts are thereby partially overlapping and are required to be interpreted in the context of the TYNDP 2024 PS-CBA:

- The support study[53] of the quoted European Commission Recommendation states that demand side management includes two parts: energy efficiency and demand response. Energy efficiency is understood to contain renovation of buildings.
- Market arrangement solutions and market mechanisms are understood as the respective energy market design which is captured in the market behaviour and assumptions of the model. It includes demand side response (based on demand side resources) which is understood as the option that demand can be optimised on the
  - end user level: e.g., hybrid heat pumps shifting demand between sectors based on temperature-related efficiencies and prices, or demand of certain end users being shifted into more favourable time steps, or the demand of certain end

52 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32021H1749
53 https://op.europa.eu/en/publication-detail/-/publication/b9cc0d80-c1f8-11eb-a925-01aa75ed71a1/language-en/format-PDF/source-292832016

users being subject of demand side response due to a trigger like a certain energy price;
    - conversion level: e.g., electrolyser usage based on prices, conversion efficiencies, and energy availabilities in the sectors.
- Digital solutions are understood both as technologies enabling the optimised behaviour of end users as well as technologies that enable better utilisation of existing infrastructure by operational mechanisms.

6.1 Consideration of the energy efficiency first principle in the NT+ scenario development

In the NT+ scenario, the energy efficiency first principle was considered in the following ways:

- Inclusion of options for better utilisation of existing infrastructure
    - The existing infrastructure considered in the scenario topology is updated for each scenario cycle with information that is provided by the infrastructure operators and/or publicly consulted. This provides the option to update the underlying energy infrastructure capacities. The capacities are the main parameter capturing the ability of better utilisation through operational improvements, including by digital solutions. Additionally, the consideration of infrastructure of multiple energy sectors like hydrogen and electricity allows an optimisation of the utilisation of the existing infrastructure's capacities in the model, through flexibility provisions across energy sectors.
- Inclusion of options to include more energy-efficient technologies
    - The NT+ scenario is developed on an NECP-based scenario storyline. Within the NT+ scenario development, energy-efficient technologies are set at ambitious levels based on the NECPs, EU energy and climate targets, or infrastructure operator inputs in combination with stakeholder consultations. The renovation of buildings is also included in the set of assumptions at a highly ambitious level.
- Inclusion of options to make better use of the market mechanisms
    - By considering perfect competition only limited by infrastructure constraints between zones being represented as nodes (e.g., hydrogen zone 1 of a country, hydrogen zone 2 of a country, or individual electricity bidding zones) as well as by allowing demand side response to be acting without infrastructure or market restrictions (e.g., if the demand side response is located at DSO level) within a whole zone, the market behaviour is optimistic regarding the effects of demand side management. Several demand side responses are thereby considered like optimised utilisation of :

  - assets coupling the sectors through conversion (i.e., electrolysers and hydrogen-fired power plants);
  - demand shedding (e.g., reduction of industrial demand for a limited time that is triggered by a certain market clearing price).

> Aiming at balancing security of supply, quality of energy supplied, and cost-efficiency
  - The wider benefits of investments including energy efficiency measures and infrastructure developments are addressed from a system efficiency perspective within the scenario modelling by
    - monetising unserved energy demand (i.e., VoLL and CODH);
    - including adequacy loops;
    - penalising energy losses contributing negatively to life cycle efficiencies (e.g., reflection in marginal costs of fuels, conversion losses of electrolysers, conversion losses of power plants, efficiencies of energy storages);
    - penalising of emissions (e.g., cross-checking with the EU's legal energy and climate targets and reflection in marginal costs of fuels).
  - In line with the energy efficiency first principle, the most energy efficient solution does not have to prevail but should be considered within the decision making process and be preferred if being similarly cost-efficient, and beneficial for security of supply.

6.2 Consideration of the energy efficiency first principle in the PS-CBA process

> Inclusion of options for better utilisation of existing infrastructure
  - The existing infrastructure considered in the TYNDP 2024 topology is updated with information that is provided by the infrastructure operators. This provides the option to update the underlying energy infrastructure capacities which are the main parameter capturing the ability of better utilisation through operational improvements, including by digital solutions. Also, the consideration of infrastructure of multiple energy sectors like hydrogen, electricity, and natural gas allows an optimisation of the utilisation of the existing infrastructure's capacities in the model through flexibility provisions across energy sectors.

> Inclusion of options to include more energy-efficient technologies
  - The PS-CBA is performed on the basis of the NT+ scenario that includes energy efficiency measures as described in the previous section. Thereby, a decisive share of the measures (e.g., renovations of buildings) have been set at the

highest level that can be considered as feasible and realistic under current targets, policies, and expected technological advancements. Thereby, in line with the energy efficiency first principle, the most energy efficient solution does not have to prevail but should be considered within the decision making process and be preferred if being similarly cost-efficient, and beneficial for security of supply. By already being part of the NT+ scenario, the selected energy efficiency measures are not associated with additional investments in the PS-CBA exercise and their usage is always an option alongside the assessment of hydrogen infrastructure investments.

- Inclusion of options to make better use of the market mechanisms
  - By considering perfect competition only limited by infrastructure constraints between nodes, as well as by allowing demand side response to be acting without infrastructure or market restrictions (e.g., if the demand side response is located at DSO level) within a whole zone, the market behaviour is optimistic regarding the effects of demand side management. Several demand side responses are therefore considered. The pattern of the total demand is not simply transferred from the NT+ scenario to the TYNDP, but the underlying assets are considered to be used within their specifications to allow their optimised utilisation.
  - Concerning the DHEM-based assessments, this relates to
    - assets coupling the sectors through conversion (i.e., electrolysers and hydrogen-fired power plants);
    - demand shedding (e.g., reduction of industrial demand for a limited time that is triggered by a certain market clearing price).
  - Concerning the DGM-based assessments, this relates to
    - the calculation of monthly profiles for the DGM, which is not only a simplification, but also assumes the possibility of significant temporal flexibility of natural gas and hydrogen demand, interpretable as demand-shifting possibilities within a sector and/or additional availability of storage options and/or further optimisation of existing infrastructure's utilisation. This prioritises all relevant alternatives to new infrastructure, while being agnostic concerning the actual solution;
    - assets coupling the sectors through conversion (i.e., hydrogen production from natural gas);
    - the model being allowed to investigate the optimal solution for each stress case with several degrees of freedom (i.e., usage of hydrogen supply sources and natural gas supply sources).
- Aiming at balancing security of supply, quality of energy supplied, and cost-efficiency

- The wider benefits of investments are addressed from a system efficiency and societal perspective.
- Concerning the DHEM-based assessments, this relates to
  - monetising unserved energy demand (i.e.., VoLL and CODH);
  - penalising energy losses contributing negatively to life cycle efficiencies (e.g., reflection in marginal costs of fuels, conversion losses of electrolysers, conversion losses of power plants, efficiencies of energy storages);
  - assessing indicators covering both the electricity sector and the hydrogen sector;
  - penalising of emissions (e.g., reflection in marginal costs of fuels, reflection in relevant indicators).
- Concerning the DGM-based assessments, this relates to
  - monetising unserved energy demand (e.g., CODH);
  - penalising energy losses contributing negatively to life cycle efficiencies and emissions (e.g., conversion losses of hydrogen production from natural gas, reflection in merit order);
  - assessing indicators based on both the natural gas sector and the hydrogen sector.

ANNEX I: List of projects conforming hydrogen and natural gas infrastructure levels

List of hydrogen projects included in the PCI/PMI hydrogen infrastructure level[54]:

Code	*Project Name*	*Country*	*Promoter*	*Maturity Status*	*Project Commissioning Year First*	*Project Commissioning Year Last*
H2T-F-899	**mosaHYc - Mosel Saar Hydrogen Conversion**	France	GRTgaz	FID	2027	2027
H2T-A-987	**mosaHYc (Mosel Saar Hydrogen Conversion) - Germany**	Germany	Creos Deutschland Wasserstoff GmbH	Advanced	2027	2027
H2T-A-986	**H2 Readiness of the TAG pipeline system**	Austria	Trans Austria Gasleitung GmbH	Advanced	2028	2029
H2T-A-1205	**Italian H2 Backbone**	Italy	Snam Rete Gas S.p.A.	Advanced	2029	2029
H2T-A-642	**HyPipe Bavaria – The Hydrogen Hub**	Germany	bayernets GmbH	Advanced	2029	2029
H2T-A-757	**H2 Backbone WAG + Penta West**	Austria	GAS CONNECT AUSTRIA GmbH	Advanced	2029	2029
H2T-A-1001	**Danish-German Hydrogen Network; German Part - HyPerLink Phase III**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2028	2035
H2T-A-1236	**DK Hydrogen Pipeline, West DK Hydrogen System**	Denmark	Energinet	Advanced	2028	2035
H2T-A-788	**H2 transmission system in Bulgaria**	Bulgaria	Bulgartransgaz EAD	Advanced	2029	2029
H2T-N-970	**Internal hydrogen infrastructure in Greece towards the Bulgarian border**	Greece	DESFA S.A.	Less-Advanced	2029	2029
H2T-A-1136	**Nordic Hydrogen Route – Bothnian Bay – Finnish section - Pipeline**	Finland	Gasgrid Finland Oy	Advanced	2029	2029
H2T-A-1171	**Nordic Hydrogen Route - Bothnian Bay- Swedish section - Pipeline**	Sweden	Nordion Energi AB	Advanced	2029	2029
H2T-A-443	**Nordic-Baltic Hydrogen Corridor - FI section - Pipeline**	Finland	Gasgrid Finland Oy	Advanced	2029	2029
H2T-A-1144	**Nordic-Baltic Hydrogen Corridor - PL section**	Poland	GAZ-SYSTEM S.A.	Advanced	2029	2039
H2T-A-1280	**Nordic-Baltic Hydrogen Corridor - LV section**	Latvia	Conexus Baltic Grid, JSC	Advanced	2029	2029
H2T-N-1122	**Nordic-Baltic Hydrogen Corridor - EE section**	Estonia	Elering AS	Less-Advanced	2029	2029
H2T-N-1239	**Nordic-Baltic Hydrogen Corridor - LT section**	Lithuania	AB Amber Grid	Less-Advanced	2029	2050
H2T-N-1310	**Nordic-Baltic Hydrogen Corridor - DE section**	Germany	ONTRAS Gastransport GmbH	Less-Advanced	2029	2029
H2T-F-468	**National H2 Backbone**	Netherlands	N.V. Nederlandse Gasunie	FID	2026	2035
H2L-A-754	**ACE Terminal**	Netherlands	N.V. NEDERLANDSE GASUNIE	Advanced	2027	2027
H2S-A-767	**RWE H2 Storage expansion Gronau-Epe**	Germany	RWE Gas Storage West GmbH	Advanced	2028	2028
H2T-A-906	**Vlieghuis - Ochtrup**	Germany	Thyssengas GmbH	Advanced	2026	2029
H2T-A-1035	**Franco-Belgian H2 corridor**	France	GRTgaz	Advanced	2028	2034
H2T-A-1037	**H2ercules Network North**	Germany	Open Grid Europe GmbH	Advanced	2027	2029
H2T-A-1038	**H2ercules Network West**	Germany	Open Grid Europe GmbH	Advanced	2028	2028
H2S-A-1279	**Hystock Opslag H2**	Netherlands	N.V.Nederlandse Gasunie	Advanced	2028	2034
H2T-A-1311	**Belgian Hydrogen Backbone**	Belgium	Fluxys Hydrogen	Advanced	2026	2045
H2L-N-664	**Antwerp NH3 Import Terminal**	Belgium	Fluxys	Less-Advanced	2029	2029
H2L-N-820	**Dunkerque New Molecules development**	France	Fluxys	Less-Advanced	2034	2034
H2T-N-884	**CHE Pipeline**	Norway	Equinor ASA and Gassco AS	Less-Advanced	2030	2030
H2L-N-968	**Green Wilhelmshaven Terminal/Storage/Cracker**	Germany	Uniper Hydrogen GmbH	Less-Advanced	2029	2029

[54] More details on PCI/PMI hydrogen projects can be found in the TYNDP 2024 Annex A – List of projects (link)

H2T-N-991	**AquaDuctus**	Germany	GASCADE Gastransport GmbH	Less-Advanced	2029	2030
H2L-N-1099	**Ammonia Import Terminal Brunsbüttel**	Germany	RWE Supply & Trading GmbH	Less-Advanced	2030	2030
H2L-N-1159	**bp Wilhelmshaven Green Hydrogen Hub**	Germany	BP Europa SE	Less-Advanced	2028	2028
H2L-N-1325	**Zeebrugge New Molecules development**	Belgium	Fluxys	Less-Advanced	2032	2032
H2T-N-796	**FLOW - Making Hydrogen Happen (East)**	Germany	GASCADE Gastransport GmbH	Less-Advanced	2025	2035
H2T-A-1355	**Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland**	Finland	Gasgrid Finland Oy	Advanced	2029	2031
H2T-A-969	**RHYn**	France	GRTgaz	Advanced	2029	2033
H2T-A-1096	**RHYn Interco**	Germany	terranets bw GmbH	Advanced	2029	2029
H2S-A-508	**H2 storage North-1**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2029
H2S-A-565	**GeoH2**	France	Géométhane	Advanced	2029	2029
H2T-A-978	**Portuguese Hydrogen Backbone**	Portugal	REN - Gasodutos, S.A.	Advanced	2029	2029
H2T-A-1052	**H2ercules Network South-West**	Germany	Open Grid Europe GmbH, GRTgaz Deutschland GmbH	Advanced	2029	2029
H2T-A-1149	**Spanish Hydrogen Backbone 2030**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2029
H2S-A-1152	**H2 storage North-2**	Spain	Enagás Infraestructuras de Hidrógeno	Advanced	2029	2029
H2T-A-1156	**H2Med/CelZa**	Portugal	REN - Gasodutos, S.A.	Advanced	2029	2029
H2T-N-569	**HY-FEN – H2 Corridor Spain – France – Germany connection**	France	GRTgaz	Less-Advanced	2029	2030
H2T-N-1151	**H2Med-BarMar**	Spain	Enagás Infraestructuras de Hidrógeno/Terega/GRTgaz/Open Grid Europe	Less-Advanced	2029	2029
H2T-N-1324	**H2Med-CelZa (Enagás)**	Spain	Enagás Infraestructuras de Hidrógeno	Less-Advanced	2029	2029
H2T-A-1034	**Czech H2 Backbone WEST**	Czechia	NET4GAS,s.r.o.	Advanced	2029	2029
H2T-A-926	**Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Sweden**	Sweden	Nordion Energi AB	Advanced	2029	2029
H2S-A-1238	**DK Hydrogen Storage**	Denmark	Energinet	Advanced	2027	2027
H2L-N-543	**LH2.Rotterdam**	Netherlands	Vopak LNG Holding B.V.	Less-Advanced	2028	2028
H2S-N-934	**SaltHy Harsefeld**	Germany	Storengy Deutschland GmbH	Less-Advanced	2030	2030
H2L-N-1100	**Amplifhy Antwerp**	Belgium	VTTI Terminal Support Services (“VTTI”)	Less-Advanced	2028	2035
H2L-N-1127	**Amplifhy Rotterdam**	Netherlands	VTTI Terminal Support Services (“VTTI”)	Less-Advanced	2028	2035

Capacities increments related to PCI/PMI hydrogen projects:

Code	Project Name	Promoter	From System	To System	Comm. Year	Capacity (GWh/d)*
H2T-A-1096	RHYn Interco	terranets bw GmbH	Transmission Germany	Final Consumers Germany	2029	12,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	NP Send-out Netherlands (NL Hydrogen Transport)	Transmission Netherlands (NL Hydrogen)	2029	0,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2025	2,400
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2027	36,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2030	72,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2035	384,000
H2T-N-991	AquaDuctus	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2029	240,000
H2T-N-991	AquaDuctus	GASCADE Gastransport GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2030	240,000
H2T-A-1149	Spanish Hydrogen Backbone 2030	Enagás Infraestructuras de Hidrógeno	NP Send-out Spain (ES Hydrogen Transport)	Transmission Spain (ES Hydrogen)	2029	426,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	NP Send-out Lithuania (LT Hydrogen Transport)	Transmission Lithuania (LT Hydrogen)	2029	15,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	NP Send-out Lithuania (LT Hydrogen Transport)	Transmission Lithuania (LT Hydrogen)	2040	15,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	NP Send-out Lithuania (LT Hydrogen Transport)	Transmission Lithuania (LT Hydrogen)	2050	25,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Interconnector United Kingdom (UK Hydrogen)	Transmission Belgium (BE Hydrogen)	2032	96,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Interconnector United Kingdom (UK Hydrogen)	Transmission Belgium (BE Hydrogen)	2045	144,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Interconnector United Kingdom (UK Hydrogen)	2032	96,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Interconnector United Kingdom (UK Hydrogen)	2045	144,000
H2T-A-443	Nordic-Baltic Hydrogen Corridor - FI section - Pipeline	Gasgrid Finland Oy	Transmission Estonia (EE Hydrogen)	Transmission Finland (FI Hydrogen South)	2029	100,000
H2T-A-443	Nordic-Baltic Hydrogen Corridor - FI section - Pipeline	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen South)	Transmission Estonia (EE Hydrogen)	2029	200,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (TTF)	Transmission Belgium (H-Zone)	2026	-141,600
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2026	96,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2026	96,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Belgium (BE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2026	36,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Belgium (BE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	84,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Belgium (BE Hydrogen)	2026	36,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Belgium (BE Hydrogen)	2029	84,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2026	16,800
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	14,400

H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2026	16,800
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	14,400
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	76,800
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	76,800
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	76,800
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	76,800
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission Germany (NCG)	Transmission France (NS1)	2029	-310,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission Germany (DE Hydrogen)	Transmission France (FR Hydrogen)	2029	192,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France (FR Hydrogen)	Transmission Germany (DE Hydrogen)	2029	192,000
H2T-A-642	HyPipe Bavaria – The Hydrogen Hub	bayernets GmbH	Transmission Austria (CEGH)	Transmission Germany	2029	-150,000
H2T-A-642	HyPipe Bavaria – The Hydrogen Hub	bayernets GmbH	Transmission Germany	Transmission Austria (CEGH)	2029	-150,000
H2T-A-642	HyPipe Bavaria – The Hydrogen Hub	bayernets GmbH	Transmission Austria (AT Hydrogen)	Transmission Germany (DE Hydrogen)	2029	150,000
H2T-A-642	HyPipe Bavaria – The Hydrogen Hub	bayernets GmbH	Transmission Germany (DE Hydrogen)	Transmission Austria (AT Hydrogen)	2029	150,000
H2L-A-754	ACE Terminal	N.V. NEDERLANDSE GASUNIE	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2027	48,700
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Germany (NCG)	Transmission Austria (CEGH)	2029	-47,000
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Austria (CEGH)	Transmission Germany (NCG)	2029	-142,000
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Germany (DE Hydrogen)	Transmission Austria (AT Hydrogen)	2029	150,000
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Austria (AT Hydrogen)	Transmission Germany (DE Hydrogen)	2029	150,000
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Slovakia (SK Hydrogen) (SK West)	Transmission Austria (AT Hydrogen)	2029	150,000
H2T-A-757	H2 Backbone WAG + Penta West	GAS CONNECT AUSTRIA GmbH	Transmission Austria (AT Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK West)	2029	150,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	Transmission Czechia (CZ Hydrogen)	Transmission Germany (DE Hydrogen)	2029	144,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2035	153,600
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	Transmission Finland (FI Hydrogen Aland)	Transmission Germany (DE Hydrogen)	2029	262,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Denmark (DK Hydrogen Bornholm Transport)	Transmission Germany (DE Hydrogen)	2028	18,000
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Denmark (DK Hydrogen Bornholm Transport)	Transmission Germany (DE Hydrogen)	2030	27,600
H2T-N-796	FLOW - Making Hydrogen Happen (East)	GASCADE Gastransport GmbH	NP Send-out Denmark (DK Hydrogen Bornholm Transport)	Transmission Germany (DE Hydrogen)	2035	74,400
H2T-N-884	CHE Pipeline	Equinor ASA and Gassco AS	Transmission Norway (Fork NO h2)	Transmission Germany (DE Hydrogen)	2030	432,000
H2T-N-884	CHE Pipeline	Equinor ASA and Gassco AS	Transmission Norway (NO Hydrogen)	Transmission Norway (Fork NO h2)	2030	432,000
H2T-F-899	mosaHYc - Mosel Saar Hydrogen Conversion	GRTgaz	Transmission Germany (DE Hydrogen)	Transmission France (FR Hydrogen)	2027	0,900
H2T-F-899	mosaHYc - Mosel Saar Hydrogen Conversion	GRTgaz	Transmission France (FR Hydrogen)	Transmission Germany (DE Hydrogen)	2027	5,500
H2T-A-906	Vlieghuis - Ochtrup	Thyssengas GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2026	16,800

H2T-A-906	Vlieghuis - Ochtrup	Thyssengas GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	14,400
H2T-A-926	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Sweden	Nordion Energi AB	Transmission Finland (FI Hydrogen Aland)	Transmission Sweden (SE Hydrogen)	2029	504,000
H2T-A-926	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Sweden	Nordion Energi AB	Transmission Sweden (SE Hydrogen)	Transmission Finland (FI Hydrogen Aland)	2029	504,000
H2T-A-969	RHYn	GRTgaz	Transmission France (FR Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000
H2T-A-986	H2 Readiness of the TAG pipeline system	Trans Austria Gasleitung GmbH	Transmission Austria (CEGH)	Transmission Italy (PSV) (Italy Northern Export Fork)	2028	-216,000
H2T-A-986	H2 Readiness of the TAG pipeline system	Trans Austria Gasleitung GmbH	Transmission Italy (PSV) (IB IT h2)	Transmission Austria (AT Hydrogen)	2029	168,000
H2T-A-986	H2 Readiness of the TAG pipeline system	Trans Austria Gasleitung GmbH	Transmission Austria (AT Hydrogen)	Transmission Italy (PSV) (IB IT h2)	2029	126,000
H2T-A-986	H2 Readiness of the TAG pipeline system	Trans Austria Gasleitung GmbH	Transmission Slovakia (SK Hydrogen) (SK West)	Transmission Austria (AT Hydrogen)	2029	126,000
H2T-A-986	H2 Readiness of the TAG pipeline system	Trans Austria Gasleitung GmbH	Transmission Austria (AT Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK West)	2029	142,000
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Czech Republic (VOB)	Transmission Germany (NCG)	2029	-319,500
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Czech Republic (VOB) (Brandov)	Transmission Czech Republic (VOB)	2029	-902,300
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Czechia (CZ Hydrogen)	Transmission Germany (DE Hydrogen)	2029	144,000
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-1034	Czech H2 Backbone WEST	NET4GAS,s.r.o.	Transmission Czechia (CZ Hydrogen)	Transmission Germany (DE Hydrogen)	2029	144,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission Belgium (BE Hydrogen)	Transmission France (FR Hydrogen)	2030	36,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen)	Transmission Belgium (BE Hydrogen)	2030	36,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission Belgium (H-Zone)	Transmission France (NS1)	2030	-45,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission Belgium (BE Hydrogen Mons)	Transmission France (FR Hydrogen Valenciennes)	2028	24,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen Valenciennes)	Transmission Belgium (BE Hydrogen Mons)	2028	24,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission Belgium (BE Hydrogen)	Transmission France (FR Hydrogen North)	2034	48,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen North)	Transmission Belgium (BE Hydrogen)	2034	48,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2027	96,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2027	96,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Transmission Norway (Fork NO h2)	Transmission Germany (DE Hydrogen)	2029	432,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	NP Send-out Germany (DE Hydrogen Electrolysis)	NP Send-out Germany (DE Hydrogen Transport)	2027	136,000
H2T-A-1038	H2ercules Network West	Open Grid Europe GmbH	Transmission Belgium (BE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	91,200
H2T-A-1038	H2ercules Network West	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Transmission Belgium (BE Hydrogen)	2028	91,200
H2T-A-1052	H2ercules Network South-West	Open Grid Europe GmbH, GRTgaz Deutschland GmbH	Transmission France (FR Hydrogen)	Transmission Germany (DE Hydrogen)	2029	192,000
H2T-A-1052	H2ercules Network South-West	Open Grid Europe GmbH, GRTgaz Deutschland GmbH	Transmission Germany (DE Hydrogen)	Transmission France (FR Hydrogen)	2029	192,000
H2T-A-1096	RHYn Interco	terranets bw GmbH	Transmission France (FR Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000

H2T-N-1122	Nordic-Baltic Hydrogen Corridor - EE section	Elering AS	Transmission Finland (FI Hydrogen South)	Transmission Estonia (EE Hydrogen)	2029	200,000
H2T-N-1122	Nordic-Baltic Hydrogen Corridor - EE section	Elering AS	Transmission Estonia (EE Hydrogen)	Transmission Finland (FI Hydrogen South)	2029	100,000
H2T-N-1122	Nordic-Baltic Hydrogen Corridor - EE section	Elering AS	Transmission Latvia (LV Hydrogen)	Transmission Estonia (EE Hydrogen)	2029	100,000
H2T-N-1122	Nordic-Baltic Hydrogen Corridor - EE section	Elering AS	Transmission Estonia (EE Hydrogen)	Transmission Latvia (LV Hydrogen)	2029	200,000
H2T-A-1136	Nordic Hydrogen Route – Bothnian Bay – Finnish section - Pipeline	Gasgrid Finland Oy	Transmission Sweden (SE Hydrogen)	Transmission Finland (FI Hydrogen North)	2029	162,000
H2T-A-1136	Nordic Hydrogen Route – Bothnian Bay – Finnish section - Pipeline	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen North)	Transmission Sweden (SE Hydrogen)	2029	162,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Lithuania (LT Hydrogen)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2029	200,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Lithuania (LT Hydrogen)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2029	100,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Germany (DE Hydrogen)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2029	100,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Poland (PL Hydrogen nordic baltic corridor)	Transmission Germany (DE Hydrogen)	2029	200,000
H2T-A-1149	Spanish Hydrogen Backbone 2030	Enagás Infraestructuras de Hidrógeno	Transmission France (FR Hydrogen South)	Transmission Spain (ES Hydrogen)	2029	216,000
H2T-A-1149	Spanish Hydrogen Backbone 2030	Enagás Infraestructuras de Hidrógeno	Transmission Spain (ES Hydrogen)	Transmission France (FR Hydrogen South)	2029	216,000
H2T-A-1149	Spanish Hydrogen Backbone 2030	Enagás Infraestructuras de Hidrógeno	Transmission Portugal (PT Hydrogen)	Transmission Spain (ES Hydrogen)	2029	81,000
H2T-A-1149	Spanish Hydrogen Backbone 2030	Enagás Infraestructuras de Hidrógeno	Transmission Spain (ES Hydrogen)	Transmission Portugal (PT Hydrogen)	2029	81,000
H2T-N-1151	H2Med-BarMar	Enagás Infraestructuras de Hidrógeno/Terega/GRTgaz/Open Grid Europe	Transmission Spain (ES Hydrogen)	Transmission France (FR Hydrogen South)	2029	216,000
H2T-N-1151	H2Med-BarMar	Enagás Infraestructuras de Hidrógeno/Terega/GRTgaz/Open Grid Europe	Transmission France (FR Hydrogen South)	Transmission Spain (ES Hydrogen)	2029	216,000
H2T-A-1156	H2Med/CelZa	REN - Gasodutos, S.A.	Transmission Spain (ES Hydrogen)	Transmission Portugal (PT Hydrogen)	2029	81,000
H2T-A-1156	H2Med/CelZa	REN - Gasodutos, S.A.	Transmission Portugal (PT Hydrogen)	Transmission Spain (ES Hydrogen)	2029	81,000
H2T-A-1171	Nordic Hydrogen Route - Bothnian Bay- Swedish section - Pipeline	Nordion Energi AB	Transmission Finland (FI Hydrogen North)	Transmission Sweden (SE Hydrogen)	2029	162,000
H2T-A-1171	Nordic Hydrogen Route - Bothnian Bay- Swedish section - Pipeline	Nordion Energi AB	Transmission Sweden (SE Hydrogen)	Transmission Finland (FI Hydrogen North)	2029	162,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Austria (AT Hydrogen)	Transmission Italy (PSV) (IB IT h2)	2029	168,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (IB IT h2)	Transmission Austria (AT Hydrogen)	2029	168,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Switzerland (CH Hydrogen)	Transmission Italy (PSV) (IB IT h2)	2029	88,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (IB IT h2)	Transmission Switzerland (CH Hydrogen)	2029	88,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Italy (IT Hydrogen)	Transmission Italy (PSV) (IB IT h2)	2029	200,000
H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Transmission Germany (DE Hydrogen)	Transmission Denmark (DK Hydrogen)	2028	103,200

H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Transmission Denmark (DK Hydrogen)	Transmission Germany (DE Hydrogen)	2028	103,200
H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Transmission Denmark (Ellund)	Transmission Denmark	2028	-71,000
H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Transmission Denmark	Transmission Denmark (Ellund)	2028	-71,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	Transmission Latvia (LV Hydrogen)	Transmission Lithuania (LT Hydrogen)	2029	200,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	Transmission Lithuania (LT Hydrogen)	Transmission Latvia (LV Hydrogen)	2029	100,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	Transmission Poland (PL Hydrogen nordic baltic corridor)	Transmission Lithuania (LT Hydrogen)	2029	100,000
H2T-N-1239	Nordic-Baltic Hydrogen Corridor - LT section	AB Amber Grid	Transmission Lithuania (LT Hydrogen)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2029	200,000
H2T-A-1280	Nordic-Baltic Hydrogen Corridor - LV section	Conexus Baltic Grid, JSC	Transmission Lithuania (LT Hydrogen)	Transmission Latvia (LV Hydrogen)	2029	100,000
H2T-A-1280	Nordic-Baltic Hydrogen Corridor - LV section	Conexus Baltic Grid, JSC	Transmission Latvia (LV Hydrogen)	Transmission Lithuania (LT Hydrogen)	2029	200,000
H2T-A-1280	Nordic-Baltic Hydrogen Corridor - LV section	Conexus Baltic Grid, JSC	Transmission Estonia (EE Hydrogen)	Transmission Latvia (LV Hydrogen)	2029	200,000
H2T-A-1280	Nordic-Baltic Hydrogen Corridor - LV section	Conexus Baltic Grid, JSC	Transmission Latvia (LV Hydrogen)	Transmission Estonia (EE Hydrogen)	2029	100,000
H2T-N-1310	Nordic-Baltic Hydrogen Corridor - DE section	ONTRAS Gastransport GmbH	Transmission Poland (PL Hydrogen nordic baltic corridor)	Transmission Germany (DE Hydrogen)	2029	200,000
H2T-N-1310	Nordic-Baltic Hydrogen Corridor - DE section	ONTRAS Gastransport GmbH	Transmission Germany (DE Hydrogen)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2029	100,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Germany (DE Hydrogen)	Transmission Belgium (BE Hydrogen)	2028	91,200
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	91,200
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission France (FR Hydrogen)	Transmission Belgium (BE Hydrogen)	2030	36,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission France (FR Hydrogen)	2030	36,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Luxemburg (LU Hydrogen)	Transmission Belgium (BE Hydrogen)	2035	58,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Luxemburg (LU Hydrogen)	2035	58,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Netherlands (NL Hydrogen)	Transmission Belgium (BE Hydrogen)	2026	36,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Netherlands (NL Hydrogen)	Transmission Belgium (BE Hydrogen)	2030	84,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2026	36,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2030	84,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen Mons)	Transmission France (FR Hydrogen Valenciennes)	2028	24,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission France (FR Hydrogen Valenciennes)	Transmission Belgium (BE Hydrogen Mons)	2028	24,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission France (FR Hydrogen North)	Transmission Belgium (BE Hydrogen)	2034	48,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (BE Hydrogen)	Transmission France (FR Hydrogen North)	2034	48,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission France (PEG North) (Dunkerque)	Transmission Belgium (H-Zone) (Zeebrugge Beach)	2034	-271,200
H2T-N-1324	H2Med-CelZa (Enagás)	Enagás Infraestructuras de Hidrógeno	Transmission Portugal (PT Hydrogen)	Transmission Spain (ES Hydrogen)	2029	81,000

H2T-N-1324	H2Med-CelZa (Enagás)	Enagás Infraestructuras de Hidrógeno	Transmission Spain (ES Hydrogen)	Transmission Portugal (PT Hydrogen)	2029	81,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Sweden (SE Hydrogen)	Transmission Finland (FI Hydrogen Aland)	2029	504,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen Aland)	Transmission Sweden (SE Hydrogen)	2029	504,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen Aland)	Transmission Germany (DE Hydrogen)	2029	504,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen Aland)	Transmission Poland (PL Hydrogen North)	2031	504,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France	Transmission France (NS2)	2029	-310,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France (NS2)	Transmission France	2029	-310,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France (FR Hydrogen South)	Transmission France (FR Hydrogen)	2029	192,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France (FR Hydrogen)	Transmission France (FR Hydrogen South)	2029	192,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen Valenciennes)	Transmission France (FR Hydrogen)	2028	24,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen)	Transmission France (FR Hydrogen Valenciennes)	2028	24,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen North)	Transmission France (FR Hydrogen)	2034	0,000
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Transmission France (FR Hydrogen)	Transmission France (FR Hydrogen North)	2034	0,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Poland (PL Hydrogen South)	Transmission Poland (PL Hydrogen nordic baltic corridor)	2039	50,000
H2T-A-1144	Nordic-Baltic Hydrogen Corridor - PL section	GAZ-SYSTEM S.A.	Transmission Poland (PL Hydrogen nordic baltic corridor)	Transmission Poland (PL Hydrogen North)	2029	100,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Transmission Belgium (H-Zone) (Zeebrugge Beach)	Transmission Belgium (H-Zone)	2032	-120,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2028	14,000
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2029	29,100
H2T-F-468	National H2 Backbone	N.V. Nederlandse Gasunie	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2035	86,300
H2L-A-664	Antwerp NH3 Import Terminal	Fluxys	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2029	16,200
H2L-A-754	ACE Terminal	N.V. NEDERLANDSE GASUNIE	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2027	47,700
H2L-N-820	Dunkerque New Molecules development	Fluxys	Liquid Hydrogen France (PEG North)	Transmission France (FR Hydrogen North)	2034	48,000
H2L-N-968	Green Wilhelmshaven Terminal/Storage/Cracker	Uniper Hydrogen GmbH	Liquid Hydrogen Germany	Transmission Germany (DE Hydrogen)	2029	31,200
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Liquid Hydrogen Germany	Transmission Germany (DE Hydrogen)	2030	23,500
H2T-A-1035	Franco-Belgian H2 corridor	GRTgaz	Liquid Hydrogen France (PEG North)	Transmission France (FR Hydrogen North)	2034	48,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Liquid Hydrogen Germany	Transmission Germany (DE Hydrogen)	2027	209,000
H2L-N-1099	Ammonia Import Temrminal Brunsbüttel	RWE Supply & Trading GmbH	Liquid Hydrogen Germany	Transmission Germany (DE Hydrogen)	2030	23,500
H2L-N-1100	Amplifhy Antwerp	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2028	14,000

H2L-N-1100	Amplifhy Antwerp	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2029	29,100
H2L-N-1100	Amplifhy Antwerp	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2035	86,300
H2L-N-1127	Amplifhy Rotterdam	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2028	14,000
H2L-N-1127	Amplifhy Rotterdam	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2029	29,100
H2L-N-1127	Amplifhy Rotterdam	VTTI Terminal Support Services ("VTTI")	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2035	86,300
H2L-A-1159	bp Wilhelmshaven Green Hydrogen Hub	BP Europa SE	Liquid Hydrogen Germany (DE Hy BP)	Transmission Germany (DE Hydrogen BP)	2028	13,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2029	16,200
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2028	15,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2028	14,000
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2029	29,100
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2035	86,300
H2T-A-1311	Belgian Hydrogen Backbone	Fluxys Hydrogen	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2032	48,000
H2L-N-1325	Zeebrugge New Molecules development	Fluxys	Liquid Hydrogen Belgium ()	Transmission Belgium (BE Hydrogen)	2032	48,000
H2S-A-508	H2 storage North-1	Enagás Infraestructuras de Hidrógeno	Transmission Spain (ES Hydrogen)	Storage Spain (ES Hydrogen)	2029	41,000
H2S-A-508	H2 storage North-1	Enagás Infraestructuras de Hidrógeno	Storage Spain (ES Hydrogen)	Transmission Spain (ES Hydrogen)	2029	41,000
H2S-A-565	GeoH2	Géométhane	Transmission France (FR Hydrogen South)	Storage France (FR Hydrogen South)	2029	10,000
H2S-A-565	GeoH2	Géométhane	Storage France (FR Hydrogen South)	Transmission France (FR Hydrogen South)	2029	10,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Storage France (FR Hydrogen)	Transmission France (FR Hydrogen)	2030	12,000
H2T-N-569	HY-FEN – H2 Corridor Spain – France – Germany connection	GRTgaz	Transmission France (FR Hydrogen)	Storage France (FR Hydrogen)	2030	12,000
H2S-A-767	RWE H2 Storage expansion Gronau-Epe	RWE Gas Storage West GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2028	10,200
H2S-A-767	RWE H2 Storage expansion Gronau-Epe	RWE Gas Storage West GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	10,200
H2S-N-934	SaltHy Harsefeld	Storengy Deutschland GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2030	17,000
H2S-N-934	SaltHy Harsefeld	Storengy Deutschland GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2030	17,000
H2T-A-969	RHYn	GRTgaz	Storage France (FR Hydrogen)	Transmission France (FR Hydrogen)	2033	10,000
H2T-A-969	RHYn	GRTgaz	Transmission France (FR Hydrogen)	Storage France (FR Hydrogen)	2033	10,000
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2030	16,800
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2033	24,000
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2035	24,000
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2030	16,800

H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2033	24,000
H2T-A-1001	Danish-German Hydrogen Network; German Part - HyPerLink Phase III	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2035	24,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2027	57,000
H2T-A-1037	H2ercules Network North	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2027	56,400
H2S-A-1152	H2 storage North-2	Enagás Infraestructuras de Hidrógeno	Transmission Spain (ES Hydrogen)	Storage Spain (ES Hydrogen)	2029	21,000
H2S-A-1152	H2 storage North-2	Enagás Infraestructuras de Hidrógeno	Storage Spain (ES Hydrogen)	Transmission Spain (ES Hydrogen)	2029	21,000
H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Storage Denmark (DK Hydrogen)	Transmission Denmark (DK Hydrogen)	2028	103,200
H2T-A-1236	DK Hydrogen Pipeline, West DK Hydrogen System	Energinet	Transmission Denmark (DK Hydrogen)	Storage Denmark (DK Hydrogen)	2028	103,200
H2S-A-1238	DK Hydrogen Storage	Energinet	Storage Denmark (DK Hydrogen)	Transmission Denmark (DK Hydrogen)	2027	9,500
H2S-A-1238	DK Hydrogen Storage	Energinet	Transmission Denmark (DK Hydrogen)	Storage Denmark (DK Hydrogen)	2027	3,160
H2S-A-1279	Hystock Opslag H2	N.V.Nederlandse Gasunie	Storage Netherlands (NL Hydrogen)	Transmission Netherlands (NL Hydrogen)	2028	3,300
H2S-A-1279	Hystock Opslag H2	N.V.Nederlandse Gasunie	Storage Netherlands (NL Hydrogen)	Transmission Netherlands (NL Hydrogen)	2034	9,900
H2S-A-1279	Hystock Opslag H2	N.V.Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Storage Netherlands (NL Hydrogen)	2028	3,300
H2S-A-1279	Hystock Opslag H2	N.V.Nederlandse Gasunie	Transmission Netherlands (NL Hydrogen)	Storage Netherlands (NL Hydrogen)	2034	9,900
H2T-A-978	Portuguese Hydrogen Backbone	REN - Gasodutos, S.A.	Transmission Portugal (PT Hydrogen)	Transmission Portugal (PT Hydrogen)	2029	81,000
H2T-A-978	Portuguese Hydrogen Backbone	REN - Gasodutos, S.A.	Transmission Portugal (PT Hydrogen)	Transmission Portugal (PT Hydrogen)	2029	81,000
H2T-A-788	H2 transmission system in Bulgaria	Bulgartransgaz EAD	Transmission Greece (GR Hydrogen)	Transmission Bulgaria (BG Hydrogen)	2029	80,000
H2T-A-788	H2 transmission system in Bulgaria	Bulgartransgaz EAD	Transmission Bulgaria (BG Hydrogen)	Transmission Greece (GR Hydrogen)	2029	80,000
H2T-N-970	Internal hydrogen infrastructure in Greece towards the Bulgarian border	DESFA S.A.	Transmission Bulgaria (BG Hydrogen)	Transmission Greece (GR Hydrogen)	2029	80,000
H2T-N-970	Internal hydrogen infrastructure in Greece towards the Bulgarian border	DESFA S.A.	Transmission Greece (GR Hydrogen)	Transmission Bulgaria (BG Hydrogen)	2029	80,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen Aland)	Transmission Finland (FI Hydrogen)	2029	504,000
H2T-N-1355	Baltic Sea Hydrogen Collector – Offshore Pipeline [BHC] – Finland	Gasgrid Finland Oy	Transmission Finland (FI Hydrogen)	Transmission Finland (FI Hydrogen Aland)	2029	504,000

Additional advanced hydrogen projects (without PCI/PMI status[55]):

Code	*Project Name*	*Country*	*Promoter*	*Maturity Status*	*Project Commissioning Year First*	*Project Commissioning Year Last*
H2T-A-0	**OGE H2ercules Central**	Germany	Open Grid Europe GmbH	Advanced	2025	2030
H2T-A-418	**Connection Fiume Treste Livello F**	Italy	Snam Rete Gas Spa	Advanced	2029	2029
H2T-A-555	**Apulia H2 Backbone**	Italy	Snam S.p.A.	Advanced	2027	2027
H2T-N-735	**North Africa Hydrogen Corridor[56]**	Tunisia	Sea Corridor S.r.l.	Less-Advanced	2029	2029
H2S-A-818	**RWE H2 Storage Xanten**	Germany	RWE Gas Storage West GmbH	Advanced	2029	2029
H2T-A-876	**IP Elten/Zevenaar - Cologne**	Germany	Thyssengas GmbH	Advanced	2029	2029
H2T-A-917	**Emsbüren - Leverkusen**	Germany	Thyssengas GmbH	Advanced	2027	2027
H2T-A-933	**Hyperlink 4-5 Wilhelmshaven - Emsbüren**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2027	2032
H2T-A-990	**Czech H2 Backbone SOUTH**	Czechia	NET4GAS, s.r.o.	Advanced	2029	2029
H2T-A-1137	**Central European Hydrogen Corridor (UKR part)**	Ukraine	LLC Gas TSO of Ukraine	Advanced	2029	2029
H2T-A-1075	**H2ercules Network North-West**	Germany	Open Grid Europe GmbH	Advanced	2029	2029
H2S-A-1244	**UST Hydrogen Storage Krummhörn**	Germany	Uniper Energy Storage GmbH	Advanced	2029	2029
H2T-A-1250	**NWH2**	Germany	Nord-West Oelleitung GmbH (NWO)	Advanced	2027	2027
H2S-A-1284	**RWE H2 Storage Gronau-Epe**	Germany	RWE Gas Storage West GmbH	Advanced	2026	2026
H2S-A-1287	**RWE H2 Storage Gronau-Epe - 2nd expansion**	Germany	RWE Gas Storage West GmbH	Advanced	2028	2028
H2T-A-1055	**H2ercules Network South-East**	Germany	Open Grid Europe GmbH; GRTgaz Deutschland GmbH	Advanced	2029	2029
H2S-F-1304	**HYPSTER**	France	STORENGY	FID	2025	2025
H2T-A-444	**HySoW Mediterranean**	France	Teréga	Advanced	2029	2049
H2T-A-909	**Connexion HY-FEN-GeoH2**	France	GRTgaz	Advanced	2029	2029

[55] More details on Advanced hydrogen projects can be found in the TYNDP 2024 Annex A – List of projects (link)
[56] Project H2T-N-735 is considered as part of Advanced hydrogen Infrastructure level despite maturity status of the project defined as less-advanced based on EC input

H2T-A-1264	**Slovak Hydrogen Backbone**	Slovakia	eustream,a.s.	Advanced	2029	2029
H2T-A-1291	**Hynframed**	France	GRTgaz	Advanced	2029	2029
H2T-A-1327	**HySoW Atlantic**	France	Teréga	Advanced	2029	2041
H2S-A-1352	**HySoW storage (Hydrogen South West corridor of France storage)**	France	Teréga (TSO+SSO company)	Advanced	2029	2029
H2T-A-1206	**HU/SK hydrogen corridor**	Hungary	FGSZ Ltd.	Advanced	2029	2029
H2S-F-887	**HYDRA**	Germany	STORAG Etzel GmbH	FID	2026	2026
H2T-A-666	**H2Coastlink**	Germany	Gastransport Nord GmbH	Advanced	2027	2032
H2S-A-802	**RWE H2 Storage Staßfurt**	Germany	RWE Gas Storage West GmbH	Advanced	2028	2028
H2T-A-66	**Interconnection Croatia-Bosnia and Herzegovina (Slobodnica-Bosanski Brod)**	Croatia	Plinacro Ltd	Advanced	2027	2027
H2T-A-224	**Northern Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS Sarajevo	Advanced	2028	2028
H2T-A-302	**Interconnection Croatia-Bosnia and Herzegovina (South)**	Croatia	Plinacro Ltd	Advanced	2026	2026
H2T-A-851	**Southern Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS Sarajevo	Advanced	2027	2027
H2T-A-303	**Interconnection Croatia-Bosnia and Herzegovina (west)**	Croatia	Plinacro Ltd	Advanced	2028	2028
H2T-A-910	**Western Interconnection BiH/CRO**	Bosnia Herzegovina	Gas Production and Transport Company BH-GAS Sarajevo	Advanced	2029	2029
H2T-A-70	**Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)**	Croatia	Plinacro Ltd	Advanced	2027	2030
H2T-A-68	**Ionian Adriatic Pipeline**	Croatia	Plinacro Ltd	Advanced	2029	2029
H2T-A-835	**SK-HU H2 corridor**	Slovakia	eustream, a.s.	Advanced	2029	2029
H2T-A-1065	**UAHU hydrogen corridor**	Hungary	FGSZ Ltd.	Advanced	2029	2029
H2S-A-749	**EWE Hydrogen Storage Huntorf**	Germany	EWE GASSPEICHER	Advanced	2029	2029
H2S-A-839	**EWE Hydrogen Storage Huntorf_IPCEI**	Germany	EWE GASSPEICHER	Advanced	2027	2027
H2S-A-761	**EWE Hydrogen Storage Jemgum**	Germany	EWE GASSPEICHER	Advanced	2029	2029
H2T-A-779	**Pomeranian Green Hydrogen Cluster**	Poland	GAZ-SYSTEM S.A.	Advanced	2029	2029
H2T-A-1000	**Hyperlink**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2027	2032
H2T-A-542	**HyBRIDS**	Italy	SGI S.p.A.	Advanced	2025	2029
H2L-A-665	**Eemshaven H2**	Netherlands	N.V. NEDERLANDSE GASUNIE	Advanced	2029	2030
H2S-A-805	**Project Hydrogen Infrastructure Storage and Distribution (HENRI)**	Slovakia	NAFTA a.s. (joint stock company)	Advanced	2027	2027
H2T-A-821	**Hydrogen Highway – Northern Section**	Poland	GAZ-SYSTEM S.A.	Advanced	2029	2039
H2T-A-1014	**Giurgiu Nădlac hydrogen corridor with new H2 interconnector**	Romania	SNTGN Transgaz SA	Advanced	2029	2029
H2T-A-1015	**New Hydrogen pipeline from Black Sea area to Podișor**	Romania	SNTGN Transgaz SA	Advanced	2029	2029
H2L-A-1041	**Ammonia terminal in Gdansk**	Poland	GAZ-SYSTEM S.A.	Advanced	2029	2029
H2T-A-1091	**Connection of DESFA's transmission system with East Med pipeline**	Greece	DESFA S.A.	Advanced	2027	2036
H2T-A-1092	**Metering and Regulating Station at UHS South Kavala**	Greece	DESFA S.A.	Advanced	2029	2029
H2T-A-1259	**HU/RO hydrogen corridor**	Hungary	FGSZ Ltd.	Advanced	2029	2029

Capacity increments related to additional advanced hydrogen projects (non PCI/PMI):

Code	Project Name	Promoter	From System	To System	Commissioning Year	Capacity (GWh/d)*
H2T-A-555	Apulia H2 Backbone	Snam S.p.A.	NP Send-out Italy (IT Hydrogen Transport)	Transmission Italy (IT Hydrogen)	2027	8,600
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2027	4,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2032	6,000
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2027	1,400
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2028	4,300
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	NP Send-out Germany (DE Hydrogen Transport)	Transmission Germany (DE Hydrogen)	2029	4,300
H2T-A-1327	HySoW Atlantic	Teréga	NP Send-out France (FR Hydrogen South West Transport)	Transmission France (FR Hydrogen South West)	2029	23,000
H2T-N-735	North Africa Hydrogen Corridor	Sea Corridor S.r.l.	Transmission Algeria (DZ Hydrogen)	Transmission Italy (IT Hydrogen)	2029	448,000
H2T-A-1205	Italian H2 Backbone	Snam Rete Gas S.p.A.	Transmission Algeria (DZ Hydrogen)	Transmission Italy (IT Hydrogen)	2029	448,000
H2T-A-66	Interconnection Croatia-Bosnia and Herzegovina (Slobodnica-Bosanski Brod)	Plinacro Ltd	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2027	139,000
H2T-A-66	Interconnection Croatia-Bosnia and Herzegovina (Slobodnica-Bosanski Brod)	Plinacro Ltd	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2027	139,000
H2T-A-68	Ionian Adriatic Pipeline	Plinacro Ltd	Transmission Croatia (HR Hydrogen)	Transmission Albania (AL Hydrogen)	2029	40,500
H2T-A-70	Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)	Plinacro Ltd	Transmission Serbia (RS Hydrogen)	Transmission Croatia (HR Hydrogen)	2027	32,000
H2T-A-70	Interconnection Croatia/Serbia (Slobodnica-Sotin-Bačko Novo Selo)	Plinacro Ltd	Transmission Croatia (HR Hydrogen)	Transmission Serbia (RS Hydrogen)	2027	27,000
H2T-A-224	Northern Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2028	40,000
H2T-A-224	Northern Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2028	40,000
H2T-A-302	Interconnection Croatia-Bosnia and Herzegovina (South)	Plinacro Ltd	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2026	40,000
H2T-A-302	Interconnection Croatia-Bosnia and Herzegovina (South)	Plinacro Ltd	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2026	40,000
H2T-A-303	Interconnection Croatia-Bosnia and Herzegovina (west)	Plinacro Ltd	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2028	35,000
H2T-A-303	Interconnection Croatia-Bosnia and Herzegovina (west)	Plinacro Ltd	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2028	35,000

H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2027	60,000
H2T-A-779	Pomeranian Green Hydrogen Cluster	GAZ-SYSTEM S.A.	Transmission Germany (DE Hydrogen)	Transmission Poland (PL Hydrogen North)	2029	19,200
H2T-A-779	Pomeranian Green Hydrogen Cluster	GAZ-SYSTEM S.A.	Transmission Poland (PL Hydrogen North)	Transmission Germany (DE Hydrogen)	2029	19,200
H2T-A-835	SK-HU H2 corridor	eustream, a.s.	Transmission Hungary (HU Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK Center)	2029	100,000
H2T-A-835	SK-HU H2 corridor	eustream, a.s.	Transmission Slovakia (SK Hydrogen) (SK Center)	Transmission Hungary (HU Hydrogen)	2029	100,000
H2T-A-851	Southern Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2027	40,000
H2T-A-851	Southern Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2027	40,000
H2T-A-876	IP Elten/Zevenaar - Cologne	Thyssengas GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	76,800
H2T-A-910	Western Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Croatia (HR Hydrogen)	Transmission Bosnia Herzegovina (BA Hydrogen)	2029	35,000
H2T-A-910	Western Interconnection BiH/CRO	Gas Production and Transport Company BH-GAS Sarajevo	Transmission Bosnia Herzegovina (BA Hydrogen)	Transmission Croatia (HR Hydrogen)	2029	35,000
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	Transmission Norway (Fork NO h2)	Transmission Germany (DE Hydrogen)	2027	153,600
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Slovakia	Transmission Czech Republic (VOB)	2029	-565,400
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Czech Republic (VOB)	Transmission Slovakia	2029	-231,400
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Germany (NCG)	Transmission Czech Republic (VOB)	2029	-120,000
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Czech Republic (VOB)	Transmission Germany (NCG)	2029	-351,500
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Slovakia (SK Hydrogen) (SK West)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-990	Czech H2 Backbone SOUTH	NET4GAS, s.r.o.	Transmission Czechia (CZ Hydrogen)	Transmission Germany (DE Hydrogen)	2029	144,000
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2027	96,000
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2027	96,000
H2T-A-1055	H2ercules Network South-East	Open Grid Europe GmbH; GRTgaz Deutschland GmbH	Transmission Czechia (CZ Hydrogen)	Transmission Germany (DE Hydrogen)	2029	144,000

H2T-A-1055	H2ercules Network South-East	Open Grid Europe GmbH; GRTgaz Deutschland GmbH	Transmission Germany (DE Hydrogen)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	NP Send-out Slovakia (SK Hydrogen East Transport)	Transmission Slovakia (SK Hydrogen East)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Ukraine	Transmission Slovakia	2029	-478,400
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Czech Republic (VOB)	Transmission Slovakia	2029	-218,400
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia	Transmission Czech Republic (VOB)	2029	-265,200
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia	Transmission Austria (CEGH)	2029	-104,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Austria (AT Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK West)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen) (SK West)	Transmission Austria (AT Hydrogen)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Czechia (CZ Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK West)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen) (SK West)	Transmission Czechia (CZ Hydrogen)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Ukraine (UA Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK East)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen) (SK East)	Transmission Ukraine (UA Hydrogen)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen East Zone 1)	Transmission Slovakia (SK Hydrogen East)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen East)	Transmission Slovakia (SK Hydrogen East Zone 1)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen West Zone 1)	Transmission Slovakia (SK Hydrogen West)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	Transmission Slovakia (SK Hydrogen West)	Transmission Slovakia (SK Hydrogen West Zone 1)	2029	144,000
H2T-A-1264	Slovak Hydrogen Backbone	eustream,a.s.	NP Send-out Slovakia (SK Hydrogen West Transport)	Transmission Slovakia (SK Hydrogen West)	2029	144,000
H2T-A-1075	H2ercules Network North-West	Open Grid Europe GmbH	Transmission Netherlands (NL Hydrogen)	Transmission Germany (DE Hydrogen)	2029	76,800
H2T-A-1075	H2ercules Network North-West	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	76,800
H2T-A-1091	Connection of DESFA's transmission system with East Med pipeline	DESFA S.A.	Transmission East Med Greece	Transmission Greece	2027	90,000
H2T-A-1137	Central European Hydrogen Corridor (UKR part)	LLC Gas TSO of Ukraine	Transmission Ukraine (UA Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK East)	2029	144,000

H2T-A-1206	HU/SK hydrogen corridor	FGSZ Ltd.	Transmission Slovakia (SK Hydrogen) (SK Center)	Transmission Hungary (HU Hydrogen)	2029	100,000
H2T-A-1206	HU/SK hydrogen corridor	FGSZ Ltd.	Transmission Hungary (HU Hydrogen)	Transmission Slovakia (SK Hydrogen) (SK Center)	2029	100,000
H2T-A-444	HySoW Mediterranean	Teréga	Transmission France (FR Hydrogen South)	Transmission France (FR Hydrogen South West)	2029	44,000
H2T-A-444	HySoW Mediterranean	Teréga	Transmission France (FR Hydrogen South West)	Transmission France (FR Hydrogen South)	2029	44,000
H2T-A-821	Hydrogen Highway – Northern Section	GAZ-SYSTEM S.A.	Transmission Poland (PL Hydrogen nordic baltic corridor)	Transmission Poland (PL Hydrogen North)	2029	50,000
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen Barseel)	Transmission Germany (DE Hydrogen)	2027	43,000
H2T-A-1250	NWH2	Nord-West Oelleitung GmbH (NWO)	Transmission Germany (DE Hydrogen Barseel)	Transmission Germany (DE Hydrogen)	2027	43,000
H2T-A-1327	HySoW Atlantic	Teréga	Transmission France (FR Hydrogen)	Transmission France (FR Hydrogen South West)	2029	60,000
H2T-A-1327	HySoW Atlantic	Teréga	Transmission France (FR Hydrogen South West)	Transmission France (FR Hydrogen)	2029	60,000
H2T-A-444	HySoW Mediterranean	Teréga	Liquid Hydrogen France (FR Hy South West)	Transmission France (FR Hydrogen South West)	2029	18,000
H2L-A-665	Eemshaven H2	N.V. NEDERLANDSE GASUNIE	Liquid Hydrogen Netherlands (TTF)	Transmission Netherlands (NL Hydrogen)	2029	45,500
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	Liquid Hydrogen Germany	Transmission Germany (DE Hydrogen)	2029	31,200
H2T-A-933	Hyperlink 4-5 Wilhelmshaven - Emsbüren	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen BP)	Transmission Germany (DE Hydrogen)	2029	13,000
H2L-A-1041	Ammonia terminal in Gdansk	GAZ-SYSTEM S.A.	Liquid Hydrogen Poland (PL Hy North)	Transmission Poland (PL Hydrogen North)	2029	17,700
H2T-A-1250	NWH2	Nord-West Oelleitung GmbH (NWO)	Transmission Germany (DE Hydrogen BP)	Transmission Germany (DE Hydrogen Barseel)	2027	43,000
H2T-A-1327	HySoW Atlantic	Teréga	Liquid Hydrogen France (FR Hy South West)	Transmission France (FR Hydrogen South West)	2029	15,000
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2025	4,250
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	10,200
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2025	4,250
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2028	10,200
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2025	4,000

H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2025	4,000
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	4,000
H2T-A-0	OGE H2ercules Central	Open Grid Europe GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	4,000
H2T-A-418	Connection Fiume Treste Livello F	Snam Rete Gas Spa	Storage Italy (IT Hydrogen)	Transmission Italy (IT Hydrogen)	2029	6,000
H2T-A-418	Connection Fiume Treste Livello F	Snam Rete Gas Spa	Transmission Italy (IT Hydrogen)	Storage Italy (IT Hydrogen)	2029	6,000
H2L-A-665	Eemshaven H2	N.V. NEDERLANDSE GASUNIE	Storage Netherlands (NL Hydrogen)	Transmission Netherlands (NL Hydrogen)	2029	45,500
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	12,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2027	3,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2027	3,000
H2T-A-666	H2Coastlink	Gastransport Nord GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	12,000
H2S-A-749	EWE Hydrogen Storage Huntorf	EWE GASSPEICHER	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	9,000
H2S-A-749	EWE Hydrogen Storage Huntorf	EWE GASSPEICHER	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	9,000
H2S-A-761	EWE Hydrogen Storage Jemgum	EWE GASSPEICHER	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	12,000
H2S-A-761	EWE Hydrogen Storage Jemgum	EWE GASSPEICHER	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000
H2S-A-802	RWE H2 Storage Staßfurt	RWE Gas Storage West GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2028	14,000
H2S-A-802	RWE H2 Storage Staßfurt	RWE Gas Storage West GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	14,000
H2S-A-818	RWE H2 Storage Xanten	RWE Gas Storage West GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	14,000
H2S-A-818	RWE H2 Storage Xanten	RWE Gas Storage West GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	14,000
H2S-A-839	EWE Hydrogen Storage Huntorf_IPCEI	EWE GASSPEICHER	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2027	3,000
H2S-A-839	EWE Hydrogen Storage Huntorf_IPCEI	EWE GASSPEICHER	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2027	3,000
H2T-A-876	IP Elten/Zevenaar - Cologne	Thyssengas GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	14,000
H2T-A-876	IP Elten/Zevenaar - Cologne	Thyssengas GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	14,000

H2T-A-909	Connexion HY-FEN-GeoH2	GRTgaz	Storage France (FR Hydrogen South)	Transmission France (FR Hydrogen South)	2029	10,000
H2T-A-909	Connexion HY-FEN-GeoH2	GRTgaz	Transmission France (FR Hydrogen South)	Storage France (FR Hydrogen South)	2029	10,000
H2T-A-917	Emsbüren - Leverkusen	Thyssengas GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2027	6,800
H2T-A-917	Emsbüren - Leverkusen	Thyssengas GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2027	6,800
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	12,000
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2032	12,000
H2T-A-1000	Hyperlink	Gasunie Deutschland Transport Services GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	12,000
H2T-A-1092	Metering and Regulating Station at UHS South Kavala	DESFA S.A.	Storage Greece (GR Hydrogen)	Transmission Greece (GR Hydrogen)	2029	35,000
H2T-A-1092	Metering and Regulating Station at UHS South Kavala	DESFA S.A.	Transmission Greece (GR Hydrogen)	Storage Greece (GR Hydrogen)	2029	35,000
H2S-A-1189	Fiume Treste Livello F Underground Hydrogen Storage	STOGIT	Transmission Italy (IT Hydrogen)	Storage Italy (IT Hydrogen)	2029	0,000
H2S-A-1189	Fiume Treste Livello F Underground Hydrogen Storage	STOGIT	Storage Italy (IT Hydrogen)	Transmission Italy (IT Hydrogen)	2029	0,000
H2S-A-1244	UST Hydrogen Storage Krummhörn	Uniper Energy Storage GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2029	4,000
H2S-A-1244	UST Hydrogen Storage Krummhörn	Uniper Energy Storage GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2029	4,000
H2S-A-1284	RWE H2 Storage Gronau-Epe	RWE Gas Storage West GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2026	4,250
H2S-A-1284	RWE H2 Storage Gronau-Epe	RWE Gas Storage West GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2026	4,250
H2S-A-1287	RWE H2 Storage Gronau-Epe - 2nd expansion	RWE Gas Storage West GmbH	Transmission Germany (DE Hydrogen)	Storage Germany (DE Hydrogen)	2028	6,800
H2S-A-1287	RWE H2 Storage Gronau-Epe - 2nd expansion	RWE Gas Storage West GmbH	Storage Germany (DE Hydrogen)	Transmission Germany (DE Hydrogen)	2028	6,800
H2S-F-1304	HYPSTER	STORENGY	Transmission France (FR Hydrogen)	Storage France (FR Hydrogen)	2025	2,000
H2S-F-1304	HYPSTER	STORENGY	Storage France (FR Hydrogen)	Transmission France (FR Hydrogen)	2025	2,000
H2S-A-1352	HySoW storage (Hydrogen South West corridor of France storage)	Teréga (TSO+SSO company)	Storage France (FR Hydrogen South West)	Transmission France (FR Hydrogen South West)	2029	9,300
H2S-A-1352	HySoW storage (Hydrogen South West corridor of France storage)	Teréga (TSO+SSO company)	Transmission France (FR Hydrogen South West)	Storage France (FR Hydrogen South West)	2029	9,300
H2T-A-1014	Giurgiu Nădlac hydrogen corridor with new H2 interconnector	SNTGN Transgaz SA	Transmission Hungary (HU Hydrogen)	Transmission Romania (RO Hydrogen)	2029	76,800
H2T-A-1014	Giurgiu Nădlac hydrogen corridor with new H2 interconnector	SNTGN Transgaz SA	Transmission Romania (RO Hydrogen)	Transmission Hungary (HU Hydrogen)	2029	100,000

H2T-A-1014	Giurgiu Nădlac hydrogen corridor with new H2 interconnector	SNTGN Transgaz SA	Transmission Bulgaria (BG Hydrogen)	Transmission Romania (RO Hydrogen)	2029	80,000
H2T-A-1014	Giurgiu Nădlac hydrogen corridor with new H2 interconnector	SNTGN Transgaz SA	Transmission Romania (RO Hydrogen)	Transmission Bulgaria (BG Hydrogen)	2029	80,000
H2T-A-1259	HU/RO hydrogen corridor	FGSZ Ltd.	Transmission Romania (RO Hydrogen)	Transmission Hungary (HU Hydrogen)	2029	100,000
H2T-A-1259	HU/RO hydrogen corridor	FGSZ Ltd.	Transmission Hungary (HU Hydrogen)	Transmission Romania (RO Hydrogen)	2029	76,800

List of natural gas projects included in the Low infrastructure level[57]

Code	*Project Name*	*Country*	*Promoter*	*Maturity Status*	*Project Commissioning Year First*	*Project Commissioning Year Last*
TRA-F-496	**Increase of Gas Transport to the Netherlands**	Germany	Gasunie Deutschland Transport Service GmbH	FID	2027	2027
TRA-F-873	**Additional import at Oude StatenZijl area**	Netherlands	Gasunie Transport Services B.V.	FID	2027	2027
TRA-F-1199	**LNG Terminal Brunsbuettel - Grid Integration**	Germany	Gasunie Deutschland Transport Service GmbH	FID	2024	2024
LNG-F-62	**LNG terminal in northern Greece / Alexandroupolis - LNG Section**	Greece	Gastrade S.A.	FID	2024	2024
TRA-F-63	**LNG terminal in northern Greece / Alexandroupolis - Pipeline Section**	Greece	Gastrade S.A.	FID	2024	2024
TRA-F-566	**FSRU Ravenna Connection**	Italy	Snam Rete Gas S.p.A.	FID	2024	2024
LNG-F-1142	**FSRU Ravenna**	Italy	FSRU Italia	FID	2024	2024
TRA-F-1145	**Export enhancements phase 1**	Italy	Snam Rete Gas S.p.A.	FID	2024	2026
TRA-F-192	**Entry capacity expansion GATE terminal**	Netherlands	Gasunie Transport Services B.V.	FID	2027	2027
LNG-F-880	**Gate 4th tank, 4 bcma expansion**	Netherlands	Gate terminal B.V.	FID	2026	2026
TRA-F-1031	**Reverse flow at IP Cieszyn - Polish section**	Poland	GAZ-SYSTEM S.A.	FID	2024	2024
TRA-F-7	**Development for new import from the South (Adriatica Line)**	Italy	Snam Rete Gas S.p.A.	FID	2026	2027
TRA-F-128	**Compressor Station Komotini (former Kipi)**	Greece	DESFA S.A.	FID	2024	2025
UGS-F-138	**UGS Chiren Expansion**	Bulgaria	Bulgartransgaz EAD	FID	2025	2025
UGS-F-260	**System Enhancements - Stogit - on-shore gas fields**	Italy	Stogit S.p.A.	FID	2024	2032
LNG-F-272	**Upgrade of LNG terminal in Świnoujście**	Poland	GAZ-SYSTEM S.A.	FID	2023	2023
UGS-F-311	**Bilciuresti daily withdrawal capacity increase**	Romania	SNGN ROMGAZ SA - FILIALA DE INMAGAZINARE GAZE NATURALE DEPOGAZ PLOIESTI SRL	FID	2027	2027
TRA-F-329	**ZEELINK**	Germany	Open Grid Europe GmbH and Thyssengas GmbH	FID	2023	2023
TRA-F-362	**Development on the Romanian territory of the Southern Transmission Corridor**	Romania	SNTGN Transgaz SA	FID	2025	2025
UGS-F-374	**Enhancement of Incukalns UGS**	Latvia	Conexus Baltic Grid, JSC	FID	2019	2025
UGS-F-398	**Ghercesti underground gas storage in Romania**	Romania	SNGN ROMGAZ SA - FILIALA DE INMAGAZINARE GAZE NATURALE DEPOGAZ PLOIESTI SRL	FID	2028	2028
TRA-F-402	**TENP Security of Supply**	Germany	Fluxys TENP GmbH & Open Grid Europe GmbH	FID	2024	2024
TRA-F-439	**Stazione di Spinta "San Marco"**	Italy	S.G.I. S.p.A.	FID	2022	2022

[57] More details on FID Natural gas projects can be found in the TYNDP 2024 Annex A – List of projects (link)

TRA-F-500	**L/H Conversion Belgium**	Belgium	Fluxys Belgium	FID	2024	2024
TRA-F-505	**Lucera - San Paolo**	Italy	Società Gasdotti Italia S.p.A.	FID	2025	2025
TRA-F-967	**Pipeline Nea Messimvria – Evzoni/ Gevgelija and Metering Station**	Greece	DESFA S.A.	FID	2025	2025
TRA-F-971	**Booster Compressor Station for TAP in Nea Messimvria**	Greece	DESFA S.A.	FID	2025	2028
TRA-F-1095	**TENP Security of Supply plus**	Germany	Fluxys TENP GmbH & Open Grid Europe GmbH	FID	2025	2025
TRA-F-1278	**Compressor station at Ambelia**	Greece	DESFA S.A.	FID	2024	2024

Capacity increments related to FID natural gas projects (Low NG infrastructure level):

Code	*Project Name*	*Promoter*	*From System*	*To System*	*Commissioning Year*	*Capacity (GWh/d)**
TRA-F-967	Pipeline Nea Messimvria – Evzoni/ Gevgelija and Metering Station	DESFA S.A.	Transmission Greece	Transmission North Macedonia	2025	28,000
TRA-F-128	Compressor Station Komotini (former Kipi)	DESFA S.A.	Transmission Greece (Komotini)	Transmission Interconnector Greece-Bulgaria Bulgaria	2024	120,000
TRA-F-128	Compressor Station Komotini (former Kipi)	DESFA S.A.	Transmission Greece (Komotini)	Transmission Interconnector Greece-Bulgaria Bulgaria	2025	30,000
TRA-F-402	TENP Security of Supply	Fluxys TENP GmbH & Open Grid Europe GmbH	Transmission Germany (NCG)	Transmission Switzerland	2024	319,200
TRA-F-496	Increase of Gas Transport to the Netherlands	Gasunie Deutschland Transport Service GmbH	Transmission Germany (GASPOOL)	Transmission Netherlands (TTF) (fork NL DE)	2027	271,200
TRA-F-873	Additional import at Oude StatenZijl area	Gasunie Transport Services B.V.	Transmission Netherlands (TTF) (fork NL DE)	Transmission Netherlands (TTF)	2027	271,200
TRA-F-873	Additional import at Oude StatenZijl area	Gasunie Transport Services B.V.	Transmission Netherlands (TTF)	Transmission Netherlands (TTF) (fork NL DE)	2027	271,200
TRA-F-971	Booster Compressor Station for TAP in Nea Messimvria	DESFA S.A.	Transmission Greece	Transmission Trans-Adriatic Pipeline Greece	2025	5,000
TRA-F-971	Booster Compressor Station for TAP in Nea Messimvria	DESFA S.A.	Transmission Greece	Transmission Trans-Adriatic Pipeline Greece	2028	25,000
TRA-F-1031	Reverse flow at IP Cieszyn - Polish section	GAZ-SYSTEM S.A.	Transmission Poland (VTP - GAZ-SYSTEM)	Transmission Czech Republic (VOB)	2024	10,800
TRA-F-1095	TENP Security of Supply plus	Fluxys TENP GmbH & Open Grid Europe GmbH	Transmission Germany (NCG)	Transmission Switzerland	2025	69,600
TRA-F-1145	Export enhancements phase 1	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (Italy Northern Export Fork)	Transmission Austria (CEGH)	2024	65,000
TRA-F-1145	Export enhancements phase 1	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (Italy Northern Export Fork)	Transmission Austria (CEGH)	2026	174,000
TRA-F-1278	Compressor station at Ambelia	DESFA S.A.	Transmission Trans-Adriatic Pipeline Greece	Transmission Greece	2024	27,400
TRA-F-7	Development for new import from the South (Adriatica Line)	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (Southern Projects)	Transmission Italia (PSV)	2026	55,400
TRA-F-7	Development for new import from the South (Adriatica Line)	Snam Rete Gas S.p.A.	Transmission Italy (PSV) (Southern Projects)	Transmission Italia (PSV)	2027	210,400
TRA-F-7	Development for new import from the South (Adriatica Line)	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	32,500
TRA-F-7	Development for new import from the South (Adriatica Line)	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	98,600
TRA-F-63	LNG terminal in northern Greece / Alexandroupolis - Pipeline Section	Gastrade S.A.	Transmission Greece	Transmission Greece (Komotini)	2024	150,000

			(Alexandropolis LNG)			
TRA-F-192	Entry capacity expansion GATE terminal	Gasunie Transport Services B.V.	LNG Terminals Netherlands (TTF)	Transmission Netherlands (TTF)	2027	132,000
LNG-F-272	Upgrade of LNG terminal in Świnoujście	GAZ-SYSTEM S.A.	LNG Terminals Poland (VTP - GAZ-SYSTEM)	Transmission Poland (VTP - GAZ-SYSTEM)	2023	45,000
TRA-F-566	FSRU Ravenna Connection	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2024	222,000
LNG-F-880	Gate 4th tank, 4 bcma expansion	Gate terminal B.V.	LNG Terminals Netherlands (TTF)	Transmission Netherlands (TTF)	2026	117,400
LNG-F-1142	FSRU Ravenna	FSRU Italia	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2024	222,000
TRA-F-1199	LNG Terminal Brunsbuettel - Grid Integration	Gasunie Deutschland Transport Service GmbH	LNG Terminals Germany (GASPOOL)	Transmission Germany (GASPOOL)	2024	97,410
TRA-F-1199	LNG Terminal Brunsbuettel - Grid Integration	Gasunie Deutschland Transport Service GmbH	LNG Terminals Germany (GASPOOL)	Transmission Germany (GASPOOL)	2024	96,930
UGS-F-138	UGS Chiren Expansion	Bulgartransgaz EAD	Storage Bulgaria (NGTS) (Storage)	Transmission Bulgaria (NGTS)	2025	48,900
UGS-F-138	UGS Chiren Expansion	Bulgartransgaz EAD	Transmission Bulgaria (NGTS)	Storage Bulgaria (NGTS) (Storage)	2025	51,070
UGS-F-260	System Enhancements - Stogit - on-shore gas fields	Stogit S.p.A.	Storage Italia (PSV)	Transmission Italia (PSV)	2024	10,600
UGS-F-260	System Enhancements - Stogit - on-shore gas fields	Stogit S.p.A.	Storage Italia (PSV)	Transmission Italia (PSV)	2024	10,600
UGS-F-260	System Enhancements - Stogit - on-shore gas fields	Stogit S.p.A.	Storage Italia (PSV)	Transmission Italia (PSV)	2032	153,300
UGS-F-311	Bilciuresti daily withdrawal capacity increase	SNGN ROMGAZ SA - FILIALA DE INMAGAZINARE GAZE NATURALE DEPOGAZ PLOIESTI SRL	Storage Romania	Transmission Romania	2027	42,000
UGS-F-374	Enhancement of Incukalns UGS	Conexus Baltic Grid, JSC	Storage Latvia	Transmission Latvia	2019	84,000
UGS-F-374	Enhancement of Incukalns UGS	Conexus Baltic Grid, JSC	Transmission Latvia	Storage Latvia	2025	8,500
UGS-F-398	Ghercesti underground gas storage in Romania	SNGN ROMGAZ SA - FILIALA DE INMAGAZINARE GAZE NATURALE DEPOGAZ PLOIESTI SRL	Transmission Romania	Storage Romania	2028	28,000
UGS-F-398	Ghercesti underground gas storage in Romania	SNGN ROMGAZ SA - FILIALA DE INMAGAZINARE GAZE NATURALE DEPOGAZ PLOIESTI SRL	Storage Romania	Transmission Romania	2028	28,000
TRA-F-439	Stazione di Spinta "San Marco"	S.G.I. S.p.A.	Transmission Italia (PSV)	Transmission Italia (SGI)	2022	53,000

Advanced natural gas projects[58]

Code	Project Name	Country	Promoter	Maturity Status	Project Commissioning Year First	Project Commissioning Year Last
TRA-A-86	**Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)**	Croatia	Plinacro Ltd	Advanced	2026	2030
TRA-A-75	**LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac**	Croatia	Plinacro Ltd	Advanced	2026	2026
TRA-A-1322	**Development on the Romanian territory of the NTS (BG–RO-HU-AT)-Phase II**	Romania	SNTGN Transgaz SA	Advanced	2025	2025
TRA-A-988	**LNG Terminal Stade - Grid Intergration**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2026	2026
TRA-A-1009	**Czech-Polish Gas Interconnection Bezměrov (CZ) – Hať (CZ/PL Border)**	Czechia	NET4GAS, s.r.o.	Advanced	2027	2027
TRA-A-1141	**Czech-Polish Gas Interconnection - PL section**	Poland	GAZ-SYSTEM S.A.	Advanced	2028	2028
TRA-A-10	**Poseidon Pipeline**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Advanced	2027	2027
TRA-A-330	**EastMed Pipeline**	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Advanced	2027	2036
TRA-A-810	**TAP Expansion**	Greece	Trans Adriatic Pipeline AG	Advanced	2025	2029
TRA-A-298	**Modernization and rehabilitation of the Bulgarian GTS-Phase 3**	Bulgaria	Bulgartransgaz EAD	Advanced	2028	2028
LNG-A-304	**Italy-Sardinia Virtual Pipeline**	Italy	Snam Rete Gas S.p.A.	Advanced	2027	2027
TRA-A-429	**Adaptation L- gas - H-gas**	France	GRTgaz	Advanced	2025	2028
TRA-A-607	**Transmission Hybrid Compressor Stations**	Italy	Snam Rete Gas S.p.A.	Advanced	2026	2032
TRA-A-786	**Capacity Expansion for the German LNG Terminals**	Germany	Gasunie Deutschland Transport Services GmbH	Advanced	2026	2026
LNG-A-947	**FSRU terminal in Gdańsk**	Poland	GAZ-SYSTEM S.A.	Advanced	2027	2027
LNG-A-1005	**Thrace LNG Terminal**	Greece	GASTRADE SA	Advanced	2025	2025
TRA-A-1114	**Grid extension for LNG Wilhelmshaven**	Germany	Open Grid Europe GmbH	Advanced	2026	2026
TRA-A-1194	**Sardinia Methanization**	Italy	ENURA S.p.A.	Advanced	2027	2027
TRA-A-1268	**Romania-Serbia Interconnection**	Romania	SNTGN Tranzgaz SA	Advanced	2024	2028
TRA-A-1275	**Zeebrugge-Opwijk**	Belgium	Fluxys Belgium	Advanced	2024	2026
TRA-A-1317	**Connection FSRU Alto Tirreno**	Italy	Snam Rete Gas S.p.A.	Advanced	2026	2026

[58] More details on Advanced Natural gas projects can be found in the TYNDP 2024 Annex A – List of projects (link)

Capacity increments related to advanced natural gas projects:

Code	Project Name	Promoter	From System	To System	Commissioning Year	Capacity (GWh/d)*
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	NP Send-out Cyprus	Transmission East Med Greece	2027	330,000
TRA-A-298	Modernization and rehabilitation of the Bulgarian GTS-Phase 3	Bulgartransgaz EAD	Transmission Serbia	Transmission Bulgaria (NGTS)	2028	41,000
TRA-A-298	Modernization and rehabilitation of the Bulgarian GTS-Phase 3	Bulgartransgaz EAD	Transmission Bulgaria (NGTS)	Transmission Serbia	2028	41,000
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Trans-Anatolian Pipeline Turkey	Transmission Trans-Adriatic Pipeline Greece	2025	30,000
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Trans-Anatolian Pipeline Turkey	Transmission Trans-Adriatic Pipeline Greece	2029	205,000
TRA-A-1268	Romania-Serbia Interconnection	SNTGN Tranzgaz SA	Transmission Serbia	Transmission Romania	2028	46,270
TRA-A-1268	Romania-Serbia Interconnection	SNTGN Tranzgaz SA	Transmission Romania	Transmission Serbia	2028	46,270
TRA-A-10	Poseidon Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission Italy (PSV) (Southern Projects)	Transmission ITGI Poseidon Greece	2027	160,000
TRA-A-10	Poseidon Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission ITGI Poseidon Greece	Transmission Italy (PSV) (Southern Projects)	2027	320,000
TRA-A-10	Poseidon Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission East Med Greece	Transmission ITGI Poseidon Greece	2027	320,000
TRA-A-10	Poseidon Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission ITGI Poseidon Greece	Transmission East Med Greece	2027	160,000
TRA-A-75	LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac	Plinacro Ltd	Transmission Croatia	Transmission Hungary (MGP)	2026	51,000
TRA-A-86	Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)	Plinacro Ltd	Transmission Croatia	Transmission Slovenia	2026	34,000
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission East Med Greece	Transmission Cyprus	2027	30,000
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission Greece (Crete)	Transmission East Med Greece	2027	190,000
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission East Med Greece	Transmission Greece (Crete)	2027	20,000
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission ITGI Poseidon Greece	Transmission East Med Greece	2027	600,000
TRA-A-330	EastMed Pipeline	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Transmission East Med Greece	Transmission Greece	2027	90,000
TRA-A-429	Adaptation L- gas - H-gas	GRTgaz	Transmission Belgium (L-Zone)	Transmission France (FR PEG North L-Gas)	2025	-85,000
TRA-A-429	Adaptation L- gas - H-gas	GRTgaz	Transmission Belgium (L-Zone)	Transmission France (FR PEG North L-Gas)	2028	-115,000
TRA-A-786	Capacity Expansion for the German LNG Terminals	Gasunie Deutschland Transport Services GmbH	Transmission Denmark (Ellund)	Transmission Germany (GASPOOL)	2026	48,450
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Trans-Adriatic Pipeline Albania	Transmission Italy (PSV) (Southern Projects)	2025	30,000

TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Trans-Adriatic Pipeline Albania	Transmission Italy (PSV) (Southern Projects)	2029	205,000
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Trans-Adriatic Pipeline Greece	Transmission Interconnector Greece-Bulgaria Bulgaria	2029	30,000
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Greece	Transmission Trans-Adriatic Pipeline Greece	2025	5,000
TRA-A-810	TAP Expansion	Trans Adriatic Pipeline AG	Transmission Greece	Transmission Trans-Adriatic Pipeline Greece	2029	25,000
TRA-A-1009	Czech-Polish Gas Interconnection Bezměrov (CZ) – Hať (CZ/PL Border)	NET4GAS, s.r.o.	Transmission Poland (VTP - GAZ-SYSTEM)	Transmission Czech Republic (VOB)	2027	31,000
TRA-A-1009	Czech-Polish Gas Interconnection Bezměrov (CZ) – Hať (CZ/PL Border)	NET4GAS, s.r.o.	Transmission Czech Republic (VOB)	Transmission Poland (VTP - GAZ-SYSTEM)	2027	31,000
TRA-A-1141	Czech-Polish Gas Interconnection - PL section	GAZ-SYSTEM S.A.	Transmission Czech Republic (VOB)	Transmission Poland (VTP - GAZ-SYSTEM)	2028	31,000
TRA-A-1141	Czech-Polish Gas Interconnection - PL section	GAZ-SYSTEM S.A.	Transmission Poland (VTP - GAZ-SYSTEM)	Transmission Czech Republic (VOB)	2028	31,000
TRA-A-1322	Development on the Romanian territory of the NTS (BG–RO-HU-AT)-Phase II	SNTGN Transgaz SA	Transmission Hungary (MGP)	Transmission Romania	2025	51,600
TRA-A-1322	Development on the Romanian territory of the NTS (BG–RO-HU-AT)-Phase II	SNTGN Transgaz SA	Transmission Romania	Transmission Hungary (MGP)	2025	57,600
TRA-A-1275	Zeebrugge-Opwijk	Fluxys Belgium	Transmission Belgium (H-Zone) (Zeebrugge Beach)	Transmission Belgium (H-Zone)	2024	349,000
TRA-A-1275	Zeebrugge-Opwijk	Fluxys Belgium	Transmission Belgium (H-Zone) (Zeebrugge Beach)	Transmission Belgium (H-Zone)	2026	120,000
TRA-A-75	LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac	Plinacro Ltd	LNG Terminals Croatia	Transmission Croatia	2026	83,000
LNG-A-304	Italy-Sardinia Virtual Pipeline	Snam Rete Gas S.p.A.	LNG Terminals Italy (Sardinia)	Transmission Italy (Sardinia)	2027	46,500
TRA-A-786	Capacity Expansion for the German LNG Terminals	Gasunie Deutschland Transport Services GmbH	LNG Terminals Germany (GASPOOL)	Transmission Germany (GASPOOL)	2026	183,480
TRA-A-786	Capacity Expansion for the German LNG Terminals	Gasunie Deutschland Transport Services GmbH	LNG Terminals Germany (GASPOOL)	Transmission Germany (GASPOOL)	2026	423,870
LNG-A-947	FSRU terminal in Gdańsk	GAZ-SYSTEM S.A.	LNG Terminals Poland (VTP - GAZ-SYSTEM)	Transmission Poland (VTP - GAZ-SYSTEM)	2027	210,000
LNG-A-1005	Thrace LNG Terminal	GASTRADE SA	LNG Terminals Greece	Transmission Greece (Komotini)	2025	189,000
TRA-A-1194	Sardinia Methanization	ENURA S.p.A.	LNG Terminals Italy (Sardinia)	Transmission Italy (Sardinia)	2027	46,500
TRA-A-1317	Connection FSRU Alto Tirreno	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	-222,000
TRA-A-1317	Connection FSRU Alto Tirreno	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	222,000
TRA-A-1317	Connection FSRU Alto Tirreno	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	-222,000
TRA-A-1317	Connection FSRU Alto Tirreno	Snam Rete Gas S.p.A.	LNG Terminals Italia (PSV)	Transmission Italia (PSV)	2026	222,000
TRA-A-607	Transmission Hybrid Compressor Stations	Snam Rete Gas S.p.A.	Transmission Italia (PSV)	Transmission Italia (PSV)	2026	0,000

ANNEX II: Capacities of hydrogen and natural gas infrastructure levels

Cross-border, import, storage capacities from PCI/PMI hydrogen infrastructure level

From Country	*To Country*	*Year*	*PCI/PMI*	*Unit*
Austria	Germany	2030	150	GWh/d
Austria	Germany	2040	150	GWh/d
Austria	Italy	2030	126	GWh/d
Austria	Italy	2040	126	GWh/d
Belgium	France	2040	36	GWh/d
Belgium	France	2040	48	GWh/d
Belgium	France	2030	48	GWh/d
Belgium	France	2040	48	GWh/d
Belgium	Germany	2030	91,2	GWh/d
Belgium	Germany	2040	91,2	GWh/d
Belgium	Netherlands	2030	36	GWh/d
Belgium	Netherlands	2040	120	GWh/d
Bulgaria	Greece	2030	80	GWh/d
Bulgaria	Greece	2040	80	GWh/d
Czechia	Germany	2030	144	GWh/d
Czechia	Germany	2040	144	GWh/d
Estonia	Finland	2030	100	GWh/d
Estonia	Finland	2040	100	GWh/d
Estonia	Latvia	2030	200	GWh/d
Estonia	Latvia	2040	200	GWh/d
Finland	Estonia	2030	200	GWh/d
Finland	Estonia	2040	200	GWh/d
Finland	Germany	2030	262	GWh/d
Finland	Germany	2040	262	GWh/d
Finland	Sweden	2030	504	GWh/d
Finland	Sweden	2040	504	GWh/d
Finland	Sweden	2030	162	GWh/d
Finland	Sweden	2040	162	GWh/d
France	Belgium	2040	36	GWh/d
France	Belgium	2040	48	GWh/d
France	Belgium	2030	48	GWh/d
France	Belgium	2040	48	GWh/d
France	Germany	2030	204	GWh/d
France	Germany	2040	204	GWh/d
France	Spain	2030	216	GWh/d
France	Spain	2040	216	GWh/d
Germany	Austria	2030	150	GWh/d
Germany	Austria	2040	150	GWh/d
Germany	Belgium	2030	91,2	GWh/d
Germany	Belgium	2040	91,2	GWh/d
Germany	Czechia	2030	144	GWh/d
Germany	Czechia	2040	144	GWh/d
Germany	France	2030	192	GWh/d
Germany	France	2040	192	GWh/d
Germany	Netherlands	2030	172,8	GWh/d
Germany	Netherlands	2040	172,8	GWh/d
Germany	Poland	2030	100	GWh/d
Germany	Poland	2040	100	GWh/d
Greece	Bulgaria	2030	80	GWh/d
Greece	Bulgaria	2040	80	GWh/d
Greece	Cyprus	2040	30	GWh/d
Italy	Austria	2030	168	GWh/d
Italy	Austria	2040	168	GWh/d
Latvia	Estonia	2030	100	GWh/d
Latvia	Estonia	2040	100	GWh/d
Latvia	Lithuania	2030	200	GWh/d
Latvia	Lithuania	2040	200	GWh/d

Lithuania	Latvia	2030	100	GWh/d
Lithuania	Latvia	2040	100	GWh/d
Lithuania	Poland	2030	200	GWh/d
Lithuania	Poland	2040	200	GWh/d
Netherlands	Belgium	2030	36	GWh/d
Netherlands	Belgium	2040	120	GWh/d
Netherlands	Germany	2030	204	GWh/d
Netherlands	Germany	2040	204	GWh/d
Norway	Germany	2040	432	GWh/d
Poland	Germany	2030	200	GWh/d
Poland	Germany	2040	200	GWh/d
Poland	Lithuania	2030	100	GWh/d
Poland	Lithuania	2040	100	GWh/d
Portugal	Spain	2030	81	GWh/d
Portugal	Spain	2040	81	GWh/d
Spain	France	2030	216	GWh/d
Spain	France	2040	216	GWh/d
Spain	Portugal	2030	81	GWh/d
Spain	Portugal	2040	81	GWh/d
Sweden	Finland	2030	504	GWh/d
Sweden	Finland	2040	504	GWh/d
Sweden	Finland	2030	162	GWh/d
Sweden	Finland	2040	162	GWh/d
LH2 Belgium	Belgium	2030	59,3	GWh/d
LH2 Belgium	Belgium	2040	193,6	GWh/d
LH2 France	France	2040	48	GWh/d
LH2 Germany	Germany	2030	31,2	GWh/d
LH2 Germany	Germany	2040	54,7	GWh/d
LH2 Germany	Germany	2030	13	GWh/d
LH2 Germany	Germany	2040	13	GWh/d
LH2 Netherlands	Netherlands	2030	90,8	GWh/d
LH2 Netherlands	Netherlands	2040	177,1	GWh/d
Storage France	France	2040	2	GWh/d
Storage Germany	Germany	2040	17	GWh/d
Storage Spain	Spain	2030	62	GWh/d
Storage Spain	Spain	2040	62	GWh/d
France	Storage France	2040	2	GWh/d
Germany	Storage Germany	2040	17	GWh/d
Spain	Storage Spain	2030	62	GWh/d
Spain	Storage Spain	2040	62	GWh/d

Cross-border, import, storage capacities from Advanced hydrogen infrastructure level

From Country	To Country	Year	ADVANCED	Unit
Algeria	Italy	2030	448	GWh/d
Algeria	Italy	2040	448	GWh/d
Austria	Germany	2030	150	GWh/d
Austria	Germany	2040	150	GWh/d
Austria	Italy	2030	126	GWh/d
Austria	Italy	2040	126	GWh/d
Austria	Slovakia	2030	144	GWh/d
Austria	Slovakia	2040	144	GWh/d
Belgium	France	2040	36	GWh/d
Belgium	France	2040	48	GWh/d
Belgium	France	2030	48	GWh/d
Belgium	France	2040	48	GWh/d
Belgium	Germany	2030	91,2	GWh/d
Belgium	Germany	2040	91,2	GWh/d
Belgium	Netherlands	2030	36	GWh/d
Belgium	Netherlands	2040	120	GWh/d
Bosnia Herzegovina	Croatia	2030	115	GWh/d
Bosnia Herzegovina	Croatia	2040	115	GWh/d
Bulgaria	Greece	2030	80	GWh/d
Bulgaria	Greece	2040	80	GWh/d
Croatia	Bosnia Herzegovina	2030	115	GWh/d
Croatia	Bosnia Herzegovina	2040	115	GWh/d
Czechia	Germany	2030	288	GWh/d
Czechia	Germany	2040	288	GWh/d
Denmark	Germany	2030	103,2	GWh/d
Denmark	Germany	2040	103,2	GWh/d
Estonia	Finland	2030	100	GWh/d
Estonia	Finland	2040	100	GWh/d
Estonia	Latvia	2030	200	GWh/d
Estonia	Latvia	2040	200	GWh/d
Finland	Estonia	2030	200	GWh/d
Finland	Estonia	2040	200	GWh/d
Finland	Germany	2030	262	GWh/d
Finland	Germany	2040	262	GWh/d
Finland	Sweden	2030	504	GWh/d
Finland	Sweden	2040	504	GWh/d
Finland	Sweden	2030	162	GWh/d
Finland	Sweden	2040	162	GWh/d
France	Belgium	2040	36	GWh/d
France	Belgium	2040	48	GWh/d
France	Belgium	2030	48	GWh/d
France	Belgium	2040	48	GWh/d
France	Germany	2030	209,5	GWh/d
France	Germany	2040	209,5	GWh/d
France	Spain	2030	216	GWh/d
France	Spain	2040	216	GWh/d
Germany	Austria	2030	150	GWh/d
Germany	Austria	2040	150	GWh/d
Germany	Belgium	2030	91,2	GWh/d
Germany	Belgium	2040	91,2	GWh/d
Germany	Czechia	2030	288	GWh/d
Germany	Czechia	2040	288	GWh/d
Germany	Denmark	2030	103,2	GWh/d
Germany	Denmark	2040	103,2	GWh/d
Germany	France	2030	192,9	GWh/d
Germany	France	2040	192,9	GWh/d
Germany	Netherlands	2030	298,3	GWh/d

Germany	Netherlands	2040	298,3	GWh/d
Germany	Poland	2030	19,2	GWh/d
Germany	Poland	2040	19,2	GWh/d
Germany	Poland	2030	100	GWh/d
Germany	Poland	2040	100	GWh/d
Greece	Bulgaria	2030	80	GWh/d
Greece	Bulgaria	2040	80	GWh/d
Greece	Cyprus	2040	30	GWh/d
Hungary	Romania	2030	76,8	GWh/d
Hungary	Romania	2040	76,8	GWh/d
Hungary	Slovakia	2030	100	GWh/d
Hungary	Slovakia	2040	100	GWh/d
Italy	Austria	2030	168	GWh/d
Italy	Austria	2040	168	GWh/d
Latvia	Estonia	2030	100	GWh/d
Latvia	Estonia	2040	100	GWh/d
Latvia	Lithuania	2030	200	GWh/d
Latvia	Lithuania	2040	200	GWh/d
Lithuania	Latvia	2030	100	GWh/d
Lithuania	Latvia	2040	100	GWh/d
Lithuania	Poland	2030	200	GWh/d
Lithuania	Poland	2040	200	GWh/d
Netherlands	Belgium	2030	36	GWh/d
Netherlands	Belgium	2040	120	GWh/d
Netherlands	Germany	2030	280,8	GWh/d
Netherlands	Germany	2040	280,8	GWh/d
Norway	Germany	2040	432	GWh/d
Poland	Germany	2030	19,2	GWh/d
Poland	Germany	2040	19,2	GWh/d
Poland	Germany	2030	200	GWh/d
Poland	Germany	2040	200	GWh/d
Poland	Lithuania	2030	100	GWh/d
Poland	Lithuania	2040	100	GWh/d
Portugal	Spain	2030	81	GWh/d
Portugal	Spain	2040	81	GWh/d
Romania	Hungary	2030	100	GWh/d
Romania	Hungary	2040	100	GWh/d
Slovakia	Austria	2030	144	GWh/d
Slovakia	Austria	2040	144	GWh/d
Slovakia	Czechia	2030	144	GWh/d
Slovakia	Czechia	2040	144	GWh/d
Slovakia	Hungary	2030	100	GWh/d
Slovakia	Hungary	2040	100	GWh/d
Spain	France	2030	216	GWh/d
Spain	France	2040	216	GWh/d
Spain	Portugal	2030	81	GWh/d
Spain	Portugal	2040	81	GWh/d
Sweden	Finland	2030	504	GWh/d
Sweden	Finland	2040	504	GWh/d
Sweden	Finland	2030	162	GWh/d
Sweden	Finland	2040	162	GWh/d
Ukraine	Slovakia	2030	144	GWh/d
Ukraine	Slovakia	2040	144	GWh/d
LH2 Belgium	Belgium	2030	59,3	GWh/d
LH2 Belgium	Belgium	2040	193,6	GWh/d
LH2 France	France	2040	48	GWh/d
LH2 Germany	Germany	2030	31,2	GWh/d
LH2 Germany	Germany	2040	54,7	GWh/d
LH2 Germany	Germany	2030	13	GWh/d
LH2 Germany	Germany	2040	13	GWh/d
LH2 Netherlands	Netherlands	2030	136,3	GWh/d
LH2 Netherlands	Netherlands	2040	222,6	GWh/d
Storage France	France	2040	2	GWh/d
Storage France	France	2030	10	GWh/d
Storage France	France	2040	10	GWh/d
Storage Germany	Germany	2030	63,25	GWh/d

Storage Germany	Germany	2040	80,25	GWh/d
Storage Italy	Italy	2040	6	GWh/d
Storage Spain	Spain	2030	62	GWh/d
Storage Spain	Spain	2040	62	GWh/d
France	Storage France	2040	2	GWh/d
France	Storage France	2030	10	GWh/d
France	Storage France	2040	10	GWh/d
Germany	Storage Germany	2030	63,25	GWh/d
Germany	Storage Germany	2040	80,25	GWh/d
Greece	Storage Greece	2030	35	GWh/d
Greece	Storage Greece	2040	35	GWh/d
Italy	Storage Italy	2040	6	GWh/d
Spain	Storage Spain	2030	62	GWh/d
Spain	Storage Spain	2040	62	GWh/d

Internal capacities between Zone 1 and Zone 2:

BORDER	*YEAR*	*Summary Direction 2*	*Units*
ATH2Z1-ATH2Z2	2030	0	GW/Day
ATH2Z1-ATH2Z2	2040	0	GW/Day
BEH2Z1-BEH2Z2	2030	15,6	GW/Day
BEH2Z1-BEH2Z2	2040	15,6	GW/Day
BGH2Z1-BGH2Z2	2030	9,12	GW/Day
BGH2Z1-BGH2Z2	2040	9,12	GW/Day
CZH2Z1-CZH2Z2	2030	0	GW/Day
CZH2Z1-CZH2Z2	2040	0	GW/Day
DEH2Z1-DEH2Z2	2030	66,24	GW/Day
DEH2Z1-DEH2Z2	2040	66,24	GW/Day
EEH2Z1-EEH2Z2	2030	0	GW/Day
EEH2Z1-EEH2Z2	2040	0	GW/Day
ESH2Z1-ESH2Z2	2030	0	GW/Day
ESH2Z1-ESH2Z2	2040	0	GW/Day
FIH2Z1-FIH2Z2	2030	0	GW/Day
FIH2Z1-FIH2Z2	2040	0	GW/Day
FRH2Z1-FRH2Z2	2030	18	GW/Day
FRH2Z1-FRH2Z2	2040	18	GW/Day
GRH2Z1-GRH2Z2	2030	5,28	GW/Day
GRH2Z1-GRH2Z2	2040	5,28	GW/Day
HRH2Z1-HRH2Z2	2030	6,24	GW/Day
HRH2Z1-HRH2Z2	2040	6,24	GW/Day
HUH2Z1-HUH2Z2	2030	8,64	GW/Day
HUH2Z1-HUH2Z2	2040	8,64	GW/Day
ITH2Z1-ITH2Z2	2030	21,36	GW/Day
ITH2Z1-ITH2Z2	2040	21,36	GW/Day
LTH2Z1-LTH2Z2	2030	0	GW/Day
LTH2Z1-LTH2Z2	2040	0	GW/Day
NLH2Z1-NLH2Z2	2030	45,84	GW/Day
NLH2Z1-NLH2Z2	2040	45,84	GW/Day
PLH2Z1-PLH2Z2	2030	0	GW/Day
PLH2Z1-PLH2Z2	2040	0	GW/Day
PTH2Z1-PTH2Z2	2030	0	GW/Day
PTH2Z1-PTH2Z2	2040	0	GW/Day
ROH2Z1-ROH2Z2	2030	0	GW/Day
ROH2Z1-ROH2Z2	2040	0	GW/Day
SEH2Z1-SEH2Z2	2030	0	GW/Day
SEH2Z1-SEH2Z2	2040	0	GW/Day
SKH2Z1-SKH2Z2	2030	0	GW/Day
SKH2Z1-SKH2Z2	2040	0	GW/Day
UKH2Z1-UKH2Z2	2030	13,44	GW/Day
UKH2Z1-UKH2Z2	2040	13,44	GW/Day

Cross-border, import, storage capacities from **Low natural gas** infrastructure level

From Country	*To Country*	*Year*	*LOW*	*Unit*
Albania	Italy	2030	325	GWh/d
Albania	Italy	2040	325	GWh/d
Algeria	Italy	2030	1154,47	GWh/d
Algeria	Italy	2040	1154,47	GWh/d
Algeria	Spain	2030	337,1	GWh/d
Algeria	Spain	2040	337,1	GWh/d
Austria	Germany	2030	340,5	GWh/d
Austria	Germany	2040	340,5	GWh/d
Austria	Germany	2030	136,9	GWh/d
Austria	Germany	2040	136,9	GWh/d
Austria	Germany	2030	399,45	GWh/d
Austria	Germany	2040	399,5	GWh/d
Austria	Hungary	2030	153,1	GWh/d
Austria	Hungary	2040	153,1	GWh/d
Austria	Italy	2030	1176,1	GWh/d
Austria	Italy	2040	1176,1	GWh/d
Austria	Slovakia	2030	138,3	GWh/d
Austria	Slovakia	2040	138,3	GWh/d
Austria	Slovakia	2030	246,5	GWh/d
Austria	Slovakia	2040	246,5	GWh/d
Austria	Slovenia	2030	112,5	GWh/d
Austria	Slovenia	2040	112,5	GWh/d
Belarus	Lithuania	2030	325,4	GWh/d
Belarus	Lithuania	2040	325,4	GWh/d
Belgium	France	2030	640	GWh/d
Belgium	France	2040	640	GWh/d
Belgium	France	2030	170	GWh/d
Belgium	France	2040	170	GWh/d
Belgium	Germany	2030	230,4	GWh/d
Belgium	Germany	2040	230,4	GWh/d
Belgium	Germany	2030	410,6	GWh/d
Belgium	Germany	2040	345,2	GWh/d
Belgium	Luxemburg	2030	48,8	GWh/d
Belgium	Luxemburg	2040	48,8	GWh/d
Belgium	Netherlands	2030	428,4	GWh/d
Belgium	Netherlands	2040	428,4	GWh/d
Belgium	United Kingdom	2030	803,4	GWh/d
Belgium	United Kingdom	2040	803,4	GWh/d
Bulgaria	Greece	2030	120,4	GWh/d
Bulgaria	Greece	2040	120,4	GWh/d
Bulgaria	North Macedonia	2030	32,5	GWh/d
Bulgaria	North Macedonia	2040	32,5	GWh/d
Bulgaria	Romania	2030	184,5	GWh/d
Bulgaria	Romania	2040	184,5	GWh/d
Bulgaria	Serbia	2030	406,5	GWh/d
Bulgaria	Serbia	2040	406,5	GWh/d
Croatia	Hungary	2030	51,05	GWh/d
Croatia	Hungary	2040	51,05	GWh/d
Croatia	Slovenia	2030	7,7	GWh/d
Croatia	Slovenia	2040	7,7	GWh/d
Czechia	Germany	2030	625,8	GWh/d
Czechia	Germany	2040	625,8	GWh/d
Czechia	Germany	2030	335,1	GWh/d
Czechia	Germany	2040	335,1	GWh/d
Czechia	Poland	2030	28,03	GWh/d
Czechia	Poland	2040	28,03	GWh/d
Czechia	Slovakia	2030	1399	GWh/d
Czechia	Slovakia	2040	1399	GWh/d
Czechia	Slovakia	2030	95,6	GWh/d
Czechia	Slovakia	2040	95,6	GWh/d
Denmark	Germany	2030	11,6	GWh/d

Denmark	Germany	2040	11,6	GWh/d
Denmark	Germany	2030	4,1	GWh/d
Denmark	Germany	2040	4,1	GWh/d
Denmark	Poland	2030	321,6	GWh/d
Denmark	Poland	2040	321,6	GWh/d
Estonia	Finland	2030	70,5	GWh/d
Estonia	Finland	2040	70,5	GWh/d
Estonia	Latvia	2030	75,6	GWh/d
Estonia	Latvia	2040	75,6	GWh/d
Finland	Estonia	2030	78	GWh/d
Finland	Estonia	2040	78	GWh/d
France	Belgium	2030	270	GWh/d
France	Belgium	2040	270	GWh/d
France	Germany	2030	100	GWh/d
France	Germany	2040	100	GWh/d
France	Spain	2030	164,6	GWh/d
France	Spain	2040	164,6	GWh/d
France	Switzerland	2030	259,0	GWh/d
France	Switzerland	2040	259,0	GWh/d
Germany	Austria	2030	298,3	GWh/d
Germany	Austria	2040	298,3	GWh/d
Germany	Austria	2030	31,1	GWh/d
Germany	Austria	2040	31,1	GWh/d
Germany	Austria	2030	25,4	GWh/d
Germany	Austria	2040	25,4	GWh/d
Germany	Austria	2030	78,9	GWh/d
Germany	Austria	2040	78,9	GWh/d
Germany	Austria	2030	340,3	GWh/d
Germany	Austria	2040	340,3	GWh/d
Germany	Belgium	2030	129,4	GWh/d
Germany	Belgium	2040	129,4	GWh/d
Germany	Belgium	2030	226,5	GWh/d
Germany	Belgium	2040	226,5	GWh/d
Germany	Czechia	2030	190,37	GWh/d
Germany	Czechia	2040	190,37	GWh/d
Germany	Czechia	2030	721,2	GWh/d
Germany	Czechia	2040	721,2	GWh/d
Germany	Denmark	2030	101,2	GWh/d
Germany	Denmark	2040	101,2	GWh/d
Germany	Denmark	2030	22,5	GWh/d
Germany	Denmark	2040	22,5	GWh/d
Germany	France	2030	613,7	GWh/d
Germany	France	2040	613,7	GWh/d
Germany	Luxemburg	2030	24	GWh/d
Germany	Luxemburg	2040	24	GWh/d
Germany	Netherlands	2030	493,1	GWh/d
Germany	Netherlands	2040	493,1	GWh/d
Germany	Netherlands	2030	162,2	GWh/d
Germany	Netherlands	2040	162,2	GWh/d
Germany	Netherlands	2030	69,6	GWh/d
Germany	Netherlands	2040	69,6	GWh/d
Germany	Netherlands	2030	197,1	GWh/d
Germany	Netherlands	2040	197,1	GWh/d
Germany	Netherlands	2030	117,2	GWh/d
Germany	Netherlands	2040	117,2	GWh/d
Germany	Netherlands	2030	754,6	GWh/d
Germany	Netherlands	2040	754,6	GWh/d
Germany	Poland	2030	48,7	GWh/d
Germany	Poland	2040	48,7	GWh/d
Germany	Poland	2030	277,58	GWh/d
Germany	Poland	2040	277,58	GWh/d
Germany	Switzerland	2030	581,48	GWh/d
Germany	Switzerland	2040	581,48	GWh/d
Greece	Bulgaria	2030	66,57	GWh/d
Greece	Bulgaria	2040	66,57	GWh/d
Greece	Bulgaria	2030	106	GWh/d

Greece	Bulgaria	2040	106	GWh/d
Greece	Bulgaria	2030	119,4	GWh/d
Greece	Bulgaria	2040	119,4	GWh/d
Greece	North Macedonia	2030	28	GWh/d
Greece	North Macedonia	2040	28	GWh/d
Hungary	Croatia	2030	77,6	GWh/d
Hungary	Croatia	2040	77,6	GWh/d
Hungary	Romania	2030	77,5	GWh/d
Hungary	Romania	2040	77,5	GWh/d
Hungary	Serbia	2030	142,0	GWh/d
Hungary	Serbia	2040	142,0	GWh/d
Hungary	Slovakia	2030	50,9	GWh/d
Hungary	Slovakia	2040	50,9	GWh/d
Hungary	Ukraine	2030	84,8	GWh/d
Hungary	Ukraine	2040	84,8	GWh/d
Ireland	United Kingdom	2030	66,3	GWh/d
Ireland	United Kingdom	2040	66,3	GWh/d
Italy	Austria	2030	268,6	GWh/d
Italy	Austria	2040	268,6	GWh/d
Italy	San Marino	2030	4,31	GWh/d
Italy	San Marino	2040	4,31	GWh/d
Italy	Slovenia	2030	39,0	GWh/d
Italy	Slovenia	2040	39,0	GWh/d
Italy	Switzerland	2030	374,8	GWh/d
Italy	Switzerland	2040	374,8	GWh/d
Italy	Switzerland	2030	13,0	GWh/d
Italy	Switzerland	2040	13,0	GWh/d
Latvia	Estonia	2030	75,6	GWh/d
Latvia	Estonia	2040	75,6	GWh/d
Latvia	Lithuania	2030	82	GWh/d
Latvia	Lithuania	2040	82	GWh/d
Latvia	Russia	2030	105	GWh/d
Latvia	Russia	2040	105	GWh/d
Libya	Italy	2030	493,7	GWh/d
Libya	Italy	2040	493,7	GWh/d
Lithuania	Latvia	2030	90	GWh/d
Lithuania	Latvia	2040	90	GWh/d
Lithuania	Poland	2030	58,1	GWh/d
Lithuania	Poland	2040	58,1	GWh/d
Lithuania	Russia	2030	114,2	GWh/d
Lithuania	Russia	2040	114,2	GWh/d
Moldavia	Romania	2030	21,6	GWh/d
Moldavia	Romania	2040	21,6	GWh/d
Morocco	Spain	2030	442,9	GWh/d
Morocco	Spain	2040	442,9	GWh/d
Netherlands	Belgium	2030	650,4	GWh/d
Netherlands	Belgium	2040	650,4	GWh/d
Netherlands	Belgium	2030	595,6	GWh/d
Netherlands	Belgium	2040	595,6	GWh/d
Netherlands	Germany	2030	48,72	GWh/d
Netherlands	Germany	2040	48,72	GWh/d
Netherlands	Germany	2030	94,53	GWh/d
Netherlands	Germany	2040	94,53	GWh/d
Netherlands	Germany	2030	88,8	GWh/d
Netherlands	Germany	2040	88,8	GWh/d
Netherlands	Germany	2030	334,0	GWh/d
Netherlands	Germany	2040	334,0	GWh/d
Netherlands	Germany	2030	2,4	GWh/d
Netherlands	Germany	2030	75,8	GWh/d
Netherlands	Germany	2040	75,8	GWh/d
Netherlands	Germany	2030	370,7	GWh/d
Netherlands	Germany	2040	370,7	GWh/d
Netherlands	United Kingdom	2030	494,4	GWh/d
Netherlands	United Kingdom	2040	494,4	GWh/d
Norway	Belgium	2030	488	GWh/d
Norway	Belgium	2040	488	GWh/d

Norway	Denmark	2030	321,6	GWh/d
Norway	Denmark	2040	321,6	GWh/d
Norway	France	2030	575	GWh/d
Norway	France	2040	575	GWh/d
Norway	Germany	2030	306,4	GWh/d
Norway	Germany	2040	306,4	GWh/d
Norway	Germany	2030	422,7	GWh/d
Norway	Germany	2040	422,7	GWh/d
Norway	Germany	2030	211,9	GWh/d
Norway	Germany	2040	211,9	GWh/d
Norway	Germany	2030	57,6	GWh/d
Norway	Germany	2040	57,6	GWh/d
Norway	Germany	2030	232,3	GWh/d
Norway	Germany	2040	232,3	GWh/d
Norway	Netherlands	2030	963,6	GWh/d
Norway	Netherlands	2040	963,6	GWh/d
Norway	United Kingdom	2030	1499,1	GWh/d
Norway	United Kingdom	2040	1499,1	GWh/d
Poland	Denmark	2030	91,2	GWh/d
Poland	Denmark	2040	91,2	GWh/d
Poland	Germany	2030	0,09	GWh/d
Poland	Germany	2040	0,09	GWh/d
Poland	Lithuania	2030	21,4	GWh/d
Poland	Lithuania	2040	21,4	GWh/d
Poland	Slovakia	2030	144,5	GWh/d
Poland	Slovakia	2040	144,5	GWh/d
Portugal	Spain	2030	80	GWh/d
Portugal	Spain	2040	80	GWh/d
Romania	Bulgaria	2030	231,5	GWh/d
Romania	Bulgaria	2040	231,5	GWh/d
Romania	Hungary	2030	73,37	GWh/d
Romania	Hungary	2040	73,37	GWh/d
Romania	Moldavia	2030	55,7	GWh/d
Romania	Moldavia	2040	55,7	GWh/d
Russia	Estonia	2030	26,8	GWh/d
Russia	Estonia	2040	26,8	GWh/d
Russia	Germany	2030	217,9	GWh/d
Russia	Germany	2040	217,9	GWh/d
Russia	Germany	2030	117,5	GWh/d
Russia	Germany	2040	117,5	GWh/d
Russia	Latvia	2030	105	GWh/d
Russia	Latvia	2040	105	GWh/d
Serbia	Bosnia Herzegovina	2030	14	GWh/d
Serbia	Bosnia Herzegovina	2040	14	GWh/d
Serbia	Bulgaria	2030	342,3	GWh/d
Serbia	Bulgaria	2040	342,3	GWh/d
Serbia	Hungary	2030	245,8	GWh/d
Serbia	Hungary	2040	245,8	GWh/d
Slovakia	Austria	2030	138,3	GWh/d
Slovakia	Austria	2040	138,3	GWh/d
Slovakia	Austria	2030	1570,4	GWh/d
Slovakia	Austria	2040	1570,4	GWh/d
Slovakia	Czechia	2030	395,2	GWh/d
Slovakia	Czechia	2040	395,2	GWh/d
Slovakia	Czechia	2030	74,34	GWh/d
Slovakia	Czechia	2040	74,34	GWh/d
Slovakia	Hungary	2030	129,0	GWh/d
Slovakia	Hungary	2040	129,0	GWh/d
Slovakia	Poland	2030	173,9	GWh/d
Slovakia	Poland	2040	173,9	GWh/d
Slovakia	Ukraine	2030	287,3	GWh/d
Slovakia	Ukraine	2040	287,3	GWh/d
Slovenia	Croatia	2030	53,7	GWh/d
Slovenia	Croatia	2040	53,7	GWh/d
Slovenia	Italy	2030	25,8	GWh/d
Slovenia	Italy	2040	25,8	GWh/d

Spain	France	2030	224,4	GWh/d
Spain	France	2040	224,4	GWh/d
Spain	Morocco	2030	31,9	GWh/d
Spain	Morocco	2040	31,9	GWh/d
Spain	Portugal	2030	144	GWh/d
Spain	Portugal	2040	144	GWh/d
Switzerland	France	2030	100	GWh/d
Switzerland	France	2040	100	GWh/d
Switzerland	Germany	2030	172	GWh/d
Switzerland	Germany	2040	172	GWh/d
Switzerland	Italy	2030	640,5	GWh/d
Switzerland	Italy	2040	640,5	GWh/d
Turkey	Bulgaria	2030	584,1	GWh/d
Turkey	Bulgaria	2040	584,1	GWh/d
Turkey	Greece	2030	350	GWh/d
Turkey	Greece	2040	350	GWh/d
Ukraine	Hungary	2030	517,5	GWh/d
Ukraine	Hungary	2040	517,5	GWh/d
Ukraine	Moldavia	2030	465,3	GWh/d
Ukraine	Moldavia	2040	465,3	GWh/d
Ukraine	Poland	2030	135,6	GWh/d
Ukraine	Poland	2040	135,6	GWh/d
Ukraine	Romania	2030	201,9	GWh/d
Ukraine	Romania	2040	201,9	GWh/d
Ukraine	Slovakia	2030	1649,2	GWh/d
Ukraine	Slovakia	2040	1649,2	GWh/d
Ukraine	Slovakia	2030	202,2	GWh/d
Ukraine	Slovakia	2040	202,2	GWh/d
United Kingdom	Belgium	2030	651,7	GWh/d
United Kingdom	Belgium	2040	651,7	GWh/d
United Kingdom	Ireland	2030	297,3	GWh/d
United Kingdom	Ireland	2040	297,3	GWh/d
United Kingdom	Netherlands	2030	168	GWh/d
United Kingdom	Netherlands	2040	168	GWh/d
LNG Belgium	Belgium	2030	668,9	GWh/d
LNG Belgium	Belgium	2040	668,9	GWh/d
LNG Croatia	Croatia	2030	85,5	GWh/d
LNG Croatia	Croatia	2040	85,5	GWh/d
LNG Finland	Finland	2030	146	GWh/d
LNG Finland	Finland	2040	146	GWh/d
LNG France	France	2030	150	GWh/d
LNG France	France	2040	150	GWh/d
LNG France	France	2030	320,5	GWh/d
LNG France	France	2040	320,5	GWh/d
LNG France	France	2030	416,7	GWh/d
LNG France	France	2040	416,7	GWh/d
LNG France	France	2030	368,6	GWh/d
LNG France	France	2040	368,6	GWh/d
LNG Germany	Germany	2030	341,7	GWh/d
LNG Germany	Germany	2040	341,7	GWh/d
LNG Germany	Germany	2030	240,4	GWh/d
LNG Germany	Germany	2040	240,4	GWh/d
LNG Greece	Greece	2030	224,6	GWh/d
LNG Greece	Greece	2040	224,6	GWh/d
LNG Italy	Italy	2030	596,4	GWh/d
LNG Italy	Italy	2040	596,4	GWh/d
LNG Italy	Italy	2030	288,5	GWh/d
LNG Italy	Italy	2040	288,5	GWh/d
LNG Lithuania	Lithuania	2030	122,4	GWh/d
LNG Lithuania	Lithuania	2040	122,4	GWh/d
LNG Malta	Malta	2030	22,4	GWh/d
LNG Malta	Malta	2040	22,4	GWh/d
LNG Netherlands	Netherlands	2030	876	GWh/d
LNG Netherlands	Netherlands	2040	876	GWh/d
LNG Poland	Poland	2030	227,3	GWh/d
LNG Poland	Poland	2040	227,3	GWh/d

LNG Portugal	Portugal	2030	200	GWh/d
LNG Portugal	Portugal	2040	200	GWh/d
LNG Spain	Spain	2030	1197,0	GWh/d
LNG Spain	Spain	2040	1197,0	GWh/d
LNG Spain	Spain	2030	936,15	GWh/d
LNG Spain	Spain	2040	936,15	GWh/d
LNG United Kingdom	United Kingdom	2030	1616,4	GWh/d
LNG United Kingdom	United Kingdom	2040	1616,4	GWh/d
Storage Austria	Austria	2030	526,8	GWh/d
Storage Austria	Austria	2040	526,8	GWh/d
Storage Belgium	Belgium	2030	169,5	GWh/d
Storage Belgium	Belgium	2040	169,5	GWh/d
Storage Croatia	Croatia	2030	56,37	GWh/d
Storage Croatia	Croatia	2040	56,37	GWh/d
Storage Czechia	Czechia	2030	534,8	GWh/d
Storage Czechia	Czechia	2040	534,8	GWh/d
Storage Czechia	Czechia	2030	50,9	GWh/d
Storage Czechia	Czechia	2040	50,9	GWh/d
Storage Denmark	Denmark	2030	180,9	GWh/d
Storage Denmark	Denmark	2040	180,9	GWh/d
Storage France	France	2030	562,5	GWh/d
Storage France	France	2040	562,5	GWh/d
Storage France	France	2030	445,3	GWh/d
Storage France	France	2040	445,3	GWh/d
Storage France	France	2030	223	GWh/d
Storage France	France	2040	223	GWh/d
Storage France	France	2030	558,2	GWh/d
Storage France	France	2040	558,2	GWh/d
Storage France	France	2030	555,0	GWh/d
Storage France	France	2040	555,0	GWh/d
Storage Germany	Germany	2030	1760,0	GWh/d
Storage Germany	Germany	2040	1760,0	GWh/d
Storage Germany	Germany	2030	260,8	GWh/d
Storage Germany	Germany	2040	260,8	GWh/d
Storage Germany	Germany	2030	96,9	GWh/d
Storage Germany	Germany	2040	96,9	GWh/d
Storage Germany	Germany	2030	206,6	GWh/d
Storage Germany	Germany	2040	206,6	GWh/d
Storage Germany	Germany	2030	682,4	GWh/d
Storage Germany	Germany	2040	682,4	GWh/d
Storage Hungary	Hungary	2030	673,4	GWh/d
Storage Hungary	Hungary	2040	673,4	GWh/d
Storage Hungary	Hungary	2030	272,6	GWh/d
Storage Hungary	Hungary	2040	272,6	GWh/d
Storage Italy	Italy	2030	3100,6	GWh/d
Storage Italy	Italy	2040	3100,6	GWh/d
Storage Latvia	Latvia	2030	231	GWh/d
Storage Latvia	Latvia	2040	231	GWh/d
Storage Netherlands	Netherlands	2030	2385,8	GWh/d
Storage Netherlands	Netherlands	2040	2385,8	GWh/d
Storage Poland	Poland	2030	595,3	GWh/d
Storage Poland	Poland	2040	595,3	GWh/d
Storage Portugal	Portugal	2030	84	GWh/d
Storage Portugal	Portugal	2040	84	GWh/d
Storage Romania	Romania	2030	377,0	GWh/d
Storage Romania	Romania	2040	377,0	GWh/d
Storage Serbia	Serbia	2030	50,34	GWh/d
Storage Serbia	Serbia	2040	50,34	GWh/d
Storage Slovakia	Slovakia	2030	491,7	GWh/d
Storage Slovakia	Slovakia	2040	491,7	GWh/d
Storage Spain	Spain	2030	200,5	GWh/d
Storage Spain	Spain	2040	200,5	GWh/d
Storage United Kingdom	United Kingdom	2030	867,7	GWh/d
Storage United Kingdom	United Kingdom	2040	867,7	GWh/d
Austria	Storage Austria	2030	411,6	GWh/d
Austria	Storage Austria	2040	411,6	GWh/d

Belgium	Storage Belgium	2030	88	GWh/d
Belgium	Storage Belgium	2040	88	GWh/d
United Kingdom	Storage United Kingdom	2030	647,5	GWh/d
United Kingdom	Storage United Kingdom	2040	647,5	GWh/d
Bulgaria	Storage Bulgaria	2030	89,8	GWh/d
Bulgaria	Storage Bulgaria	2040	89,8	GWh/d
Croatia	Storage Croatia	2030	42,3	GWh/d
Croatia	Storage Croatia	2040	42,3	GWh/d
Czechia	Storage Czechia	2030	367,5	GWh/d
Czechia	Storage Czechia	2040	367,5	GWh/d
Czechia	Storage Czechia	2030	50,9	GWh/d
Czechia	Storage Czechia	2040	50,9	GWh/d
Denmark	Storage Denmark	2030	90,7	GWh/d
Denmark	Storage Denmark	2040	90,7	GWh/d
France	Storage France	2030	137,6	GWh/d
France	Storage France	2040	137,6	GWh/d
France	Storage France	2030	100	GWh/d
France	Storage France	2040	100	GWh/d
France	Storage France	2030	248,7	GWh/d
France	Storage France	2040	248,7	GWh/d
France	Storage France	2030	333,3	GWh/d
France	Storage France	2040	333,3	GWh/d
France	Storage France	2030	300	GWh/d
France	Storage France	2040	300	GWh/d
Germany	Storage Germany	2030	806,3	GWh/d
Germany	Storage Germany	2040	806,3	GWh/d
Germany	Storage Germany	2030	272,4	GWh/d
Germany	Storage Germany	2040	272,4	GWh/d
Germany	Storage Germany	2030	185,8	GWh/d
Germany	Storage Germany	2040	185,8	GWh/d
Germany	Storage Germany	2030	115,6	GWh/d
Germany	Storage Germany	2040	115,6	GWh/d
Germany	Storage Germany	2030	621,1	GWh/d
Germany	Storage Germany	2040	621,1	GWh/d
Hungary	Storage Hungary	2030	349,1	GWh/d
Hungary	Storage Hungary	2040	349,1	GWh/d
Hungary	Storage Hungary	2030	29,1	GWh/d
Hungary	Storage Hungary	2040	29,1	GWh/d
Italy	Storage Italy	2030	1975,6	GWh/d
Italy	Storage Italy	2040	1975,6	GWh/d
Latvia	Storage Latvia	2030	59,5	GWh/d
Latvia	Storage Latvia	2040	59,5	GWh/d
Netherlands	Storage Netherlands	2030	461	GWh/d
Netherlands	Storage Netherlands	2040	461	GWh/d
Poland	Storage Poland	2030	345,0	GWh/d
Poland	Storage Poland	2040	345,0	GWh/d
Portugal	Storage Portugal	2030	24	GWh/d
Portugal	Storage Portugal	2040	24	GWh/d
Romania	Storage Romania	2030	274,8	GWh/d
Romania	Storage Romania	2040	274,8	GWh/d
Serbia	Storage Serbia	2030	35,2	GWh/d
Serbia	Storage Serbia	2040	35,2	GWh/d
Slovakia	Storage Slovakia	2030	410,7	GWh/d
Slovakia	Storage Slovakia	2040	410,7	GWh/d
Spain	Storage Spain	2030	125,7	GWh/d
Spain	Storage Spain	2040	125,7	GWh/d

Cross-border, import, storage capacities from Advanced natural gas infrastructure level

From Country	To Country	Year	ADVANCED	Unit
Albania	Italy	2030	494,3	GWh/d
Albania	Italy	2040	494,3	GWh/d
Algeria	Italy	2030	1154,5	GWh/d
Algeria	Italy	2040	1154,5	GWh/d
Algeria	Spain	2030	337,1	GWh/d
Algeria	Spain	2040	337,1	GWh/d
Austria	Germany	2030	340,5	GWh/d
Austria	Germany	2040	340,5	GWh/d
Austria	Germany	2030	137,0	GWh/d
Austria	Germany	2040	137,0	GWh/d
Austria	Germany	2030	399,5	GWh/d
Austria	Germany	2040	399,5	GWh/d
Austria	Hungary	2030	153,1	GWh/d
Austria	Hungary	2040	153,1	GWh/d
Austria	Italy	2030	984,4	GWh/d
Austria	Italy	2040	984,4	GWh/d
Austria	Slovakia	2030	138,3	GWh/d
Austria	Slovakia	2040	138,3	GWh/d
Austria	Slovakia	2030	246,5	GWh/d
Austria	Slovakia	2040	246,5	GWh/d
Austria	Slovenia	2030	112,5	GWh/d
Austria	Slovenia	2040	112,5	GWh/d
Belarus	Lithuania	2030	325,4	GWh/d
Belarus	Lithuania	2040	325,4	GWh/d
Belgium	France	2030	640	GWh/d
Belgium	France	2040	595	GWh/d
Belgium	Germany	2030	230,4	GWh/d
Belgium	Germany	2040	230,4	GWh/d
Belgium	Germany	2030	410,6	GWh/d
Belgium	Germany	2040	345,2	GWh/d
Belgium	Luxemburg	2030	48,8	GWh/d
Belgium	Luxemburg	2040	48,8	GWh/d
Belgium	Netherlands	2030	428,4	GWh/d
Belgium	Netherlands	2040	428,4	GWh/d
Belgium	United Kingdom	2030	803,4	GWh/d
Belgium	United Kingdom	2040	803,4	GWh/d
Bulgaria	Greece	2030	120,4	GWh/d
Bulgaria	Greece	2040	120,4	GWh/d
Bulgaria	North Macedonia	2030	32,5	GWh/d
Bulgaria	North Macedonia	2040	32,5	GWh/d
Bulgaria	Romania	2030	184,5	GWh/d
Bulgaria	Romania	2040	184,5	GWh/d
Bulgaria	Serbia	2030	406,5	GWh/d
Bulgaria	Serbia	2040	406,5	GWh/d
Croatia	Hungary	2030	51,7	GWh/d
Croatia	Hungary	2040	51,7	GWh/d
Croatia	Slovenia	2030	7,7	GWh/d
Croatia	Slovenia	2040	7,7	GWh/d
Cyprus	Greece	2030	330	GWh/d
Cyprus	Greece	2040	330	GWh/d
Czechia	Germany	2030	400,5	GWh/d
Czechia	Germany	2040	400,5	GWh/d
Czechia	Germany	2030	335,1	GWh/d
Czechia	Germany	2040	335,1	GWh/d
Czechia	Poland	2030	59,0	GWh/d
Czechia	Poland	2040	59,0	GWh/d
Czechia	Slovakia	2030	1167,6	GWh/d
Czechia	Slovakia	2040	1167,6	GWh/d
Czechia	Slovakia	2030	95,6	GWh/d
Czechia	Slovakia	2040	95,6	GWh/d

Denmark	Germany	2030	36	GWh/d
Denmark	Germany	2040	36	GWh/d
Denmark	Germany	2030	4,1	GWh/d
Denmark	Germany	2040	4,1	GWh/d
Denmark	Poland	2030	321,6	GWh/d
Denmark	Poland	2040	321,6	GWh/d
Estonia	Finland	2030	70,5	GWh/d
Estonia	Finland	2040	70,5	GWh/d
Estonia	Latvia	2030	75,6	GWh/d
Estonia	Latvia	2040	75,6	GWh/d
Finland	Estonia	2030	78	GWh/d
Finland	Estonia	2040	78	GWh/d
France	Belgium	2030	270	GWh/d
France	Belgium	2040	270	GWh/d
France	Germany	2030	100	GWh/d
France	Germany	2040	100	GWh/d
France	Spain	2030	164,6	GWh/d
France	Spain	2040	164,6	GWh/d
France	Switzerland	2030	259,0	GWh/d
France	Switzerland	2040	259,0	GWh/d
Germany	Austria	2030	298,3	GWh/d
Germany	Austria	2040	298,3	GWh/d
Germany	Austria	2030	31,1	GWh/d
Germany	Austria	2040	31,1	GWh/d
Germany	Austria	2030	25,4	GWh/d
Germany	Austria	2040	25,4	GWh/d
Germany	Austria	2030	78,9	GWh/d
Germany	Austria	2040	78,9	GWh/d
Germany	Austria	2030	340,3	GWh/d
Germany	Austria	2040	340,3	GWh/d
Germany	Belgium	2030	129,4	GWh/d
Germany	Belgium	2040	129,4	GWh/d
Germany	Belgium	2030	226,5	GWh/d
Germany	Belgium	2040	226,5	GWh/d
Germany	Czechia	2030	190,4	GWh/d
Germany	Czechia	2040	190,4	GWh/d
Germany	Czechia	2030	721,2	GWh/d
Germany	Czechia	2040	721,2	GWh/d
Germany	Denmark	2030	36,0	GWh/d
Germany	Denmark	2040	36,0	GWh/d
Germany	Denmark	2030	22,5	GWh/d
Germany	Denmark	2040	22,5	GWh/d
Germany	France	2030	613,7	GWh/d
Germany	France	2040	613,7	GWh/d
Germany	Luxemburg	2030	24	GWh/d
Germany	Luxemburg	2040	24	GWh/d
Germany	Netherlands	2030	493,1	GWh/d
Germany	Netherlands	2040	493,1	GWh/d
Germany	Netherlands	2030	162,2	GWh/d
Germany	Netherlands	2040	162,2	GWh/d
Germany	Netherlands	2030	69,6	GWh/d
Germany	Netherlands	2040	69,6	GWh/d
Germany	Netherlands	2030	197,1	GWh/d
Germany	Netherlands	2040	197,1	GWh/d
Germany	Netherlands	2030	117,2	GWh/d
Germany	Netherlands	2040	117,2	GWh/d
Germany	Netherlands	2030	754,6	GWh/d
Germany	Netherlands	2040	754,6	GWh/d
Germany	Poland	2030	48,7	GWh/d
Germany	Poland	2040	48,7	GWh/d
Germany	Poland	2030	277,6	GWh/d
Germany	Poland	2040	277,6	GWh/d
Germany	Switzerland	2030	581,5	GWh/d
Germany	Switzerland	2040	581,5	GWh/d
Greece	Bulgaria	2030	66,6	GWh/d
Greece	Bulgaria	2040	66,6	GWh/d

Greece	Bulgaria	2030	106	GWh/d
Greece	Bulgaria	2040	106	GWh/d
Greece	Bulgaria	2030	119,4	GWh/d
Greece	Bulgaria	2040	119,4	GWh/d
Greece	Cyprus	2030	30	GWh/d
Greece	Cyprus	2040	30	GWh/d
Greece	North Macedonia	2030	28	GWh/d
Greece	North Macedonia	2040	28	GWh/d
Hungary	Croatia	2030	77,6	GWh/d
Hungary	Croatia	2040	77,6	GWh/d
Hungary	Romania	2030	77,5	GWh/d
Hungary	Romania	2040	77,5	GWh/d
Hungary	Serbia	2030	142,0	GWh/d
Hungary	Serbia	2040	142,0	GWh/d
Hungary	Slovakia	2030	50,9	GWh/d
Hungary	Slovakia	2040	50,9	GWh/d
Hungary	Ukraine	2030	84,8	GWh/d
Hungary	Ukraine	2040	84,8	GWh/d
Ireland	United Kingdom	2030	66,3	GWh/d
Ireland	United Kingdom	2040	66,3	GWh/d
Italy	Austria	2030	268,6	GWh/d
Italy	Austria	2040	268,6	GWh/d
Italy	San Marino	2030	4,3	GWh/d
Italy	San Marino	2040	4,3	GWh/d
Italy	Slovenia	2030	39,0	GWh/d
Italy	Slovenia	2040	39,0	GWh/d
Italy	Switzerland	2030	374,8	GWh/d
Italy	Switzerland	2040	374,8	GWh/d
Italy	Switzerland	2030	13,0	GWh/d
Italy	Switzerland	2040	13,0	GWh/d
Latvia	Estonia	2030	75,6	GWh/d
Latvia	Estonia	2040	75,6	GWh/d
Latvia	Lithuania	2030	82	GWh/d
Latvia	Lithuania	2040	82	GWh/d
Latvia	Russia	2030	105	GWh/d
Latvia	Russia	2040	105	GWh/d
Libya	Italy	2030	493,7	GWh/d
Libya	Italy	2040	493,7	GWh/d
Lithuania	Latvia	2030	90	GWh/d
Lithuania	Latvia	2040	90	GWh/d
Lithuania	Poland	2030	58,1	GWh/d
Lithuania	Poland	2040	58,1	GWh/d
Lithuania	Russia	2030	114,2	GWh/d
Lithuania	Russia	2040	114,2	GWh/d
Moldavia	Romania	2030	21,6	GWh/d
Moldavia	Romania	2040	21,6	GWh/d
Morocco	Spain	2030	442,9	GWh/d
Morocco	Spain	2040	442,9	GWh/d
Netherlands	Belgium	2030	650,4	GWh/d
Netherlands	Belgium	2040	650,4	GWh/d
Netherlands	Belgium	2030	595,6	GWh/d
Netherlands	Belgium	2040	595,6	GWh/d
Netherlands	Germany	2030	48,72	GWh/d
Netherlands	Germany	2040	48,72	GWh/d
Netherlands	Germany	2030	94,53	GWh/d
Netherlands	Germany	2040	94,53	GWh/d
Netherlands	Germany	2030	88,8	GWh/d
Netherlands	Germany	2040	88,8	GWh/d
Netherlands	Germany	2030	334,0	GWh/d
Netherlands	Germany	2040	334,0	GWh/d
Netherlands	Germany	2030	2,4	GWh/d
Netherlands	Germany	2030	75,8	GWh/d
Netherlands	Germany	2040	75,8	GWh/d
Netherlands	Germany	2030	370,7	GWh/d
Netherlands	Germany	2040	370,7	GWh/d
Netherlands	United Kingdom	2030	494,4	GWh/d

Netherlands	United Kingdom	2040	494,4	GWh/d
Norway	Belgium	2030	488	GWh/d
Norway	Belgium	2040	488	GWh/d
Norway	Denmark	2030	321,6	GWh/d
Norway	Denmark	2040	321,6	GWh/d
Norway	France	2030	575	GWh/d
Norway	France	2040	575	GWh/d
Norway	Germany	2030	306,4	GWh/d
Norway	Germany	2040	306,4	GWh/d
Norway	Germany	2030	422,7	GWh/d
Norway	Germany	2040	422,7	GWh/d
Norway	Germany	2030	211,9	GWh/d
Norway	Germany	2040	211,9	GWh/d
Norway	Germany	2030	57,6	GWh/d
Norway	Germany	2040	57,6	GWh/d
Norway	Germany	2030	232,3	GWh/d
Norway	Germany	2040	232,3	GWh/d
Norway	Netherlands	2030	963,6	GWh/d
Norway	Netherlands	2040	963,6	GWh/d
Norway	United Kingdom	2030	1499,1	GWh/d
Norway	United Kingdom	2040	1499,1	GWh/d
Poland	Czechia	2030	31	GWh/d
Poland	Czechia	2040	31	GWh/d
Poland	Denmark	2030	91,2	GWh/d
Poland	Denmark	2040	91,2	GWh/d
Poland	Germany	2030	0,1	GWh/d
Poland	Germany	2040	0,1	GWh/d
Poland	Lithuania	2030	21,4	GWh/d
Poland	Lithuania	2040	21,4	GWh/d
Poland	Slovakia	2030	144,5	GWh/d
Poland	Slovakia	2040	144,5	GWh/d
Portugal	Spain	2030	80	GWh/d
Portugal	Spain	2040	80	GWh/d
Romania	Bulgaria	2030	231,5	GWh/d
Romania	Bulgaria	2040	231,5	GWh/d
Romania	Hungary	2030	73,4	GWh/d
Romania	Hungary	2040	73,4	GWh/d
Romania	Moldavia	2030	55,7	GWh/d
Romania	Moldavia	2040	55,7	GWh/d
Romania	Serbia	2030	46,3	GWh/d
Romania	Serbia	2040	46,3	GWh/d
Russia	Estonia	2030	26,8	GWh/d
Russia	Estonia	2040	26,8	GWh/d
Russia	Germany	2030	217,9	GWh/d
Russia	Germany	2040	217,9	GWh/d
Russia	Germany	2030	117,5	GWh/d
Russia	Germany	2040	117,5	GWh/d
Russia	Latvia	2030	105	GWh/d
Russia	Latvia	2040	105	GWh/d
Serbia	Bosnia Herzegovina	2030	14	GWh/d
Serbia	Bosnia Herzegovina	2040	14	GWh/d
Serbia	Bulgaria	2030	342,3	GWh/d
Serbia	Bulgaria	2040	342,3	GWh/d
Serbia	Hungary	2030	245,8	GWh/d
Serbia	Hungary	2040	245,8	GWh/d
Serbia	Romania	2030	46,3	GWh/d
Serbia	Romania	2040	46,3	GWh/d
Slovakia	Austria	2030	138,3	GWh/d
Slovakia	Austria	2040	138,3	GWh/d
Slovakia	Austria	2030	1466,4	GWh/d
Slovakia	Austria	2040	1466,4	GWh/d
Slovakia	Czechia	2030	130	GWh/d
Slovakia	Czechia	2040	130	GWh/d
Slovakia	Czechia	2030	74,3	GWh/d
Slovakia	Czechia	2040	74,3	GWh/d
Slovakia	Hungary	2030	129,0	GWh/d

Slovakia	Hungary	2040	129,0	GWh/d
Slovakia	Poland	2030	173,9	GWh/d
Slovakia	Poland	2040	173,9	GWh/d
Slovakia	Ukraine	2030	287,3	GWh/d
Slovakia	Ukraine	2040	287,3	GWh/d
Slovenia	Croatia	2030	53,7	GWh/d
Slovenia	Croatia	2040	68,9	GWh/d
Slovenia	Italy	2030	25,8	GWh/d
Slovenia	Italy	2040	25,8	GWh/d
Spain	France	2030	224,4	GWh/d
Spain	France	2040	224,4	GWh/d
Spain	Morocco	2030	31,9	GWh/d
Spain	Morocco	2040	31,9	GWh/d
Spain	Portugal	2030	144	GWh/d
Spain	Portugal	2040	144	GWh/d
Switzerland	France	2030	100	GWh/d
Switzerland	France	2040	100	GWh/d
Switzerland	Germany	2030	172	GWh/d
Switzerland	Germany	2040	172	GWh/d
Switzerland	Italy	2030	640,5	GWh/d
Switzerland	Italy	2040	640,5	GWh/d
Turkey	Bulgaria	2030	584,1	GWh/d
Turkey	Bulgaria	2040	584,1	GWh/d
Turkey	Greece	2030	585	GWh/d
Turkey	Greece	2040	585	GWh/d
Ukraine	Hungary	2030	517,5	GWh/d
Ukraine	Hungary	2040	517,5	GWh/d
Ukraine	Moldavia	2030	465,3	GWh/d
Ukraine	Moldavia	2040	465,3	GWh/d
Ukraine	Poland	2030	135,6	GWh/d
Ukraine	Poland	2040	135,6	GWh/d
Ukraine	Romania	2030	201,9	GWh/d
Ukraine	Romania	2040	201,9	GWh/d
Ukraine	Slovakia	2030	1435,2	GWh/d
Ukraine	Slovakia	2040	1435,2	GWh/d
Ukraine	Slovakia	2030	202,16	GWh/d
Ukraine	Slovakia	2040	202,16	GWh/d
United Kingdom	Belgium	2030	651,7	GWh/d
United Kingdom	Belgium	2040	651,7	GWh/d
United Kingdom	Ireland	2030	297,3	GWh/d
United Kingdom	Ireland	2040	297,3	GWh/d
United Kingdom	Netherlands	2030	168	GWh/d
United Kingdom	Netherlands	2040	168	GWh/d
LNG Belgium	Belgium	2030	668,9	GWh/d
LNG Belgium	Belgium	2040	668,9	GWh/d
LNG Croatia	Croatia	2030	85,5	GWh/d
LNG Croatia	Croatia	2040	85,5	GWh/d
LNG Finland	Finland	2030	146	GWh/d
LNG Finland	Finland	2040	146	GWh/d
LNG France	France	2030	150	GWh/d
LNG France	France	2040	150	GWh/d
LNG France	France	2030	320,5	GWh/d
LNG France	France	2040	320,5	GWh/d
LNG France	France	2030	416,7	GWh/d
LNG France	France	2040	416,7	GWh/d
LNG France	France	2030	368,6	GWh/d
LNG France	France	2040	368,6	GWh/d
LNG Germany	Germany	2030	629,4	GWh/d
LNG Germany	Germany	2040	629,4	GWh/d
LNG Germany	Germany	2030	240,4	GWh/d
LNG Germany	Germany	2040	240,4	GWh/d
LNG Greece	Greece	2030	224,6	GWh/d
LNG Greece	Greece	2040	224,6	GWh/d
LNG Greece	Greece	2030	189	GWh/d
LNG Greece	Greece	2040	189	GWh/d
LNG Italy	Italy	2030	666,8	GWh/d

LNG Italy	Italy	2040	666,8	GWh/d
LNG Italy	Italy	2030	288,5	GWh/d
LNG Italy	Italy	2040	288,5	GWh/d
LNG Italy	Italy	2030	93	GWh/d
LNG Italy	Italy	2040	93	GWh/d
LNG Lithuania	Lithuania	2030	122,4	GWh/d
LNG Lithuania	Lithuania	2040	122,4	GWh/d
LNG Malta	Malta	2030	22,4	GWh/d
LNG Malta	Malta	2040	22,4	GWh/d
LNG Netherlands	Netherlands	2030	876	GWh/d
LNG Netherlands	Netherlands	2040	876	GWh/d
LNG Poland	Poland	2030	437,3	GWh/d
LNG Poland	Poland	2040	437,3	GWh/d
LNG Portugal	Portugal	2030	200	GWh/d
LNG Portugal	Portugal	2040	200	GWh/d
LNG Spain	Spain	2030	1197,0	GWh/d
LNG Spain	Spain	2040	1197,0	GWh/d
LNG Spain	Spain	2030	936,2	GWh/d
LNG Spain	Spain	2040	936,2	GWh/d
LNG United Kingdom	United Kingdom	2030	1616,4	GWh/d
LNG United Kingdom	United Kingdom	2040	1616,4	GWh/d
Storage Austria	Austria	2030	526,8	GWh/d
Storage Austria	Austria	2040	526,8	GWh/d
Storage Belgium	Belgium	2030	169,5	GWh/d
Storage Belgium	Belgium	2040	169,5	GWh/d
Storage Croatia	Croatia	2030	56,4	GWh/d
Storage Croatia	Croatia	2040	56,4	GWh/d
Storage Czechia	Czechia	2030	534,8	GWh/d
Storage Czechia	Czechia	2040	534,8	GWh/d
Storage Czechia	Czechia	2030	50,9	GWh/d
Storage Czechia	Czechia	2040	50,9	GWh/d
Storage Denmark	Denmark	2030	180,9	GWh/d
Storage Denmark	Denmark	2040	180,9	GWh/d
Storage France	France	2030	562,5	GWh/d
Storage France	France	2040	562,5	GWh/d
Storage France	France	2030	445,3	GWh/d
Storage France	France	2040	445,3	GWh/d
Storage France	France	2030	223	GWh/d
Storage France	France	2040	223	GWh/d
Storage France	France	2030	558,2	GWh/d
Storage France	France	2040	558,2	GWh/d
Storage France	France	2030	555,0	GWh/d
Storage France	France	2040	555,0	GWh/d
Storage Germany	Germany	2030	1760,0	GWh/d
Storage Germany	Germany	2040	1760,0	GWh/d
Storage Germany	Germany	2030	260,8	GWh/d
Storage Germany	Germany	2040	260,8	GWh/d
Storage Germany	Germany	2030	96,9	GWh/d
Storage Germany	Germany	2040	96,9	GWh/d
Storage Germany	Germany	2030	206,6	GWh/d
Storage Germany	Germany	2040	206,6	GWh/d
Storage Germany	Germany	2030	682,4	GWh/d
Storage Germany	Germany	2040	682,4	GWh/d
Storage Hungary	Hungary	2030	673,4	GWh/d
Storage Hungary	Hungary	2040	673,4	GWh/d
Storage Hungary	Hungary	2030	272,6	GWh/d
Storage Hungary	Hungary	2040	272,6	GWh/d
Storage Italy	Italy	2030	3100,6	GWh/d
Storage Italy	Italy	2040	3100,6	GWh/d
Storage Latvia	Latvia	2030	231	GWh/d
Storage Latvia	Latvia	2040	231	GWh/d
Storage Netherlands	Netherlands	2030	2385,8	GWh/d
Storage Netherlands	Netherlands	2040	2385,8	GWh/d
Storage Poland	Poland	2030	595,3	GWh/d
Storage Poland	Poland	2040	595,3	GWh/d
Storage Portugal	Portugal	2030	84	GWh/d

Storage Portugal	Portugal	2040	84	GWh/d
Storage Romania	Romania	2030	377,0	GWh/d
Storage Romania	Romania	2040	377,0	GWh/d
Storage Serbia	Serbia	2030	50,4	GWh/d
Storage Serbia	Serbia	2040	50,4	GWh/d
Storage Slovakia	Slovakia	2030	491,7	GWh/d
Storage Slovakia	Slovakia	2040	491,7	GWh/d
Storage Spain	Spain	2030	200,5	GWh/d
Storage Spain	Spain	2040	200,5	GWh/d
Storage United Kingdom	United Kingdom	2030	867,7	GWh/d
Storage United Kingdom	United Kingdom	2040	867,7	GWh/d
Austria	Storage Austria	2030	411,6	GWh/d
Austria	Storage Austria	2040	411,6	GWh/d
Belgium	Storage Belgium	2030	88	GWh/d
Belgium	Storage Belgium	2040	88	GWh/d
United Kingdom	Storage United Kingdom	2030	647,5	GWh/d
United Kingdom	Storage United Kingdom	2040	647,5	GWh/d
Bulgaria	Storage Bulgaria	2030	89,8	GWh/d
Bulgaria	Storage Bulgaria	2040	89,8	GWh/d
Croatia	Storage Croatia	2030	42,3	GWh/d
Croatia	Storage Croatia	2040	42,3	GWh/d
Czechia	Storage Czechia	2030	367,5	GWh/d
Czechia	Storage Czechia	2040	367,5	GWh/d
Czechia	Storage Czechia	2030	50,9	GWh/d
Czechia	Storage Czechia	2040	50,9	GWh/d
Denmark	Storage Denmark	2030	90,7	GWh/d
Denmark	Storage Denmark	2040	90,7	GWh/d
France	Storage France	2030	137,6	GWh/d
France	Storage France	2040	137,6	GWh/d
France	Storage France	2030	100	GWh/d
France	Storage France	2040	100	GWh/d
France	Storage France	2030	248,7	GWh/d
France	Storage France	2040	248,7	GWh/d
France	Storage France	2030	333,3	GWh/d
France	Storage France	2040	333,3	GWh/d
France	Storage France	2030	300,0	GWh/d
France	Storage France	2040	300,0	GWh/d
Germany	Storage Germany	2030	806,3	GWh/d
Germany	Storage Germany	2040	806,3	GWh/d
Germany	Storage Germany	2030	272,4	GWh/d
Germany	Storage Germany	2040	272,4	GWh/d
Germany	Storage Germany	2030	185,7	GWh/d
Germany	Storage Germany	2040	185,7	GWh/d
Germany	Storage Germany	2030	115,6	GWh/d
Germany	Storage Germany	2040	115,6	GWh/d
Germany	Storage Germany	2030	621,1	GWh/d
Germany	Storage Germany	2040	621,1	GWh/d
Hungary	Storage Hungary	2030	349,1	GWh/d
Hungary	Storage Hungary	2040	349,1	GWh/d
Hungary	Storage Hungary	2030	29,1	GWh/d
Hungary	Storage Hungary	2040	29,1	GWh/d
Italy	Storage Italy	2030	1975,6	GWh/d
Italy	Storage Italy	2040	1975,6	GWh/d
Latvia	Storage Latvia	2030	59,5	GWh/d
Latvia	Storage Latvia	2040	59,5	GWh/d
Netherlands	Storage Netherlands	2030	461,0	GWh/d
Netherlands	Storage Netherlands	2040	461,0	GWh/d
Poland	Storage Poland	2030	345,0	GWh/d
Poland	Storage Poland	2040	345,0	GWh/d
Portugal	Storage Portugal	2030	24	GWh/d
Portugal	Storage Portugal	2040	24	GWh/d
Romania	Storage Romania	2030	274,8	GWh/d
Romania	Storage Romania	2040	274,8	GWh/d
Serbia	Storage Serbia	2030	35,2	GWh/d
Serbia	Storage Serbia	2040	35,2	GWh/d
Slovakia	Storage Slovakia	2030	410,7	GWh/d

Slovakia	Storage Slovakia	2040	410,7	GWh/d
Spain	Storage Spain	2030	125,7	GWh/d
Spain	Storage Spain	2040	125,7	GWh/d

ANNEX III: Additional markets assumptions

Hydrogen supply potentials

The hydrogen supply potentials are defined in the TYNDP 2024 draft Scenario Report as displayed in **Figure 20: Extra-EU supply potential for Hydrogen in National Trends+ in 2030 and 2040 (TWh/y)**

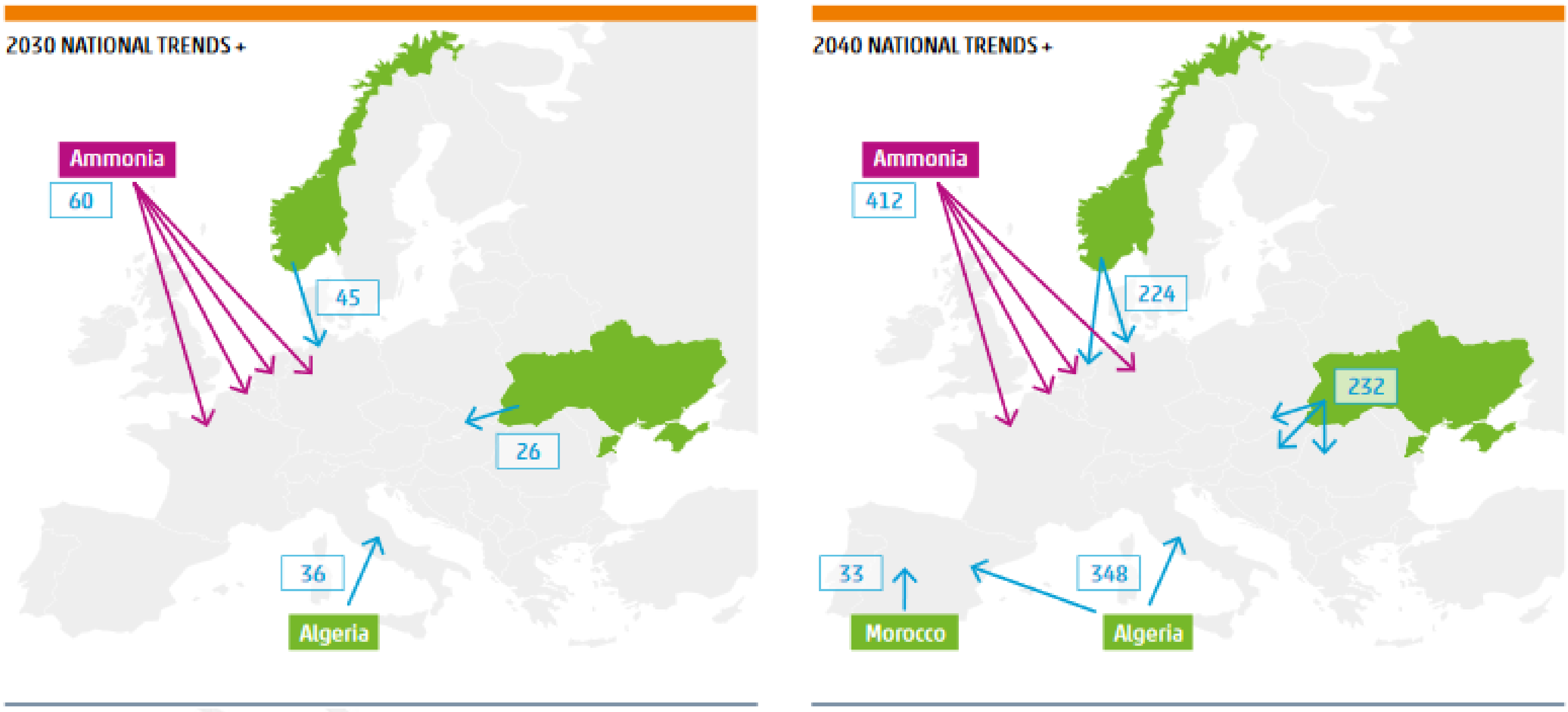

Figure 20: Extra-EU supply potential for Hydrogen in National Trends+ in 2030 and 2040 (TWh/y)

Natural gas supply potentials

Methane MAX import potentials (TWh/year)

Supply	2030	2040	2050
Algeria	460	460	460
Caspian	230	230	230
Libya	115	115	115
Norway	1.400	1.100	1.100
Turkey	60	60	60
Cyprus / Israel	110	110	110
Worldwide LNG	2.750	2.750	2.750
Russia (TurkStream)	250	250	250
Total	**5.375**	**5.075**	**5.075**

Figure 21: Natural Gas Supply Potentials (TWh/y)

Split of hydrogen demand sectors into Zone 1 and Zone 2

Table 5: Hydrogen demand shares for 2030 and 2040 applied in the hydrogen zones (source: ENTSOG based on TYNDP 2024 draft Scenario Methodology Report)

H_2 node	Sector	2030	2040
Zone 1	Feedstock	60%	30%
	Industry – Energetic	50%	30%
	Transport	50%	25%
Zone 2	Feedstock	40%	70%
	Industry – Energetic	50%	70%
	Space & Water Heat	100%	100%
	Transport	50%	75%
	e-Fuels	100%	100%
	Hydrogen-based Power Plants	100%	100%

Willingness to pay for hydrogen (WTP_{H2})

WTP values for hydrogen industrial and mobility sectors derived from the results of the Pilot Auction for Renewable Hydrogen[59] by the European Hydrogen Bank (EHB) are shown in Figure 22, i.e. 144 €/MWh$_{H2}$ for the industry sector and 212 €/MWh$_{H2}$ for the mobility sector. In the TYNDP 2024 Implementation Guidelines, ENTSOG proposes to estimate the WTP based on an weighted average between both sectors. The weighting is based on the NT+ scenario with a transport demand sector share of the final energy demand for hydrogen of 14% in 2030 and of 19% in 2040. The WTP for the calculation of the increase of market rents indicator (B4) is therefore 154 €/MWh$_{H2}$ in 2030 and 157 €/MWh$_{H2}$ in 2040.

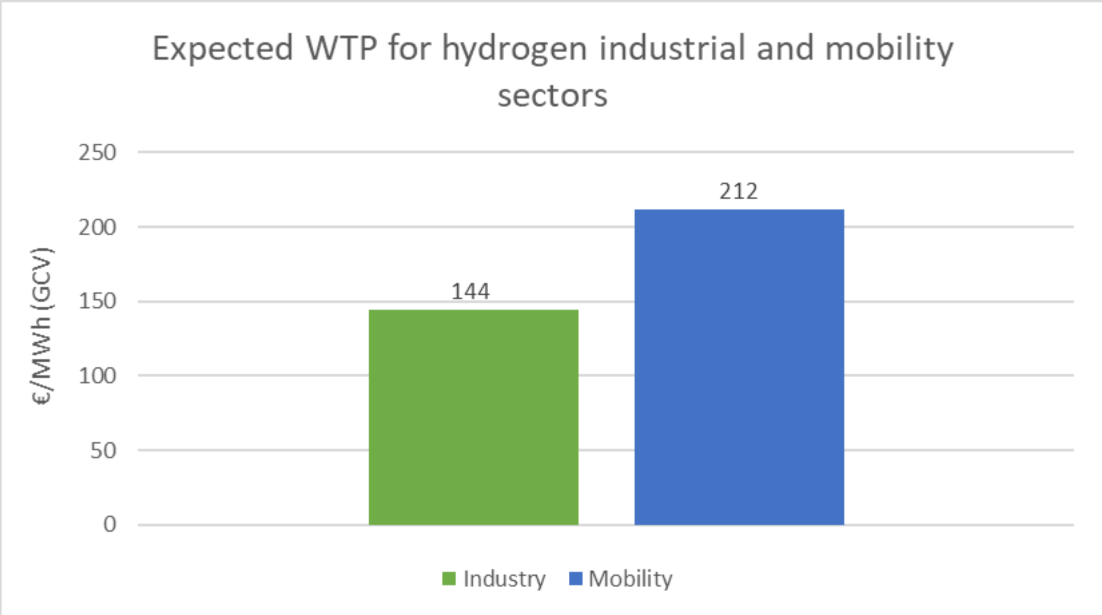

Figure 22: WTP for hydrogen industrial and mobility sectors (source: EHB).

European tap water prices

Member State	Price tap water (€/m3)[60]
Norway	5.51
Germany	3.47
Denmark	4.37
Netherlands	3.82
Sweden	3.60
France	2.82
Belgium	3.49
Switzerland	2.80
Czechia	3.09
Austria	2.80
Finland	2.52
Spain	1.87
Italy	1.16
Ireland	1.85
Croatia	1.68
Portugal	1.66
Poland	1.42
Hungary	1.23
Greece	1.16

Monthly maximum daily average wholesale electricity prices[61] (EU-28 countries and North Macedonia):

Month	Maximum daily average price per month (2022) (unit: €/MWhe)	Maximum daily average price per month (2023) (unit: €/MWhe)
January	246,6	182,8
February	207,9	161,2
March	427,9	147,9
April	218,2	132,2
May	217,5	104,6

[59] https://climate.ec.europa.eu/eu-action/eu-funding-climate-action/innovation-fund/competitive-bidding_en
[60] Water prices are taken from The International Benchmarking Network for Water and Sanitation Utilities (IBNET) database. The data compares tap water prices in the cities up to 15m³ per month. https://www.waternewseurope.com/water-prices-compared-in-36-eu-cities/
[61] Source: https://ember-climate.org/data-catalogue/european-wholesale-electricity-price-data/

June	308,2	116,4
July	405,3	111,6
August	598,1	141,2
September	512,2	131,9
October	255,7	128,6
November	365,6	156,0
December	400,3	136,7

ANNEX IV: GHG emissions factors

GHG emissions factors of Power Plants

The proposed GHG emissions factors consider direct GHG emissions (CO_2, N_2O and CH_4) from the fuels' stationary combustion.

These emissions factors account for unoxidised carbon by consideration of default factors of: solid = 0.98, liquid = 0.99, and gas = 0.995 (Source: IPCC, 2006[62])

Fuel	Type	Efficiency range NCV terms	Standard efficiency NCV terms	CO_2 eq EF (t/ net TJ)	CO2 eq EF (t/ gross MWh)	CO2 eq EF (t/ net MWh)
Nuclear	-	30% – 35%	33%	0,00	0,00	0,00
Hard coal	old 1	30% – 37%	35%	95,03	0,32	0,96
Hard coal	old 2	38% – 43%	40%	95,03	0,32	0,84
Hard coal	new	44% – 46%	46%	95,03	0,32	0,73
Hard coal	CCS	30% – 40%	38%	9,50	0,03	0,09
Lignite	old 1	30% – 37%	35%	101,43	0,34	1,02
Lignite	old 2	38% – 43%	40%	101,43	0,34	0,89
Lignite	new	44% - 46%	46%	101,43	0,34	0,78
Lignite	CCS	30% - 40%	38%	10,14	0,03	0,09
Natural Gas	conventional old 1	25% – 38%	36%	56,16	0,18	0,56
Natural Gas	conventional old 2	39% – 42%	41%	56,16	0,18	0,49
Natural Gas	CCGT old 1	33% – 44%	40%	56,16	0,18	0,50
Natural Gas	CCGT old 2	45% – 52%	48%	56,16	0,18	0,42
Natural Gas	CCGT present 1	53% – 60%	56%	56,16	0,18	0,36
Natural Gas	CCGT present 2	53% – 60%	58%	56,16	0,18	0,35
Natural Gas	CCGT new	53% – 60%	60%	56,16	0,18	0,34
Natural Gas	CCGT CCS	43% – 52%	51%	5,62	0,02	0,04
Natural Gas	OCGT old	35% – 38%	35%	56,16	0,18	0,57
Natural Gas	OCGT new	39% – 44%	42%	56,16	0,18	0,48
Light oil	-	32% – 38%	35%	74,34	0,25	0,76
Heavy oil	old 1	25% – 37%	35%	74,34	0,25	0,76
Heavy oil	old 2	38% – 43%	40%	74,34	0,25	0,66
Oil shale	old	28% – 33%	29%	101,43	0,34	1,23
Oil shale	new	34% – 39%	39%	101,43	0,34	0,92

[62] Source: IPCC Report, 2006 (https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html)

GHG emissions factors of fuels as considered for alternative fuel approach and hydrogen supply

The proposed GHG emissions factors for the alternative fuel approach for oil and coal are the same as for power plants displayed in the table above (CO2 eq in t/gross MWh).and for hydrogen production and imports are based on the TYNDP 2024 draft Scenario Methodology Report which is mainly derived from a JRC report[63]:

Fuel	Source specification, if relevant	CO_2 eq EF (t/ net MWh)	CO_2 eq EF (t/ gross MWh)
Hydrogen produced from natural gas with CCS	Imports from Norway and national production in the following countries: Bulgaria, Croatia, Czech Republic, Denmark, France, Greece, Hungary, Italy, The Netherlands, UK, Germany, Belgium.	0.0262	0.022
Hydrogen produced from natural gas without CCS	National production in the countries not listed in the cell above.	0.262	0.222
Renewable hydrogen imports	Imports from North Africa and Ukraine as well as imports by ship.	0	0

[63] https://op.europa.eu/en/publication-detail/-/publication/278ae66b-809b-11e7-b5c6-01aa75ed71a1

ANNEX IV: non-GHG emissions factors

Non-GHG emissions factors of Power Plants (source: ENTSO-E[64])

Fuel	Type	NO_x EF (kg/gross GJ)	NH_3 EF (kg/gross GJ)	SO2 EF (kg/gross GJ)	PM2.5 and smaller EF (kg/gross GJ)	PM10 EF (kg/gross GJ)	NMVOC EF (kg/gross GJ)
Hard coal	old 1	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	old 2	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	new	0,068	0,0016	0,067	0,0024	0,005	0,0007
Hard coal	CCS	0,068	0,0016	0,067	0,0024	0,005	0,0007
Lignite	old 1	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	old 2	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	new	0,080	0,0009	0,152	0,0040	0,005	0,0009
Lignite	CCS	0,080	0,0009	0,152	0,0040	0,005	0,0009
Gas	Conventional old 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	Conventional old 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT old 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT old 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT present 1	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT present 2	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT new	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	CCGT CCS	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	OCGT old	0,017	0,0054	0,001	0,0001	0,000	0,0019
Gas	OCGT new	0,017	0,0054	0,001	0,0001	0,000	0,0019
Light oil	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil	old 1	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil	old 2	0,226	0,0000	0,150	0,0058	0,008	0,0022
Oil shale	old	0,228	0,0000	0,152	0,0059	0,008	0,0022
Oil shale	new	0,228	0,0000	0,152	0,0059	0,008	0,0022
Other non-RES	-	0,049	0,0114	0,036	0,0030	0,003	0,0037
Lignite biofuel	-	0,080	0,0009	0,152	0,0040	0,005	0,0009
Hard Coal biofuel	-	0,068	0,0016	0,067	0,0024	0,005	0,0007
Gas biofuel	-	0,018	0,0057	0,001	0,0002	0,000	0,0020

[64] Implementation Guidelines for TYNDP 2024 based on 4th ENTSO-E Guideline for Cost-Benefit Analysis of grid development projects

Light oil biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Heavy oil biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022
Oil shale biofuel	-	0,226	0,0000	0,150	0,0058	0,008	0,0022

Non-GHG emissions factors of hydrogen production (source: E4tech[65])

Fuel	*Source*	*NO_x EF (kg/gross GJ)*	*SO2 EF (kg/gross GJ)*	*PM2.5 and smaller EF (kg/gross GJ)*	*PM10 EF (kg/gross GJ)*	*NMVOC EF (kg/gross GJ)*
Hydrogen produced from natural gas with CCS	Salkuyeh et al., 2017[66]	0,1219	0,0001	-	0,0134	0,0155
Hydrogen produced from natural gas without CCS	Salkuyeh et al., 2017	0,0832	0,0001	-	0,0113	0,0113
	Sun et al., 2019[67]	0,0063	0,0001	0,0020	0,0021	0,0017
	Nnabuife et al., 2023[68]	0,0118	0,0007	0,0031	0,0038	0,0000

Non-GHG emissions factor of hydrogen production for TYNDP 2024 PS-CBA process to be decided according to the outcome of the Public Consultation of the TYNDP 2024 Implementation Guidelines.

[65] *source: https://assets.publishing.service.gov.uk/media/5cc6f1e640f0b676825093fb/H2_Emission_Potential_Report_BEIS_E4tech.pdf*

[66] Yaser Khojasteh Salkuyeh, Bradley A. Saville, Heather L. MacLean, Techno-economic analysis and life cycle assessment of hydrogen production from natural gas using current and emerging technologies, International Journal of Hydrogen Energy,Volume 42, Issue 30,2017,Pages 18894-18909,ISSN 0360-3199

[67] Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities, Pingping Sun, Ben Young, Amgad Elgowainy, Zifeng Lu, Michael Wang, Ben Morelli, and Troy Hawkins, Environmental Science & Technology 2019 53 (12), 7103-7113, DOI: 10.1021/acs.est.8b06197

[68] Nnabuife, S.G.; Darko, C.K.; Obiako, P.C.; Kuang, B.; Sun, X.; Jenkins, K. A Comparative Analysis of Different Hydrogen Production Methods and Their Environmental Impact. Clean Technol. 2023, 5, 1344-1380. https://doi.org/10.3390/cleantechnol5040067

ANNEX VI: Examples for the total surplus approach

The consideration of the global market rents as described for the increase of market rents indicator (B4) is the application of the total surplus approach. In this Annex V, the producer rent includes the storage rent.

The following figures show how a new transmission project between two regions changes the price of both market areas (e.g., electricity bidding zone or hydrogen market area). This will change the consumer rent and the producer rent in both the export region and the import region. Also the congestion rent will be influenced as both the price difference between the regions as well as the amount of transferred energy is changing. The benefit of the project on the market rents is the sum of the changes that it introduces to all parts of the market rents along all hours of the year. This total surplus is maximised when the market price is at the intersection of the demand and supply curves.

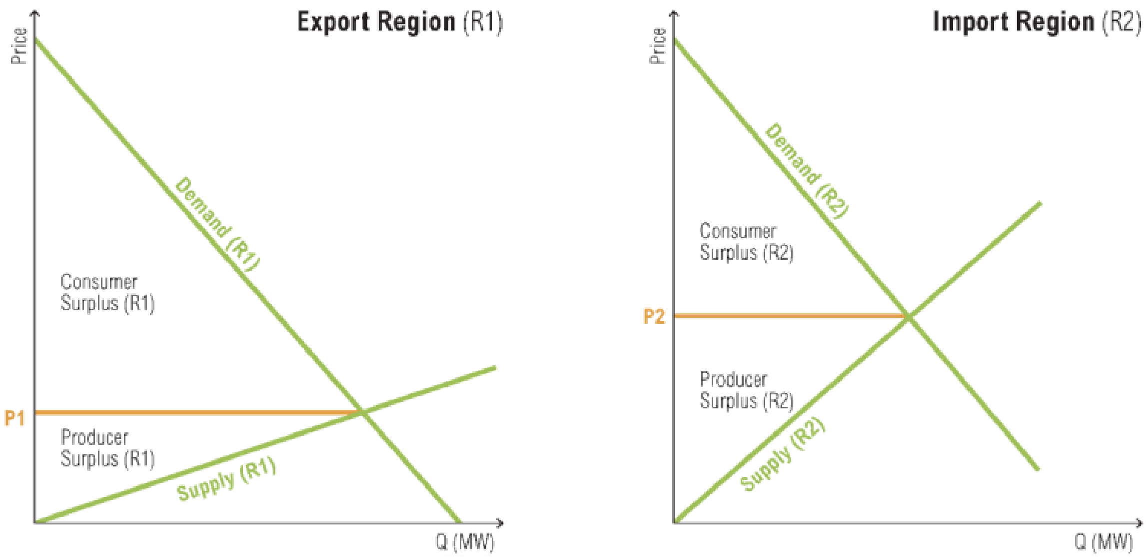

Figure 23: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity between the two regions and elastic (i.e., price-dependent) demand assumed.

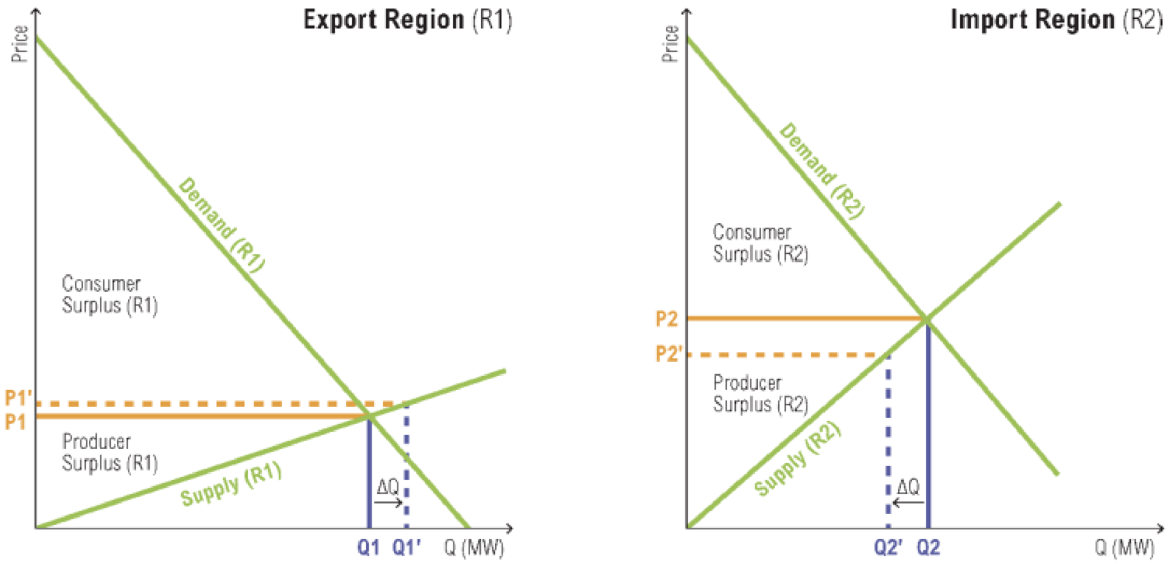

Figure 24: Example of an export region (left) and an import region (right) with a new project increasing the capacity between the two regions and elastic (i.e., price-dependent) demand assumed.

For inelastic demand, the change of the consumer rents is equal to the change of the market clearing price that is introduced by the new project multiplied by the demand.

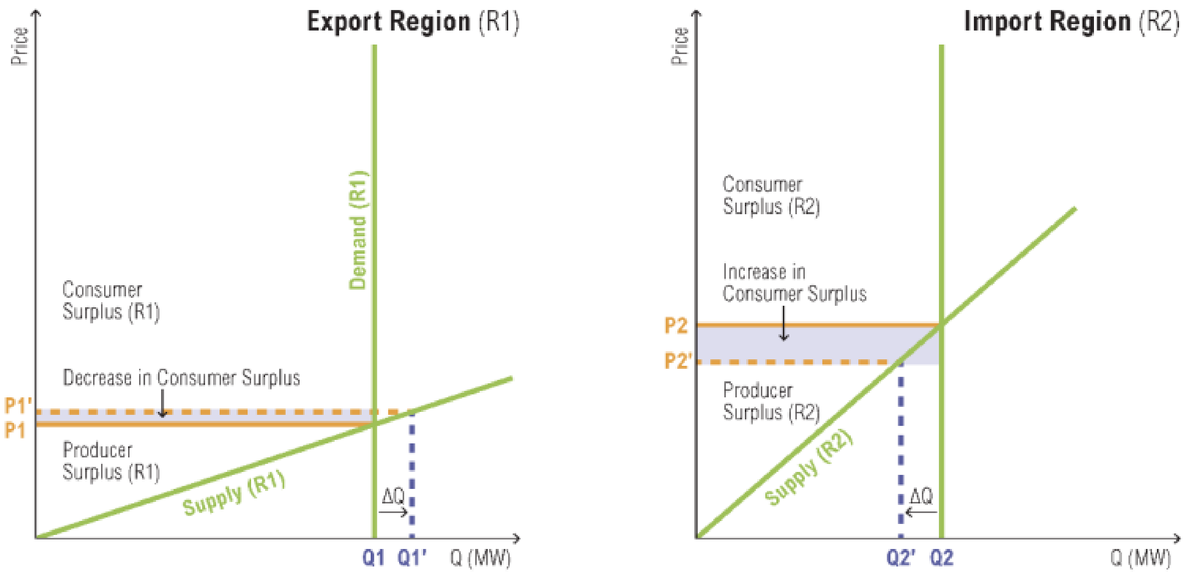

Figure 25: Example of the change of the consumer rent of an export region (left) and an import region (right) with a new project increasing the capacity between the two regison and inelastic demand assumed.

The change of the producer rent of a specific sector is equivalent to the change in production revenues minus the change in marginal production costs.

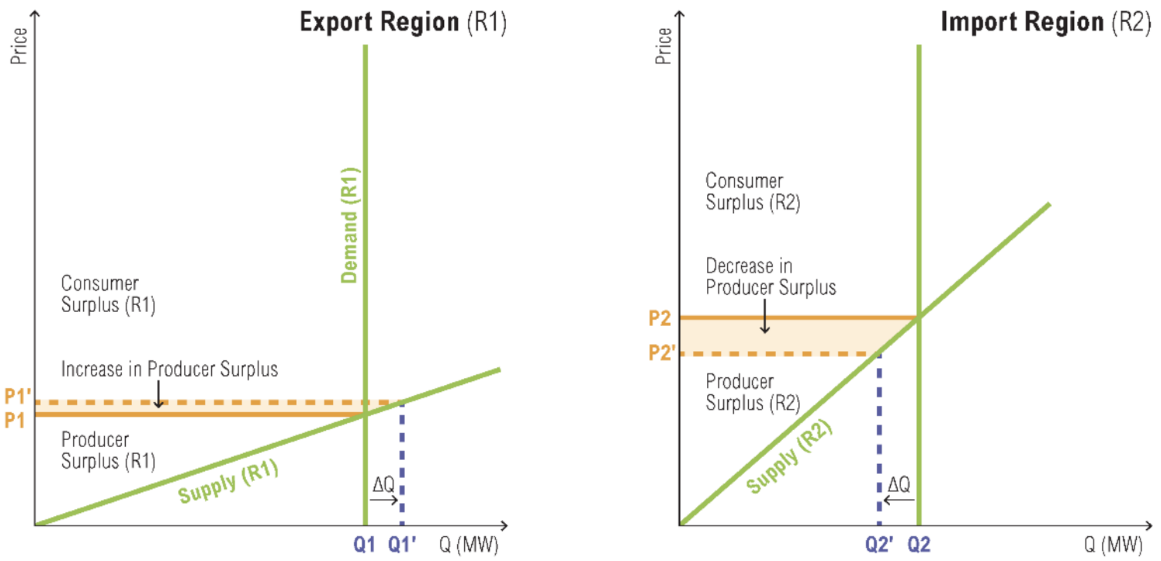

Figure 26: Example of the change of the producer rent of an export region (left) and an import region (right) with a new project increasing the capacity between the two regison and inelastic demand assumed.

The congestion rents can be calculated from the market clearing price difference between the importing and the exporting regions, multiplied by the energy traded between the two regions. The change of the congestion rent introduced by a new project is equivalent to the change of congestion rents at all transmission capacities between the two regions.

The cross-sector rent can be calculated from the price difference between the coupled sectors, the energy conversion efficiency and the additional power required for the energy conversion from energy carrier A into energy carrier B. The change of the total cross-sectoral rent introduced by a new project is equivalent to the change of all cross-sector rents between the associated sectors.

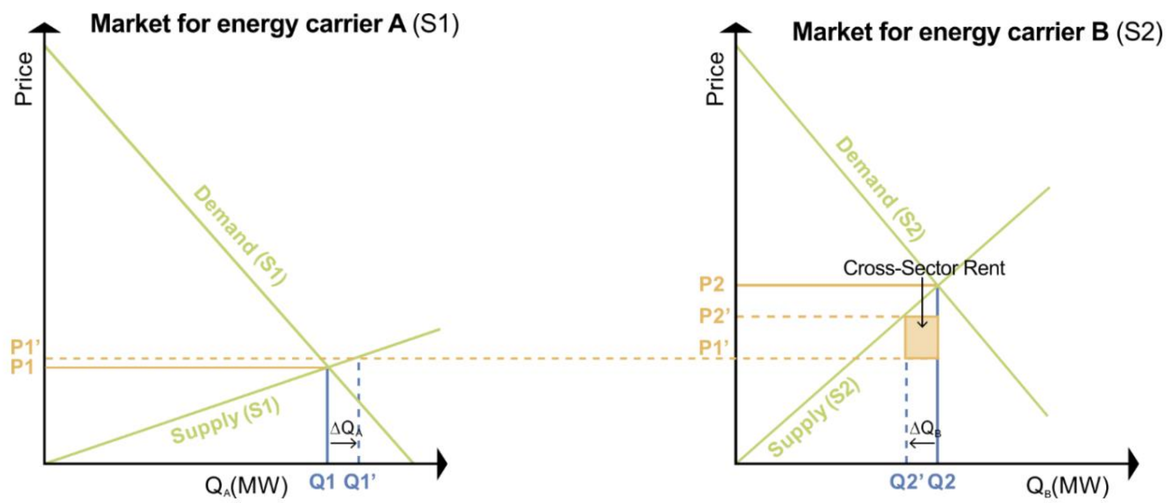

Figure 27: Illustration of sectorial market coupling. The cross-sector rent captures the benefit of sector coupling and describes the rent movement from sector A to sector B.

ANNEX VII: Factors

Assumed GCV/NCV ratio per fuel type

Fuel	*Ratio GCV/NCV*
Hydrogen	1,176
Natural gas	1,108
Coal	1,053
Light oil	1,064

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