METHODOLOGY

for Cost-Benefit Analyses of Hydrogen Infrastructure Projects

2024

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Picture courtesy of FGSZ

1 INTRODUCTION

The objective of this single-sector Cost-Benefit Analysis (CBA) methodology is to provide guidelines to be applied to the CBA of hydrogen infrastructure projects. This CBA methodology is based on a Multi-Criteria Analysis (MCA), combining monetised and non-monetised elements to measure the achievement of relevant EU energy and climate policy targets. It contains relevant interlinkages with the electricity sector and with the natural gas sector.

Picture courtesy of Teréga

1.1 CONTEXT AND TEN-E REGULATION

This CBA methodology is developed as required by Article 11 of the Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure (TEN-E Regulation). It is the 3rd CBA methodology developed by ENTSOG and focusses on the hydrogen infrastructure category, as defined in Annex II(3) of the TEN-E Regulation. It is prepared with consideration of the feedback received during the extensive consultation[1] of its preliminary draft version.[2]

It also includes consideration of the Opinion of the Agency for the Cooperation of Energy Regulators (ACER)[3] on its draft version[4] as well as feedback received from the European Commission during the preparation of the final CBA methodology. In line with Article 11 of the TEN-E Regulation, the next update of the CBA methodology will be initiated in 2025.

1 Follow **this link** for more information.

2 Follow **this link** for more information.

3 Follow **this link** for more information.

4 Follow **this link** for more information.

The TEN-E Regulation foresees four decision-making processes for which project-specific CBAs consistent with this hydrogen CBA methodology are used as input:

- Selection process of candidate projects to grant the status Project of Common Interest (PCI) or Project of Mutual Interest (PMI)[5];
- Cross-border cost allocation decisions for PCIs and PMIs[6];
- Decision to grant regulatory incentives for PCIs[7];
- Eligibility check of PCIs and PMIs for Union financial assistance in form of grants for works[8].

The input data set necessary for the implementation of this CBA methodology requires regular updates. This data update is undertaken through ENTSOG's Ten-Year Network Development Plan (TYNDP) process, every two years, and ensures stakeholders' involvement through feedback workshops and consultations. This input data set must be made publicly available as part of the TYNDP process. This TYNDP input data set is used when applying this CBA methodology to the submitted projects in the TYNDP.[9]

The CBA methodology is complemented by the following documents, jointly providing comprehensive guidance on the application of project-specific CBAs for the TYNDP process:

- Dedicated input data specifications for each TYNDP cycle, known as Implementation Guidelines, that outline the rules defined in this CBA methodology;
- TYNDP-specific Guidelines for Project Inclusion;
- The Project Submission Handbook for practical guidance for project promoters;
- The Scenario Report and accompanying documents for necessary underlying assumptions[10].

On this joint basis, the projects that are submitted to ENTSO-E[11] and ENTSOG during the TYNDP process determine the outputs.

Process-wise, the first required steps for the application of this CBA methodology in ENTSOG's TYNDP are the preparation of the scenarios and its models in accordance with Article 12 of the TEN-E Regulation as well as the establishment of the Guidelines for Project Inclusion and the subsequent project submission phase. The Implementation Guidelines then specify how the scenario information and the submitted projects are used to build the CBA models in the Dual Hydrogen/Electricity Model (DHEM) and in the Dual Hydrogen/Natural Gas Model (Dual Gas Model, DGM) (see section 2). The Implementation Guidelines also specify other input data for the CBAs (see section 1.3). Following the project grouping into functional groups (see section 3.1), the benefit indicators are calculated for each (group of) project(s). In combination with information about the project costs (see section 3.2.13), the monetised benefits (see sections 3.2.5 to 3.2.10) are used to establish economic performance indicators (see section 5). The CBA results are then summarised in project fiches that are made available to the PCI/PMI process.

5 See Annex III.2.(1)(d) of the TEN-E Regulation. In line with Article 3 and Annex III.1. of the TEN-E Regulation, the selection decision is taken by the decision-making body of the Regional Groups (i.e., Member States and the European Commission) and can be objected by the European Parliament or the Council in accordance with Article 20(6) of the TEN-E Regulation.

6 See Article 16(4)(a) and Article 16(12) of the TEN-E Regulation. The decision on the cost allocation is taken by the relevant national regulatory authorities in accordance with Article 16(5) of the TEN-E Regulation, whereas ACER has to take the decision in accordance with Article 16(7) of the TEN-E Regulation if the relevant national regulatory authorities cannot reach an agreement.

7 See Article 17(2) of the TEN-E Regulation with the relevant national regulatory authority taking the decision.

8 See Article 18(2) and 18(5) of the TEN-E Regulation.

9 It also constitutes a robust input data source for other fields of application of the CBA methodology. It is therefore recommended to use the latest available TYNDP input data set whenever performing CBAs.

10 For the purpose of cross-border cost allocation decisions, additional scenarios may be used in line with Art. 16(4)(a) of the TEN-E Regulation.

11 Inputs to ENTSO-E's TYNDP are relevant since the assessments detailed in this CBA methodology contain analyses that may be based on ENTSO-E's TYNDP reference grid (see section 2.2.2.2).

1.2 GUIDELINES FOR PROJECT INCLUSION

Project submissions are specified in the Guidelines for Project Inclusion and its Project Submission Handbook for each TYNDP. The Guidelines for Project Inclusion provide guidance to project promoters on the procedural steps as well as administrative and technical requirements that the project promoters need to comply with to have their projects included in the TYNDP.

In accordance with Annex III.2(5) of the TEN-E Regulation, draft Guidelines for Project Inclusion are required to be consulted with ACER and the European Commission and their recommendations are required to be taken into account before the publication of the final Guidelines for Project Inclusion. The Guidelines for Project Inclusion aim at implementing the requirement of subparagraph 1 of Annex III.2(5) of the TEN-E Regulation to ensure equal treatment and transparency of the TYNDP project inclusion process.

Brief explanation of the TYNDP process	Including current status of deadlines applying to following TYNDP steps and interlinkages with the PCI/PMI process.
Project categories	Aggregation of certain network elements (e. g., transmission and storage) of the relevant topologies (e. g., natural gas and hydrogen) into categories and possibly sub-categories.
Project promoter categories	Potentially considering each project category individually, project promoters' categorisation can factor in certifications, licenses, exemptions, unbundling, and ENTSOG affiliation status (e. g., membership, observer status, associated partnership).
Administrative criteria	The criteria consider: ◢ Administrative criteria to be fulfilled by project promoters: these criteria are defined to ensure project promoters' credibility in terms of financial capability and technical expertise, and to ensure equal and fair treatment of all TYNDP project promoters. ◢ Administrative criteria for projects to be included in the TYNDP: these criteria are defined to ensure the acceptability and TYNDP relevance of submitted projects, and to ensure equal and fair treatment of all TYNDP projects. These criteria may be grouped in different categories and applied accordingly, depending on the type of infrastructure the respective project would implement. The final decision on the inclusion of a project in the TYNDP project list belongs to ENTSOG[12].
Technical criteria for projects to be included in TYNDP	Technical criteria are defined per infrastructure category or sub-category. These criteria ensure that the minimum set of information required to assess all projects is provided (e. g., costs, technical assumptions considered, capacity increments, commissioning year). This includes supply and demand allocations with the required granularity if not provided by the scenarios.
Plausibility check for commissioning year of projects	Definition of a validation check to verify project schedules. The project promoter is solely responsible for the correctness of the submitted information.
Plausibility check for project costs	Definition of a validation check to verify project costs. The project promoter is solely responsible for the correctness of the submitted information.
Project data requirements	Definition of the mandatory data submissions by projects promoters. This includes supply and demand allocations with the required granularity if not provided by scenarios.
Definition of natural gas projects' maturity status	For the allocation of natural gas projects to natural gas infrastructure level(s).

12 To prove the eligibility of projects for the PCI/PMI process, further eligibility checks are required that are outside of ENTSOG's mandate.

Definition of hydrogen projects' maturity status	For the allocation of hydrogen projects to hydrogen infrastructure level(s).
Interlinkage indication between natural gas and hydrogen infrastructure projects	Concerning costs, relationship (e. g., natural gas projects that enable hydrogen projects), capacities
Definitions and criteria used to define cross-border and internal infrastructures	Complementary information to definitions in this CBA methodology, but not needed for this CBA methodology.
Simplified inclusion process into TYNDP for PCIs and PMIs on the Union list[13]	Description of the simplifications for PCIs and PMIs. Re-submission of PCIs and PMIs by project promoters is required for their inclusion in the TYNDP.
Consistency check phase of submitted information by ENTSOG and correction of input data by project promoters	Description of the procedure to receive missing information and to correct data and the respective roles of ENTSOG and project promoters. This may include an internal review phase between ENTSOG and ENTSOG's members to ensure the natural gas infrastructure representation is accurate and up to date. After the implementation of the findings of the check phase, it is not possible for project promoters to further amend the submitted project data (except if it is deemed that the changes would not influence any analysis). The relevant data submission deadline is displayed in the TYNDP.
Project promoters' access to assessment results	Description of the approach of sharing of assessment results by ENTSOG including bi-lateral data sharing and/or meetings with project promoters as well as public workshops.
Project promoters' right to review their project assessment	Description of the approach of handling requests of project promoters to review their project assessment. The approach could include consultations with ACER and/or the European Commission.
Consistency of ENTSO-E and ENTSOG data collections	Consistency check of data with focus on collected electrolyser projects.

Table 1: Complementary information to be provided by TYNDP-specific Guidelines for Project Inclusion and its Project Submission Handbook.


Picture courtesy of FGSZ

13 Sentence 2 of subparagraph 1 of Annex III.2(5) of the TEN-E Regulation states that the Guidelines for Project Inclusion establish a simplified process of inclusion in the TYNDP for all projects on the Union list in force at the time. This simplification takes into account the documentation and data already submitted during the previous TYNDP process, provided that the documentation and data already submitted remains valid. The Union list is the joint list of PCIs and PMIs (see Recital (20) and Art. 3(5) of the TEN-E Regulation).

Picture courtesy of GRTgaz

1.3 IMPLEMENTATION GUIDELINES

The CBA methodology is a guidance document for the assessment of projects that is expected to be valid for more than one cycle of assessment (e. g., for several TYNDPs or PCI/PMI processes) and it is therefore not required to include exhaustive implementation details of the methodologies, which may vary for each cycle of assessment. Therefore, the CBA methodology requires supplementary Implementation Guidelines for each assessment cycle.

The Implementation Guidelines are extensively consulted with relevant stakeholders before their application in the TYNDP. When planning the stakeholder consultation on the Implementation Guidelines, ENTSOG provides sufficient time to ensure that the feedback received can be adequately considered. On some occasions, the Implementation Guidelines can also be prepared in several steps with individual consultations. Where required, ENTSOG provides reasons where it has not, or has only partially, integrated the feedback received during the public consultation.

The following table outlines a summary of the typical information included in the TYNDP-specific Implementation Guidelines.

Market assumptions	Assumptions made if required data was not provided by the scenarios. This may include additional assumptions on seasonality of commodity prices and/or on seasonality of supply potentials applied to the calculation of the benefit indicators.
Simulation tools used to perform the assessment	List of tools used for market, network, and redispatch simulations, description of the functions of these tools used for the TYNDP, and if required, clarification of the party executing the simulations.
Definitions and criteria to define cross-border and internal infrastructure	Definitions of cross-border and internal infrastructure.
Capacity types	Definitions of the different types of capacities considered (e. g., yearly firm capacity, peak capacities, etc.) in case more detailed rules are required compared to the provisions of this CBA methodology.
Hydrogen infrastructure level for CBAs	Selection of hydrogen infrastructure level(s) for the CBAs.
Perimeter updates	If required, description of the approach to introduce additional countries to the assessment perimeter of the CBA methodology compared to the available perimeter of the scenarios.
Network assumptions	List and number of nodes, storage curves, and capacities included in the proposed hydrogen infrastructure level(s) and the proposed natural gas infrastructure level(s).

Project and capacity list	The list of TYNDP projects and related capacities including storage curves included in the proposed hydrogen infrastructure level(s) and the proposed natural gas infrastructure level(s).
Brief explanation of the TYNDP process	Update of information provided by the Guidelines for Project Inclusion, including the status of deadlines applying to the TYNDP process and interlinkages with the PCI/PMI process.
Additional rules for grouping of projects	If required, additional grouping guidelines applied to the CBAs, including complementary rules for the identification and treatment of competing projects.
Ranking between hydrogen demand curtailment and natural gas demand curtailment	For the calculation of the reduction in exposure to curtailed hydrogen demand indicator (B5), the cooperation mode between the natural gas sector and the hydrogen sector needs to be clarified. Both are linked through the capacities of facilities to produce hydrogen from natural gas. If there is insufficient natural gas available to satisfy the demand of hydrogen consumers while satisfying the demand of natural gas consumers, the analysis includes a decision on how the hydrogen production from natural gas is disrupted. On that basis, rules must be established. Possible ranking rules for the disruption of hydrogen production from natural gas are: ◢ before all other natural gas demand is curtailed; ◢ after all other natural gas demand is curtailed; ◢ at the same rate as all other natural gas demand; ◢ at a rate that results in hydrogen demand being curtailed at the same rate as the part of the natural gas demand that is not used for the production of hydrogen.
Probability (and if needed duration) of stress cases	For the calculation of the monetised reduction in exposure to curtailed hydrogen demand indicator (B5).
Cost of Disrupted Hydrogen (CODH)	The approach and values of the CODH for the calculation of the increase of the market rents indicator (B4) and of the reduction in exposure to curtailed hydrogen demand indicator (B5).
Non-CO_2 emission types and emission factors	A list of non-CO_2 (greenhouse gas and non-greenhouse gas) emission types and related emission factors. Non-CO_2 GHG emissions are used for the calculation of the GHG emissions variations indicator (B1) and non-GHG emissions are used for the calculation of the non-GHG emissions variations indicator (B2).
Emission costs	Definition of the cost of CO_2e for the monetisation of GHG emissions within the GHG emissions variations indicator (B1) and the damage costs of non-GHG emissions for the monetisation of the non-GHG emissions variations indicator (B2).
Seasonality of demand and supply	If required, description of the approach to transform ◢ annual demand and supply data from the scenarios into seasonal values; ◢ hourly data from the DHEM into monthly values for usage in the DGM (see sections 2.2.3.5 and 2.2.3.6).
Usage of unit investment costs	Description of the unit investment costs used for CBAs, if relevant. These may be ACER's unit investment costs established as required by Art. 11(9) of the TEN-E Regulation.
General approach for non-GHG emissions variations indicator (B2)	If required (see section 3.2.6).
Sensitivities	Selection of sensitivities (see section 4) and details required to calculate them.
Details on calculation of benefit indicators	If required, any other details for the calculation of benefit indicators that are not clarified in this CBA methodology.

Table 2: Complementary information to be provided by TYNDP-specific implementation guidelines.

In case ENTSOG would propose to include in the Implementation Guidelines for public consultation a set of elements which are not listed in Table 2, ENTSOG shall consult ACER and the European Commission and take due account of their recommendations before taking a final decision.

2 INPUT TO THE CBA

2.1 SCENARIO REPORT

The Scenarios for the TYNDPs are established in line with Article 12 of the TEN-E Regulation. Article 12(2) of the TEN-E Regulation reads: *"The ENTSO for Electricity and ENTSO for Gas shall follow ACER's framework guidelines when developing the joint scenarios to be used for the Union-wide ten-year network development plans. The joint scenarios shall also include a long-term perspective until 2050 and include intermediary steps as appropriate."*

Article 12(1) of the TEN-E Regulation stipulates that ACER's *"guidelines shall establish criteria for a transparent, non-discriminatory and robust development of scenarios taking into account best practices in the field of infrastructures assessment and network development planning. The guidelines shall also aim to ensure that the underlying ENTSO-E and ENTSOG scenarios are fully in line with the energy efficiency first principle and with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective and shall take into account the latest available Commission scenarios, as well as, when relevant, the national energy and climate plans."*

Each joint Scenario Report of ENTSO-E and ENTSOG is specific to each distinct TYNDP cycle and the report and its accompanying documents define the relevant information. From the scenarios, the following information is needed for the application of this CBA methodology for a certain TYNDP cycle:

Time horizon	Years for which data are prepared.
Scenarios	The CBAs are required to be based on the corresponding scenarios developed, according to Article 12 of the TEN-E Regulation.
Demand	Including peak demand cases and (seasonal) profiles. The scenarios are constructed so that they are in line with the energy efficiency targets as defined in the Energy Efficiency Directive (EU) 2018/2002 (EED) and its subsequent revisions. This ensures that subsequent steps of the TYNDP process are also in line with the energy efficiency first principle.
Supply	Potentials, flexibilities, and profiles of sources of electricity (e. g., power plant fleet), hydrogen (e. g., supply potentials, unabated hydrogen production facilities, low-carbon hydrogen production facilities, electrolyser capacities), and natural gas (e. g., national production, biomethane production, supply potentials).
Fuel prices, CO_2 prices, emission factors	To provide the required inputs to the DHEM, calculate benefit indicators, and monetise results.
Market assumptions	Market assumptions needed for the DHEM simulations.

Table 3: Consideration of scenario data in the CBAs on the basis of this CBA methodology.

All scenario storylines should be used for the CBAs. If a required element was not provided by the scenario process, another high quality and publicly available data source is used and referenced, after having been consulted through the Implementation Guidelines process.

2.2 MODELS

2.2.1 KEY ELEMENTS

2.2.1.1 MULTI-SECTORIAL MARKET SIMULATIONS

In general, energy markets can be organised by exchanges. These entities collect, for a certain commodity, buy and sell orders from consumers and producers. The orders are stacked in the form of demand and supply curves. Under uniform price auction schemes, the markets are cleared by matching demand and supply curves to obtain market clearing prices for the corresponding commodities. Market models are able to capture these principles and are essential for the project assessment. By running market simulations, they are applied to reflect realistic market outcomes.

Interlinked (sector) models or integrated multi-energy system (MES) models capture energy market transactions and interactions with different sectors. In this regard, sectors correspond to energy carriers for which corresponding markets for energy trading exist. MES models could contain energy carriers such as electricity, hydrogen, natural gas, heat, biomass, coal etc. Components that couple markets across space are transport infrastructures (e. g., power transmission lines and pipelines), whereas components (e. g., electrolysers and hydrogen-based power plants) introduce a sectorial market coupling.

Projects that introduce mutual influences across sectors can undergo a multi-sector or multi-system CBA assessment. Sectors either represent energy carriers or end-use sectors associated with energy carriers (e. g., comprising transport, industry or building sectors).

2.2.1.2 TWO DUAL MODELS: HYDROGEN/ELECTRICITY AND HYDROGEN/NATURAL GAS

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

ELECTRICITY SYSTEM ⟷ HYDROGEN SYSTEM ⟷ NATURAL GAS SYSTEM

Dual hydrogen/electricity Model (DHEM)

Dual hydrogen/natural gas (DGM)

Figure 1: Representation of the interlinkages in this CBA methodology between hydrogen, electricity, and natural gas systems.

Joint modelling of the above-mentioned energy carriers are captured as follows:

- Interlinkages between hydrogen and electricity through a network and market modelling of the joint hydrogen/electricity systems (i.e., the 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 DGM). This model is used for the benefit indicator capturing reduction in exposure to curtailed hydrogen demand (B5).

With minor adaptations explained in section 2.2.3.1, 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 infrastructures 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.

2.2.1.3 CONCEPT OF ARCS AND NODES

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. Depending on the nodes and the arcs, different properties are attributed to these objects.

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 (e. g., imports, aggregation of storages, aggregation of demand).

Arc

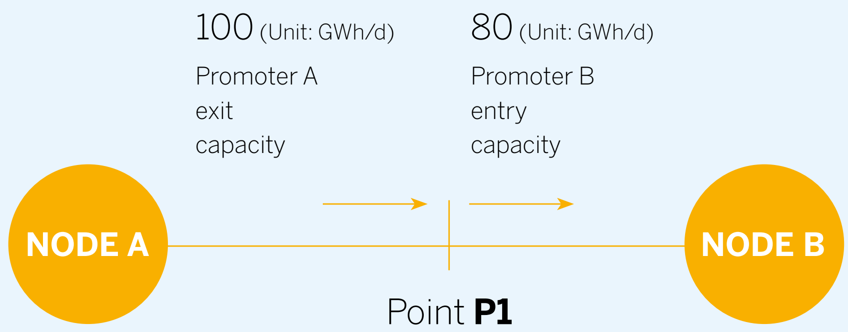
An arc represents a connection between two nodes. It allows for transfer of some energy between these two nodes. This transfer is thereby limited to the sum of the capacity of all interconnection points between these two nodes that the arc is representing after application of the lesser-of-rule. According 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.


Picture courtesy of TAP

EXAMPLE FOR THE LESSER-OF-RULE (LOR)

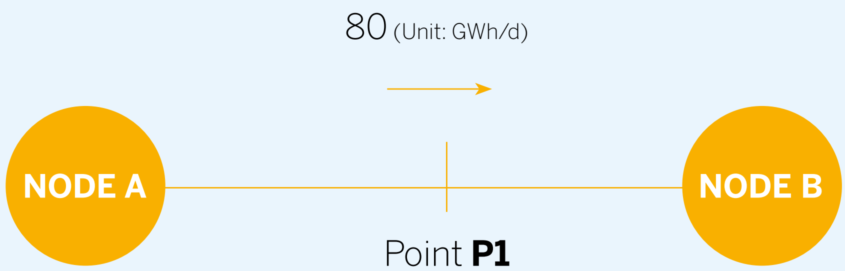
Case: Point P1 is attached to the arc linking node A and node B, TSO A submits an exit capacity out of node A in the direction of node B at P1 of 100 GWh/d and TSO B submits an entry capacity from node A into node B at P1 of 80 GWh/d.

Before LOR



Resulting modelling capacity after LOR application from node A into node B via P1 is defined as the minimum value of project promoters' submissions (i.e., MIN (100 GWh/d;80 GWh/d) = 80 GWh/d).

After LOR



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.

2.2.1.4 CONCEPT OF 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 (e. g., hydrogen or natural gas) 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). The supply potentials are defined in the scenarios.

2.2.1.5 CONCEPT OF AN OBJECTIVE FUNCTION

An objective function is a function that is either maximised or minimised 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: parameters that the model must respect whatever the consequences (even if it leads to the absence of a solution). Examples of hard constraints are capacities, working gas volumes of underground storages, and the maximum supply potentials.
- 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 formula that gives the solution. It is found through an optimisation programme. Often, there is no best solution, but one best solution, among many.

2.2.1.6 GEOGRAPHICAL PERIMETER

The geographical perimeter should cover at least the EU, the European Economic Area, the Energy Community, and any other third country in which the project is located.

2.2.2 DUAL HYDROGEN/ELECTRICITY MODEL (DHEM)

2.2.2.1 INTRODUCTION AND INTERLINKAGES BETWEEN THE HYDROGEN AND ELECTRICITY SECTORS

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.[14] The default hydrogen topology can be refined based on project submissions to the TYNDP. Complementary information about possible refinements of the hydrogen topology may be provided in the Guidelines for Project Inclusion.

The two sides of the DHEM 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 demand 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 demand in the hydrogen system and as supply in the electricity system.

Indirectly, the two sides of the DHEM can furthermore be joined by connections of certain end users with hydrogen nodes as well as electricity nodes. This enables demand shifting across the sectors, e. g.:

- **Hybrid heat pumps[15]:** A hybrid heat pump (if based on hydrogen) can choose to act as a demand in the electricity system or in the hydrogen system.

2.2.2.2 ELECTRICITY TOPOLOGY AND INFRASTRUCTURE LEVEL

The electricity infrastructure level in the DHEM reflects the reference grid including generation and storage assets i) used in ENTSO-E's TYNDP or ii) used in a relevant scenario. Each node in the topology represents one electricity bidding zone. Most countries use one bidding zone and therefore one node per country, while other countries have multiple bidding zones and therefore multiple nodes per country. Additionally, there are offshore nodes. Within the model, arcs between nodes are used to establish capacities between the connected nodes. In the future, a more granular topology may be introduced to better capture bidding zone-internal bottlenecks.

14 This is based on the current approach in the scenario process and might be subject of change.

15 Hybrid heat pumps would only be considered by the DHEM if directly provided by the scenarios.

Picture courtesy of terranets bw

2.2.2.3 HYDROGEN TOPOLOGY

The hydrogen topology represents existing hydrogen infrastructure as well as certain hydrogen projects submitted by project promoters during the TYNDP-specific project data collection phase, while striving for structural consistency with the scenarios. The hydrogen topology is structured along different hydrogen infrastructure levels (see section 2.3).

a) Topological properties per hydrogen infrastructure type

The following information must be captured by the modelled representation of the hydrogen infrastructure to allow the calculation of the benefit indicators described in section 3.2.3.

For hydrogen transmission infrastructure:

- Cross-border capacities between countries;
- (Cross-border) off-shore capacities;
- Expected capacities for hydrogen production (including production type) and demand enabled by the transmission project;
- Expected location of enabled supply and demand and its connection to the hydrogen transmission grid (node and capacities);
- Transmission constraints within one country or area (i.e., internal infrastructures or bottlenecks defining a more granular network within a country, where the connected sub-country nodes are linked to expected enabled production and demand).

For hydrogen storage infrastructure:

- Node of connection in the hydrogen grid;
- The working gas volume;
- The withdrawal and injection capacities;
- The withdrawal and injection curves that define their ability to withdraw or inject hydrogen depending on the filling level.

For LH_2 (or hydrogen embedded in other chemical substances) import terminals (also labelled hydrogen reception facilities):

- Node of connection in the hydrogen grid;
- Injection capacities into the hydrogen grid (along the year and during high demand situations if applicable);
- Storage volumes.

For LH_2 (or hydrogen embedded in other chemical substances) export terminals that are a joint project with a respective import terminal:

- Node of connection in the hydrogen grid or hydrogen production facility;
- Production capacities;
- Efficiency of the process of LH_2 production, ammonia production, hydrogen compression, or LOHC loading etc.;
- Storage volumes.

For hydrogen production facilities:

- Node of connection in the hydrogen grid;
- Injection capacity into the hydrogen grid;
- Capacity of the production facility;
- Efficiency of the process of hydrogen production (e. g., electrolyser, SMR with CCS, ATR with CCS);
- Additional information for electrolysers:
  - Connection to dedicated RES or shared RES and/or electricity grid;
  - If connected to electricity grid:
    - Node of connection in the electricity grid (i.e., connected electricity bidding zone);
    - Grid connection capacity.
- Additional information for production facilities using natural gas:
  - Node of connection in the natural gas grid (e. g., connected natural gas market area).

For infrastructure enabling hydrogen (or hydrogen-derived fuels) demand in the transport sector:

- Enabled hydrogen demand in the transport sector;
- Loading capacity (i.e., hydrogen offtake capacity) if relevant;
- Share of alternative fuel(s) expected to be replaced per country sector and subsector.

b) Approach to synthesise information from scenarios and from submitted hydrogen projects

It is possible that the European hydrogen system will consist of interconnected national hydrogen transmission systems, as well as local hydrogen valleys. Latter may to some extent be progressively integrated into the national hydrogen transmission systems. In comparison with the scenarios, updated hydrogen infrastructure is collected and used in the TYNDP. This requires changes to the scenario models. In the scenarios, two hydrogen zones are defined per country that each contain a certain share of the national hydrogen demand and production means. These shares defined in the scenarios are preserved in the TYNDP as described below:

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 scenarios, 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).[16]
- Facilities for hydrogen production from natural gas which exist today, with properties including capacities defined in the scenarios;
- Steel tanks with properties including capacities defined in the scenarios;
- A share of the national hydrogen demand which is defined in the scenarios.

To reflect the presence of bottlenecks, Zone 1 can be further split into different nodes, eventually being connected to different Zone 2 nodes. However, to ensure consistency with the scenarios, the total country values assigned to Zone 1 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 and hydrogen demand for hybrid heat pumps and other DSR options);
- Hydrogen-based power plant capacities;
- Hybrid heat pump capacities;
- Electrolyser capacities;
- Other DSR options;
- Hydrogen production capacities from natural gas;
- Steel tanks.

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.
- Internal hydrogen infrastructures, either existing or from submitted projects;
- Cross-border capacities to/from other Member States or third countries, either existing or from submitted projects;
- Hydrogen reception facilities, either existing or from submitted projects;
- Facilities for hydrogen production from natural gas, either existing or from submitted projects;
- Hydrogen underground storages (e.g., salt cavern storage), either existing or from submitted projects;
- The share of the national hydrogen demand, including all hydrogen-based power plants, assumed to be connected to the main hydrogen infrastructure system as defined in the scenarios;
- A capacity to/from Zone 1.

16 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.

To reflect the presence of bottlenecks and introduce further granularity within a country, Zone 2 can be further split into different nodes, 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 scenarios, 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 and hydrogen demand for hybrid heat pumps or other DSR options);
- Hydrogen-based power plant capacities;
- Hybrid heat pump capacities;
- Other DSR options;
- Electrolyser capacities;
- Hydrogen production capacities from natural gas.

If the zonal approach would be adjusted in the scenario process, the provisions of this section would need to be understood in the new context.

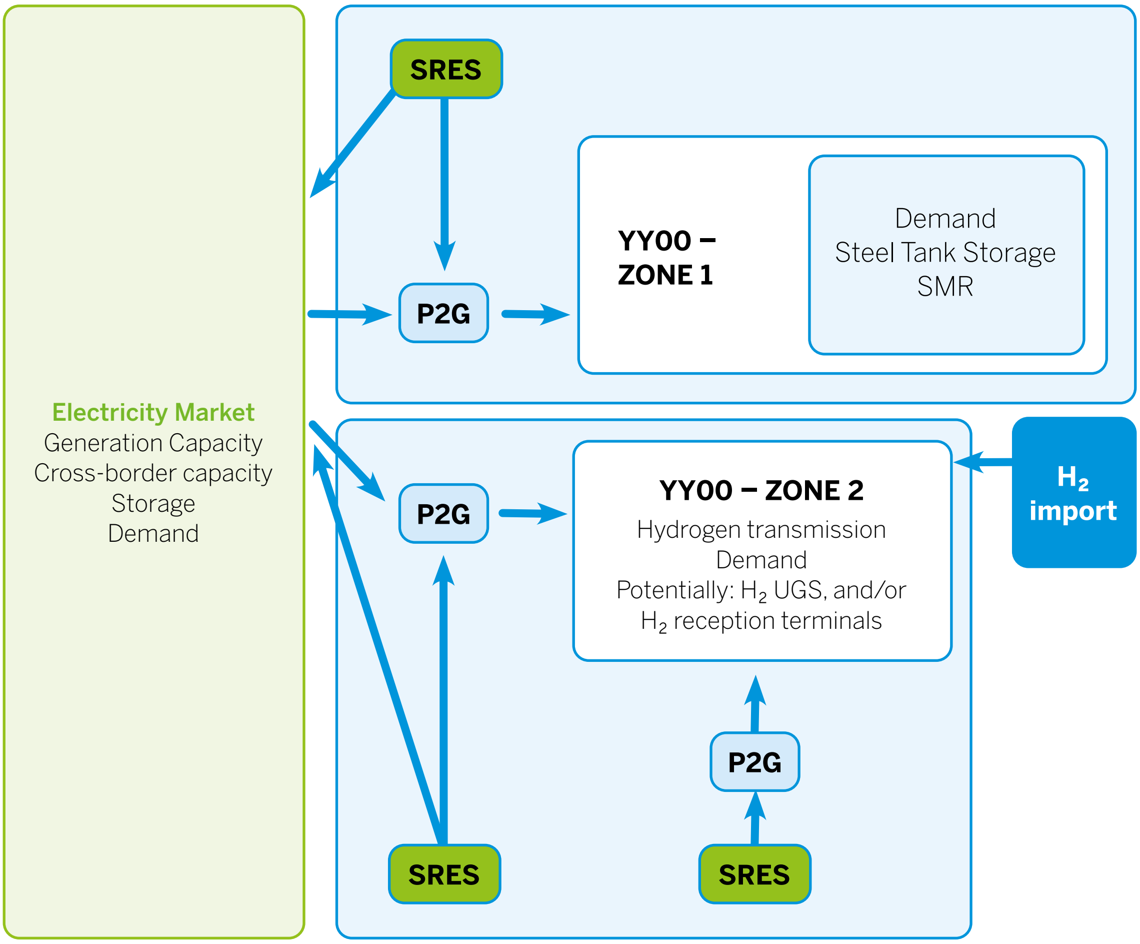


Figure 2: Simplified representation in the DHEM of a country with one electricity bidding zone, the default number of hydrogen nodes, without hydrogen-based power plants, without hybrid heat pumps, and without cross-border interconnections besides one hydrogen import option.

2.2.2.4 OBJECTIVE FUNCTION

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 III). 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, electricity demand, and demand-side response (e. g., in the form of hybrid hydrogen heat pumps and hybrid natural gas heat pumps). Electricity market prices are then determined endogenously in the DHEM. 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, other types of hydrogen demand, and demand-side response. Hydrogen market prices are then determined endogenously in the DHEM. 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.

Picture courtesy of SNAM

2.2.3 DUAL HYDROGEN/NATURAL GAS MODEL (DUAL GAS MODEL, DGM)

2.2.3.1 HYDROGEN TOPOLOGY

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 two changes 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]
- Also, hydrogen steel tanks will not be considered in the DGM since these are used for short-term hydrogen storage, while short- and mid-term storage options are already addressed by the transfer from hourly into monthly supply and demand profiles (see sections 2.2.3.5 and 2.2.3.6).

2.2.3.2 INTRODUCTION AND INTERLINKAGES BETWEEN THE HYDROGEN AND THE NATURAL GAS SECTORS

The DGM represents the hydrogen and natural gas infrastructure within the geographical scope of the TYNDP. 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 2.2.1.3 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 (e. g., SMR or ATR units) act as a demand 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.

2.2.3.3 NATURAL GAS TOPOLOGY AND INFRASTRUCTURE LEVEL

The natural gas infrastructure level in the DGM is defined by ENTSOG for each TYNDP and contains transmission, storage, and LNG infrastructure. In case ENTSOG defines multiple natural gas infrastructure levels, the choice of the natural gas infrastructure level for the DGM is made in the Implementation Guidelines.

2.2.3.4 OBJECTIVE FUNCTION

The objective function is defined, for a given simulation, as the sum of all costs in the system (see Figure 3). 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 (e. g., a month), but only one objective function for the full simulation horizon (e. g., a year).

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.

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 3: Objective function of the Dual Hydrogen/Natural Gas Model.

The DGM's objective function has the following costs categories (represented in blue in Figure 3), 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. This ranking of possible curtailments is defined in the Implementation Guidelines.
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_2e 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 productions over imports or to minimise or maximise the usage of certain sources.[18]
- Infrastructure: incremental residual costs.
- 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.

18 For example, a pre-defined import source of gas from country X could be attributed with the highest costs of all sources, resulting in a minimized usage.

2.2.3.5 DEMAND INPUT

The hydrogen demand for the DGM is derived from the scenario process with the DHEM, as described in this section. This is to increase consistency between DHEM-based and DGM-based calculations. If the hydrogen demand provided by the scenario process would be at a geographical granularity that was insufficient for the hydrogen transmission topology required for the application of this CBA methodology, the breakdown of demand (e. g., for country-level into sub-country-level nodes) must be provided by the project promoters. If not available, it should be defined by ENTSOG acting as last resource. The Guidelines for Project Inclusion and/or the Implementation Guidelines provide further details in this respect.

Hydrogen demand input

Through the following strictly consecutive steps, monthly hydrogen demand profiles can be derived for the DGM per assessed hydrogen infrastructure level.

0. In the scenarios, certain parameters of relevance for the hydrogen demand are defined per country (or zone):
   - inelastic hydrogen demand per hour;
   - capacities of components with elastic hydrogen demand (e. g., hydrogen-fired power plants and hybrid heat pumps).
1. All scenario parameters of relevance for the DHEM (see section 3.2.4) including those of step 0 are inserted in the DHEM. This requires an allocation of scenario parameters to the updated DHEM topology following the TYNDP project submissions (see section 2.2.2.3). The DHEM simulations are executed with the DHEM's objective function (see section 2.2.2.4).[19]
2. The DHEM simulations described in step 1 provide per node and hour:
   - Updated elastic hydrogen demand values compared to the scenarios due to an optimised usage of cross-sectoral components and DSR options; [20]
   - Amount of inelastic hydrogen demand that could be satisfied. On country (or zone) level, it is identical to the inelastic hydrogen demand of the scenarios if sufficient hydrogen is available.
3. As the DHEM and the DGM are based on the same hydrogen topology, the sum per hydrogen node as delivered by step 2 of i) the elastic hydrogen demand and ii) the satisfied inelastic hydrogen demand for the DHEM is directly transferrable from the DHEM results for this hydrogen node into the DGM inputs for the same hydrogen node. As the DHEM and the DGM are however based on different time step 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

The natural gas demand for the DGM is derived from the scenario process with the DHEM. This is to increase consistency between DHEM-based and DGM-based calculations. The full details are provided by the Implementation Guidelines.

19 For the CBAs, this simulation is run with and without the assessed (group of) project(s) to implement the incremental approach.

20 Example: In the scenarios, high import volumes of hydrogen are available at a cost that result in an economic advantage of hydrogen-based power plants over natural gas-fired power plants. A reduced infrastructure level in the DHEM may restrict the access to these hydrogen imports, increasing the hydrogen market clearing price, changing the position of hydrogen- and natural gas-fired power plants in the electricity generation merit order list, decreasing the usage of hydrogen for power generation.

Picture courtesy of GASCADE

2.2.3.6 SUPPLY INPUT

Hydrogen supply input

The hydrogen production from electrolysers is sourced from the DHEM with an equivalent methodology as described in the previous section, while on this basis the DGM itself calculates the values for hydrogen production from natural gas and hydrogen imports. 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 available in the DGM may require adaptions in the hydrogen flow patterns.

For import from third countries (both through pipelines and terminals) that are not covered with their own supply and demand profiles, the concept of a supply potential is used (see section 2.2.1.4). The actual use of a supply source is a result of the model taking into account the constraints of the scenarios.

Natural gas supply input

The natural gas supply for the DGM is derived from the scenario process with the DHEM. This is to increase consistency between DHEM-based and DGM-based calculations. The full details are provided by the Implementation Guidelines.

Picture courtesy of SGI

2.3 INFRASTRUCTURE LEVELS

2.3.1 CONCEPT OF 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 situations against which projects are assessed, the CBA results are strictly dependent on the definition of the infrastructure level(s).

The following rules are considered when defining the infrastructure levels:

- When building the infrastructure levels, the lesser-of-rule should be 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 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.

The infrastructure level(s) for the CBAs are defined for each TYNDP cycle through the Implementation Guidelines.

2.3.2 HYDROGEN INFRASTRUCTURE LEVELS

There are two default hydrogen infrastructure levels (see Figure 4):

- A **PCI/PMI hydrogen infrastructure level** containing existing hydrogen infrastructure, FID hydrogen projects, and PCI/PMI hydrogen projects.
- An **Advanced hydrogen infrastructure level** containing the complete PCI/PMI hydrogen infrastructure level as well as advanced hydrogen projects.

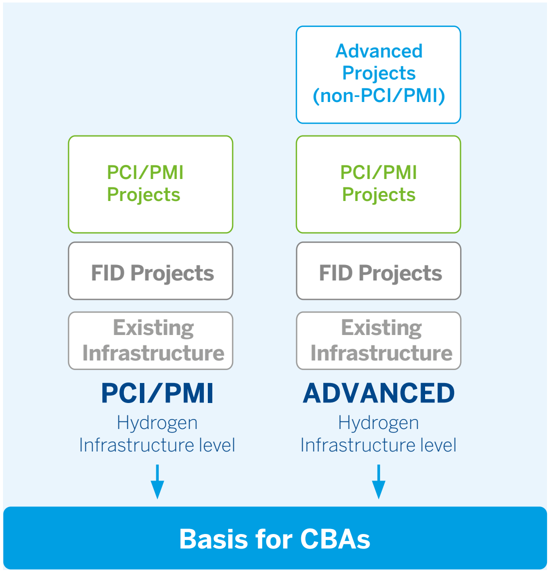


Figure 4: Hydrogen infrastructure levels as potential basis for the CBAs.

Whereas:

- **Existing hydrogen infrastructure** refers to hydrogen infrastructure that is existing at the time of the TYNDP 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 of the nominal year of the TYNDP (e. g., 2024 for TYNDP 2024). 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 relevant TYNDP project data collection.
- **Advanced hydrogen project** refers to projects with an expected commissioning date no later than six years after the 31 December of the year of the TYNDP project data collection (e. g., 2029 in case of TYNDP 2024, with projects collected in 2023) 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 PCI/PMI Union list still in force at the moment of the creation of the hydrogen infrastructure levels.

By default, both default hydrogen infrastructure levels are used for the CBAs. In specific cases, the assessment can be limited to one hydrogen infrastructure level through the Implementation Guidelines. If such a case occurs, a justification of the reasons behind such a selection is required.

3 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.

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.

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 FOR AN ENABLING PROJECT AND AN ENABLED PROJECT

Case: 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 FOR AN ENHANCING PROJECT AND AN 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

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 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 its enabling project.
- Projects that are enabling projects with project advancement status "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 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*[21], 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 NEPV[22] than implementing only one.
  - Complementary rules on the identification and treatment of (potentially) competing projects can be part of the Implementation Guidelines.
- **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 of 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**[23], each phase should be assessed separately in order to evaluate the incremental impact of all phases (e. g., in case of a 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 extra-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).

21 ACER Recommendation No 02/2023

22 ACER in its Recommendation No 02/2023 refers to the "net impact" which is the equivalent of the ENPV of this CBA methodology.

23 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.).

3.2 PROJECT ASSESSMENT

3.2.1 QUANTIFICATION AND MONETISATION PRINCIPLES

This CBA methodology combines monetary elements pertaining to the CBA approach, as well as non-monetary and/or qualitative elements referring to the Multi-Criteria Analysis approach. 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 indicator defined in this CBA methodology 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 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. Over time, specific investigations outside of the scope of this methodology may allow identification of meaningful and reliable ways to monetise an increased number of quantified benefits. Further monetisation should then be proposed and consulted as part of the TYNDP process.

Picture courtesy of Gas Connect Austria

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 analysis, and it is based on the differences in 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 (the combination of infrastructure levels as described in section 2.3). It should be consistent across the different projects assessed.

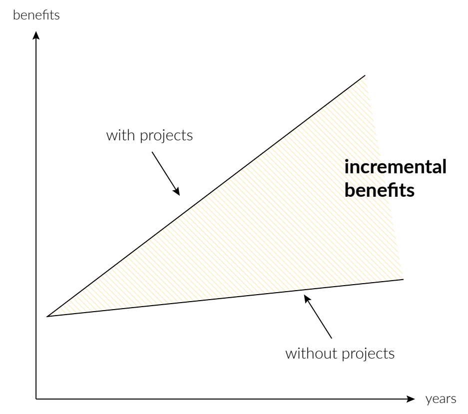


Figure 5: Incremental approach for benefits from the implementation of an assessed project.

The counterfactual situation against which the project is assessed impacts the value given to the project (or group of projects in line with section 3.1, when applicable).

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.

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 projects that are 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.

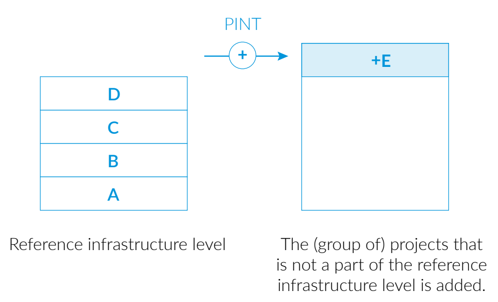


Figure 6: Incremental approach with PINT of project E.

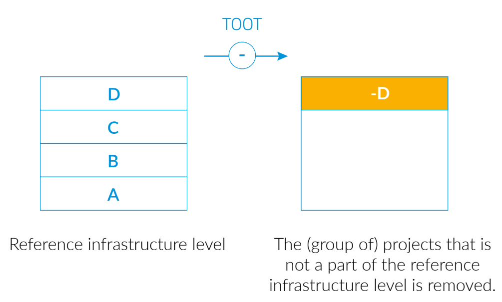


Figure 7: Incremental approach with TOOT of project D.

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 can be measured through the following 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.

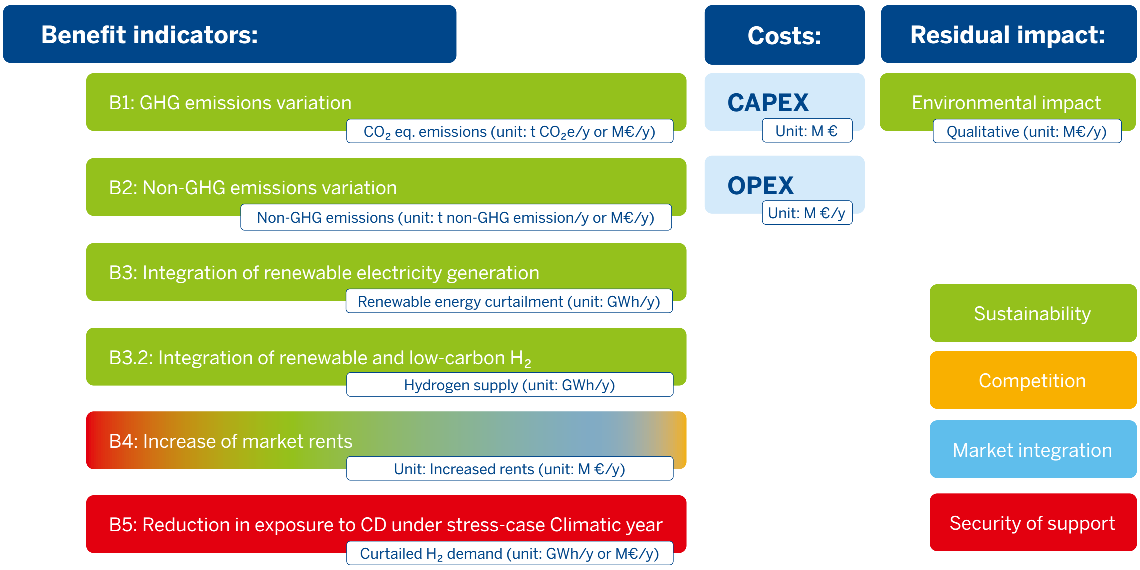


Figure 8: CBA metric and TEN-E Regulation criteria.

All benefit indicators are calculated through the incremental approach (as per section 3.2.2) in order to evaluate the EU-related contribution of a (group of) project(s). If stipulated in the Implementation Guidelines, a complementary benefit indicator capturing the effect of hydrogen projects on the security of natural gas supply may be produced.

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 (B3.1), integration of renewable and low-carbon hydrogen (B3.2), and increase of market rents (B4) are based on the same DHEM simulation run, while different simulation output parameters are used for their calculations. The reduction in exposure to curtailed hydrogen demand indicator (B5) is based on another DHEM simulation run 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 FOR THE DUAL HYDROGEN/ELECTRICITY MODEL

Market assumption	Description	Source
ETS price	Costs for covered GHG emissions.	Scenarios
Fuel prices	Costs for lignite per region, hard coal, natural gas, nuclear, oil, hydrogen imports, etc. per source.	Scenarios
Hydrogen supply potentials	Hydrogen import supply potentials for suppliers for which the interplay of the internal electricity and hydrogen networks are not modelled, while a marginal cost of hydrogen production is considered to allow the calculation of the merit order list, producer rent, and congestion rent.	Scenarios
Additional seasonality	A seasonality of certain fuel prices (e. g., for natural gas and hydrogen produced from natural gas) and/or of the availability of supply potentials may be assumed in order to better capture the storage capabilities of the hydrogen infrastructure.	Implementation Guidelines
Facilities to produce hydrogen from natural gas	Market assumptions needed for the DHEM simulations.	Scenarios
Electrolysers	Technical parameters, economic parameters, capacities and their localisation.	Scenarios
Hydrogen steel tanks		Scenarios
Thermal power plants		Scenarios
Demand-side response		Scenarios
Hydro storages		Scenarios
Battery storages		Scenarios
RES plants		Scenarios
Electricity generation profiles of RES	Per type (e. g., onshore wind, offshore wind, photovoltaic solar, concentrated solar power, other RES) and per country.	Scenarios
VoLL	Value of Lost Load in the electricity system.	Scenarios
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 costs below the Value of Lost Load) electricity demand.	Scenarios
CODH	Cost of Disrupted Hydrogen in the hydrogen system.	Implementation Guidelines
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.	Scenarios

Table 4: Market assumptions of the Dual Hydrogen/Electricity Model (DHEM).

3.2.5 B1: GHG EMISSIONS VARIATIONS

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), and hydrogen import options (e. g., low-carbon hydrogen from Norway) with respective CO_2 equivalent emission factors capturing direct emissions; ◢ Is first expressed in quantitative terms in tonnes of CO_2 equivalent emissions savings per year (tCO_2e/y); ◢ Can be expressed in monetary terms (€/y) by multiplying the CO_2 equivalent emissions savings (tCO_2e/y) by the cost of carbon (€/tCO_2e) 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.

As a minimum, besides CO_2, the following primary non-CO_2 GHG emissions should be considered: Nitrous oxide (N_2O) and methane (CH_4).

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

$$
\begin{aligned}
&\textit{GHG emissions variation enabled by (group of) project(s)}\\
&\quad = \Big(\sum_{i}^{n} (\textit{power generation}_{i,\,\textit{with (group of) project(s)}} \times CO_2e\ \textit{emission factor}_i)\\
&\quad + \sum_{j}^{m} (\textit{hydrogen production}_{j,\,\textit{with (group of) project(s)}} \times CO_2e\ \textit{emission factor}_j)\\
&\quad + \sum_{k}^{r} (\textit{hydrogen import from supply potential}_{k,\,\textit{with (group of project(s)}} \times CO_2e\ \textit{emission factor}_k)\Big)\\
&\quad - \Big(\sum_{i}^{n} (\textit{power generation}_{i,\,\textit{without (group of) project(s)}} \times CO_2e\ \textit{emission factor}_i)\\
&\quad + \sum_{j}^{m} (\textit{hydrogen production}_{j,\,\textit{without (group of) project(s)}} \times CO_2e\ \textit{emission factor}_j)\\
&\quad + \sum_{k}^{r} (\textit{hydrogen import from supply potential}_{k,\,\textit{without (group of) project(s)}} \times CO_2e\ \textit{emission factor}_k)\Big)
\end{aligned}
$$

On the basis of:

- n: number of different types of electricity generation.
- m: number of different types of hydrogen production.
- r: number of different supply sources that are considered with the supply potential approach.
- All CO_2 equivalent emission factors capture direct GHG emissions.
- 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_2e 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_2e emission factor$_j$: GHG emission factor expressed in CO_2 equivalence of hydrogen production of type 'j' per unit of energy produced in form of hydrogen.
- Hydrogen import from supply potential$_k$: Amount of hydrogen imported from hydrogen source that is considered with the supply potential approach of type 'k'. It is used to capture the changes of imports from supply sources that are considered with the supply potential approach.
- CO_2e emission factor$_k$: GHG emission factor expressed in CO_2 equivalence of hydrogen source that is considered with the supply potential approach of type 'k' per unit of energy used.

The resulting amount of variation of GHG emissions in tonnes of CO_2e 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[24]:
  - 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 they are 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. Because of the expected spread of values that typically arise from different sources, the costs that are used can be given as a range, e. g., by defining minimum, medium and maximum values. They should ideally be agreed between the main stakeholders and reflect the most recent values as given by the European Commission. The values used for the monetisation of this indicator are required to be provided within the Implementation Guidelines, together with a link to the scientific and agreed study. As default reference source, the shadow cost of carbon of the European Investment Bank (EIB) should be used for the monetisation of GHG emissions through this indicator (B1). When available, the cost of carbon should include more granular inputs with respect to its development over time (e. g., yearly inputs).

$$B1_{monetised} = (\textit{Societal Cost of Carbon} \times \textit{GHG emissions variations enabled by (group of) project(s)}) - \textit{total GHG emission costs monetised in B4}$$

24 IPCC Special report on the impacts of global warming of 1.5 °C (2018) – Chapter 2

On the basis of:

- Societal Cost of Carbon: Cost of Carbon for the specific year as published by the EIB[25].
- GHG emissions variations enabled by (group of) project(s): As defined in the formula above.
- Total GHG emission costs monetised in B4: Variation of GHG emission costs enabled by the (group of) project(s) as considered in the increase of market rents indicator (B4) on the basis of the forecasted ETS price.

This benefit indicator (B1) is interlinked with

- The integration of renewable electricity generation indicator (B3.1) as using more renewable electricity generation reduces 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 CO_2 equivalent emission factors, which reduces GHG emissions;
- The increase of market rents indicator (B4) which also includes a monetisation of the part of the GHG emissions as described above. Therefore, the GHG emissions costs that are monetised in the increase of market rents indicator (B4) are removed from this benefit indicator (B1) to avoid double-counting.

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

This benefit indicator (B1) requires careful consideration if the assessed (group of) project(s) reduces curtailed hydrogen demand in the reference weather year: As curtailed hydrogen demand is not creating emissions in the DHEM, even electrolytic or low carbon hydrogen that satisfies hydrogen demand can increase emissions in comparison to hydrogen demand curtailment. Therefore, this benefit indicator (B1) underestimates the reduction of emissions enabled by a (group of) project(s) that reduces hydrogen demand curtailment. To mitigate this fact, the Implementation Guidelines may provide improvements based on thorough and targeted consultations of relevant industries. These consultations shall investigate under which circumstances end users would continue using other, more polluting fuels if insufficient hydrogen was available. On this basis, assumptions could be introduced to the DHEM. This would allow to capture the reduction of emissions enabled by a (group of) project(s) that supplies additional hydrogen quantities and thereby reduces the usage of other, more polluting fuels.

EXAMPLE FOR A HYPOTHETICAL HYDROGEN STORAGE PROJECT

- Case: The hydrogen storage project allows increased usage of renewable hydrogen which replaces unabated hydrogen production from natural gas.
- Assumed ETS price in the assessed year: 30 €/tCO_2.
- Assumed societal cost of carbon in the assessed year: 100 €/tCO_2
- Results:
  - Reduction of CO_2 equivalent emissions covered by the ETS and this benefit indicator (B1): 0.1 MtCO_2/y
  - Reduction of CO_2 equivalent emissions covered by the ETS and the increase of market rents indicator (B4): 0.05 MtCO_2/y
  - Reduction of total CO_2 equivalent emissions covered by this benefit indicator (B1): 0.1 MtCO_2/y
  - CO_2 equivalent emissions variations monetised in the increase of market rents indicator (B4): 0.05 × 30 M€/y = 1.5 M€/y
- CO_2 equivalent emissions variations monetised in this benefit indicator (B1): 0.1 × 100 M€/y – 1.5 M€/y = 8.5 M€/y

25 EIB Group Climate Bank Roadmap 2021 – 2025 (November 2020)

3.2.6 B2: NON-GHG EMISSIONS VARIATIONS

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), and hydrogen import options (e. g., low-carbon hydrogen from Norway with respective emission factors capturing direct; - Is first expressed in quantitative terms in variations of tonnes of pollutant emitted per year (e. g., tNO_x/y, tSO_2/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), fine particulate matter, non-methane volatile organic compounds, and ammonia (NH_3). Also, the European Commission has set in the European Green Deal the zero-pollution ambition for a toxic-free environment[26], in addition to 2030 targets for the reduction of air pollution set in the zero-pollution Action Plan[27].

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. 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, the following formula is applied.

$$
\begin{aligned}
&GHG\ emissions\ variation\ enabled\ by\ (group\ of)\ \ project(s)_y \\
&\quad = \Big(\sum_i^n (power\ generation_{\ i,\ with\ (group\ of)\ project(s)} \times Non-GHG\ emission\ factor_{i,\ y}) \\
&\quad + \sum_j^m (hydrogen\ production_{\ j,\ with\ (group\ of)\ project(s)} \times Non-GHG\ emission\ factor_{i,\ y}) \\
&\quad + \sum_l^r (hydrogen\ import\ from\ supply\ potential_{\ l,\ with\ (group\ of\ \ project(s)} \times Non-GHG\ emission\ factor_{l,\ y}) \Big) \\
&\quad - \Big(\sum_i^n (power\ generation_{\ i,\ without\ (group\ of)\ project(s)} \times Non-GHG\ emission\ factor_{i,\ y}) \\
&\quad + \sum_j^m (hydrogen\ production_{\ j,\ without\ (group\ of)\ project(s)} \times Non-GHG\ emission\ factor_{j,\ y}) \\
&\quad + \sum_l^r (hydrogen\ import\ from\ supply\ potential_{\ l,\ without\ (group\ of)\ project(s)} \times Non-GHG\ emission\ factor_{l,\ y}) \Big)
\end{aligned}
$$

26 EC Communication: Pathway to a Healthy Planet for All

27 EU Action Plan: Towards Zero Pollution for Air, Water and Soil

On the basis of:

- n: number of different types of electricity generation.
- m: number of different types of hydrogen production.
- r: number of different supply sources that are considered with the supply potential approach.
- All non-GHG emission factors capture direct emissions.
- 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.
- 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 B2 indicator.

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

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

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 costy: Cost of the emission of pollutant 'y' (€/t[Pollutant]).

Transparent and preferably publicly available sources of information (such as the European Environment Agency[28]) regarding the damage costs of pollutants are preferred. In addition, the sources of the used emission factors and the damage costs must be referenced and should be consulted in the Implementation Guidelines.

28 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 €/tCO_2
- Assumed damage cost of pollutant x in the assessed year: 200 €/tCO_2
- Non-monetised results of this benefit indicator (B2):
  - Reduction of emissions of pollutant y: 0.1 Mt/y
  - Reduction of emissions of pollutant x: 0.05 Mt/y
- Non-GHG emissions variations monetised in this benefit indicator (B2):
  100 × 0.1 M€/y + 200 × 0.05 M€/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.

This benefit indicator (B2) requires careful consideration if the assessed (group of) project(s) reduces curtailed hydrogen demand in the reference weather year: As curtailed hydrogen demand is not creating emissions in the DHEM, even electrolytic or low carbon hydrogen that satisfies hydrogen demand can increase emissions in comparison to hydrogen demand curtailment. Therefore, this benefit indicator (B2) underestimates the reduction of emissions enabled by a (group of) project(s) that reduces hydrogen demand curtailment. To mitigate this fact, the Implementation Guidelines may provide improvements based on thorough and targeted consultations of relevant industries. These consultations shall investigate under which circumstances end users would continue using other, more polluting fuels if insufficient hydrogen was available. On this basis, assumptions could be introduced to the DHEM. This would allow to capture the reduction of emissions enabled by a (group of) project(s) that supplies additional hydrogen quantities and thereby reduces the usage of other, more polluting fuels.

3.2.7 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, the following formula is applied.

$$B3.1 = \sum_{i}^{n} (uncurtailed\ renewable\ electricity\ generation_{\ i,with\ (group\ of)\ project(s)})$$
$$- \sum_{i}^{n} (uncurtailed\ renewable\ electricity\ generation_{\ i,with\ (group\ of)\ project(s)})$$

On the basis of:

- n: number of types of renewable generation.
- Uncurtailed renewable electricity generation$_i$: 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 generation by providing a storage option for renewable energy in the form of hydrogen. Thereby, the hydrogen storage project reduces the curtailment of renewable electricity generation.
- 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.

3.2.8 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, the following formula is applied.

$$B3.2 = \begin{pmatrix} \textit{Electrolytic hydrogen production}_{\text{with (group of) project(s)}} \\ + \quad \textit{Low carbon hydrogen production}_{\text{with (group of) project(s)}} \\ + \quad \textit{Renewable hydrogen imports}_{\text{with (group of) project(s)}} \\ + \quad \textit{Low carbon hydrogen imports}_{\text{with (group of) project(s)}} \end{pmatrix} - \begin{pmatrix} \textit{Electrolytic hydrogen production}_{\text{with (group of) project(s)}} \\ + \quad \textit{Low carbon hydrogen production}_{\text{with (group of) project(s)}} \\ + \quad \textit{Renewable hydrogen imports}_{\text{with (group of) project(s)}} \\ + \quad \textit{Low carbon hydrogen imports}_{\text{with (group of) project(s)}} \end{pmatrix}$$

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 scenarios (MWh/y).
- Low carbon hydrogen imports: Hydrogen imported from supply sources that are considered to supply low carbon hydrogen in the scenarios (MWh/y).

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.

3.2.9 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 the hydrogen sector and cross-sector rents between the hydrogen sector and the electricity sector[29]; ◢ 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 approach that is further detailed in Annex III. 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 following formula is used for the calculation of this benefit indicator (B4), while a more detailed mathematical description of the terms of the formula is provided in Annex III.

$$Market\ rents = \sum_a \sum_b R^{H2}_{Producer,\,a,\,b} + \sum_c \sum_d R^{H2}_{Consumer,\,c,\,d} + \sum_e R^{H2}_{Grid\ congestion,\,e} + \sum_f \sum_g R^{H2 \leftrightarrow el}_{Cross\text{-}sector,\,f,\,g} + \sum_h R^{H2}_{Storage,\,h}$$

On the basis of:

- $R^{H2}_{Producer,\,a,\,b}$ is the hydrogen producer surplus, i.e., the sum of the hourly differences between the marginal cost of producing energy in the form of hydrogen (including conversion) and how much the market is willing to pay for the energy in the form of hydrogen. Here, it is calculated as the difference between the marginal cost of hydrogen production of type 'a' and the market clearing price in the hydrogen market area 'b' multiplied by the quantity of energy produced in the form of hydrogen by this production type 'a' in the hydrogen market area 'b'. Curtailed hydrogen demand is essentially a missed opportunity to create a hydrogen producer surplus from satisfying this demand.
- $R^{H2}_{Consumer,\,c,\,d}$ is the hydrogen consumer surplus, i.e., the difference between the price consumers pay for energy in the form of hydrogen and the price they are willing to pay for it. In the context of this CBA methodology, this threshold price that consumers are still willing to pay is set at the CODH while some hydrogen users may be assumed with a hydrogen demand side response activation below the CODH. Here, the consumer surplus is calculated as the sum of the hourly differences between the price consumers of type 'c' are willing to pay for hydrogen and the hydrogen market clearing price in hydrogen market area 'd' multiplied by the quantity of energy in form of hydrogen consumed by consumers of type 'c' in the hydrogen market area 'd'.

29 The DHEM could in principle also evaluate the increase of market rents under consideration of multiple sectors like the hydrogen and the electricity sector.

- $R^{H2}_{Grid\ congestion,\ e}$ is the hydrogen congestion rent. It occurs at borders between markets with different market clearing prices that are interconnected. In such cases, in the exporting market, the producer rent definition as provided above does not capture the additional surpluses that are created from selling a part of the production above the market clearing price of the exporting market, i.e., at the market clearing price of the importing market. If there was no infrastructure bottleneck, the market clearing prices of connected markets would be equal, resulting in a congestion rent of 0. The congestion rent therefore indicates that there is inadequate capacity to deliver the lowest-cost supply to consumers. Higher cost supply is dispatched instead, raising prices. In the DHEM, the hydrogen congestion rent is the sum of the hourly differences in the hydrogen market clearing prices at both sides of each interconnection point 'e' in the hydrogen system multiplied by the quantity of energy transported across this interconnection point.

- $R^{H2 \leftrightarrow el}_{Cross\text{-}sector,\ f,\ g}$ is the cross-sector rent. It is based on the price differences between two coupled systems, and the energy conversion efficiency. In the case of the DHEM, the systems considered are electricity and hydrogen. Typically, when energy is transferred, there is a price difference. The cross-sector rent is the difference in the marginal cost of production in the two systems. In the DHEM, the cross-sector rent is calculated as the sum of the hourly differences in the market clearing price within the electricity bidding zone 'f' multiplied by the quantity of energy in the form of electricity, and the hydrogen market area 'g' multiplied by the quantity of energy in the form of hydrogen. It reflects a part of the surplus of the electrolyser usage that is not captured in the electricity producer rent which is calculated using the electricity market clearing price, while the part of the electricity generation that is transferred into the hydrogen system is sold at a higher price in the hydrogen system. With the same logic, it captures additional surplus of hydrogen-based power plants.

- $R^{H2}_{Storage,\ h}$ is the hydrogen storage operator surplus, i.e., the sum of the hourly differences between the cost of buying energy in the form of hydrogen for injection and the income from selling energy in the form of hydrogen from withdrawal. Here, these expenses and revenues are calculated with reference to the hydrogen market clearing price in the hydrogen market area 'h', multiplied by the quantity of energy in the form of hydrogen that is injected or withdrawn from the storage. Energy losses from storage operations can be reflected in the share of injected energy that can be later withdrawn.

This benefit indicator (B4) is interlinked with

- The GHG emissions variations indicator (B1) which also includes a monetisation of the GHG emissions (see section 3.2.5). 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.

Under this benefit indicator (B4), additional information can be provided. This may include information about the reduction of curtailed hydrogen demand enabled by the (group of) project(s) and thereby its contribution to the security of hydrogen supply under reference weather conditions. This additional information can improve the interpretation of the GHG emissions variations indicator (B1) and the non-GHG emissions variations indicator (B2).

3.2.10 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).[30]
Indicator Calculation	This benefit indicator (B5) ◢ Is calculated under consideration of a more stressful weather year than the reference 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 future Cost of Disrupted Hydrogen (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 weather 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.

30 Outside of the reduction in exposure to curtailed hydrogen demand indicator (B5), the following security of supply assessments could be performed that are further detailed in Annex II: An assessment of i) the reduction in exposure to curtailed natural gas demand for the same or other stress cases, and ii) the reduction in exposure to curtailed hydrogen demand for other stress cases. These assessments may be used by NRAs and ACER for decisions on cross-border cost allocations.

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

Next, the DGM input data is prepared in line with section 2.2.3.5 and section 2.2.3.6. Thereby, the input data of the DGM is sourced from the DHEM simulation for the 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.

$$\triangle HDC_{DGM,\ stress\ year} = DC_{DGM,\ European\ Union,\ stress\ year,\ with\ (group\ of)\ project(s)} - DC_{DGM,\ European\ Union,\ stress\ year,\ without\ (group\ of)\ project(s)}$$

When comparing the DHEM and the DGM, both have certain restraints that the other model does not have. The DHEM is using hourly time steps compared to the monthly time steps 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 to produce natural gas from it. In the DHEM, the availability of natural gas for this purpose is just assumed. 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.

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

The non-monetised benefit indicator is therefore defined as follows:

$$\triangle HDC_{B5} = MAX(MAX(\triangle HDC_{DHEM,\ stress\ year}; \triangle HDC_{DGM,\ stress\ year}) - \triangle HDC_{DHEM,\ reference\ year}; 0)$$

This benefit indicator can then be monetised as follows:

$$B5_{monetised} = CODH \times \triangle HDC_{B5} \times Probability\ of\ occurence$$

On the basis of:

- CODH: Cost of Disrupted Hydrogen (€/MWh). An approximation based on the CODG for relevant industrial sectors or based on the observed willingness to pay of (future) hydrogen users may be applied.
- Probability of occurrence: Probability of the occurrence of a stressful weather year (e. g., 10 %), to be defined in the Implementation Guidelines.If with the definition of an EU hydrogen and low carbon gases security of supply policy[31], a definition of a Cost of Disrupted Hydrogen (CODH) would be recommended, this CODH value could be introduced as harmonised reference value of the monetisation factor at EU level unless differently defined in the Implementation Guidelines.

31 Report from the European Commission to the Council and the European Parliament reviewing the application of Regulation (EU) 2017/1938, October 2023.

3.2.11 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[32], 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 [33] 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.

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

Table 5: Minimum set of information to be included in the PS-CBA assessment phase regarding the environmental impact of a hydrogen project.

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
- 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 5).
- 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.

32 https://ec.europa.eu/environment/nature/natura2000/index_en.htm

33 EIA Directive (Council Directive 2011/92/CE)

3.2.12 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, this CBA methodology recommends project promoters to assess climate vulnerability and identify the related climate risks as part of the project assessment.

In line with the EC 'Technical Guidance on the climate proofing of infrastructure in the period 2021 – 2027', this CBA methodology recommends to integrate the assessment of climate vulnerability and related risk assessment from the beginning of the project development process.

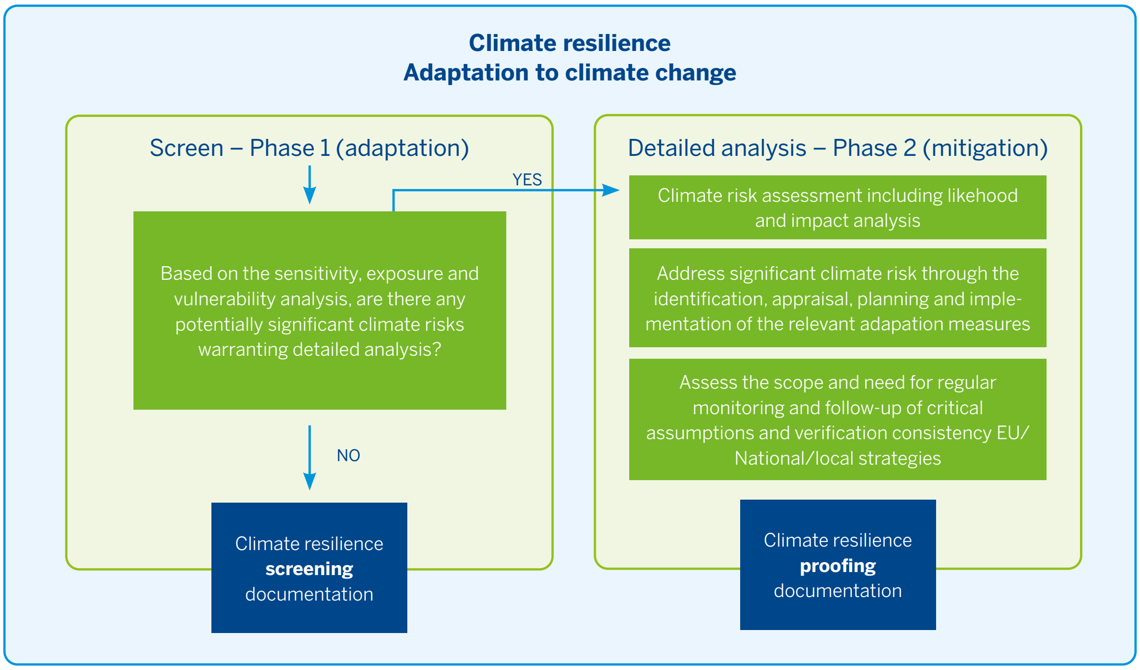


Figure 9: Overview of the climate adaptation-related process (source: Technical guidance on the climate proofing of infrastructure in the period 2021 – 2027, European Commission)

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 e. g. flooding, extreme heat or extreme cold, hurricanes, thunderstorms, etc.

3.2.13 PROJECTS COSTS

Costs represent an inherent element of a 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[34] 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-way, groundwork, preparatory work, designing, equipment purchase, equipment installation and decommissioning.
  - 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[35], 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.

All cost data should be considered at constant (real) prices. As part of the TYNDP, it is recommended that constant prices refer to the year of the TYNDP project collection.

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.

34 This classification is in line with the **EC Guide to Cost-Benefit Analysis of Investment Projects**

35 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.

Picture courtesy of terranets bw

4 SENSITIVITY ANALYSES

Given the uncertainties when defining possible future scenarios, for each CBA, sensitivity analyses should be conducted to increase the validity of the CBA results.

Sensitivity analyses can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the model results. This provides a deeper understanding of the system's behaviour with respect to the chosen parameter or interlinked parameters. It should be noted that interdependencies between the below listed sensitivities can occur. However, as a robust investigation on these interdependencies can become very complex, this goes beyond the single treatment of sensitivities as addition to the CBA.

In general, a sensitivity analysis must be performed on a uniform level, i.e., the sensitivity needs to be applied to all projects under assessment in the respective study. However, in some cases the added value of the sensitivity might be given only for specific projects (e.g., a sensitivity using 40 years of economic lifetime instead of 25 years does not influence the assessment of projects that have a technical lifetime of 25 years, as the economic lifetime cannot be longer than the technical lifetime). In such cases it is, together with a sufficient argumentation within the Implementation Guidelines, reasonable to apply the respective sensitivity only to the relevant projects. In principle, each individual model parameter can be used for a sensitivity analysis. Furthermore, different parameters can have a different impact on the results depending on the scenario. For this purpose, detailed information about the selection of the parameters must be given within the Implementation Guidelines.

The parameters listed below can be used to perform sensitivities. This list is not exhaustive and provides some examples of useful sensitivities within the boundaries of the scenario storylines, together with a short overview of the expected actions necessary to perform the respective sensitivity analysis.

- Fuel and ETS prices: A global set of values for fuel prices is defined as part of the scenario development process. A degree of uncertainty regarding these values and prices is unavoidable. Fuel and ETS prices determine the specific costs of various assets and, therefore, the merit order. On that basis, varying fuel and ETS prices impact the merit order, which in turn has an impact on the related benefit indicators required to be reported on, as part of this CBA methodology.
  - New simulations are required to be run to properly evaluate this sensitivity, since the prices influence the merit order. This can influence all benefit indicators and the economic performance indicators.
- Cost of carbon: A sensitivity study could be performed in which the cost of carbon is varied.
  - For this sensitivity, no new simulations are required. Instead, the GHG emissions variations indicator (B1) can be calculated with the alternative cost of carbon. This can also influence the economic performance indicators.
- Weather year: Using historical climate data from different years might influence the benefits of a project. For example, the integration of renewable electricity generation indicator (B3.1) depends on the infeed of RES and weather conditions. For this reason, performing an analysis with different weather years would lead to a better understanding of how market results depend on weather conditions. This can be used to understand how the indicators are impacted by climatic conditions.
  - For each weather year, new simulations have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- Installed energy storage, power generation, and hydrogen production capacity: The amount of these capacities is defined within the scenarios. For this sensitivity, it is crucial to not excessively change the capacities. More fundamental changes would instead lead to the definition of new scenarios. Sensitivity studies in which the installed RES capacity is varied could be performed to assess the impact of a delay or an advancement of RES capacity delivery on the benefit indicators contained in this CBA methodology.
  - New simulations using the changed capacities have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- Flexibility of energy demand, power generation, hydrogen production, and supply potentials: This sensitivity could include the change in the behaviour of demand side response or how electrolysers are modelled.
  - New simulations using the changed parameters have to be performed to properly evaluate this sensitivity. This can influence all benefit indicators and the economic performance indicators.
- Other relevant parameters: Sensitivities on project-specific data should be reflected in the CBA. This relates to
  - CAPEX and OPEX:
    - No new simulations are required. Such sensitivity will not influence the benefit indicators, but the economic performance indicators can be influenced.
  - 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.
  - Economic lifetime: A sensitivity with 40 years instead of 25 years (see section 5.2.3):
    - 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.
  - The commissioning date of various projects: The projects to be assessed and the commissioning date related to these are information provided by project promoters during the project data collection phase. However, the timely commissioning of projects might be delayed due to several reasons (e. g., longer permitting phase, unexpected incidents while construction, etc.). This CBA methodology recommends such sensitivity for the CBA of multi-phase projects and groups of projects (see section 5.2.5).

5 ECONOMIC PERFORMANCE INDICATORS

5.1 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 CBA.

This CBA methodology describes two different economic performance indicators: The Economic Net Present Value (ENPV) and the Economic Benefit-to-Cost Ratio (EBCR).

The CBA methodology builds on 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 5.2.5. 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. When monetising the interpolated quantified benefits, year-specific monetisation values should be used (e. g., for the societal cost of carbon).

To assess a project that is comprised of multi-phase investments[36], 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 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.

36 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.).

5.2 ECONOMIC PARAMETERS

5.2.1 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[37]. By doing so, one neutralises the effect of inflation for all projects.

For the TYNDP, it is recommended that constant prices refer to the year of the TYNDP project collection.

5.2.2 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.

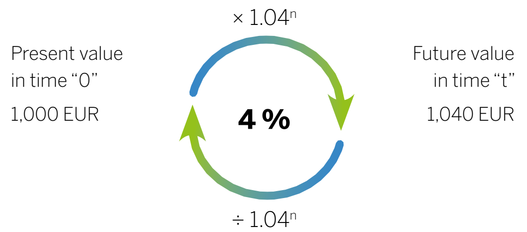


Figure 10: Example of how the social discount rate works.

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 % should be used for all projects.**

5.2.3 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.

The 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.

This CBA methodology prescribes an assessment period of 25 years as a default case, and that this same reference assessment period should be 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 the assessment period, the economic analysis will be performed based on the technical lifetime of the asset.

5.2.4 RESIDUAL VALUE

Projects should be **assessed without residual value** if the assessment period is covering 25 years of operation.

37 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.

5.2.5 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
- The assessment of all the projects should take place at the same year of analysis (n) and take into consideration an economic lifetime of 25 years. For example, projects may be commissioned in 2029 or 2033, their benefits and costs will be considered for the following 25 years but all discounted in the same year (e. g., 2024) as follows:

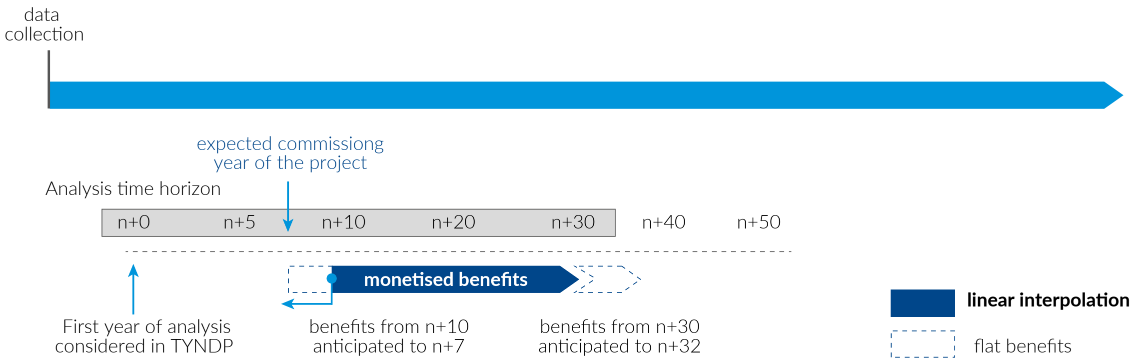


Figure 11: Representation of economic cash flow assessment in case of projects to be commissioned between two assessed years (here: reference case of 25 years economic lifetime).

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.

5.3 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 of the analysis (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.

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

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 (common for all projects).
- r: Social Discount Rate.

5.4 ECONOMIC PERFORMANCE INDICATOR 2: ECONOMIC BENEFIT-TO-COST RATIO (EBCR)

The Economic Benefit/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 (common to all projects).
- r: Social Discount Rate.

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

This performance indicator allows 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):	**Project group B (lower ENPV):**
Total discounted benefits: 9.863 (M€)	Total discounted benefits: 1.146 (M€)
Total discounted costs: −6.865 (M€)	Total discounted costs: −796 (M€)
EBCR: 1,44	EBCR: 1,44

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**, the principle's application in this CBA methodology 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 this CBA methodology:

- **The support study 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 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, 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 SCENARIO DEVELOPMENT

As the scenario development is governed by Article 12 of the TEN-E Regulation, the descriptions in this section are not intended to prejudge future scenario developments and innovations, especially in relation to the further application of the energy efficiency first principle.

- 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 scenarios are developed on an NECP-based scenario storyline as well as deviating storylines. Within the scenario development, energy-efficient technologies are either i) set at ambitious levels (due to NECPs, EU energy and climate targets, or infrastructure operator inputs in combination with stakeholder consultations); or ii) provided with an option to further expand their deployment based on economic decisions. 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 (e.g., electrolysers) or through cross-sectoral demand shifts (e.g., hybrid heat pumps);
    - assets allowing flexibility like time-shifting of demand (e.g., time flexibility of heating) or storage (e.g., electric vehicles charging in a supportive manner and providing supply if needed);
    - 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 (e.g., 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, 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. Since such investigations (especially concerning the future developments) are associated with uncertainties, different scenario storylines and/or variants are established.


Picture courtesy of Gassco

6.2 CONSIDERATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE IN THE INFRASTRUCTURE GAPS IDENTIFICATION

As the infrastructure gaps identification is governed by Article 13 of the TEN-E Regulation, the descriptions in this section are not intended to prejudge future infrastructure gaps identification developments and innovations, especially in relation to the further application of the energy efficiency first principle.

- Inclusion of options for better utilisation of existing infrastructure
  - The existing infrastructure considered in the TYNDP topology is updated for each TYNDP cycle 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 infrastructure gaps identification is performed on the basis of the scenarios that include 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 scenario, the selected energy efficiency measures are not associated with additional investments in the infrastructure gaps identification exercise and their usage is always an option alongside the assessment of hydrogen infrastructure investments. Since such investigations, especially concerning the future developments, are associated with uncertainties, different scenario storylines and/or variants should be used for the infrastructure gaps identification.
- 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 scenarios 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 (e. g., electrolysers) or through cross-sectoral demand shifts (e. g., hybrid heat pumps);
  - assets allowing flexibility like time-shifting of demand (e. g., time flexibility of heating) or storage (e. g., electric vehicles charging in a supportive manner and providing supply if needed);
  - 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 (e. g., hydrogen production from natural gas);
  - the model being allowed to investigate the optimal solution for each stress case with several degrees of freedom (e. g., usage of hydrogen 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 (e. g., 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.

6.3 CONSIDERATION OF THE ENERGY EFFICIENCY FIRST PRINCIPLE IN THE CBAS

The description of the previous section applies mutatis mutandis.

ANNEX I: LEGAL BACKGROUND

ENTSOG prepared this CBA methodology based on Article 11 of the TEN-E Regulation. Article 1(1) states that ENTSOG's CBA methodology covers energy infrastructure set out in Annex II (3).

Annex II(3) of the TEN-E Regulation concerns following hydrogen infrastructure categories:

(a) pipelines for the transport, mainly at high pressure, of hydrogen, including repurposed natural gas infrastructure, giving access to multiple network users on a transparent and non-discriminatory basis;

(b) storage facilities connected to the high-pressure hydrogen pipelines referred to in point (a);

(c) reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances with the objective of injecting the hydrogen, where applicable, into the grid;

(d) any equipment or installation essential for the hydrogen system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations;

(e) any equipment or installation allowing for hydrogen or hydrogen-derived fuels use in the transport sector within the TEN-T core network identified in accordance with Chapter III of Regulation (EU) No 1315/2013 of the European Parliament and of the Council.

Any of the assets listed in points (a) to (d) may be newly constructed or repurposed from natural gas to hydrogen, or a combination of the two.

Art. 11(1) of the TEN-E Regulation furthermore states that ENTSOG's CBA methodology *shall be drawn up in line with the principles laid down in* ***Annex V,*** *be based on common assumptions allowing for project comparison, and be* ***consistent with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objectives****, as well as with the rules and indicators set out in* ***Annex IV****.*

Annex V of the TEN-E Regulation sets up principles for the energy system-wide CBAs:

The methodologies for cost-benefit analyses developed by the ENTSO for Electricity and the ENTSO for Gas shall be consistent with each other, taking into account sectorial specificities. The methodologies for a harmonised and transparent energy system-wide cost-benefit analysis for projects on the Union list shall be uniform for all infrastructure categories, unless specific divergences are justified. They shall address costs in the broader sense, including externalities, in view of the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective and shall comply with the following principles:

(1) the area for the analysis of an individual project shall cover all Member States and third countries, on whose territory the project is located, all directly neighbouring Member States and all other Member States in which the project has a significant impact. For this purpose, ENTSO for Electricity and ENTSO for Gas shall cooperate with all the relevant system operators in the relevant third countries. In the case of projects falling under the energy infrastructure category set out at point (3) of Annex II, the ENTSO for Electricity and the ENTSO for Gas shall cooperate with the project promoter, including where it is not a system operator;

(2) each cost-benefit analysis shall include sensitivity analyses concerning the input data set, including the cost of generation and greenhouse gases as well as the expected development of demand and supply, including with regard to renewable energy sources, and including the flexibility of both, and the availability of storage, the commissioning date of various projects in the same area of analysis, climate impacts and other relevant parameters;

(3) they shall establish the analysis to be carried out, based on the relevant multi-sectorial input data set by determining the impact with and without each project and shall include the relevant interdependencies with other projects;

(4) they shall give guidance for the development and use of energy network and market modelling necessary for the cost-benefit analysis. The modelling shall allow for a full assessment of economic benefits, including market integration, security of supply and competition, as well as lifting energy isolation, social and environmental and climate impacts, including the cross-sectorial impacts. The methodology shall be fully transparent including details on why, what and how each of the benefits and costs are calculated;

(5) they shall include an explanation on how the energy efficiency first principle is implemented in all the steps of the Union-wide ten-year network development plans;

(6) they shall explain that the development and deployment of renewable energy will not be hampered by the project;

(7) they shall ensure that the Member States on which the project has a net positive impact, the beneficiaries, the Member States on which the project has a net negative impact, and the cost bearers, which may be Member States other than those on which territory the infrastructure is constructed, are identified;

(8) they shall take into account, at least, the 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. The methodologies shall give guidance on discount rates, technical lifetime and residual value to be used for the cost- benefit calculations. They shall furthermore include a mandatory methodology to calculate benefit-to-cost ratio and the net present value, as well as a differentiation of benefits in accordance with the level of reliability of their estimation methods. Methods to calculate the climate and environmental impacts of the projects and the contribution to Union energy targets, such as renewable penetrations, energy efficiency and interconnection targets shall also be taken into account;

(9) they shall ensure that the climate adaptation measures taken for each project are assessed and reflect the cost of greenhouse gas emissions and that the assessment is robust and consistent with other Union policies in order to enable comparison with other solutions which do not require new infrastructures.

Annex IV of the TEN-E Regulation sets up rules and indicators concerning criteria for projects:

(1) A project of common interest with a significant cross-border impact shall be a project on the territory of a Member State and shall fulfil the following conditions: (…)

(d) for hydrogen transmission, the project enables the transmission of hydrogen across the borders of the Member States concerned, or increases existing cross-border hydrogen transport capacity at a border between two Member States by at least 10 % compared to the situation prior to the commissioning of the project, and the project sufficiently demonstrates that it is an essential part of a planned cross-border hydrogen network and provides sufficient proof of existing plans and cooperation with neighbouring countries and network operators or, for projects decreasing energy isolation of non-interconnected systems in one or more Member States, the project aims to supply, directly or indirectly, at least two Member States; (e) for hydrogen storage or hydrogen reception facilities referred to in point (3) of Annex II, the project aims to supply, directly or indirectly, at least two Member States;

(…)

(2) A project of mutual interest with significant cross-border impact shall be a project and shall fulfil the following conditions: (…)

(b) for projects of mutual interest in the category set out in point (3) of Annex II, the hydrogen project enables the transmission of hydrogen across at the border of a Member State with one or more third countries and proves bringing significant benefits, either directly or indirectly (via interconnection with a third country) under the specific criteria listed in Article 4(3), at Union level. The calculation of the benefits for the Member States shall be performed and published by the ENTSO for Gas in the frame of Union-wide ten-year network development plan;

(…)

(5) Concerning hydrogen falling under the energy infrastructure category set out in point (3) of Annex II, the criteria listed in Article 4 shall be evaluated as follows:

(a) sustainability, measured as the contribution of a project to greenhouse gas emission reductions in various end-use applications in hard-to-abate sectors, such as industry or transport; flexibility and seasonal storage options for renewable electricity generation; or the integration of renewable and low-carbon hydrogen with a view to consider market needs and promote renewable hydrogen;

(b) market integration and interoperability, measured by calculating the additional value of the project to the integration of market areas and price convergence to the overall flexibility of the system;

(c) security of supply and flexibility, measured by calculating the additional value of the project to the resilience, diversity and flexibility of hydrogen supply;

(d) competition, measured by assessing the project's contribution to supply diversification, including the facilitation of access to indigenous sources of hydrogen supply.

Annex III specifies the inclusion of PCI and PMI candidates in the TYNDP:

(…)

2. Process for establishing regional lists

(…)

(4) From 1 January 2024, the proposed hydrogen projects of common interest falling under the energy infrastructure categories set out in point (3) of Annex II to this Regulation are part of the latest available Community-wide ten-year network development plan for gas, developed by the ENTSO for Gas pursuant to Article 8 of Regulation (EC) No 715/2009.

(5) By 30 June 2022 and subsequently for every Union-wide ten-year network development plan, the ENTSO for Electricity and the ENTSO for Gas shall issue updated guidelines for inclusion of projects in their respective Union-wide ten-year network development plan, as referred to in points (3) and (4), in order to ensure equal treatment and the transparency of the process. For all the projects on the Union list in force at the time, the guidelines shall establish a simplified process of inclusion in the Union-wide ten-year development plans taking into account the documentation and data already submitted during the previous Union-wide ten-year network development plan process, provided that the documentation and data already submitted remains valid.

The ENTSO for Electricity and the ENTSO for Gas shall consult the Commission and the Agency about their respective draft guidelines for inclusion of projects in the Union-wide ten-year network development plans and take due account of the Commission's and the Agency's recommendations before the publication of the final guidelines.

Article 4 sets up criteria for the assessment of projects by the Regional Groups:

1. A project of common interest shall meet the following general criteria:

(a) the project is necessary for at least one of the energy infrastructure priority corridors and areas set out in Annex I;

(b) the potential overall benefits of the project, assessed in accordance with the relevant specific criteria in paragraph 3, outweigh its costs, including in the longer term;

(c) the project meets any of the following criteria:

(i) it involves at least two Member States by directly or indirectly, via interconnection with a third country, crossing the border of two or more Member States;

(ii) it is located on the territory of one Member State, either inland or offshore, including islands, and has a significant cross-border impact as set out in point (1) of Annex IV.

2. A project of mutual interest shall meet the following general criteria:

(a) the project contributes significantly to the objectives referred to in Article 1(1), and those of the third country, in particular by not hindering the capacity of the third country to phase out fossil fuel generation assets for its domestic consumption, and to sustainability, including through the integration of renewable energy into the grid and the transmission and distribution of renewable generation to major consumption centres and storage sites;

(b) the potential overall benefits of the project at Union level, assessed in accordance with the relevant specific criteria in paragraph 3, outweigh its costs within the Union, including in the longer term;

(c) the project is located on the territory of at least one Member State and on the territory of at least one third country and has a significant cross-border impact as set out in point (2) of Annex IV;

(d) for the part located on Member State territory, the project is in line with Directives 2009/73/EC and (EU) 2019/944 where it falls within the infrastructure categories set out in points (1) and (3) of Annex II to this Regulation;

(e) there is a high level of convergence of the policy framework of the third country or countries involved and legal enforcement mechanisms to support the policy objectives of the Union are demonstrated, in particular to ensure:

(i) a well-functioning internal energy market;

(ii) security of supply based, inter alia, on diverse sources, cooperation and solidarity;

(iii) an energy system, including production, transmission and distribution, moving towards the objective of climate neutrality, in line with the Paris Agreement and the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective, in particular, avoiding carbon leakage;

(f) the third country or countries involved support the priority status of the project, as set out in Article 7, and commit to complying with a similar timeline for accelerated implementation and other policy and regulatory support measures as applies to projects of common interest in the Union.

(…)

3. The following specific criteria shall apply to projects of common interest falling within specific energy infrastructure categories:

(…)

(d) for hydrogen projects falling under the energy infrastructure categories set out in point (3) of Annex II, the project contributes significantly to sustainability, including by reducing greenhouse gas emissions, by enhancing the deployment of renewable or low carbon hydrogen, with an emphasis on hydrogen from renewable sources in particular in end-use applications, such as hard-to-abate sectors, in which more energy efficient solutions are not feasible, and supporting variable renewable power generation by offering flexibility, storage solutions, or both, and the project contributes significantly to at least one of the following specific criteria:

(i) market integration, including by connecting existing or emerging hydrogen networks of Member States, or otherwise contributing to the emergence of an Union-wide network for the transport and storage of hydrogen, and ensuring interoperability of connected systems;

(ii) security of supply and flexibility, including through appropriate connections and facilitating secure and reliable system operation;

(iii) competition, including by allowing access to multiple supply sources and network users on a transparent and nondiscriminatory basis;

(…)

4. For projects falling under the energy infrastructure categories set out in Annex II, the criteria set out in paragraph 3 of this Article shall be assessed in accordance with the indicators set out in points (3) to (8) of Annex IV.

TEN-E requirement	Coverage in CBA methodology
Art. 11 – Energy system wide cost-benefit analysis	
Art. 11(1) ◢ ENTSOs for Gas and Electricity are tasked with drafting single-sector methodologies, for a harmonised energy system-wide cost-benefit analysis at Union level for projects on the Union list; ◢ Such methodologies shall include energy network and market models and shall be consistent between themselves, as well as aligned with the Union's 2030 targets for energy and 2050 climate neutrality objectives; ◢ For the above, an extensive consultation process must be carried out, of relevant stakeholders.	Energy network and market models are explained in section 2.2 and will be updated in line with the deadline set by Art. 11(10). This CBA methodology covers all projects falling under the energy infrastructure category in Annex II (3), while ENTSO-E's CBA methodology covers projects falling under the energy infrastructure categories defined in Annex II(1)(a), (b), (d), and (f). As explained in the rows below, the CBA methodology is drawn up in line with the principles laid down in Annex V and the rules and indicators set out in Annex IV. As explained in the scenario section, it is also consistent with the EU's 2030 targets for energy and climate and its 2050 climate neutrality objective. For the creation of this CBA methodology, an extensive consultation process of relevant stakeholders was carried out.
Art. 11(6) ◢ Calendar for the publication of methodologies for cost-benefit analysis after EC approval: two calendar weeks; ◢ Obligation for the ENTSOs to publish input and output data relevant for such methodologies.	Input data requirements are addressed in sections 1.2, 1.3., 2.1, and 3.2.4 and by the documents referred to in these sections. Regarding output data, at least the following information shall be produced as part of the CBAs: ◢ Infrastructure level(s) used, project grouping, benefit indicators, project group costs, monetised benefits, and economic performance indicators (see sections 5.3 and 5.4).
Art. 11(9) ◢ ENTSOs may use reference unit investment costs published by ACER for comparable projects in PS-CBAs	Option to use ACER's unit investment costs covered by sections 1.3 and 3.2.13.
Annex V – Energy system wide cost-benefit analysis	
Annex V introduction ◢ The cost-benefit analysis methodologies developed by the ENTSOs for Gas and Electricity must be consistent between themselves; ◢ Such methodologies must be applied in a uniform way to all infrastructure categories; ◢ Costs, including externalities, shall be addressed in CBA methodologies.	Consistency with ENTSO-E methodology is ensured in the following ways: ◢ Definition of a common input data set through TYNDP scenarios and common market assumptions. ◢ Definition of a common TYNDP geographical perimeter. ◢ Definition of common duration of default assessment period and social discount rate for economic assessments. This is also aligned with the CBA methodologies of all other TEN-E energy infrastructure categories. ◢ Definition of common clustering rules for project grouping (see section 3.1). ◢ Alignment through the introduction of guidelines for project inclusion and TYNDP-specific implementation guidelines (see sections 1.2 and 1.3). ◢ Alignment in the consideration of project costs (see section 3.2.13) that include besides capital expenditure, operational and maintenance expenditure costs, also the costs of the project as a whole, such as decommissioning and waste management costs, including external cost. ◢ Alignment in the methodology to calculate economic performance indicators of (groups of) project(s) (see section 5). ◢ Alignment through the inclusion of common indicators and interlinkages (see sections 2.2.2 and 3.2).

TEN-E requirement	Coverage in CBA methodology
Annex V (1) ◢ The area of analysis for individual projects shall cover all territories where a project is located – Member State or third country – all neighbouring Member States and other Member States where the project has a significant impact in cooperation with involved promoters	Under the section about scenarios, ENTSOG's CBA methodology recommends to consider the full range of scenarios in the project-specific CBAs. The country dataset of the TYNDP Scenario Report includes all EU-27 Member States, as well as all Energy Community countries. Consistent application of provisions of the Guidelines for Project Inclusion and of this CBA methodology safeguard equal treatment of project promoters that are not a system operator.
Annex V (2) ◢ Methodologies for cost-benefit analysis must incorporate sensitivity analyses for factors such as: the cost of energy generation, greenhouse gas emissions, expected changes in demand and supply (including related to renewable energy sources), flexibility of these sources, storage availability, commissioning dates for projects in the same area, climate impact, *inter alia*	See section 4.
Annex V (3) ◢ Methodologies for cost-benefit analyses shall be based on pertinent multi-sectoral input data, assessing the impact with and without each project; ◢ Interdependencies with other projects should also be considered.	Integrated into the incremental approach (see section 3.2.2), the consideration of input data and of models covering the multiple sectors (see section 2.2), description of indicators for the analysis (see section 3.2), and infrastructure levels and grouping principles that capture relevant interdependencies with other projects (see sections 2.2.2.2, 2.2.3.3, and 2.3).
Annex V (4) ◢ Methodologies for cost-benefit analysis shall guide the development and use of energy networks and market models employed for cost-benefit analysis; ◢ Economic impact areas covered by such analyses should comprise: market integration, supply security, competition, energy isolation, social, environmental, and climate impacts, including cross-sector effects; ◢ Clarity should be provided on how each benefit and cost is calculated.	Details to be specified in complementary documents (see sections 1.2, 1.3, and 2.1). The development and use of the energy network and market modelling necessary for the CBAs is detailed in sections 2.2 and 3.2.
Annex V (5) ◢ Methodologies for cost-benefit analysis shall explicitly highlight how the energy efficiency first principle is implemented in all steps of the TYNDP process	The energy efficiency first principle was taken into account as described in section 6.

TEN-E requirement	Coverage in CBA methodology
Annex V (6) ◢ Methodologies for cost-benefit analysis shall explain how renewable energy production is not hampered by each project assessed	The integration of renewable electricity indicator (B3.1) evaluates how the integration of RES is affected or supported by the assessed projects (see section 3.2.7).
Annex V (7) ◢ Methodologies for cost-benefit analysis clearly identify: Member States in which projects have net positive and net negative impact, cost bears and beneficiaries, regardless of whether the project is located on their territory or not	Fulfilled as the benefit indicators can be displayed at different granularities like Member State level or EU level.
Annex V (8) ◢ Methodologies for cost-benefit analysis should account for the f ollowing variables: capital and operational and maintenance costs, including the project's entire technical lifecycle and external costs; ◢ They should define discount rates, technical lifetime, and residual value for cost-benefit analysis; ◢ Benefit-to-cost ratios and net present value, should also be defined; ◢ The degree of reliability of estimation methods of assessed benefits should be described; ◢ Methodologies should describe calculations of the climate/environmental impact of projects as well as their contributions to Union energy targets, for instance: the penetration of renewable energy, the degree of interconnection and energy efficiency.	Section 3.2.13 on costs, section 5.2.2 on the discount rate, section 5.2.3 on project lifetime, sections 5.2.4 on residual value, section 5.3 on Net Present Value, section 5.4 on Benefit-to-Cost Ratio, section 3.2.11 on the environmental impact, and section 3.2 in general regarding the contribution of projects to Union energy targets. The degrees of reliability of estimation methods of the different benefit indicators are in the following order: ◢ B4, B3.1, B3.2 indicators: The B4 indicator is directly based on the objective function of the DHEM and thereby equivalent to the starting point of all other benefit indicators with most inputs coming from the scenarios. The B3.1 and B3.2 indicators are directly derived from results of the objective function of the DHEM, thereby having a comparable level of certainty. ◢ B5 indicator: The monetisation step has uncertainties related to the cost of disruption and the assumed probabilities. ◢ B1 indicator: To mitigate uncertainty of the used cost of carbon, a sensitivity is introduced. ◢ B2 indicator: To mitigate the uncertainty of this indicator, the general approach as well as the considered pollutants are consulted with the Implementation Guidelines to ensure its improvement in future cycles. Also, the indicator should only be counted for the economic performance indicator calculations if another sustainability benefit indicator is also positive.
Annex V (9) ◢ Methodologies for cost-benefit analysis should evaluate climate adaptation measures for each project, considering costs of greenhouse gas emissions; ◢ Methodologies should be in alignment with other Union policies, to facilitate comparisons with infrastructure-free solutions.	Relevant climate adaptation measures are collected from the project promoters (see section 3.2.12). The societal cost of carbon considered in the GHG emissions variations indicator (B1) uses as reference source the EIB. This is in alignment with the EC general principles for cost benefit analyses. The environmental impact indicator investigates environmental mitigation measures (see section 3.2.11).

Table 6: Coverage of TEN-E requirements in this CBA methodology.

ANNEX II: POTENTIAL ADDITIONAL STRESS CASES FOR THE DUAL HYDROGEN / NATURAL GAS MODEL (DGM)

The reduction in exposure to curtailed hydrogen demand indicator (B5) uses a stressful weather year as stress case. Outside of the application for the PCI/PMI selection process, other stress cases than the stressful weather year can be assessed. The stress may thereby be related to the hydrogen as well as to the natural gas system. The natural gas system and the hydrogen system are inter-depending, as i) hydrogen can be produced from natural gas and thereby may depend on its availability, and ii) repurposing of natural gas infrastructure may put additional stress on the natural gas system.

Curtailment and any results derived from stress cases will be the result of imbalances between supply and demand due to hard constraints like capacities. It can be computed for the following cases:

- Normal (climatic) conditions
- Climatic stress conditions (Cold Dunkelflaute (CDF)[38] and Peak Day (PD)[39])
- Supply stress conditions as import source dependency (S-1)
  - For natural gas sources
  - For hydrogen sources
- Infrastructure stress conditions (N-1)
  - Single Largest Infrastructure Disruption for natural gas (SLID)
  - Single Largest Capacity Disruption for hydrogen (SLCD)

All these cases are expressed in terms of **Demand Curtailment (DC)** for the assessed duration (e.g., 1 day for PD, 2 weeks for CDF, full year for S-1, SLID, and SLCD) in energetic terms (MWh), each for natural gas and for hydrogen. It can be displayed on node level, country level, European Union level, or European level. It can also be displayed in relative terms (%) as **Curtailment Rate (CR)** for the mentioned levels, representing the share of total demand that is curtailed. In order to monetise these cases, additional assumptions are needed that are explained in section 3.2.10.

Stress case	Duration	Results	Granularity options
PD	1 day	HDC HCR NGDC NGCR	Node, Country, European Union, or Europe
SLID applied to Member State 1			
SLID applied to Member State n			
SLCD applied to Member State 1			
SLCD applied to Member State n			
CDF	Period as defined in scenarios		
S-1 for hydrogen source 1	Full year		
S-1 for hydrogen source n			
S-1 for natural gas source 1			
S-1 for natural gas source n			

38 An extended period of time with very low outside temperature as well as low production of wind and solar energy. Its value may be provided by the scenarios.

39 A daily maximum level of hydrogen or natural gas demand, used for the design of the network to capture maximum transported energy and ensure consistency with national regulatory frameworks. Its value may be provided by the scenarios.

S-1 for natural gas and hydrogen

The S-1 case aims at identifying infrastructure-related dependence on a specific supply source. The lower the value of S-1, the lower the dependence on the specific source. The supply dependence to source S is calculated as follows (the steps are repeated for each source):

- Step 1: The availability of source S is set down to zero.
- Step 2: The availability of the other sources remains in line with the defined supply assumptions from scenarios.
- Step 3: Only for hydrogen:
  - Step 3.1: A reference hydrogen curtailed demand is calculated without the given S-1 case. The maximum value of i) the hydrogen demand curtailment that is not satisfied in the DHEM for the reference case and of ii) the hydrogen demand curtailment in the DGM for the reference case is selected.
  - Step 3.2: In the context of the DGM, the curtailed hydrogen demand is computed with and without the given S-1 case. The delta between these hydrogen demand curtailments is calculated.
  - Step 3.3.: The results of step 3.1 and step 3.2 are added.

The absolute supply source dependence for hydrogen $CD_{Z,S,H2}$ and of natural gas $CD_{Z,S,NG}$ of a demand area (e. g., node, country, European Union, or Europe) Z to the source S is defined as the curtailed demand (MWh) in Z when S is not available. The relative supply source dependence in relative terms $CR_{Z,S,H2}$ of a demand area Z to the source S is then described as the share of $CD_{Z,S,H2}$ of the total hydrogen demand of the zone. The relative supply source dependence in relative terms $CR_{Z,S,NG}$ of a demand area Z to the source S is then described as the share of $CD_{Z,S,NG}$ of the total hydrogen demand of the zone.

Single Largest Infrastructure Disruption (SLID) for natural gas

This case intends to investigate the impact of the disruption of the natural gas network's single largest infrastructure of a country. While the disruption concerns the natural gas single largest infrastructure, the impact could also be observed on the hydrogen demand side in case the hydrogen produced from natural gas is affected. This computation allows to identify potential bottlenecks for the considered country and the other European countries.

The absolute SLID effect for hydrogen $CD_{Z,C,SLID,H2}$ and of natural gas $CD_{Z,C,SLID,NG}$ of a demand area (e. g., node, country, European Union, or Europe) Z is defined as the curtailed demand (MWh) in Z when the single largest infrastructure of the observed country C (except storages and natural production) is not available. The SLID is computed in a PD situation, with the associated supply and national production in this configuration. The relative SLID effect in relative terms $CR_{Z,C,SLID,H2}$ of a demand area Z is then described as the share of $CD_{Z,C,SLID,H2}$ of the total hydrogen demand of the zone. The relative SLID effect in relative terms $CR_{Z,C,SLID,NG}$ of a demand area Z is then described as the share of $CD_{Z,C,SLID,NG}$ of the total natural gas demand of the zone.

Single Largest Capacity Disruption (SLCD) for hydrogen

This case intends to investigate the impact of the disruption of the hydrogen network's single largest capacity of a country. This single largest capacity is the aggregated capacity between two nodes: Either between two countries, or one storage node and one demand node, or one production node and one demand node. While the disruption concerns the hydrogen single largest capacity, the impact could also be observed on the natural gas demand side in case of an increase in the hydrogen production from natural gas to cover the missing hydrogen deliveries through the disrupted capacity. This computation allows to identify potential bottlenecks for the considered country and the other European countries.

The absolute SLCD effect for hydrogen $CD_{Z,C,SLCD,H2}$ and of natural gas $CD_{Z,C,SLCD,NG}$ of a demand area (e. g., node, country, European Union, or Europe) Z is defined as the curtailed demand (MWh) in Z when the single largest capacity of the observed country C is not available. The SLCD is computed in a PD situation, with the associated supply and national production in this configuration. The relative SLCD effect in relative terms $CR_{Z,C,SLCD,H2}$ of a demand area Z is then described as the share of $CD_{Z,C,SLCD,H2}$ of the total hydrogen demand of the zone. The relative SLCD effect in relative terms $CR_{Z,C,SLCD,NG}$ of a demand area Z is then described as the share of $CD_{Z,C,SLCD,NG}$ of the total hydrogen demand of the zone.

Double-counting

When the impact of a combination of different stress conditions is assessed (e. g., climatic and supply stresses), it is necessary to identify which conditions are responsible for the demand curtailment. If results show demand curtailment in a specific area under climatic stress conditions, without any supply or infrastructure stress conditions, it is expected that the assessment of a supply or infrastructure disruption impacting this specific area in the same climatic conditions will show a higher (or at least equal) level of curtailed demand. In this case, only the additional demand curtailment will be considered as the impact of the additional stress. This is of utmost relevance to avoid double counting when monetising the benefit stemming from avoided demand curtailment in a different situation.

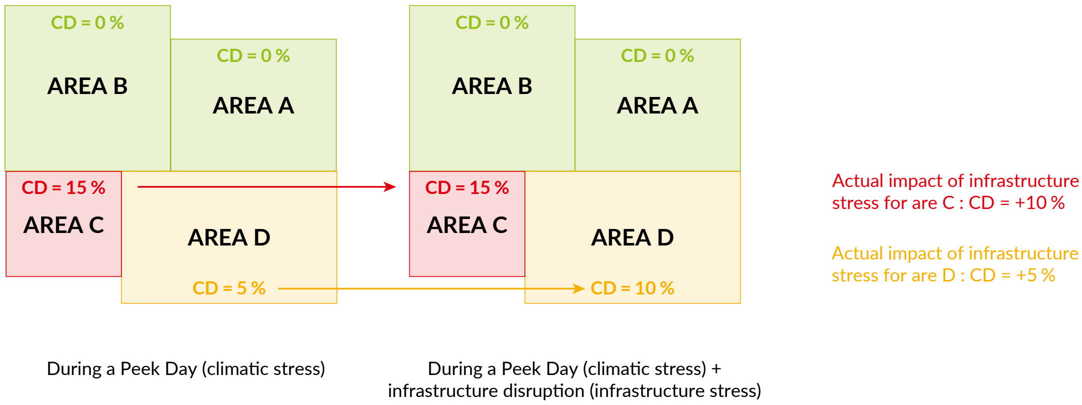


Figure 12: Example of avoidance of double-counting: Curtailed demand indicator during a PD case compared to a combination of a PD case and a supply route disruption case.

ANNEX III: EXAMPLES FOR THE TOTAL SURPLUS APPROACH AND DETAILED FORMULATION OF THE INCREASE OF MARKET RENTS INDICATOR (B4)

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. 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.

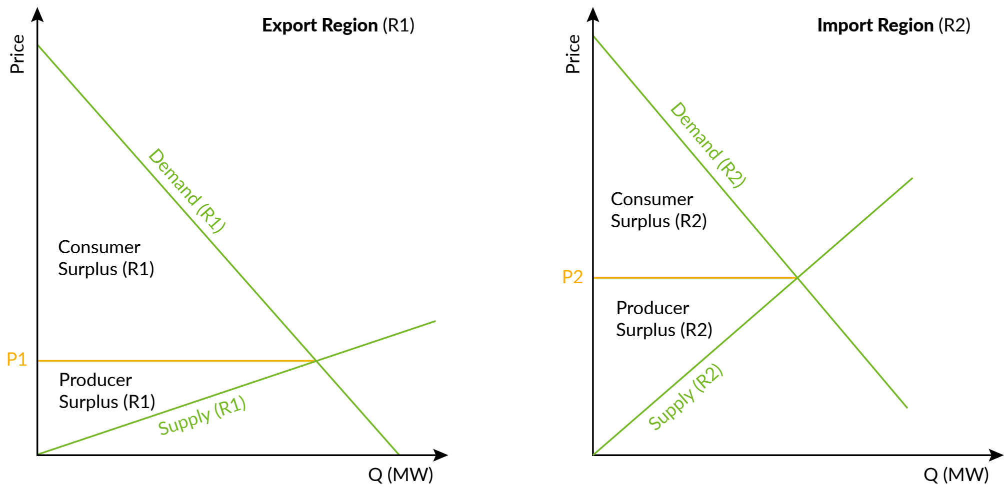


Figure 13: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity between the two regions and elastic (i.e., price-dependent) demand assumed.

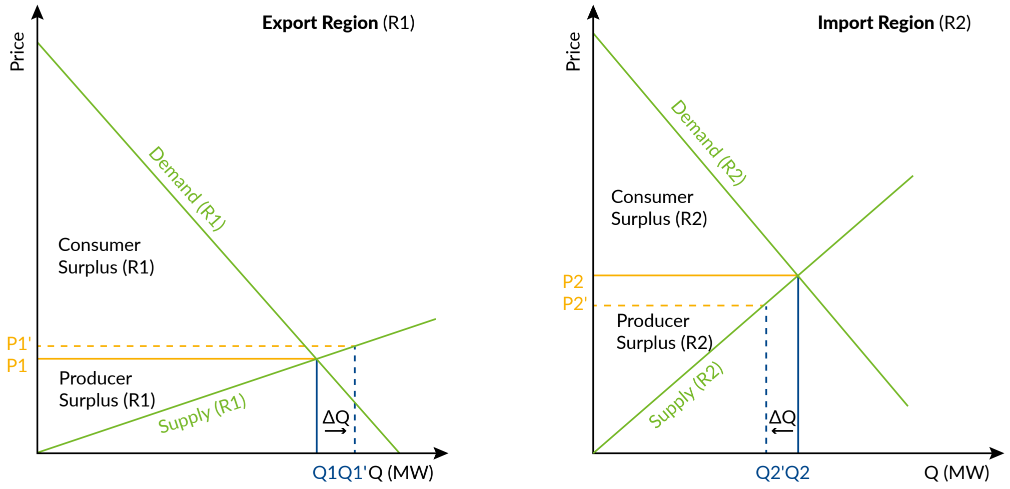


Figure 14: Example of an export region (left) and an import region (right) with a new project increasing the capacity between the two regions and elastic (i.e., price-dependent) demand assumed.

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.

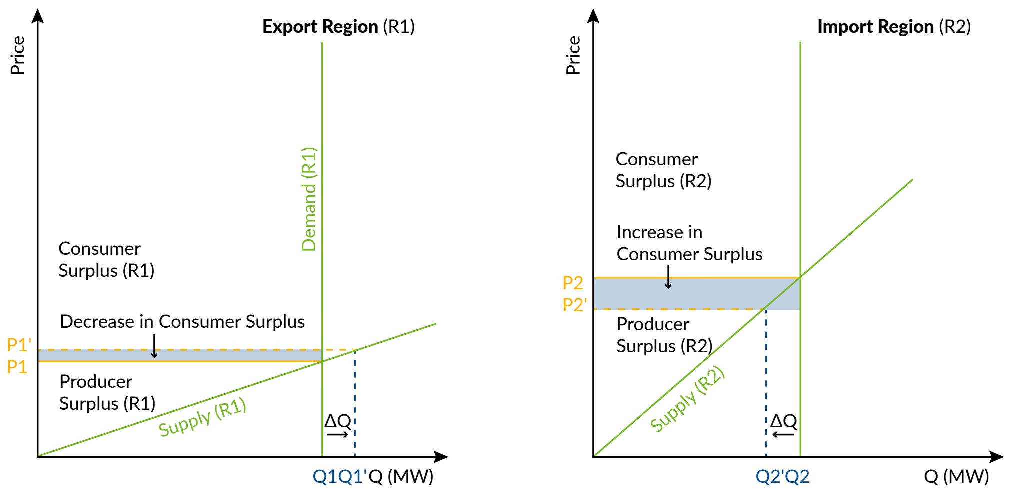


Figure 15: Example of the change of the consumer rent of an export region (left) and an import region (right) with a new project increasing the capacity between the two regison and inelastic demand assumed.

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.

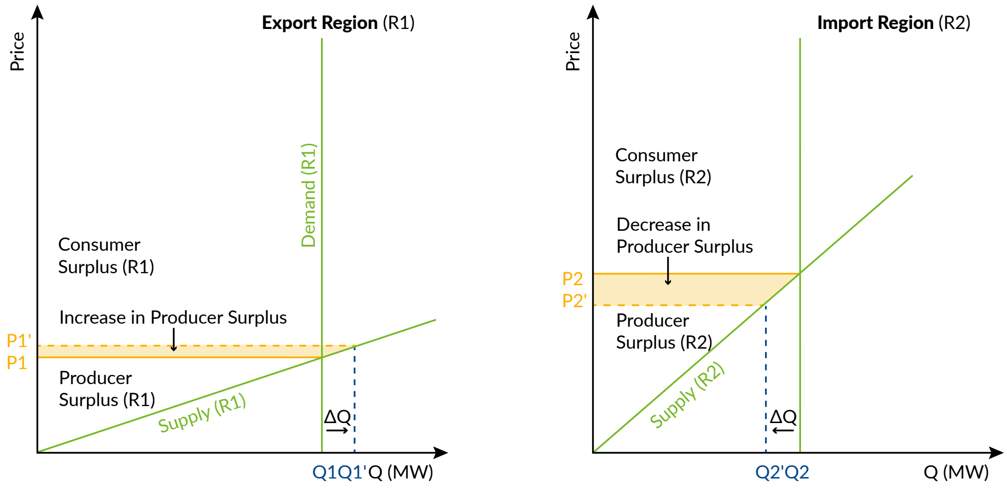


Figure 16: Example of the change of the producer rent of an export region (left) and an import region (right) with a new project increasing the capacity between the two regison and inelastic demand assumed.

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.

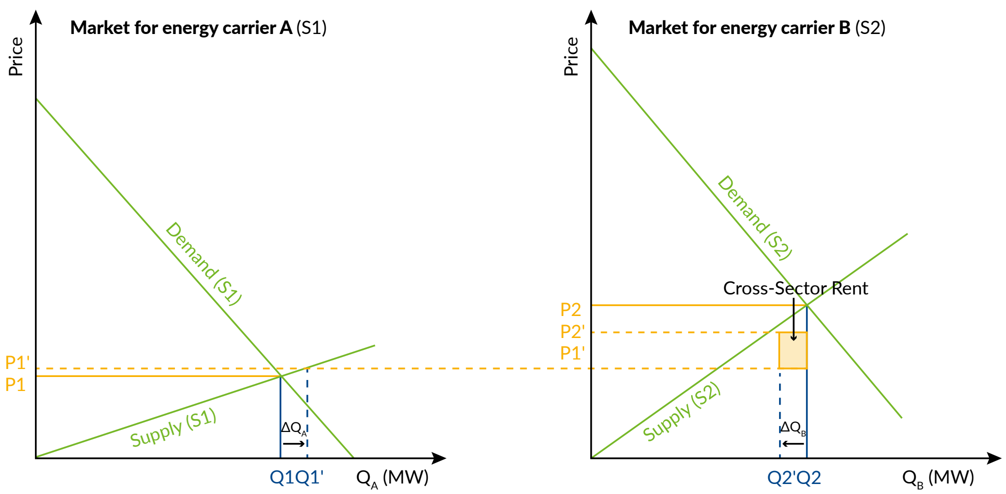


Figure 17: Illustration of sectorial market coupling. The cross-sector rent captures the benefit of sector coupling and describes the rent movement from sector A to sector B.

DETAILED FORMULATION OF THE INCREASE OF MARKET RENTS

The sum of all market rents along the sectors S ϵ {electricity, hydrogen} is calculated as follows[40]:

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

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.
- $R^{j}_{storages}$ is the storage rent of sector j ϵ S.
- $R^{j}_{congestion}$ is the congestion rent of sector j ϵ S.
- $R^{electricity \leftrightarrow hydrogen}_{cross\text{-}sector}$ 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 (e. g., electrolysers or 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:

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

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.
- $p^{c,t}_{cross\text{-}sector,\ hydrogen}$ and $p^{c,t}_{cross\text{-}sector,\ electricity}$ 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 from the production components c ϵ P (e. g., coal fired-power plants generating electricity, or steam methane reformers producing hydrogen) and the storage components c ϵ ST (e. g., batteries storing electricity, or hydrogen underground storages storing hydrogen).

40 The following calculations include the market rents of the electricity sector, going beyond the requirement of the increase of market rents indicator (B4) (i.e., its limitation to the hydrogen sector's rents and cross-sector rents). The electricity sector's rents can be removed from the equations to match the default definition of the increase of market rents indicator (B4).

The contribution of the generation portfolio to the producer rent is described by the following formula:

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

On the basis of:

- $marginalCost^{c}$ is the marginal cost of the production asset type associated with component c ϵ P.
- $mcp^{c,t}_{j}$ is the market clearing price at time step t ϵ T at the corresponding market area of sector j ϵ S.
- $p^{c,t}_{production}$ 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:

$$R^{j}_{storages} = \sum_{t \epsilon T} \sum_{c \epsilon ST} (mcp^{c,t}_{j} \times p^{c,t}_{from\ storage,j} - mcp^{c,t}_{j} \times p^{c,t}_{into\ storage,j})$$

On the basis of:

- $p^{c,t}_{into\ storage,j}$ 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 $p^{c,t}_{from\ storage,j}$ 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:

$$R^{j}_{consumer} = \sum_{t \epsilon T} \sum_{c \epsilon L} (elasticity^{c} - mcp^{c,t}_{j}) \times p^{c,t}_{consumption,j})$$

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. Inelastic electricity demands use the Value of Lost Load (VoLL) for the elasticity, inelastic hydrogen demands use the Cost of Disrupted Hydrogen (CODH) for the elasticity, and DSR units serve specific values for the elasticity.

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:

$$R^{j}_{congestion} = \sum_{t \in T} \sum_{c \in TR} \left| \left(mcp_j^{side\ 1,\, t} - mcp_j^{side\ 2,\, t} \right) \times p^{c,\, t}_{exchange,\, j} \right|$$

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.
- $p^{c,\, t}_{exchange,\, j}$ 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. 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. The global increase of market rents is described as follows:

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

ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ATR	Autothermal Reforming
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
CDF	Cold Dunkelflaute
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CODG	Cost of Disrupted Gas
CODH	Cost of Disrupted Hydrogen
DGM	Dual Gas Model
DHEM	Dual Hydrogen/ Electricity Model
DRES	Dedicated Renewable Energy Sources
DSO	Distribution System Operator
DSR	Demand Side Response
EBCR	Economic Benefit-to-Cost Ratio
EC	European Commission
EE1st	Energy Efficiency First Principle
EEA	European Environment Agency
EED	Energy Efficiency Directive (EU) 2018/2002
EIA	Environmental Impact Assessment
EIB	European Investment Bank
ENPV	Economic Net Present Value
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emission Trading Scheme
EU	European Union
FID	Final Investment Decision
GHG	Greenhouse Gases

H_2	Hydrogen
HDC	Hydrogen Demand Curtailment
HCR	Hydrogen Curtailment Rate
IPCC	Intergovernmental Penal on Climate Change
LH_2	Liquified Hydrogen
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
MCA	Multi-Criteria Analysis
MES	Multi-Energy System
Mt	Megatonnes
Mt/y	Megatonnes per Year
$MtCO_2/y$	Megatonnes of Carbon Dioxide per Year
MWh	Megawatt Hours
MWh/y	Megawatt Hours per Year
N-1	Supply stress conditions as infrastructure dependency
NDP	National Development Plan
NECP	National Energy and Climate Plan
NG	Natural Gas
NH_3	Ammonia
NO_x	Nitrogen Oxides
NRA	National Regulatory Authority
P2G	Power-to-Gas
PCI	Project of Common Interest
PD	Peak Demand
PINT	Put in One at a Time Principle
PMI	Project of Mutual Interest
RES	Renewable Energy Sources
S-1	Supply stress conditions as import source dependency
SLCD	Single Largest Capacity Disruption for hydrogen
SLID	Single Largest Infrastructure Disruption for natural gas
SMR	Steam Methane Reforming
SO_2	Sulphur Dioxides
SoS	Security of Supply

SoS Regulation	Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010
SRES	Shared Renewable Energy Sources
TEN-E Regulation	Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013
TOOT	Take out One at a Time Principle
TSO	Transmission System Operator
TWh	Terawatt Hour
TWh/year	Terawatt Hours per Year
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage (facility)
VoLL	Value of Lost Load

Publisher: ENTSOG AISBL
Avenue de Cortenbergh 100
1000 Brussels, Belgium

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Cover picture: Courtesy of Fluxys Belgium

Design: Dreidreizehn GmbH, Berlin | www.313.de

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