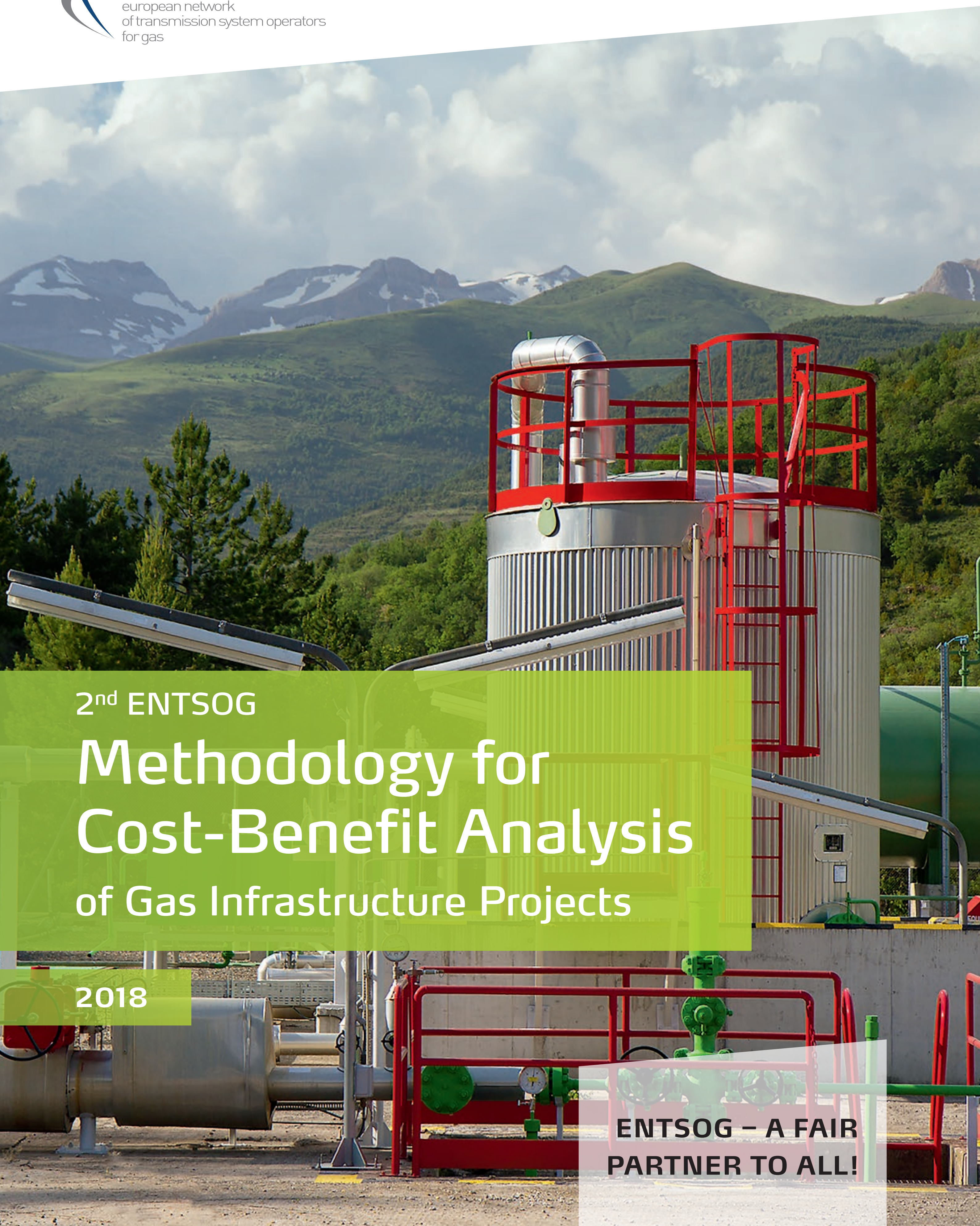
entsog

european network
of transmission system operators
for gas



2nd ENTSOG

Methodology for Cost-Benefit Analysis of Gas Infrastructure Projects

2018

ENTSOG – A FAIR PARTNER TO ALL!

2nd ENTSOG methodology for cost-benefit analysis of gas infrastructure projects

October 2018

Foreword

The first Cost-Benefit Analysis methodology, approved by the European Commission (hereafter the Commission) in February 2015, has been applied to the European-wide Network Development Plan 2015 (TYNDP 2015), the European-wide Network Development Plan 2017 (TYNDP 2017) and the subsequent 2nd and 3rd Project of Common Interest (PCI) selection processes. For TYNDP 2017, ENTSOG has complemented the assessment with additional elements on a voluntary basis. These elements were taken into account when developing this methodology.

Based on this experience, and taking into consideration the feedback received from stakeholders, ENTSOG has updated and improved the Cost-Benefit Analysis methodology (hereafter "CBA methodology") in accordance with the provisions of the Regulation (EU) 347/2013 (hereafter also "the Regulation"). The 2nd CBA methodology takes into account related opinions from ACER[1] and the Commission[2], as well as the findings of the gas CBA study mandated by the Commission, whose draft recommendations were released in March 2017[3].

This methodology is accompanied by the following accompanying documents:

> Compliance of the 2nd CBA Methodology with the Regulation (EU) 347/2013, which describes how the different requirements of Regulation (EU) 347/2013 are addressed in the 2nd ENTSOG CBA Methodology;
> Consideration of stakeholders' feedback in the 2nd CBA Methodology and main changes compared to the 1st CBA Methodology;
> Roadmap for future projects CBA assessment.

[1] The ACER opinion is available here: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2015-2017.pdf

[2] C(2018) 6649 Final.

[3] The draft recommendations are available here: http://fsr.eui.eu/event/gas-cba-2-0-online-consultation/

Introduction and CBA Methodology objective

The European gas infrastructure supports the completion of the Internal Energy Market and contributes to the achievement of the European climate and energy policies, where sustainability represents one of the major pillars together with security of supply, competition and market integration.

The objective of this CBA methodology is to provide **guidelines to be applied for the cost-benefit analysis of projects and more generally of the overall gas infrastructure**. This methodology reflects the specific provisions from the Regulation and aims to ensure their consistent application by all parties involved.

The development of the CBA methodology is a task for ENTSOG. The individual tasks defined within this methodology fall under the responsibility of different parties.

The primary field of application of this CBA methodology is within the TYNDP process and the selection of projects of common interest, in accordance with Regulation (EU) 347/2013 provision that "*[The] methodolog[y] **shall be applied for the preparation of each subsequent 10-year network development plan** developed by […] the ENTSO for Gas* […]*"* and *"for projects of common interest".*

The TYNDP comprises of an assessment of the gas system and gas infrastructure projects and subsequently of an assessment of the impact of gas infrastructure projects. As per Regulation (EC) 715/2009 the TYNDP has the important role of identifying the remaining infrastructure gaps through the assessment of the overall gas infrastructure. it defines the basis against which the project-specific cost-benefit analysis (hereafter project-specific CBA) of PCI candidates is run.

The TYNDP and each project-specific CBA build on the development of the complete input data set required to define the assessment framework, as well as the collection of the necessary information on the infrastructure and projects. Therefore, it is of utmost importance that the input data set is clearly defined and well understood by those parties delivering the input data.

Beside the use of the methodology for the preparation of the TYNDP and the selection of PCIs, the Regulation indicates other instances where CBA methodology has to be used. It should indeed be used as a basis for project-specific cost-benefit analysis in investment requests (including cross-border cost allocation) and eligibility for financial assistance.
The 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements to measure the level of completion of the pillars of the EU Energy Policy from an infrastructure perspective.

According to the definition provided by the Commission in its "Guide to Cost-Benefit Analysis of investment projects" (December 2014)[4], hereafter "EC CBA guide" [5], "*CBA is an analytical tool to be used to appraise an investment decision in order to assess the welfare change attributable to it. The purpose of CBA is to facilitate a more efficient allocation of resources, demonstrating the convenience for society of a particular intervention rather than possible alternatives*".

Generally, the cost-benefit analysis of projects should follow the steps below

- Define the assessment framework
- Assess the overall system, including the identification of the infrastructure gaps
- Assess projects through incremental approach and cost-benefit analysis

The methodology follows the above-mentioned structure.

[4] The "Guide to Cost-Benefit Analysis of Investment Projects" is available here: http://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf
[5] European Commission - Guide to Cost-Benefit Analysis of Investment Projects, page 15.

1. Assessment Framework

It is responsibility of system operators to operate the gas system and deliver gas to customers, in a secure and competitive way, whatever the future circumstances may be.

This requires the identification of infrastructure gaps that may hamper the achievement of the Union energy policies. This CBA Methodology provides guidelines for such identification to be performed as part of the TYNDP process and for the assessment of projects that may allow for the mitigation of those infrastructure gaps.

Over the last years, demand and supply patterns have shown some volatility subject to different and, sometimes unexpected, events. Over the coming years and decades, the European commitment to move towards a decarbonised energy system could materialise in different ways.
For the assessment of infrastructure projects, the context to be considered shall cover possible evolutions in terms of demand, supply patterns and development of the overall energy infrastructure. In this respect, Annex V (1) of Regulation (EU) 347/2013 defines the main input data that the methodology should be based on[6].

The input data set necessary for the implementation of a proper CBA assessment at system and project-specific level requires regular update. It is therefore built through the TYNDP every two years ensuring stakeholders involvement. This data set must be made publicly available as part of the TYNDP process.
This TYNDP input data set is used when applying the CBA Methodology to the TYNDP. 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 cost-benefit analysis of projects for TYNDP and PCI process.

[6] For more details please refer to the accompanying document "Compliance of the 2nd CBA Methodology with the Regulation".

1.1. Scenarios

Time horizon

The assessment framework must be in line with the provision of Annex V(1) of the Regulation, which requires that the input data set represents years *"n+5, n+10, n+15, and n+20 where n is the year in which the analysis is performed*".

In order to be able to evaluate projects impact against the targets set by the European policies while keeping the number of results reasonable, by default the assessment framework is defined for 5-year-rounded years (e.g. 2020, 2025, 2030, etc.).

Possible contrasted futures

The accurate identification of infrastructure gaps and the assessment of projects require the consideration of **contrasted possible futures**. This implies considering storylines based on demand and supply assumptions that reflect the possible range in terms of the evolution of the future energy mix and demand. Each storyline is then developed in quantitative scenarios that cover different situations reflecting how uncertain aspects of the future could materialise. The practice of considering different energy scenarios supports decision makers' strategies and policies in an uncertain world, with scenarios describing how alternative energy conditions could develop in the future.

Scenarios are described in terms of parameters such as demography, macroeconomic trends, technologies, energy prices, emission prices, etc. Energy and environmental policies defined at national or European level, and related targets, are relevant in building those scenarios. Contrasted yet consistent assumptions shall be retained for these different parameters, each set of assumptions corresponding to a scenario storyline.

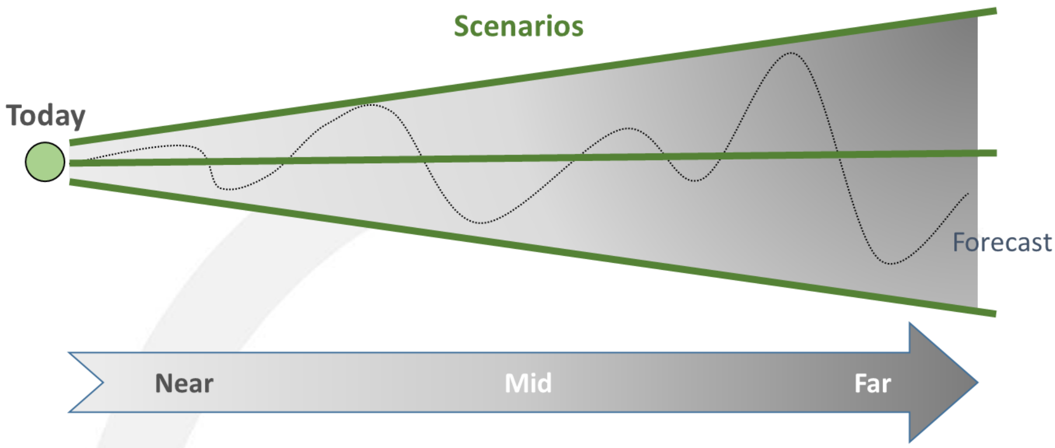


Figure 1 – Scenarios to set the range of possible futures

Demand

The following elements must be considered when building the storylines for demand scenarios

- **Energy policies and regulation**: the demand scenarios should be realistically defined, which notably implies to reflect actual energy policies/regulations set by public decision-makers. For example, any energy and environmental regulations at national or EU level should be taken into account;
- **Economic conditions**: current economic trends as well as future evolutions should be carefully considered in order to define demand scenarios. It is a major need to have contrasted views on what the economic context may be in the next decades and reflect these views when preparing scenarios for demand;
- **Commodity and CO_2 prices evolution**: contrasted views are also needed for commodity and CO_2 prices as they may have a direct influence on energy demand;
- **Energy efficiency**: it results from the combination of policy-driven measures and individual behaviour. Therefore, different assumptions regarding the capacity of stakeholders to achieve energy efficiency goals may be taken into consideration for demand scenarios;
- **Demand evolution in the different sectors**: demand evolution in the different sectors is impacted by parameters such as evolution of technologies, macroeconomic parameters, etc. Such parameters influence energy switching dynamics and in turn energy demand.

It is fundamental for the assessment of the gas infrastructure that demand scenarios cover not only a yearly volumetric perspective but also **peak demand** and **seasonal profile** perspectives.

Indeed, gas demand presents a highly seasonal pattern, particularly in relation to the role that gas plays in the heating and power sector. Therefore, peak demand situations are a key parameter for the network design and operation. **Peak demand cases**, on a single day or over a sustained period, are to be considered to reflect the capacity that the gas infrastructure must be able to provide. Consideration of the gas demand **seasonal profile** is also key for an accurate assessment of the gas infrastructure.

This information is vital to assess the role transmission systems, underground storages or LNG terminals play as part of the overall gas system in providing flexibility and ensuring a safe, secure and sustainable operation of the system. In particular, high demand situations, although their occurrence may be low, are critical for assessing security of supply.

For a comprehensive assessment of projects at the European and national level, demand data must be defined at least with a **country level granularity**. As demand for different sources of energy may evolve in a different way for different demand sectors (residential, transport, industrial and commercial, power), development of demand scenarios must **sufficiently detail sectorial breakdown** to capture the different sectorial trends.

Demand elasticity

Elasticity of demand can be defined as the variation of demand in response to either long-term or short-term factors (such as prices, income, temperature, etc.). These two types of response can result in switch among different fuels and need to be considered independently. This methodology recommends considering **elastic gas demand** where relevant, in line with the below considerations.

In the power sector, respective gas, coal (or oil) and CO2 prices impact on the generation mix and the substitution among the different fuels in the merit order. This should be considered when building scenarios which can be achieved through joint electricity and gas scenario building. The **commodity and CO2 prices are fixed** as part of the CBA assessment frame. The possibility for additional fuel switching in power generation is therefore expected to be limited. As an example of such switch, if a project has a sufficient impact on a country's gas price it may trigger a change in the power generation merit order.

In relation to other demand sectors, such as heating or transport, elasticity and consequent fuel switching is primarily related to individual behaviour in terms of replacement and choice of appliances or technologies. These represent long-term trends characterised by significant

inertia (i.e. the individual will not change appliance only observing a temporary price differential among fuels) and therefore represent **fixed technology assumptions** in the scenarios building process. As a result, for a specific assessment year, the related elasticity of demand is expected to be limited.
However, under such fixed technology assumptions **short-term elasticity of demand** may take place within an assessment year in relation to e.g. short-term price evolution or actual use of hybrid technologies. This may be worth taking into account based on thorough investigation.

Commodity and CO_2 prices

Commodity and CO_2 prices are important contextual elements which must be considered when developing possible future scenarios, as both will trigger different situations in terms of energy mix and may impact on gas demand. Additionally, in regard to commodities, it is usually useful to set a reference gas price, to be used as an input when setting the supply price(s) for the different gas supply sources.

In terms of CO_2, market prices and Social Cost of Carbon (SCC) represent two different approaches to CO_2 prices. The CO_2 market prices will be the ones driving market behaviour. In this respect, CO_2 market prices are more accurate as a parameter influencing on demand, which should be therefore taken into account for scenario building and modelling. The Social Cost of Carbon includes the full social cost of emitting one further ton of CO_2, once external effects are also integrated. It represents the full economic marginal cost of emitting an additional ton of CO_2 and may be relevant when assessing the benefits in terms of sustainability stemming from the realisation of a project.

The IEA World Energy Outlook can be one relevant source of information for possible future commodity prices and CO2 market prices.

Supplies

Compared to electricity, gas usually travels long distances between production and consumption areas. Today, a large share of the gas supply come from non-EU countries. Indigenous production of conventional gas is also significant on the continent. Additionally, new supply sources are meant to develop significantly over the next decades, including renewable gases such as biomethane and synthetic gases (e.g. from power-to-gas technologies).

Gas supply assessment is key to measure the positive contribution of a gas infrastructure project to the European gas system.

Scenarios should integrate differentiated evolutions in terms of green ambitions and potential development of renewables in order to cover possible futures and should also consider targets set by Member States and the European Union.

Supply patterns may evolve significantly over the coming decades. When assessing the European gas market, it is necessary to capture the uncertainty in the development of supplies, by defining minimum and maximum **supply potentials** per supply source. These assumed minimum and maximum potentials for each source should be used as lower and upper limits for supply imports. Import capacities along the different import routes also have to be considered since they may represent a limit to the use of the supply potential.

When defining the scenarios, in addition to the annual volumes it is recommended to define assumptions for the flexibility of the supplies at seasonal level and for high demand situations.

Supplies must be attached to supply prices that will drive the supply mix. Such supply prices must be built around a reference supply price, as referred to in the commodity price section, and possible price variations to allow to drive the modelling of supply mixes.

The granularity of the supply sources must be differentiated among EU production (per EU country), pipe gas sources and LNG sources. The level of granularity must also reflect the possible evolution over time in the types of gas transported within the gas grid.

LNG terminals allow various sources of gas to access the network. One single LNG regasification terminal may handle LNG coming from different basins across the world. This feature makes LNG terminals a significant factor for the diversity of gas sources. Therefore, when relevant, with regard to LNG it must be considered, as part of the supply assumptions, that LNG is supplied from different sources.
This must be duly reflected in the assessment, where relevant. More details can be found in chapter 3.2.2.

It is recommended to favour transparent and where possible publicly available sources of information in regards to supply data. The sources of data must be referenced.

1.2. Network and Market modelling assumptions

1.2.1. Approach to modelling

Network and market modelling are necessary for system and project assessment. This can be performed with different modelling tools (software). Additionally, network modelling and market modelling may be performed with either the same tool, or possibly with different tools.

The modelling tool(s) must allow for the calculation of the different CBA indicators.
Specific information on modelling used for developing TYNDP must be made publicly available as part of the TYNDP development process.

1.2.2. Network assumptions and description of the gas infrastructure

A robust assessment framework must have a sufficient accurate representation of the gas infrastructure, both in regard to the existing infrastructure and to its possible evolution. This representation of the gas infrastructure is an input to the network and market modelling exercise underpinning the determination of projects' benefits.

The geographical perimeter must be clearly defined. In line with the Regulation it should cover at least Europe. In instances where connections with other countries exist, these countries may be incorporated or represented with adequate assumptions. The level of detail to represent the gas infrastructure should strike a balance between the accuracy and complexity of the modelling and the availability and complexity of the underlying network information.

The **topology of the gas infrastructure** as developed and regularly updated by ENTSOG, is used in the TYNDP process. The topology refers both to the existing and planned infrastructure. The corresponding capacities should be made publicly available as part of the TYNDP development process to allow for its use in further fields of application of the CBA Methodology.

The EU-level network modelling should be able to reflect market areas transmission, storage and LNG capacities as well as internal specificities if relevant from an infrastructure assessment perspective. Capacities as provided by network operators and project promoters to ENTSOG for the description of the gas infrastructure should be calculated based on hydraulic modelling[7].

The EU-level topology should at least reflect the following European gas infrastructure, which encompasses the infrastructures that can apply as PCI as listed in Annex II(2) of the Regulation:

- Transmission infrastructure
  - cross-border capacities between countries (including complex interconnections between more than two TSOs)
  - intra-country capacities between market areas
  - and meaningful intra-market areas constraints, where relevant
  - transit capacities
- LNG terminals infrastructure
  - regasification capacities both along the year and during high demand situations
  - the tank volumes characteristics including a flexibility factor defining the share of the tank volume expected to be available during high demand situations[8]
- Underground storage infrastructure
  - connection to the gas grid
  - the working gas volume
  - the withdrawal and injection capacities
  - the withdrawal and injection curves which define their ability to withdraw or inject gas depending on the filling level[9]
- Connection to indigenous production infrastructure
- The gas infrastructure in countries adjacent to the EU as much as the infrastructure in these countries contribute to imports to or exports from Europe.

Existing infrastructure

A proper description of the existing infrastructures endowment represents one of the first steps to build a reliable assessment framework. This is essential as a basis for defining further development of the grid and for accurate project assessment.

---

[7] Based also on the stakeholders feedback received, there is no strong recommendation on using EU-level hydraulic modelling since it would require collecting and maintain a cumbersome amount of mostly non-public information, that may differ among network operators and over time. This, together with the complexity related to the need for building a reliable tool at European level, would complexify the accuracy and readability of the results by the users and may in turn hinder the interpretation of the CBA assessment.

[8] For each TYNDP ENTSOG revises those values in cooperation with GLE.

[9] For each TYNDP ENTSOG revises those curves in cooperation with GSE.

Projects

Identification of projects requires reliable and detailed information. TYNDP has a role to collect all projects of EU relevance. In particular, the Regulation defines that all projects intending to apply for the PCI label must be part of the latest available Ten-Year Network Development Plan. The TYNDP should therefore collect all relevant information for the CBA assessment of projects intending to apply for the PCI status.

It is project promoters' responsibility to provide projects information. However, in order to ensure as reliable information as possible, a consistency check phase in the data collection may be conducted by ENTSOG.

Finally, an accurate definition of the existing infrastructure and projects is fundamental for the definition of the reference grid, as this represents the credible minimum level of infrastructure development to be considered for the identification of investment gaps and against which to assess projects.

Depending on their level of maturity projects can be categorized along different **statuses**. Those statuses are a prerequisite for the definition of the infrastructure levels to be used as counterfactual situations when performing project-specific CBA. Each project status should be derived from the information provided by its promoter.

The reference grid should at least consider all the existing infrastructures. It is also recommended to consider projects having an FID status in accordance with Annex 5(1) of the Regulation which invites to take into account "*all new projects for which a final investment decision has been taken […]*" when defining the composition of the transmission network.
The **FID status** is defined in Art.2.3 of Regulation (EC) 256/2014[10] 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 […]*'.

In the TYNDP process, the **FID status** corresponds to those projects that have taken the final investment decision ahead of TYNDP project collection. In regard to assessment years, it is

[10] Regulation (EU) 256/2014 of the European Parliament and of the Council of 26 February 2014 concerning the notification to the Commission of investment projects in energy infrastructure within the European Union, replacing Council Regulation (EU, Euratom) 617/2010 and repealing Council Regulation (EC) 736/96.

recommended that FID projects are considered from their first full year of operation, meaning the calendar year following their commissioning date.

In addition, in order to better reflect the different level of maturity among non-FID projects, an **Advanced status**[11] should be considered.

1.2.3. Market assumptions

This section of the methodology describes market assumptions that should be considered. Especially when observing the short and medium term, this will allow to take into consideration the actual functioning of gas markets.

The following elements are recommended to be considered:

- Infrastructure tariffs: transmission system operators (hereafter TSO), LNG system operators (hereafter LSO) and storage system operators (hereafter SSO) tariffs incurred by gas infrastructures users. Capacity and commodity charges need to be accounted for in view of flow modelling perspective, as well as possibly the share of capacity booked upfront on medium to long-term basis to accurately reflect the impact of tariffs on the use of capacities;
- Information on gas supply prices in particular regarding variability among supply sources or import routes and possibly long-term supply contracts, provided data is available.

Infrastructure tariffs

Infrastructure tariffs correspond to charges paid by users to the operators of infrastructure such as transmission networks, storage facilities, and LNG regasification facilities, for the right

[11] In TYNDP 2017 and TYNDP 2018 the following rule for the identification of Advanced projects was applied:

1) commissioning year expected at the latest by 31st December of the year of the TYNDP project data collection + 6 (e.g. 2022 in case of TYNDP 2017, for which projects were collected in 2016)
   AND
2) projects whose permitting phase has started ahead of the TYNDP project data collection
   OR
   FEED (i.e. front end engineering design) has started (or the project has been selected for receiving CEF grants for FEED) ahead of the TYNDP project data collection

to use (i.e. "capacity charges") and the actual utilisation of such infrastructure (i.e. "commodity charges").

Infrastructure tariffs are a reality for market participants and they may influence capacity bookings and gas flows in Europe. For this reason, it is therefore recommended that infrastructure tariffs are reflected as part of the market assumptions. Nevertheless, the key drivers for defining the methodology on how to reflect tariffs in the CBA should be consistency and simplicity.

Indeed, the inclusion of tariffs comes with a number of **limitations** which have to be acknowledged and tackled:

> Consideration of infrastructure tariffs implies significant complexity in terms of data collection, completeness, validity period and accuracy;
> Calculation methodologies for tariffs and actual tariffs will evolve over time (and from a regulatory period to the next). More generally, regulated tariffs will influence bookings, which will also in turn require tariff adjustments. The lack of visibility on how tariffs will evolve over time makes it very difficult to define a clear methodology on the long-term evolution of tariffs, although assessing infrastructure requires to take such long-term perspective. A possible and simple solution can be to adopt a fixed approach assuming that the value for tariffs on the short-term is kept constant in the future;
> Regarding infrastructure tariffs charged by TSOs, LNG terminals and storage operators to infrastructure users, there are different approaches in Europe. Such approaches may vary depending on the infrastructure and the country considered. For the assessment purposes and to ensure comparability of results this requires to define a standardised approach;
> Regarding projects, any estimation of the related infrastructure tariffs should be considered carefully to avoid possible double counting in addition to project costs, in particular when computing the socio-economic welfare of projects.

Due to these limitations, the outputs stemming from the application of the Methodology, especially in terms of resulting marginal prices, should therefore be interpreted bearing in mind the underlying assumptions.

The inclusion of infrastructure tariffs in the modelling assumptions will result in tariffs being a strong driver for flows. It is important to underline that this may result in modelled flows following a more binary behaviour than real flows, as in reality different factors impact on network users' nominations. Consideration of long-term capacity bookings, with a specific approach to their use cost, and long-term supply contracts can improve the situation.

Additionally, as part of the ENTSOs Interlinked Model, any step towards a potential interlinkage of gas and electricity market modelling or project assessment would require the adoption of a consistent approach across sectors to avoid undue distortion of the results.

To ensure a consistent and comprehensive assessment, transmission tariffs as well as LNG terminals and storage tariffs should be reflected.

In terms of **transmission tariffs**, most TSOs recover costs through capacity charges, and sometimes also through commodity charges. The provisions set out in Regulation (EU) 2017/460 of 16 March 2017, i.e. the Tariff Network Code (or TAR NC), are to be fully implemented by 2019 by EU Member States. The assessment of infrastructure projects must be performed with due consideration of the TAR NC requirements or any evolution of transmission tariff regulations. The development of market elements in terms of tariffs requires to make several assumptions.
In accordance with the TAR NC, ENTSOG publishes transmission tariffs information on its Transparency Platform[12]. It is recommended to use such information for setting tariffs assumptions.

In contrast to TSO networks, **LNG terminals charges** follow significantly different rules. Some terminals offer third-party access and apply regulated tariffs, others also grant third-party access but with negotiated tariffs, while another group is exempted from third-party access. Standardised assumptions need to be defined to ensure an adequate representation of the LNG charges. It is also necessary to take into consideration **storage facilities charges**.
A description of the different elements to be considered when including transmission, LNG or storage tariffs in the market modelling assumptions is available in Annex I.

Users need to take into consideration elements regarding **long-term capacity contracts**.
These contracts, if signed before the time-horizon considered for the assessment, basically represent a given for the user, and therefore sunk cost that are not expected to impact on its short-term use of the capacity. When considering the tariffs associated to the capacity booked through these contracts, the capacity component must be disregarded (as it will not impact on the short-term use of the capacity) while focusing only on the commodity part, if any.

[12] https://transparency.entsog.eu/

Tariffs for projects

To ensure a comprehensive and sound assessment of gas infrastructures, tariffs borne by the infrastructure users from the commissioning of an infrastructure project should be considered in addition to the tariffs from the already existing infrastructure. This is relevant both

> From a system assessment perspective, as the assessed system includes a number of projects, and serves as counterfactual for the incremental project assessment;
> From a project assessment perspective.

In practice moving from project costs to tariffs is a very complex process involving institutions and is subject to assumptions that can significantly differ from one project to the next. How much of the costs of a project will be reflected on an interconnection point is subject to various uncertainties such as: the share of the project cost that will be directly reflected on the IP tariffs (which will presumably depend on the type of need the project fulfils); whether the project will be subject to Cross-Border Cost Allocation (CBCA) with part of its costs covered in a different country; whether the project will benefit from Union financial assistance.

Despite all these uncertainties, accurate system and project assessment impose to make an assumption for all the different projects considered. For this reason, the key element will be to fix a **reference to be used consistently across projects**, to ensure comparability.

In addition, as the value chosen as reference will highly influence the competition of projects with the existing infrastructure and with other projects, as well as the quantity of gas flowed through those projects, a **sensitivity analysis** on the value of tariffs for the considered project should be performed as part of the project-specific assessment (as per chapter 3.5). Such sensitivity analysis shall be performed on the same basis among projects to ensure consistency and comparability.

The CBA Methodology proposes three possible approaches on assumptions for the reference use tariff of projects:

> Uniform approach
> Project-specific approach
> Combined approach

When assessing different projects, the same approach should be used for all projects, to ensure comparable and level-playing-field outputs.

These approaches are further detailed below.

The value used should be expressed in "EUR/energy unit", i.e. as a commodity charge (e.g. in EUR/MWh).

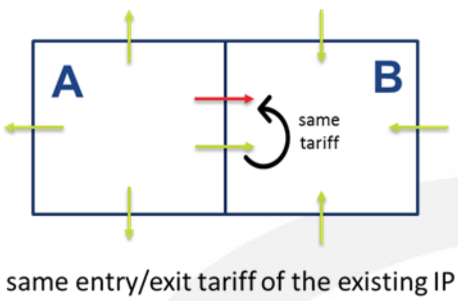
> **Uniform approach**: use of a standard and uniform value across all considered projects or, if possible, defined by type of infrastructure and technical parameters (e.g. length for pipeline projects).

> **Project-specific approach**: the tariff resulting from the realisation of a project can be derived, based on the total costs of the project and the capacity created on the impacted point/border. This approach requires additional assumptions in terms of:
>
> - the split of the costs among the countries if it departs from the cost incurred in each country;
> - the annual share of the cost of the project to be recovered every year through the tariff on the point concerned by the project;
>
> This approach is highly sensitive to the information on costs used in the assessment and therefore less preferable in terms of projects comparability.

> **Combined approach**: it combines tariffs information on neighbouring existing IPs (or entry/exit points in the case of LNG and storage projects)
>
> - where one or more IPs already exist on the same border, the weighted average of the existing tariffs (entry/exit) on these points should be considered as reference tariff for the project;
> - where there are no existing IPs the weighted average of entry/exit tariffs at the other borders should be considered.

The same Combined approach can be considered for new LNG or UGS facilities:

- if one or more facilities already exist in the country: weighted average of the tariffs
- if no facility exists in the country: weighted average of all facilities in EU



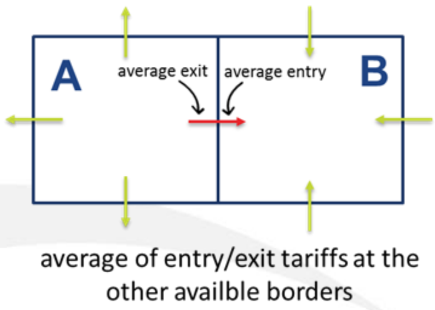


Figure 2 - Combined approach in case of an existing IP at the considered border

Figure 3 - Combined approach in case of no existing IP at the considered border

When estimating tariffs from the realisation of projects, additional assumptions may be considered regarding whether to homogenise or not the new and the existing tariffs regarding a specific border. This will have an impact on the resulting competition between existing and new infrastructures.

Long-term supply contracts

Gas long-term supply contracts represent another market element that can be considered when assessing gas infrastructures.
Gas long-term contracts exist for both pipeline and LNG gas imports to Europe. In case of LNG contracts, they may assume either fixed or multiple final destinations.
The gas long-term supply contracts in force in the first years of the assessment period therefore represent a commercial element that can be included as a constraint to better reflect market behaviour. These constraints are based on the principle of take-or-pay clauses of long-term supply contracts.

However, it must be noted that their inclusion is not a trivial exercise and may have different and opposite implications:

- The impact of projects will depend on the assumptions retained on the evolution of contracts in force, for example in terms of expiration or renegotiation period;
- Assessed gas flows and resulting future infrastructure gaps will be sensitive to the assumption made on the quantities considered to be recontracted.

Additionally, it should be noted that supply long-term contracts, as well as aggregated information stemming from long-term contracts, often represent commercially sensitive information that are beyond the remit of TSOs, in line with the unbundling principle, and may not be publicly available.

2. System Assessment / Identification of infrastructure gaps

The analysis at system level allows to verify whether the system is already able to cope with the future challenges, or whether further development of the infrastructure is still required to support the completion of the internal energy market and to achieve the climate and energy policies.
Given a certain level of infrastructure assumed in place along the considered time-horizon, the analysis of the system may reveal the need for further development. In such case, projects will be then assessed to see whether the situation is mitigated or completely solved.

Infrastructure gaps

An infrastructure gap can be identified as a situation where an infrastructure may be needed to meet the criteria defined in the Regulation (EU) 347/2013.

In accordance with Art. 8 (10) (c) of Regulation (EC) 715/2009, the TYNDP "*shall […] identify investment gaps*". This represents the basis for the identification of where additional infrastructure may be needed. The identified infrastructure gaps should be reported as a specific section of the TYNDP report.

As per the example below, the analysis at system level identifies an infrastructure gap for country 2: with the infrastructures considered in the reference grid, country 2 is in fact not able to entirely cover its gas demand even in case of infinite availability of gas from the existing supply source. One or more projects may therefore help to mitigate or entirely solve the situation.

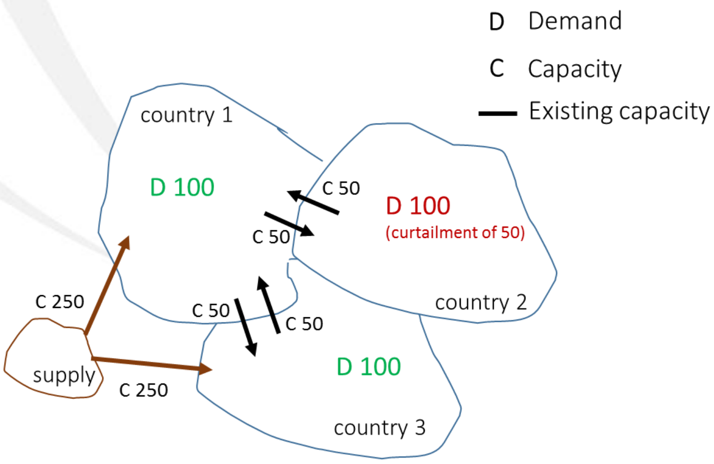


Figure 4 – Identification of infrastructure gaps

To identify the infrastructure gaps is important to define before the following:

> The threshold value beyond which an infrastructure gap does not exist or is less relevant;
> The level of the grid in place (infrastructure level) to be considered as a reasonable counterfactual situation on which to assess the system and identify possible infrastructure gaps.

Thresholds

Identification of the infrastructure gaps will be performed along the different CBA indicators. For a given indicator, and for the different countries, the existence of an infrastructure gap relates to a **threshold**[13] value which - if not achieved - signals an infrastructure gap. The threshold is the value beyond which the infrastructure gap disappears or is considered less relevant. The same threshold should be used both for evaluating the possible infrastructure gaps and for evaluating how projects mitigate or solve these gaps, to ensure comparability of results.

As an example, in case of an indicator measuring how projects solve or mitigate demand curtailment, the minimum threshold to be considered is 100%[14]. In this case, below this threshold the demand cannot be fully satisfied, resulting in an infrastructure gap that can be solved or mitigated by the realisation of one or more projects.

Infrastructure levels

The selection of the proper level of development of infrastructure is vital for the identification of infrastructure gaps and a reliable system and project assessment.

An **infrastructure level** is defined as the potential level of development of the European gas network system. It represents the level of infrastructure assumed being in place along the considered analysis time horizon. Therefore, the identification of infrastructure gaps and the

[13] Fixing such threshold is not in the scope of the CBA methodology, but should be defined as part of applying the CBA methodology.
[14] Depending on the level of flexibility targeted in terms of ensured demand coverage, a higher threshold of 100% could of course be considered.

need for further development are strictly dependent on the definition of the infrastructure level.

Infrastructure levels represent the counterfactual situations

- On which to identify infrastructure gaps and to perform system assessment;
- Against which projects should be assessed.

Considering that the analysis will be performed at least on a time horizon of 20 years, an infrastructure level formed by existing infrastructure and projects with FID status represents a credible minimum level of infrastructure development to be considered as the **reference grid** for the identification of infrastructure gaps and against which to assess projects.
The assessment of the reference grid provides the analysis of what the current infrastructure, complemented with FID projects, already achieves and which are the remaining gaps that may trigger additional investment.

Further system assessment

When applying the CBA methodology, additional infrastructure levels may be considered for the analysis of the European system and of the projects' impact and to ensure adequate comparison.

Once the infrastructure gaps are identified, the assessment of the European gas system may be complemented by assessing the overall further impact of additional infrastructure levels:

- It is recommended to perform a system assessment with the Advanced infrastructure level (including existing infrastructure and project with FID and Advanced status). This should be compared to the one based on the reference grid, ensuring an incremental approach for the overall cluster of projects with Advanced status;
- This may be complemented by the assessment of the European gas system under a PCI infrastructure level gathering all the projects of the prevailing PCI list, although it includes projects of very different maturity.

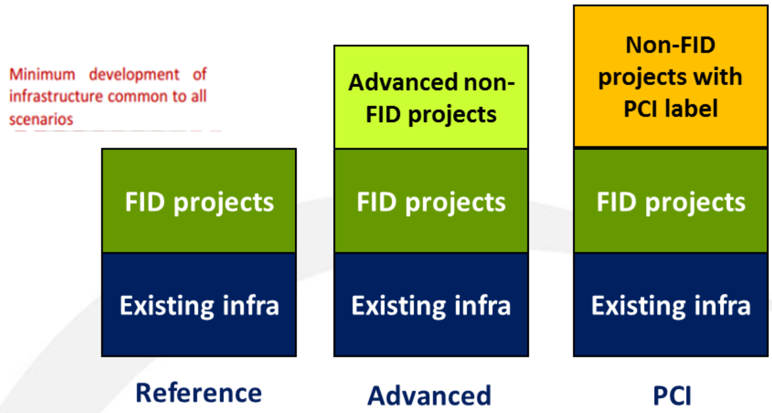


Figure 5 – Infrastructure levels

The reference grid and the Advanced infrastructure level should be used as common basis for all project-specific CBAs.

3. Project-Specific Assessment

3.1. Frame for the project-specific assessment

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 (MCA)** approach. Its perimeter is wider than the pure monetary assessment, as the reality of the gas market and its effect for the European economy and society generally require that non-monetary effects are also taken into account. Quantitative indicators provide detailed, understandable and comparable information independently from their potential monetary value.

Project-specific assessment is performed as part of the TYNDP process, as this allows for:

- The assessment of projects on a comparable basis;
- Consistent results to be provided to promoters;
- High transparency towards stakeholders on the projects assessment.

Results will be published in the TYNDP in the form of a **"Project Fiche"**. This allows to provide technical support to promoters while ensuring a level-playing field and a transparent assessment towards all stakeholders. Presenting the cost-benefit analysis of a project in a project fiche using a standardised template ensures the provision of relevant project information and PS-CBA results in a harmonised, synthetic and comparable manner.

Project grouping

Often, a number of functionally-related projects need to be implemented for their benefit(s) to materialise. The cost-benefit analysis should in this case be performed jointly for these strictly functionally-related projects, ensuring consistency between the considered benefits and costs.

For example:

- In case of an interconnector connecting two countries, two different promoters are usually involved;
- A new LNG terminal or storage may need a new evacuation pipeline to connect them to the gas network;

- In some cases, projects connecting the EU to new supply sources are actually composed by different projects whose full realisation is a prerequisite to connect the new source.

In such cases those projects need to be **grouped together** to perform their cost-benefit analysis. In other cases, groups may correspond to a single project.

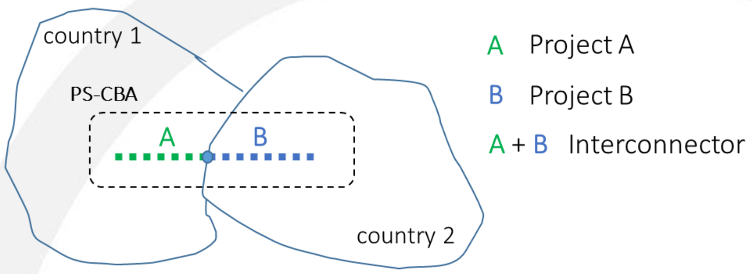


Figure 6 – Example of project grouping in case of an interconnection formed by two projects

At minimum, the following grouping is necessary:

- Interconnection between two (or more) countries or a reverse flow project;
- LNG terminal (and connecting pipe);
- Underground storage (and connecting pipe);
- A connection to an existing or new source, or a supply chain consisting of several projects bringing gas to one or more EU countries from an existing or new source.

The following grouping principles shall be applied:

- **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;
- The **enhancer(s)** need to be grouped and assessed together with the enhanced project (the main investment); an additional group separating the main investment from the enhancers should also be assessed separately;
- The **enabler(s)** need to be grouped and assessed together with the main investment
- In case of a project consisting of **several phases**, each phase should be assessed separately in order to evaluate the incremental impact of all phases (e.g. in case of a project composed by two different phases, one group should consider only phase 1 while a second group should consider phase 1 and phase 2).

Where:

- **Enabler** is a project which is indispensable for the realisation of the main project in order for the latter to start operating and show any benefit. The enabler itself might or not bring any direct capacity increment at any IP;
- **Enhancer** is a project that would allow the main project to operate at higher rate than when main project operates on its own basis, increasing the benefits stemming from the realisation of the main investment. An enhancer, unlike an enabler, it is not strictly required for the realisation of the main project;
- **Competing** are projects with similar characteristics that tackle the same objective in the same geographical area.

When grouping projects, other elements may be considered as a secondary input to check groups consistency, such as the projects implementation status (e.g. under consideration vs under construction, etc.) and the expected commissioning year. For example, grouping together projects expected to be commissioned far apart in time may introduce the risk that eventually one of more investments are not realised.

The incremental approach

Estimating benefits associated with projects require to compare the two situations "*with project*" and "*without project*": this is the incremental approach. It is at the core of the analysis, and 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 gas infrastructure against which the project is assessed (the infrastructure level, as described in chapter 2). It should be consistent across the different projects assessed.

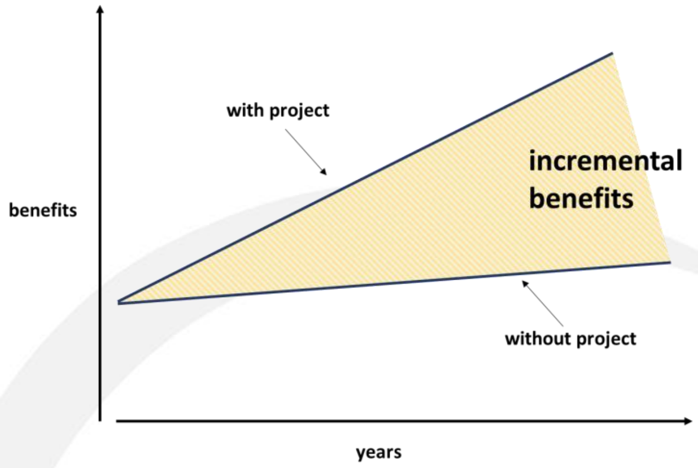


Figure 7 – Incremental approach (adapted from Belli (ed.) et al. – Economic Analysis of investment operations – 2001.

The counterfactual situation against which the project[15] is assessed will impact on the value given to the project. It is therefore recommended that the benefits of an infrastructure project are assessed against different infrastructure levels in order to get a comprehensive view of what could be the impact of the project:

> Main assessment against the reference grid;
> Additional assessment against the Advanced infrastructure level.

Indeed, assessing the benefits of projects against different infrastructure levels provides a complementary perspective that allows to reflect on different kind of interactions among projects when calculating the differences between the situation with the project and the situation without the project. In fact, the higher the number of projects included in the infrastructure level and the lower the marginal impact brought by the assessed project will be when applying the incremental approach. This approach may also allow to identify synergies with projects that are not part of the assessed group but belong to the infrastructure level used as counterfactual. The Advanced infrastructure level allows to take into account project interaction occurring under such level of development of the infrastructure.

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

[15] The term project should be understood as referring to the related group of projects (in line with the section on Project grouping), when applicable.

> **Put IN one at a time** (PINT) implies that the incremental benefit is calculated by adding the project compared to the considered counterfactual, in order to measure the impact of implementing the project compared to the corresponding infrastructure situation. Following this approach each project is assessed as if it was the very next 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, in order to measure the impact of implementing projects compared to the corresponding infrastructure situation. Compared to the PINT approach, the application of TOOT considers as if the project is the very last one to be implemented.

As showed in the example below based on the reference grid, depending on the status of the assessed project, the project will be assessed with **either one or the other** of two approaches.

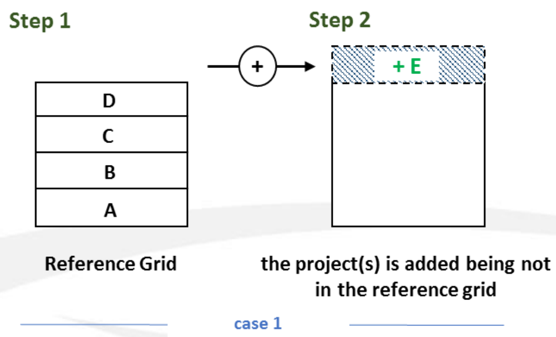


Figure 8 – Incremental approach with PINT of project E

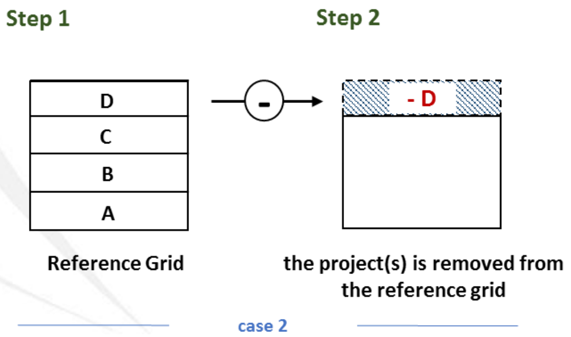


Figure 9 – Incremental approach with TOOT of project D

Infrastructure gaps as basis for project-specific assessment

- Identification of infrastructure gaps on the basis of the reference grid should be used to ensure a level-playing field project-specific assessment focused on evaluating how projects contribute to solving the gaps: in cases where a specific infrastructure gap is identified, all projects should be assessed against this gap, and project-specific assessment should show if and to which extent a specific project allows to mitigate this infrastructure gap;
- In cases where the gas infrastructure is already sufficiently developed to prevent the apparition of a specific infrastructure gap, there is no need for related project-specific assessment.

The infrastructure gaps are measured compared to **threshold** values beyond which the infrastructure gaps disappear or are considered less relevant (as mentioned in Chapter 2). The same threshold should be used both for evaluating the possible infrastructure gaps and for evaluating how projects mitigate or solve these gaps, to ensure comparability of results.

For example, it may be found out that Europe shows some dependence to Russian gas or LNG, but no dependence to other supply sources. Therefore, projects should only be assessed against the need to reduce the dependence to Russian gas or LNG.

As additional example in case the identification of infrastructure gaps concludes that:

- The European gas infrastructure is resilient to the disruption of Import Route A
- Some areas of the gas infrastructure are not resilient to the disruption of Import Route B, that is such disruption would lead to demand curtailment in some countries

In such case, there is no need to assess projects against a disruption of Import Route A. Disruption of Import Route A will not be part of the project-specific assessment framework. But there is a need to assess projects against a disruption of Import Route B.

This approach ensures a comparable basis for the assessment of projects since all projects will be assessed against the same infrastructure gap.

Continuing with the example displayed in Chapter 2:

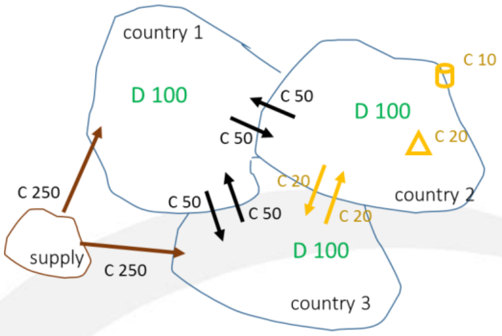


Figure 10 – Example of projects mitigating/solving the identified infrastructure gap

The realisation of one or more projects (in yellow) enabling an increment in flows reaching Country 2 by 50 GWh/d will allow to fully mitigate the risk of demand curtailment identified in the situation "*without the project*".
Different kinds of projects may allow to fully or partially mitigate the situation: a cross-border interconnection, or alternatively an LNG terminal or a storage (or a combination of those). The solution is not unique. In this perspective, when assessing projects' impact against the identified infrastructure gap, the assessment should allow to assess the different solutions, not only from a cross-border capacity perspective[16], in order to properly inform on possible investment solutions.

The next example considers the dependence to a given supply source. In the initial situation without the project, country 1 and country 3 are quite well diversified in terms of access to supply sources, as they are directly, or indirectly, connected to two supply sources (S1 and S2) and to the rest of Europe. Those countries present a maximum dependence to the considered supply source not higher than 15%. On the other hand, country 2 is connected only to country 1 and directly to one of the available supply sources (S3). This results in country 2 being more dependent to supply 3 with an irreducible share of gas coming from that source (S3) of 50%. Assuming a threshold of supply dependence of 25%[17], country 2 shows an infrastructure gap.

[16] As referred to in Art. (8) of Regulation (EC) 715/2009.
[17] This was the threshold used by Regional Groups during the 3rd PCI selection process.

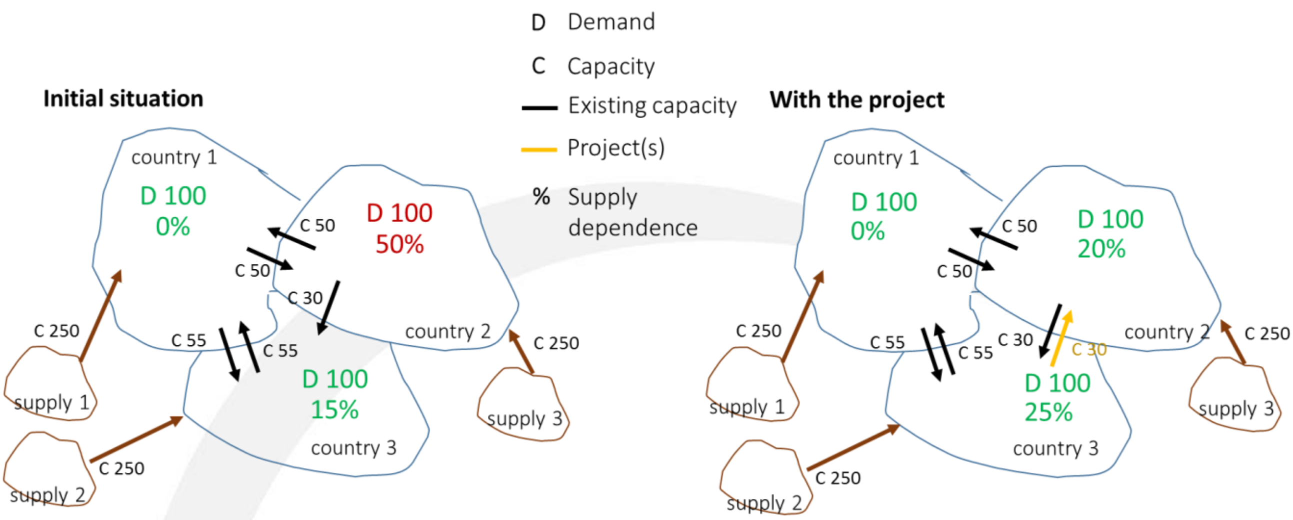


Figure 11 – Representation of a possible cross-border impact

With the realisation of a new capacity between country 2 and country 3 (the project would presumably be initiated by country 2 which is the one with the worst starting situation), country 2 increases its access to sources 1 and 2 allowing to reduce the share of dependence from source 3 to 20%. According to the communicating vessels theory, country 3 sees its source dependence increasing since now it is fully interconnected with country 2. Overall, the dependence of Europe is however reduced.
The assessment allows to identify the country on which the project has net positive impacts and the country on which the project has a net negative impact, in the context of an overall improvement in terms of supply dependence for Europe.

The situation described in the example above may happen with marginal prices. In this case, we would observe an alignment in marginal prices with the cost of gas in country 2 decreasing while increasing in the remaining countries. Still, for Europe we may observe a decrease in the cost of gas.

3.2. Project Benefits

The Regulation has identified four main criteria: market integration, security of supply, competition and sustainability. The projects should be assessed against these criteria. As part of the PCI selection process, this will allow to check if a project significantly contributes to at least one of them, which is a regulatory prerequisite to be considered as a project of common interest[18]. In line with those criteria, gas infrastructure projects potential benefits to Europe and Member States are listed below:

- Reduction of the **cost of gas supply** and **price convergence** between markets;
- Reduction in **supply dependence** and increase of the **number of supply sources** that a country has access to;
- Enhancement of **market integration**;
- Contribution to **security of supply**;
- **savings in CO_2 emissions**, related to
  - integration of renewable energy (including biomethane and other synthetic gases)
  - and/or substitution of higher-carbon energy sources (like coal in power generation) by gas;
- **Replacement of more expensive fuels** in new or existing markets.

The above-mentioned benefits can be:

- Quantified, measured through specific indicators;
- Quantified and monetized, assigning a specific monetary value to be then considered in the calculation of the Economic Performance Indicators together with cost information;
- Qualitative, when benefits cannot be quantified.

This methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements. In line with this concept, the above benefits are therefore taken into account in this methodology along with cost information, allowing for a level-playing field and comprehensive assessment of projects on all criteria.

This can be summarised in the table below.

---

[18] Art. 4 of Regulation (EU) 347/2013.

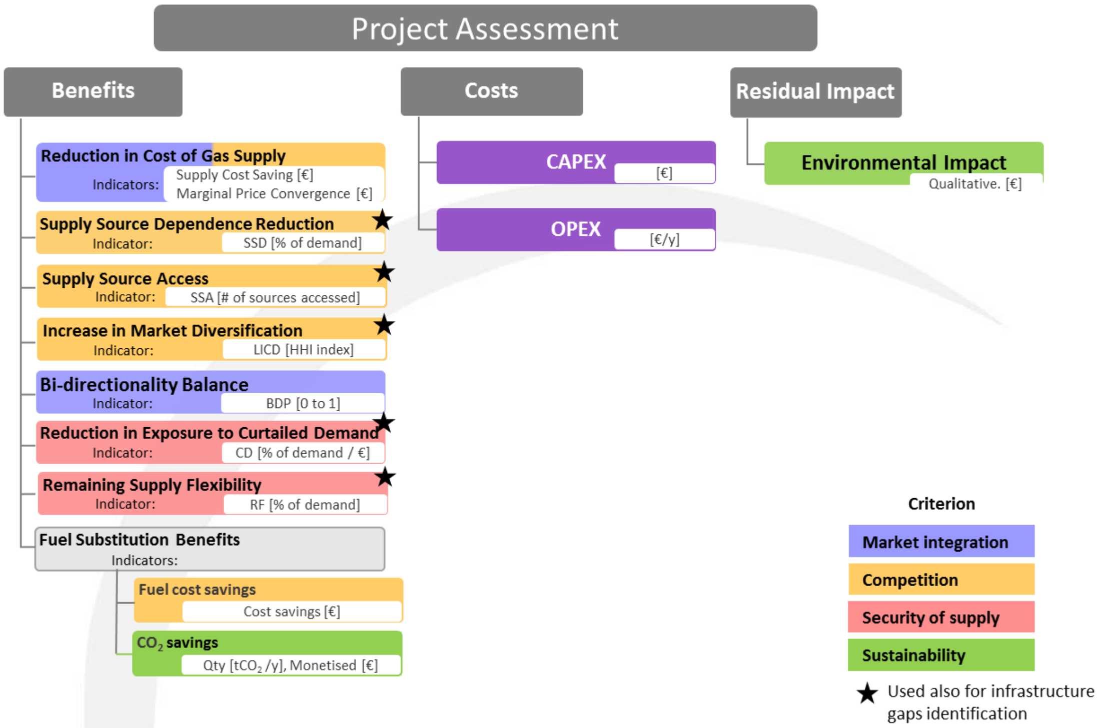


Table 1 – CBA metrics and Regulation criteria

Indicators are explained in the below section. The detail on how indicators are calculated should be part of an Annex to the TYNDP report. It may be updated and adapted over time based on experience gained and feedback received as part of the TYNDP process. Changes will be subject to advice from the Commission and ACER and public consultation.

3.2.1. Quantification and monetisation of benefits

The definition of a common set of project assessment metrics ensures the comparability between projects and reflects in an aggregated form their impact along the different policy criteria identified by the Regulation. These metrics should be analysed altogether not giving undue priority to one of them.

When it comes to monetisation, attention should be paid to potential double counting of benefits.

Monetisation should only be performed when reliable monetisation is ensured, to avoid non-robust conclusions when comparing monetised benefits to project costs. Until then (non-monetised) quantitative benefits should be maintained. Over time, specific investigations outside of the scope of this methodology may allow to identify 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.

3.2.2. Indicators

The below set of indicators covers all specific criteria of the Regulation and all the benefits identified in chapter 3.2. All indicators are to be used as part of the incremental approach (as per chapter 3.1) in order to evaluate the contribution of a project along the specific criteria set by the Regulation.

Supply cost savings

This indicator is meant at capturing the benefits stemming from projects reducing the overall European cost of gas supply.

The monetary analysis of the cost of gas supply is based on the calculation of the gas bill in the situation with and without the project. The benefits are calculated at European level and according to the following formula:

$$\text{supply cost saving} = \sum_{1}^{n}(\mathrm{S}_1^n * \mathrm{C}_1^n)\ \text{with project} - \sum_{1}^{n}(\mathrm{S}_1^n * \mathrm{C}_1^n)\ \text{without project}$$

Where:

- $\boldsymbol{S_1^n}$ represents the supply
- $\boldsymbol{C_1^n}$ represents the cost of the gas supply[19], including the price of the gas delivered at the Europe borders and the tariffs (the latter when considered in the assessment)

[19] For more details on supply and prices please refer to chapter 1.1.

The total benefit is calculated by aggregating the benefits in supply cost saving for all the considered time horizon.

The below graph represents the variation in the social economic welfare stemming from the reduction of the cost of gas supply, thanks to an increase in the availability of a cheap source. Based on economic theory, the variation in social welfare from a project inducing supply cost savings is the green area, as shown in the graph below.

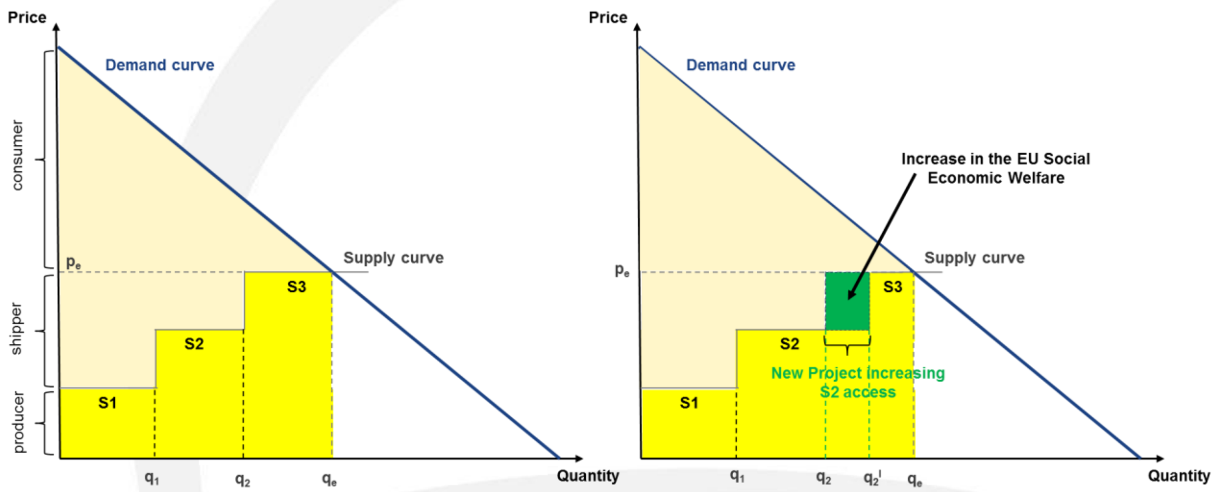


Figure 12 – Change in Socio-economic Welfare from a project increasing access to a cheap source.

As an example, the above graph shows a case where an infrastructure project allows to increase the availability of a cheap and already existing gas supply source (S2) and reduces the need for a more expensive gas supply source (S3) to cover the demand.
In this case the additional gas – provided from the same or different sources – is not cheaper than the cheapest existing source before the investment (the minimum gas price is still the minimum for which some supply is brought to the market). However, without lowering the equilibrium gas price (represented by P_e and defined as the price of the marginal supply source used to cover the demand) the total cost of the gas supply for EU (yellow area) decreases by the amount corresponding to the green area.
Therefore, the decrease of the cost of supply that can be attributed to the implementation of the project represents an increase in the social economic welfare.

In order to consider potential temporary price situations characterising a supply source, a sensitivity on the price associated to that specific source should be considered (for more details see chapter 3.5).

The inclusion of infrastructure tariffs at IPs in the modelling assumptions influences the cost of cross-border flows (pancaking effect[20]) as well as the use of LNG terminals and UGS facilities. The calculation of the cost of gas supply and the related savings stemming from the realisation of a project are therefore impacted by the considered assumptions on infrastructure tariffs.
Furthermore, with the inclusion of infrastructure tariffs, it has to be recognised that the cost of the project is (at least partially) reflected in the tariff(s).[21] When computing the monetised benefits in terms of supply cost savings as an input to the calculation of the Economic Performance Indicators it is therefore important to avoid any possible double counting of the project costs.

Supply Source Dependence (SSD)

The SSD indicator aims at identifying countries showing a strong dependence to a specific supply source and allows to identify cases where this dependence is related to an infrastructure bottleneck (physical dependence).

It should be calculated vis-à-vis each source under a whole year.

The lower the value of SSD, the lower the dependence.

It is recommended to calculate this indicator considering cooperation within relevant regions: under such cooperative approach, areas within a given region will share the same level of dependence unless an infrastructure related limitation prevent them to align their dependence.

The Supply Source Dependence to source S is calculated as follows (steps 1 to 4 are repeated for each source):

[20] As the accumulation of tariffs to be paid when shipping gas through several borders each of them having tariffs at each single IP.
[21] The final share of the cost reflected into the tariffs will depend in fact on the tariff value itself used and the actual utilisation of the infrastructure as a result of the modelling simulations.

1. The availability of source S is set down to zero
2. The availability of the other sources remains in line with the defined supply assumptions
3. Modelling of the European gas system under the whole year

The Supply Source Dependence of the Area Z to the source S is defined as:

$$\mathrm{SSD}_{\mathrm{Z,S}} = \frac{\mathrm{DC}_{\mathrm{Z,S}}}{\mathrm{Demand}_{\mathrm{Z}}}$$

Where:
> $\boldsymbol{DC_{Z,S}}$ is the demand curtailment (in GWh) in Z when S is not available
> $\boldsymbol{Demand_Z}$ is the demand of Z (in GWh)

With regards to LNG, two approaches are possible for calculating SSD:
> Considering all LNG sources as one global source on the basis that LNG is a world market and prices are set worldwide. From a competition perspective, and SSD being calculated on a whole year, this may be considered as the most sensible approach;
> Considering each LNG source independently, which allows to measure sensitivity of specific areas to specific LNG sources.

Supply Source Access
The Supply Source Access indicator (SSA) measures the number of supply sources an area can access.

The ability of an area to access a given source is measured through a supply source diversification metric. SSA provides the aggregate view across all supply sources.

This supply source diversification ability is calculated from a market perspective, as the ability of each area to benefit from a decrease in the price of the considered supply source (such ability does not always mean that the area has a physical access to the source).

It is calculated for each area under a whole year.

The supply source diversification towards source S is calculated as follows:
> 1. Maximisation of source S: the price of source S is set below the price of other sources to

ensure that the use of the source is maximised (only infrastructures may limit the access of a given area to the source). The cost of supply resulting from this maximisation is calculated for each area;

> 2. Sensitivity to the price of source S: the price is decreased by a given percentage, e.g. 10% (which does not impact on the maximisation) and cost of supply is calculated for each area;
> Comparison of the cost of supply between 2. and 1. indicates the ability of the area to benefit from a decrease in the price of source S.

$$\mathrm{SSDi} = \frac{1}{10\%} * \frac{(\text{cost of supply1} - \text{cost of supply 2} \quad)}{\text{cost of supply 1}}$$

The above formula corresponds to a decrease of the price of source S by 10% as part of 2.

The supply source diversification is expressed as a percentage in the range 0 to 100%, with e.g. 30% corresponding to the supply cost of the area being 30% responsive to a decrease in price S. The bigger the SSDi, the better the access to source S from a price perspective.

The inclusion of infrastructure tariffs in the modelling assumptions has also an influence on the results of the Supply Source Access indicator. In fact, in case gas has to cross several borders before reaching a specific country, the further the source the more expensive that gas will be, with, as a consequence, a reduction of the access to the source from a price perspective.

SSDi should be calculated independently for the different supply sources (SSDi_S1, SSDi_S2,…), and simultaneously for all areas.

The SSA indicates the number of sources for which the SSDi exceeds a given value (e.g. 20% sources). This value should be fixed as the level from which the response to source S is considered significant.

SSA = number of sources for which SSDi ≥ SSAthreshold

With regards to LNG, two approaches are possible for calculating SSDi:

> Considering all LNG sources as one global source on the basis that LNG is a world market and prices are set worldwide. From a competition perspective, this may be considered as the most sensible approach;

> Considering each LNG source independently, which allows to measure sensitivity of specific areas to specific LNG sources (including changes in LNG price).

LNG and Interconnection Capacity Diversification (LICD)

This indicator intends to look at the diversification from the perspective of market integration. It measures the diversification of paths that gas can flow through to reach a market area.

The LICD is an HHI indicator[22] and ranges from 0 to 10.000. The lower the value, the better the diversification is. Where a market would have two borders the LICD cannot be lower than 5000. For a market having three borders the LICD cannot be lower than 3333.

The indicator is calculated following the below formula.

$$\mathrm{LICD} = \left(\frac{\mathrm{LNG\ border}}{\mathrm{Total\ Capa\ border}} * 100\right)^2 + \sum_1^{\mathrm{N\ borders}} \left(\frac{\mathrm{Capa\ border_l}}{\mathrm{Total\ Capa\ border}} * 100\right)^2$$

Where

$$\mathrm{Capa\ border_i} = \min\left[\sum_k^{\mathrm{IP}} \mathrm{IP_k border_i}\,, \mathrm{Dmax}\right]$$

> **D_{max}** is the gas demand *(GWh/d)* of the area in peak conditions. This is considered in order to avoid that capacities exceeding the area demand (such as in transit routes) would distort the indicator output showing an unduly high level of the indicator.

> **IP_k $border_i$** is the capacity at the interconnection point *IP_k* at the $border_i$ with the neighbouring area *i*.

And where

$$\boldsymbol{LNG\ border = min\left[\sum_m LNG\ terminal_m, Dmax\right]}$$

> **LNG $terminal_m$** is the send-out capacity of the LNG terminal *m*.

[22] Herfindahl-Hirschman index.

$$\text{Total capa border} = \text{LNG border} + \sum_{i=1}^{\text{N borders}} \text{Capa border}_i$$

All capacities should be considered after application of the lesser-of-rule[23].

Bi-Directionality

Measuring the bi-directionality of capacities is an indication of the physical integration of markets.

The indicator is only to be calculated as part of project assessment and can by nature only be calculated for transmission projects.

The indicator measures the balance between the capacities in each direction of an interconnection. It should be recommended to calculate it at Interconnection Point (IP) level.

The indicator is calculated according the following formula:

$$\text{BDP} = \text{Min}\left(1; \frac{\text{Added capacity at IP to other direction}}{\text{Existing capacity in prevailing direction}}\right)$$

Where:

> **Denominator**: Existing capacity in prevailing direction (GWh/d);
> **Numerator**: Added capacity at IP to other direction (GWh/d): capacity of the project against the prevailing direction;

In case of a project creating a new bi-directional IP, the numerator shall be the smaller added capacity. In case the project changes the prevailing direction, the capacity in the new prevailing direction shall be the denominator.

The maximum value of the indicator is one (1). In case the project is a Reverse Flow, it will score above zero (0).

[23] The lesser-of-rule applied by ENTSOG aggregates available capacities on the two sides of a point to generate consistent capacity for modelling purposes. In case operator A submits an exit capacity with the value of 100 and operator B submits at the same point but in entry a capacity with value of 50, the latter will be considered as final value.

Curtailed Demand (CD)

To achieve the energy pillar of Security of Supply it is important to identify whether there are countries in Europe that risk to face any demand curtailment (i.e. to be not fully supplied). The analysis should allow to identify where projects provide benefits coming from mitigating possible demand curtailment.

Identification of demand curtailment risk should be performed individually for:

- **Normal (climatic) conditions**
- **Climatic stress conditions**, in case of extreme temperatures with lower probability of occurrence than normal conditions (e.g. occurring with a statistical probability of once in 20 years, 1/20);
- **Supply stress conditions**, in case of supply stress due to specific route disruptions (e.g. Russian transit trough Ukraine);
- **Infrastructure stress conditions**, in case of disruption of the single largest infrastructure of a country.

> Quantification of the avoided demand curtailment

The curtailed demand is the demand that cannot be satisfied in a given area as a result of simulating any of the above conditions.

In line with the principles set by Regulation 2017/1938 on cooperation among countries in mitigating stress situations, the indicator should be calculated considering cooperation among countries. For supply stress conditions, demand curtailment should be calculated considering cooperation among countries belonging to the concerned risk group as defined in Regulation 2017/1938.

To facilitate the understanding of the results, it is recommended that the amount of curtailed demand for a given area is provided:

- In energy (such as GWh)
- As relative share / percentage

These represent two alternative ways of displaying the same result.

Analysis of the evolution of this indicator as part of the PS-CBA allows to identify where projects provide benefits coming from the quantitative avoided demand curtailment thanks to the project.

> Monetisation of the avoided demand curtailment

The benefit of avoided demand curtailment should be monetized as follows.

Avoided Curtailed Demand [volume] * CoDG [EUR/volume]

where

- Avoided Curtailed Demand is the difference (in GWh) between the curtailed demand without the project and the resulting curtailed demand (if still any) after the project implementation;
- CoDG is the “Cost of Disruption of Gas Supply”[24] (EUR/GWh[25]).

Values should always be showed both in quantities of avoided curtailed demand and monetised terms.

The CoDG value cannot be observed on a market and needs to be calculated. Different approaches can be considered in view of calculating CoDG:

- Standardized EU-level CoDG, this ensures comparability and harmonised assessment of projects,
- Differentiated CoDG values, that may take into consideration elements such as country, type of users/consumers and duration of the curtailment.

For example, in the EC CBA Guide[26], it is possible to consider as an option a macroeconomic approach that consists in calculating the social cost of avoided unserved energy by dividing the annual gross value added (GVA) by the annual volume of energy (electricity, gas, heat, etc.)

[24] ACER in its opinion No 15/2017 recommended to name such value as “CoDG” (Cost of Disruption of Gas Supply) rather than “VoLL” (Value of Lost Load), the latter being used in the electricity CBA.
[25] For TYNDP 2017 ENTSOG used 600 EUR/MWh.
[26] European Commission, Guide to Cost-Benefit Analysis of Investment Projects, page 223.

consumed in the economy, possibly distinguishing between countries and economic sectors. The Eurostat database makes available the data on both GVA[27] and gas consumption by country and sector[28].
Any alternative approach and value(s) could be used if consensual among stakeholders and users.

> Overlapping and preventing from 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 in 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 shall 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.

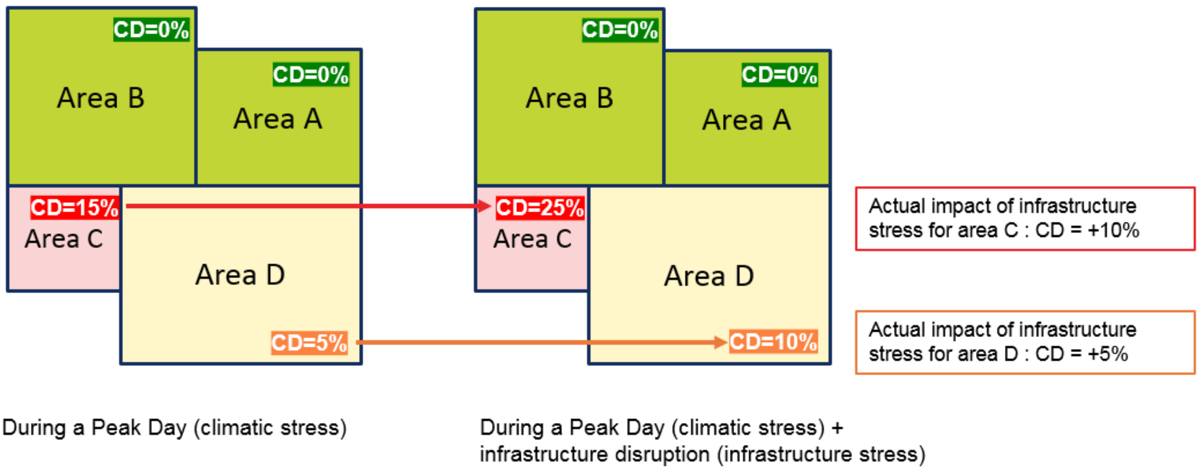


Figure 13 – Example of Curtailed Demand during a peak day compared to a combination of a peak day and an infrastructure disruption.

[27] http://ec.europa.eu/eurostat/web/national-accounts/data/database ("nama_10_a10" and "nama_10_a64_e" data series with different sectoral breakdowns).
[28] http://ec.europa.eu/eurostat/web/energy/data/database ("nrg_103a" data series).

Remaining Flexibility (RF)

In addition to assessing demand curtailment risks, the remaining flexibility assesses how resilient to climatic stress a country is. The remaining flexibility aims at capturing the extra supply flexibility a country can access through its infrastructure.

This flexibility is measured by the increase of demand an area can accommodate before an infrastructure or supply limitation is reached somewhere in the European gas system. This indicator is to be calculated independently area-by-area under stressful situations (such as climatic and supply or infrastructure stress).

The value is expressed as a percentage of the demand for a given area. The higher the value, the better the resilience.

A zero value would indicate that the country is not able to fulfil any additional demand and a 100% value would indicate that it is possible to supply twice the level of the demand.

Substitution effect (fuel switching and CO_2 impacts)

The benefits stemming from the implementation of a project enabling the substitution of other fuels with gas (including renewable gas) can mainly be of two types:

> **Reduction of CO_2 emissions** due to the replacement of higher carbon content fuels
> **Fuel cost saving** in terms of replacement of more expensive alternative fuels.

Reduction of CO2 emissions

This indicator measures the benefits related to CO_2 savings of the following types of projects:

> A project allowing to lift isolation of areas not previously connected to gas, or allowing further use of gas;
> A project allowing a switch from coal (or oil) to gas for power generation;
> A project replacing or modernising an existing infrastructure in order to increase its efficiency.

The benefits stem from the reduction of CO_2 emissions enabled by the implementation of a project allowing the substitution of higher carbon content fuels. These benefits can be monetised as follows:

Benefit from replacement of higher carbon content fuels =

$$= (Q_{fuel1} * factor_{fuel1} + ... + Q_{fuel\,n} * factor_{fuel\,n} - Q_{gas} * factor_{gas}) * CO_2 \text{ value}$$

where

- Q is the quantity of $fuel_i$ in energy terms (such as GWh). All quantities need to be expressed in the same units;
- fuel $_{i=1 \text{ to } n}$ is any alternative fuel replacement by gas driven by the project;
- $factor_{fuel}$ is the CO_2 emission factor of the specific replaced fuel;
- $factor_{gas}$ is the CO_2 emission factor of gas;
- CO_2 value (such as EUR/ton) as further described below.

Values should always be showed both in quantities of CO_2 savings and monetised terms.

Other GHG emissions may be taken into account considering proper CO_2 equivalent conversion factor[29].

The monetisation of the reduction of CO_2 emissions may follow two approaches:

- Using CO_2 market prices (e.g. the obligation of purchasing emission quotas under the Emissions Trading Scheme). The CO_2 market price is defined as part of the scenario building process. Yet, there are a number of indications in the literature that the currently foreseen future CO_2 market prices may be far below the actual Social Cost of Carbon (SCC), and may not allow to capture all societal benefits of reduction CO_2 emissions;
- Using SCC, which represents the societal value of carbon and incorporates the full economic marginal cost of emitting one more ton of CO_2 into the atmosphere. In the literature, it is calculated by summing and discounting the estimated impact over a very long period (more than 100 years) and over the most extensive list of impacted stakeholders.

Therefore, if such value is available, the SCC is seen as a more appropriate basis when assessing the monetary value attached to a reduction of the CO_2 emissions in the CBA assessment in terms of sustainability stemming from the realisation of a project.

[29] Some conversion factors are for example available in the JASPERS publication "Economic Analysis of Gas Pipeline Projects" (2011). The publication can be found here: http://www.jaspersnetwork.org/download/attachments/4948004/Economic_Analysis_of_Gas_Pipeline_Projects_Final.pdf?version=1&modificationDate=1366387572000&api=v2

Fuel cost saving

In this case, benefits come from replacement of more expensive alternative fuels with gas, which supports market competition. These benefits can be monetised as follows:

Benefit from replacement of more expensive fuels =

$$= Q_{fuel1}*P_{fuel1} + ... + Q_{fuel\mathit{n}}*P_{fuel\mathit{n}} - Q_{gas}*P_{gas}$$

where

- Q is the quantity of $fuel_i$ in energy terms (such as GWh). All quantities need to be expressed in the same units;
- Fuel $_{i=1 \text{ to } n}$ is any alternative fuel replaced by the increased gas driven by the new project
- P_{fuel} is the price of the specific replaced fuel (in EUR/GWh)

Values should always be showed both in quantities of switched fuel and monetised terms.

Environmental Impact

Any gas infrastructure has an impact on its surroundings. This impact is of particular relevance when crossing some environmentally sensitive areas. Mitigation measures are taken by the promoters to reduce this impact and comply with the EU Environmental acquis[30].
In order to give a comparable measure of project effects, the Table 2 shall be filled in by the promoter.

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

Table 2 - Environmental impact and Mitigation Measures of a Project

Where:

- The section of the project may be used to geographically identify the concerned part of the project;

[30] Directive 2001/42/EC of the European Parliament and of the Council of 27 June 2001 on the assessment of the effects of certain plans and programmes on the environment.

- Type of infrastructure identifies the nature of the section (e.g. compressor station, pipes…);
- Surface of impact is the area covered by the section in linear meters and nominal diameter for pipe, as well as in square meters, although this last value should not be used for comparison as it may depend on the national framework;
- Environmentally sensitive area 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 stemming from the realisation of the concerned project;
- Mitigation measures, that is the actions undertaken by the promoter to compensate or reduce the impact of the section (e.g. they can be related to the Environmental impact assessment which is carried out by the promoter);
- Related costs: the promoter should indicate whether this impact was already taken into account in the considered CAPEX and OPEX and providing adequate justification;
- Additional expected costs: if the costs of the environmental impact were not already internalised in the CAPEX and OPEX of the projects, the promoters should indicate here the cost of such additional measures.

In case of any other environmental impact not covered by the CBA assessment ran by ENTSOG or the table above, it is responsibility of the project promoter to submit them in form of qualitative or quantitative information. These other impacts will be included and displayed in the TYNDP assessment results together with the other indicators.

Overlapping Indicators

The 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements. The indicators defined in this methodology aim at providing relevant and quantified information that cannot always be monetised.

The figure below shows the criteria addressed by each indicator and the possible overlaps that shall be taken into consideration when applying the methodology.

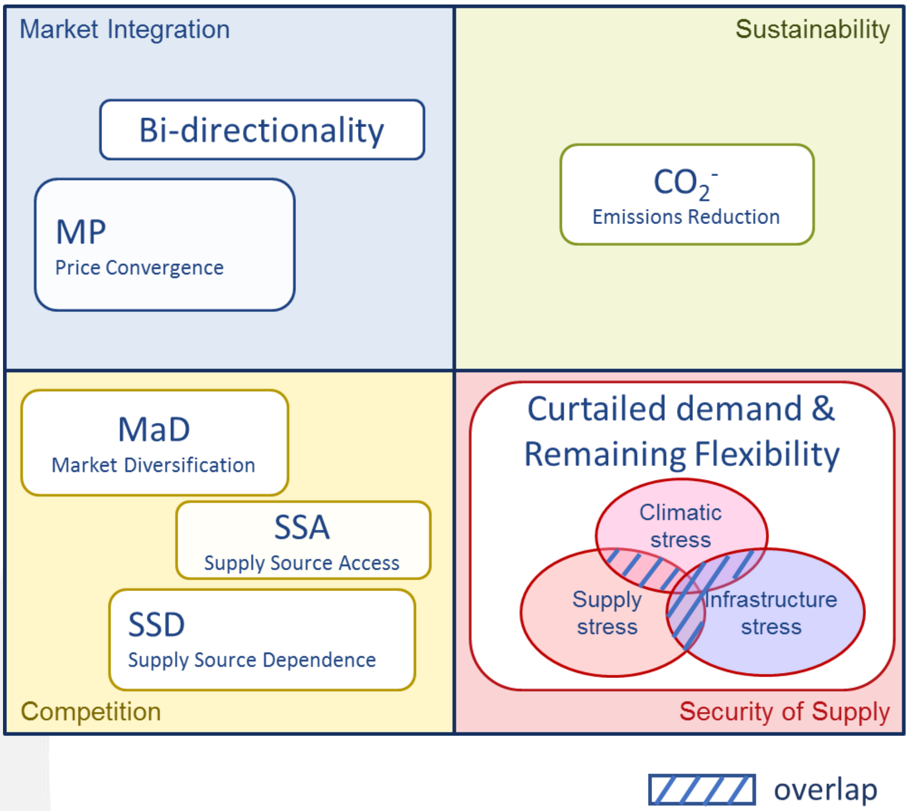


Figure 14 - Description of indicators and potential overlapping

Each indicator defined in the methodology is measuring specific criteria independently from the others and is considered as non-overlapping with the others. However, the curtailed demand and remaining flexibility indicators measuring the resilience of the infrastructure to different possible categories of stress shall be considered as overlapping when a combination of stresses is assessed in addition to each stress individually (e.g. consideration of a combination of climatic and supply stresses in addition to the consideration of a climatic stress only). In such cases, the impact of the combination of stresses shall be clearly identified and distinguished from the impact of a single stress assessment.

3.2.3. Qualitative elements

Qualitative elements can be added by the project promoter to complement monetised and quantitative indicators in order to:

> Comment on the results from the monetised and non-monetised indicators
> Provide possible additional information regarding the project and competitive projects
> Justify potential additional benefits of the project that may not have been sufficiently captured by the analysis

As part of the potential additional benefits, the realisation of a project could theoretically avoid investing in a more expensive project or replacing or allowing to decrease the maintenance costs of an existing infrastructure. This could for example happen in case of:

> A reverse flow enabling bi-directional capacity and avoiding investment in the construction of an additional pipeline;
> An interconnection or an LNG terminal replacing an FSRU;
> Other cases to be identified on an ad hoc basis depending on the grid and other gas infrastructure composing the specific system configuration

The avoided costs may be considered as a benefit for the considered project. Such benefits should at least be described from a qualitative perspective, substantiating the background for the avoided costs.

3.3. Project costs

Costs represent an inherent element of a CBA analysis. According to Annex V(5) of the Regulation, "*the cost-benefit analysis shall at least take into account the following costs: capital expenditure, operational and maintenance expenditure over the technical lifecycle of the project and decommissioning and waste management costs, where relevant*".

Investment costs are therefore classified[31] by:

> **Capital expenditure** (CAPEX)
  - **initial investment cost**, that corresponds to the cost effectively incurred by the promoter to build and start operation of the gas infrastructure. CAPEX should consider the costs of obtaining permits, feasibility studies, obtaining rights-of-way, ground work, preparatory work, designing, dismantling, equipment purchase and installation[32]
  - **replacement costs**, are the costs borne to ensure that the infrastructure remains operational by changing specific parts of it[33]

> **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.

All cost data should be considered at constant (real) prices (see section 3.4.1).
As part of the TYNDP and PCI processes, it is recommended that constant prices refer to the year of the TYNDP project collection.

---

[31] This classification is in line with the EC Guide to Cost-Benefit Analysis of Investment Projects.
[32] 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.
[33] Over the project assessment period.

3.4. Economic Net Present Value and other Economic Performance Indicators

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, the retained Social Discount Rate and therefore to the distribution of benefits and costs over the assessment period.

The CBA methodology builds on Multi-Criteria Analysis, on the ground that not all benefits of projects can be monetised. For this reason, Economic performance indicators, and in particular Economic Net Present Value, only represent a part of the balance between project costs and benefits.

Economic performance indicators are therefore useful to compare projects. But when considering if the potential overall benefits of a project outweigh its costs, as per Art. 4.1(b) of the Regulation, the Regional Group members should also consider non-monetised benefits in addition to the Economic performance indicators.

This chapter focuses mostly on the Economic Net Present Value (ENPV). Other Economic Performance Indicators are explained in Annex III.

3.4.1. Economic Parameters

Constant (real) prices

In order to ensure transparency and comparability, the analysis of socio-economic benefits and costs should be carried out at **constant (real) prices**, i.e. considering fixed prices at a base year[34]. By doing so, one neutralises the effect of inflation.

As part of the TYNDP and PCI processes, it is recommended that constant prices refer to the year of the TYNDP project collection.

[34] 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.

Socio-Economic discount rate

The notion of "socio-economic discount rate" (SDR) corresponds to the rate which 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 to take into account the time value of money.

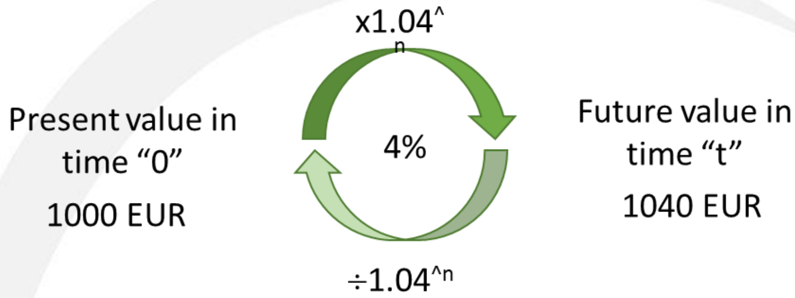


Figure 15 – Example of how the social discount rate works.

It can be interpreted as the minimum profitability that should be reached by a gas infrastructure project for it to bring net economic benefits. It can also be interpreted as the economic interest rate provided by the best alternative project, following the principle of opportunity costs. This discount rate represents the weight that society attributes to benefits, with future benefits having a lower value than present ones.

A zero SDR means that today's and future benefits are indifferent to the society point of view. A positive discount rate, on the other hand, indicates a preference for current over future benefits, whereas the opposite is true if the discount rate is negative.

The literature offers different approaches on how to estimate the socio-economic discount rate. For the cost-benefit analysis of projects, a same **SDR equal to 4% shall be used for all projects**. It corresponds to the middle-ground solution between EC recommendations to use a SDR of 5% for major projects in Cohesion countries and 3% for the other countries[35]. It therefore provides a fair basis for the comparison of projects, unbiased by the location of the projects. Indeed, it would be possible to use different social discount rates but, in order to

[35] European Commission - Guide to Cost-Benefit Analysis of Investment Projects, page 55.

guarantee comparability of project assessments and results consistency, this methodology recommends using one social discount rate for all projects.

SDR has to be considered in real terms, in line with the recommendations that the analysis of socio-economic benefits and costs should be carried out at constant (real) prices.

Economic life and physical life of project

Literature describes different notions of project's life. For the purpose of this document it is important to provide two definitions: physical and economic life.

The physical life is the life for which the facility is designed under given operating conditions and depends on the quality of the different project's components. The physical life of gas infrastructures is generally high and could be considered in the range of 40-50 years.

The EIB defines the economic life of a project as "*the period over which an asset is expected to be usable, with normal repairs and maintenance*"[36]. The EIB methodology to estimate the economic life of an infrastructure is based on the estimated average physical life, that is defined as the cost-weighted average of the physical life of the components of the project under normal operating and maintenance conditions. Once estimated the average physical life of a project, additional considerations are made, taking into account some of the already above-mentioned elements such as market risk or whether the technology is already well developed or new. This might increase the project risk and reduce the economic life.

The Asian Development Bank in the "Guidelines for the economic analysis of projects"[37] (2017) explains that "*the number of operating years to be included in the analysis is usually determined by the technical life of a project, which is the number of years of normal operation before a project is fully worn out. In cases where the economic life of the project can be estimated and there is evidence that this will be significantly shorter than the technical life, the economic life should be used*".

---

[36] EIB - The Economic Appraisal of Investment Projects at the EIB, page 41 (http://www.eib.org/attachments/thematic/economic_appraisal_of_investment_projects_en.pdf)

[37] ADB - Guidelines for the economic analysis of projects, page 14 (https://www.adb.org/sites/default/files/institutional-document/32256/economic-analysis-projects.pdf)

Let's take a concrete example: assuming that a person is supposed to live for 80 years, we can therefore consider that the physical life of a human being is 80 years. But for the company the person works for, the actual economic life will be lower and will depend on the retirement age (e.g. 60 years).

Finally, the EC CBA Guide provides a table showing the durations it uses as a reference period for various economic sectors. The EC refers to 15-25 years for the energy sector.

Table 2.1 European Commission's reference periods by sector

Sector	Reference period (years)
Railways	30
Roads	25-30
Ports and airports	25
Urban transport	25-30
Water supply/sanitation	30
Waste management	25-30
Energy	15-25
Broadband	15-20
Research and Innovation	15-25
Business infrastructure	10-15
Other sectors	10-15

Source: ANNEX I to Commission Delegated Regulation (EU) No 480/2014.

Table 3 – Reference assessment period by sector (Guide to Cost-Benefit Analysis of Investment Projects, page 42 – December 2014)

In line with EC CBA Guide[38] and recommendations by ACER this methodology recommends to consider an **economic life of 25 years**. This same reference economic life should be retained for all projects assessed to ensure comparability in the analysis of the results.

[38] European Commission - "Guide to Cost-Benefit Analysis of Investment Projects", page 42 (http://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf)

3.4.2. Socio-Economic Welfare

The analysis of the socio-economic benefits of gas infrastructure projects is based on an assessment of their impact on welfare. A project will imply changes on the gas sector through evolutions in prices and flows. The economic approach insists on the notion of externalities[39], and the need for estimating also non-market effects of a new project (in terms of reduced CO_2 emissions for example).

Change in the total socio-economic welfare (SEW) can be induced by projects

- Bringing more gas to hubs;
- Connecting EU to new sources or new national production;
- Connecting existing sources or national production to previously not connected Member States, or lifting an infrastructure bottleneck limiting the access to a given supply source;
- Allowing for further price convergence.

Additionally, change in the social welfare benefits can also stem from **change in the externalities** due to projects

- Mitigating the risk of demand curtailment;
- Avoiding the cost of alternative fuels, due to a substitution effect, both in terms of cheaper fuel and reduced CO_2 emissions.

It is recommended that these elements would be monetised separately in order to provide a better picture of how projects meet the criteria defined into the Regulation. The overall change in socio-economic welfare covering all the monetised benefits should be used to calculate the Economic Performance Indicators.

Focusing on the evolution of total social welfare is more relevant than focusing on the evolution of social welfare for each specific stakeholder. The individual social welfare may evolve even without any change in the total social welfare because of some redistribution between stakeholders.

Indirect effects (or secondary effects on the market), such as projects impact on employment, should be excluded from the assessment. This is to avoid double counting (since these benefits

[39] Theoretically externalities can be both positive and negative.

may have been already intercepted in the price variation) or evaluating benefits which are difficult to estimate through reliable techniques.

3.4.3. Economic Net Present Value (ENPV)

The ENPV is the difference between the discounted monetised benefits and the discounted costs expressed in 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 and it is considered the main performance indicator.

If the ENPV is positive the project generates a net monetary benefit and it is desirable from a socio-economic perspective. As not all benefits are monetised, a project may be desirable even if ENPV is not positive.

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

Where:

- ***c*** is the first full year of operation
- $\mathbf{B_t}$ is the monetised benefits (SEW) induced by the project on year *t* (this includes the Residual Value at the end of the project economic lifetime, when considered)
- $\mathbf{C_t}$ is the sum of CAPEX and OPEX on the year *t*
- ***n*** is the year of analysis (common for all projects)
- ***r*** is the Social Discount Rate of the project
- ***f*** is the first year where costs are incurred

In order to ensure consistent and comparable results, it is extremely important that, when computing the NPV the same approach in terms of economic lifetime, residual value and social discount rate should be applied to the different projects assessed.

Residual Value

In their "Economic Appraisal of Investment Projects"[40] (page 41), EIB indicates "*In line with sound banking practice, the Bank ensures that the maturity of its loans is shorter than the underlying project life. When the Bank is lending to guaranteed public sector projects, the main reason for capping the maturity of the loan is to make beneficiaries pay for the project, avoiding potential inter-generational transfers that may arise in detriment of future generations*".

In line with this approach and in order to provide a conservative approach it is recommended as a basis approach that projects are **assessed without residual value**.

However other publications acknowledge that the physical life of the assessed projects and depreciation period of the related costs may well exceed the 25 years retained as economic life. For this reason, a sensitivity analysis can be performed considering the residual value, calculated in line with the below guidelines included in Annex II.

3.5. Sensitivity analysis

Sensitivity analysis enables the identification of those elements most affecting the performance of projects. Critical factors can be divided in the following categories:

- **Sensitivity on gas market factors**, where the concerned elements are:
  - demand evolutions
  - renewables penetration
  - commodity and CO_2 prices
  - supply potentials

  Those elements are already captured by the different demand and supply scenarios considered (see Chapter 1.1).

  It is recommended to have a scenario-based approach for such sensitivity analysis, as some of the elements (such as gas demand and prices) are interdependent over time, and to keep CBA results to a manageable level.
- **Sensitivity on project-specific data**, that should be reflected in the project-specific assessment:

[40] http://www.eib.org/attachments/thematic/economic_appraisal_of_investment_projects_en.pdf

  - commissioning year, which is of particular importance when assessing multi-phase projects or group of projects (refer to Annex IV)
  - investment and operating expenditures costs
  - tariffs for projects (refer to Chapter 1.2.3)
- **Sensitivity on monetary parameters** directly impacting the calculation of the monetised benefits and Economic performance indicators:
  - social discount rate
  - residual value (calculation of economic performance indicators with and without residual value)
  - value for the cost of disruption of gas supply (CoDG)
  - sensitivity on supply prices, associated to minimization and maximization of the considered supply sources, with the intention to measure potential temporary price situations of one supply source and to evaluate the impact of a project allowing this benefit to spread over Europe

List of figures

List of Tables

Annex I – Infrastructure tariffs

Transmission tariffs (or charges)

This Methodology recommends considering at least this minimum set of tariff components:

> **Capacity tariffs**: tariffs paid by network users based on the capacity they book during a specific time period. This tariff does not depend on the actual usage. Most TSOs currently apply such capacity tariffs. Typically, a capacity tariff is defined in

$$\mathrm{EUR/(quantity/period)/runtime_d}$$

Where:

- quantity/period: is a capacity unit. This should be converted into "energy" units. In some countries, the capacity tariff is defined in "energy per period" while in others it is defined in "volume per period", requiring the use of a specific Calorific Value to move to the same unit.
- $\mathrm{runtime_d}$: is the duration of the capacity product considered.

For example, in case of X EUR/(GWh/d)/d it means that the network user pays X euros for the right to flow 1 GWh of gas every day for a product with a duration of 1 day.

> **Commodity tariffs**: tariffs paid by network users in relation to their actual gas flows during a specific time period. A number of TSOs currently apply such commodity tariffs.

Commodity tariff is expressed as

$$\text{Commodity tariff} = \mathrm{EUR/quantity}$$

Where:

- quantity: is the amount of gas flowed for the assessed period.

For example, in case of EUR/GWh it refers to the tariff incurred for a flow of 1 GWh.

> **User "load factor"**: when needed (in particular for modelling purposes), a load factor assumption can be used to convert capacity tariffs into tariff per unit of commodity/gas flowed based on certain assumptions on capacity utilisation. It is therefore necessary to define the value of the load factor. The load factor should be defined over the same duration as the retained capacity contract duration.

The resulting equivalent commodity tariffs and consequently the flows induced by those are sensitive to the value of the load factor used. In order to guarantee an adequate comparison of the assessment results a unique common load factor shall be used among existing infrastructures. This value could be for example based on the historical observed flows. Whatever the value used, it should be duly justified by the CBA methodology users. Furthermore, it is noted that the load factor may change depending on short-term and long-term booking evolution. It is important to use the same standard approach in order to ensure comparison of results.

> **Duration of the capacity contract**: in relation with the topic of capacity tariffs, the duration of the capacity contract is one of the elements to consider.

> **Unit of measure to be used**: all tariff elements should be converted to a common unit of measure. Such unit should be defined in Euro per volume, expressed in energy unit (e.g. EUR/GWh or EUR/MWh).

> **Exchange rate**: for countries using another currency than the Euro, it is necessary to convert the monetary units into Euro. Therefore, a common reference to exchange rates is needed, for example such as the one provided by the European Central Bank[41] at a given date.

Some TSOs may also require additional costs. Depending on their nature those costs may be aggregated with the capacity tariff or the commodity tariff.

When the capacity tariff is not used directly, but converted in a commodity cost, the following formula will be applied (factoring some preliminary unit conversions where needed):

---

41 https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/index.en.html

$$\text{Transmission Tariff} = \frac{\text{Capacity Tariff}}{\text{LF}} + \text{Commodity Tariff}$$

Where LF is the user load factor, with a value between 0 and 1, but strictly higher than 0.

The formula proposed above intends to provide a standardised and general approach. It may not correspond to the way some TSOs publish their tariffs, however it is possible to convert these different approaches into the formula above.

In addition, for cases where several IPs exist at a border between two entry-exit systems, one may use capacity-weighted average of the individual IP tariffs of the points in order to define a single value at the border level. For established Virtual Interconnection Points (VIPs) as per the Capacity Allocation Mechanism Network Code (CAM NC)[42], the tariff published at each VIP can be used.

LNG terminals tariffs (or charges)

The following standard formula applies for the description of the cumulated charges to be considered to bring the LNG to the European network.

$$\text{LNG charge} = \text{LNG Regas. charges} + \text{Other LNG charges} + \text{TSO}_{\text{Entry}} + \text{Other TSO Charges}$$

Where:

- LNG charge: are the total charges related to the use of the existing LNG terminal infrastructure and to the transport of the gas from the regasification facility to the network where the gas is injected.
- LNG Regasification charges: are the charges paid by the infrastructure user to the LNG terminal operator for the regasification service provided by the latter and generally refer to a certain regasification capacity and/or quantity of gas on a specific time period.

[42] Commission Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013

- Other LNG charges: are any other costs charged by the LNG terminal operator to the infrastructure user for the use of the terminal and generally refer to a certain quantity of gas on a specific time period, or other types of charges.
- TSO entry: represents the cost applied by the TSOs to receive the gas from the regasification terminal and charged to the infrastructure user. In practice, many TSOs only apply capacity tariffs.
- Other TSO Charges (if any).

All elements must be converted to a common unit of measure (e.g. EUR/GWh or EUR/MWh).

Storages tariffs (or charges)

The formula which applies for the inclusion of storages in the market assumptions is as follows.

$$\text{Storage charge} = \text{Inj} + \text{TSO}_{\text{Exit}} + \text{With} + \text{TSO}_{\text{Entry}} + \text{Volume} + \text{Other SSO charges} + \text{Other TSO Charges}$$

Where:

- Inj and With: are the respective injection and withdrawal charges to/from the storage facility paid by the user for the right to flow a certain quantity of gas on a given time period (e.g. every day) for a product with a certain duration.
- TSO_{Exit} and $\text{TSO}_{\text{Entry}}$: are the respective TSO tariffs/charges paid by the infrastructure user to inject gas in the storage facility/to withdraw gas from the storage facility. In practice, many TSOs only apply capacity tariffs.
- Volume: are the charges applied, in some cases, by the SSO for the use of a specific volume in the facility and referred to a certain quantity of gas on a specific time period. However, this type of charges is not applied by all SSOs.
- Other SSO charges: any other costs charged by the SSO to the infrastructure user for the use of the facility (e.g. fuel gas, etc.) and referring to a certain quantity of gas on a specific time period.
- Other TSO Charges (if any).

Some of the above elements may be aggregated if bundled SSO products are considered. For example, bundled products may include injection and withdrawal charges along with the working volume charge.

Regarding storage use, additional constraints may be considered when applying the methodology in order to reflect the fact that in some countries there are regulatory requirements aiming for example at backing consumption portfolios with gas in storages.

Annex II – Residual Value

The Joint Assistance to Support Projects in European Regions (JASPERS) in the "Economic Analysis of Gas Pipeline Projects" (2011)[43] indicates that typically, 25 years of operations are considered after the investment phase and where relevant, the investment residual value should be taken into account in the last year of the time horizon. For simplicity, the residual value can be considered being equal to the share of the initial investment plus possible replacement costs that are still not depreciated.

In the already mentioned "Guidelines for the economic analysis of projects" the Asian Development Bank explains that when the economic life is shorter than the technical life, some assets will not be fully worn out at the end of the project period and the remaining value of these assets (terminal or residual value) should be considered as a negative investment cost (i.e. benefit) at the end of the project. In the document "Cost-Benefit Analysis for development – A practical Guide"[44] (2013), they indicate that residual values are often omitted from the calculations since when they are discounted at high social discount rate (i.e. 12%), for example in year 25, any value will be very low and consequently negligible.

When considered, the residual value of the asset shall be included in the analysis for the end year of the time horizon of the analysis as a benefit. This will be discounted according to the selected social discount rate. The residual value should be calculated as the part of the costs that still needs to be depreciated. Different depreciation approaches may be adopted[45]. This CBA methodology suggests using by default a **linear depreciation method** ("straight-line method").

[43] http://www.jaspersnetwork.org/download/attachments/4948004/Economic_Analysis_of_Gas_Pipeline_Projects_Final.pdf?version=1&modificationDate=1366387572000&api=v2

[44] ADB - Cost-Benefit Analysis for development – A practical Guide, page 245 (https://www.adb.org/sites/default/files/institutional-document/33788/files/cost-benefit-analysis-development.pdf)

[45] A variety of depreciation methods exist. The easiest and probably most used one is the straight-line depreciation method. Alternative methods are, among others, the sum of the years' digits method, the double declining balance method, the annuity depreciation method, and composite depreciation methods.

As part of the project's economic analysis the residual value should be calculated according to the following general formula using the social discount rate:

$$R_v = \sum_{t=e+1}^{t=w} \frac{Dep_t}{(1+r)^{t-n}}$$

Where:

- R_v is the Residual value
- n is the year of analysis (common to all projects)
- Dep_t is the nominal value of depreciation for year t, including the replacement costs of the asset, if any
- c is the commissioning year of the project
- e is the last year of the considered economic life (assumed to be the 25th year of operations, i.e. 24 years post-commissioning: *e=c+24*)
- w is the last year of the considered life for the asset
- r is the social discount rate

In the special case where straight-line depreciation is used, with no replacement costs after commissioning of the project, *Dep* is constant and defined by the ratio of total *CAPEX* divided by the number of years *(w-c+1)* in technical life. The formula becomes:

$$R_v = \frac{CAPEX}{w-c+1} \sum_{t=e+1}^{t=w} \frac{1}{(1+r)^{t-n}}$$

Using the formula of the sum of geometric series, the residual value boils down to the following equation

$$R_v = \left(\frac{CAPEX}{w-c+1}\right) \left[(1+r)^{n-e-1}\right] \left[\frac{1-(1+r)^{e-w}}{1-(1+r)^{-1}}\right]$$

For example, independently from the initial cost considered, in an assessment based on 25 years project economic life and a project physical life of 40 years, the final residual value will represent 10% of the initial investment. In case of 50 years the residual value will instead

represent 12% of the initial investment. This in the situation where the project commissioning year and the reference year for discounting are the same, and for a straight-line depreciation profile. Given a certain reference year for discounting, the sooner the project is commissioned the higher will be the residual value.
Below a table indicating the magnitude of the residual value for different durations of the economic life and project physical life (with a socio-economic discount rate of 4%). The value is represented as a percentage of the initial investment incurred in t_0.

Project Economic Life (years)	Project technical life (years)						
	20	25	30	35	40	45	50
20	0%	8%	12%	14%	16%	16%	16%
25	0%	0%	6%	9%	10%	11%	12%
30	0%	0%	0%	4%	6%	8%	8%
35	0%	0%	0%	0%	3%	5%	6%
40	0%	0%	0%	0%	0%	2%	3%
45	0%	0%	0%	0%	0%	0%	2%
50	0%	0%	0%	0%	0%	0%	0%

Table 4 – Evolution of residual value magnitude in different assessment periods and project physical life

The higher the socio-economic discount rate and the lower will be the share of the initial investment cost that the residual value will represent.

Example

Let us assume a project with the following specifications.

- Total CAPEX: 1,000 Mln (with 500 in 2025 and 500 in 2026; please note that this CAPEX distribution is only relevant for NPV calculations to be made in Annex IV)
- Assessment year (*n*): 2020
- Commissioning year (*c*): 2027
- Duration of assessment: 25 years (*e=2051*)
- Physical life of project (N): 40 years (*w=2066*)
- Social discount rate: 4%
- Straight-line depreciation

Here, the residual value is defined by the formula for the straight-line depreciation case:

$$\mathrm{R_v} = \left(\frac{1{,}000}{2066-2027+1}\right)\left[(1.04)^{2020-2051-1}\right]\left[\frac{1-(1.04)^{2051-2066}}{1-(1.04)^{-1}}\right] = 82.4 \text{ Mln}$$

The resulting residual value represents around 8% of the initial cost. As a variant, let us now suppose that the commissioning year (*c*) is postponed to 2030 instead of 2027. Therefore, the last year of the considered economic life *(e)* becomes 2054 instead of 2051, and the last year of the considered life of the asset *(w)* becomes 2069 instead of 2066.

This change has an impact on the residual value. This is because the discounts applied to depreciation flows are now higher, due to the increased number of years between these flows and the assessment year, which is still 2020. For this variant, calculation is:

$$\mathrm{R_v} = \left(\frac{1000}{2069-2030+1}\right)\left[(1.04)^{2020-2054-1}\right]\left[\frac{1-(1.04)^{2054-2069}}{1-(1.04)^{-1}}\right] = 73.3 \text{ Mln}$$

In this second case the residual value represents around 7% of the initial investment. Therefore, the commissioning year of the project is not neutral for its residual value, given a certain and common assessment year to all assessed projects. The residual value decreases when the commissioning date is later, all other things being equal.

Assumptions used for this example will be further used in Annex IV (cf. *infra*).

Annex III – Other Economic Performance Indicators

Economic Benefit/Cost ratio

It 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.

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

Where:

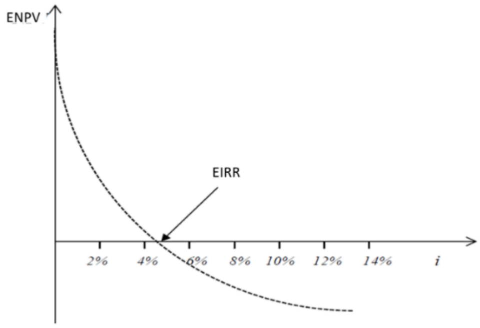
- ***c*** is the first full year of operation
- $\mathbf{B_t}$ is the monetised benefits (SEW) induced by the project on year *t* (this includes the Residual Value at the end of the project economic lifetime, when considered)
- $\mathbf{C_t}$ is the sum of CAPEX and OPEX on the year *t*
- ***n*** is the year of analysis (common to all projects)
- ***r*** is the Social Discount Rate of the project
- ***f*** is the first year where costs are incurred

If EB/C 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 ENPV and as a way to compare projects of different sizes (different level of costs and benefits).

This performance indicator allows to compare projects even in case of EB/C 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 the ranking can reward more projects that contribute less to the overall increase in public welfare.

Economic Internal rate of return (EIRR)

The indicator is defined as the discount rate that produces a zero ENPV.



A project is considered economically desirable if the EIRR exceeds its socio-economic Discount Rate.

Mathematically, the EIRR is calculated as the value of the discount rate that satisfies the following formula.

$$0 = \sum_{t=f}^{c+24} \frac{B_t - C_t}{(1 + \mathrm{EIRR})^{t-n}}$$

Where:

- ***c*** is the first full year of operation
- $\mathbf{B_t}$ is the monetised benefits (SEW) induced by the project on year *t* (this includes the Residual Value at the end of the project economic lifetime, when considered)
- $\mathbf{C_t}$ is the sum of CAPEX and OPEX on the year *t*
- ***n*** is the year of analysis (common to all projects)
- ***f*** is the first year where costs are incurred

There are several shortcomings related to the use of the EIRR:

> If the "sign" of the benefits changes in the different years of the assessed time horizon, there may be multiple EIRRs for a single project. In these cases, the indicator will be impossible to implement;

> It is highly sensitive to the assumed economic life: when projects with different economic lives are to be compared, the IRR approach inflates benefits of a short-life project because IRR is a function both of the time period and of the size of the investment incurred;

- It is highly sensitive to the timing of benefits: in case of projects not producing benefits for many years, the EIRR tends to be lower compared to projects with a more "constant" distribution of benefits over time, even though the net present value of the former may be higher;
- It cannot be used with time-varying discount rates.

For all the above-mentioned shortcomings, in case of contrasted results between the ENPV and the EIRR, the ENPV decision rule shall always be preferred.

Annex IV – Recommendation on time horizon and EPI interpolation

For the Economic Performance Indicators and based on CBA results for simulated years, the economic cash flow for each year should be calculated in the following way:

- From the first full year of operation until the next simulated year the monetised benefits should be considered equal to the monetised benefits of the simulated year
- The monetised results as coming from the simulations and used to build the EPI will be **linearly interpolated** between two simulated years (e.g. n+10 and n+15)
- The monetised benefits will be kept constant until the 25th 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 life of 25 years. For example, projects may be commissioned in 2025, 2029 or 2033, their benefits and costs will be considered for the following 25 years but all discounted in the same year (e.g. 2020). Following this approach:

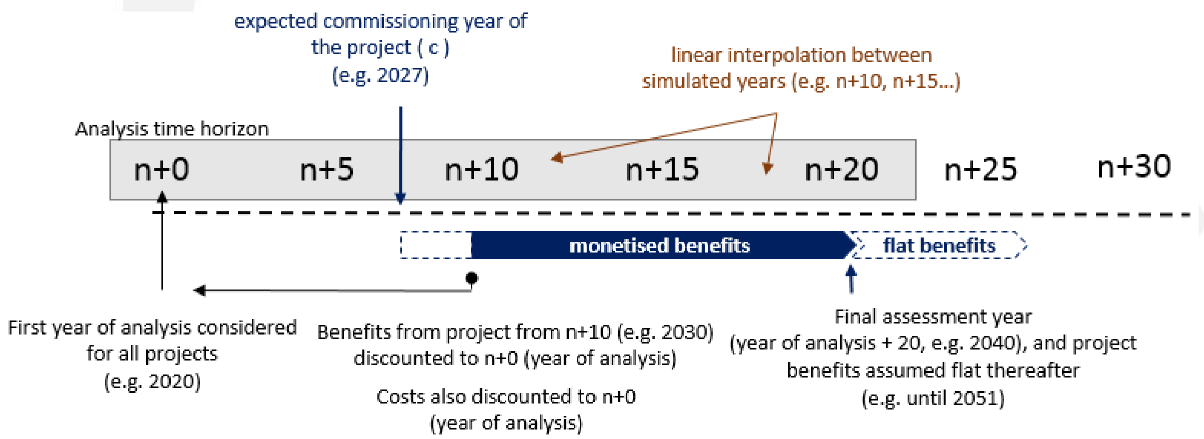


Figure 16 – Representation of economic cash flow assessment in case of projects to be commissioned between two assessed years

Practical example[46]: a project has an economic lifetime of 25 years and it is commissioned only in 2027. The benefits will be computed only until 2040, the last year of the considered time-horizon (n+20) and kept then flat until the 25th year of life of the project (in this example 2051).

[46] This example is based on the same assumptions as the example in Annex II on Residual Value calculations.

The figure below presents calculations for a project with 1,000 Mln of CAPEX (incurred half in 2025, half in 2026), 10 Mln of OPEX per year, a socio-economic discount rate of 4% and with benefits to be accounted during 25 years of economic life from its commissioning date in 2027. The assessment year starts from 2020.
Additionally, the project is considered to have a physical life of 40 years. Therefore, the residual value is calculated at the end of the 25th year of the project.

	-2	-1	0	...	4	5	6	7	...	19	20	21	22	23	24	25	26	...	30	31	32	
	2018	2019	2020	...	2024	2025	2026	2027	...	2039	2040	2041	2042	2043	2044	2045	2046	...	2050	2051	RV	
costs						500	500	10	...	10	10	10	10	10	10	10	10	...	10	10		1,250
benefits								100	...	100	100	100	100	100	100	100	100	...	100	100		2,500
costs (D)	0	0	0	...	0	411	395	8	...	5	5	4	4	4	4	4	4	...	3	3	82	847
benefits (D)	0	0	0	...	0	0	0	76	...	47	46	44	42	41	39	38	36	...	31	30		1,235
NPV (D)	387																					

Table 5 - Example of ENPV calculation for a generic project

In this example, the residual value is about 8% of the CAPEX (82 Mln compared to 1,000 Mln). The ENPV is 387 Mln. The sooner the commissioning date of the project, the higher the ENPV, since the considered reference year is the same for all projects.

For multi-phase projects or group of projects the benefits will be counted according to the year of the first phase/project to be commissioned. This allows to take into account projects or group of projects where the implementation of the first phase/project already brings benefits and contributes as the enhancers to the other phases/projects of the group.
Furthermore, in case of the assessment of multi-phase projects or group of projects the residual value (when considered) of each phase/project should be indicated accordingly to the commissioning year of the considered phase/project.

A table representing both the situation of a single phase and a multiphase project is given below.

TYNDP-horizon	n+0	…	n+4	n+5	n+6	n+7	…	n+16	…	n+24	*Constant benefit*			*Input for residual value (yrs.)*
Economic cash flow	**Single phase project**			**c**	c+1	c+2	…	c+11	…	c+15	c+16	…	c+24	**25**
	Multiphase project – Phase 1			**c**	c+1	c+2	…	c+11	…	c+15	c+16	…	c+24	**25**
	Multiphase project – Phase 2					**c**	…	C+9	…	C+13	C+14	…	C+22	**23**
				Common time horizon of 25 years of operation for EPI calculation *For multi-phase projects the Time Horizon for the whole project ends with the 25 years of operation of the first phase/commissioned project*										

(*) n is the first year of analysis
(**) c is the commissioning year
(***) number of years of operation to be considered for the depreciation of the asset in the calculation of the Residual Value

Table 6 – Illustration of the economic cash flow assessment

At the same time, in order not to overestimate the benefits and in line with chapter 3.5, a sensitivity analysis on the commissioning year should be considered, starting this time by taking into account the benefits from the full operational year of the last phase/project to be commissioned. In this way, the total benefits, when discounted, will be lower since happening further in the future. This allows to take into consideration the situation where the first phase/project are enablers of the other phases/project of the group and the benefits do not appear before the full implementation of the project/group of projects.
Continuing with the example above this time we start calculating the benefits of the overall project from the commissioning year of the last phase to become operational. Therefore, benefits stemming from the realisation of the first phase will be considered from c+2.

TYNDP-horizon	n+0	…	n+4	n+5	n+6	n+7	…	n+20	*Constant benefit*				*Input for residual value (yrs.)*
Economic cash flow	**Multiphase project – Phase 1**			c	c+1	c+2	…	c+15	…	c+19	…	C+26	**27**
	Multiphase project – Phase 2					**c**	…	C+13	…	C+17	…	C+24	**25**

(*) n is the first year of analysis
(**) c is the commissioning year
(***) number of years of operation to be considered for the depreciation of the asset in the calculation of the Residual Value

Table 7 – Illustration of the economic cash flow assessment in case of calculation based on the commissioning year of the last phase to become operational

CONTACT

Should you require any further information please contact

Mr Stefano Astorri Investment Subject Manager (Stefano.Astorri@entsog.eu)

Mr Laurent Percebois Market Adviser (Laurent.Percebois@entsog.eu)

with always in copy

Ms Carmel Carey Communication Adviser (ENTSOG.Communication@entsog.eu)

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

Co-Authors: Stefano Astorri, Laurent Percebois, Céline Heidrecheid, Louis Watine,
ENTSOG INV WG

Cover picture: Courtesy of Enagás

ENTSOG AISBL

Avenue de Cortenbergh 100
1000 Brussels, Belgium
Tel. +32 2 894 51 00

info@entsog.eu
www.entsog.eu