4th ENTSO-E Guideline

for cost-benefit analysis of grid development projects

Final version approved by the European Commission

15 YEARS OF
entsoe
ELECTRIFYING EUROPE

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The **40 member TSOs**, representing 36 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the inter-connected power system in all time frames at pan-European level and the optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources. ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with climate objectives and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility**.

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with transparency and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its **legally mandated tasks**, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (**Ten-Year Network Development Plans, TYNDPs**);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

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Foreword

This document presents the fourth version of the ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (short: 4th CBA Guideline).

This updated guideline is the result of ‘learning by implementing’ and considering stakeholder suggestions over a one-year development process initially based on the 3rd CBA Guideline. During this period, Member States and National Regulators were consulted, following which the guideline was submitted for the official opinion of the Agency for Cooperation of Energy Regulators (ACER) and the European Commission (EC).

The Regulation (EC) 2022/869 on guidelines for trans-European energy infrastructure (‘TEN-E Regulation’) mandates that ENTSO-E drafts a European Cost Benefit Analysis (CBA) guideline by 24 April 2023, which shall be further used for the assessment of the Ten-Year Network Development portfolio.

The first official CBA Guideline drafted by ENTSO-E was approved and published by the EC on 5 February 2015, and the 2nd official CBA Guideline drafted by ENTSO-E was approved by the EC on 27 September 2018 and published by ENTSO-E on 11 October 2018. The 3rd CBA Guideline was submitted to the EC on 27 October 2022 for approval.

The first edition of the CBA Guideline was used by ENTSO-E to assess projects in the Ten-Year Network Development Plan (TYNDP) 2014 and 2016. ENTSO-E registered the impact of the TYNDP project assessment results on the European Commission Projects of Common Interest (PCI) process. This experience demonstrated the need for a better guideline that enables a more consistent and comprehensive assessment of pan-European transmission projects.

The 2nd CBA Guideline has a more general approach than its predecessor and assumes that the project selection and definition, in addition to the scenario’s description, is within the frame of the TYNDP and, therefore, not defined in the assessment guideline in detail. With this approach, ENTSO-E aims to develop a CBA Guideline that can be used for one TYNDP as well as including strong principles that will stand for a longer period. The 2nd CBA Guideline has been used by ENTSO-E to assess project benefits in the TYNDP 2018. However, although improvements were included in the 2nd CBA Guideline, some so called ‘missing benefits’ were added to the TYNDP 2018 in addition to that which is defined in the 2nd CBA Guideline. This, together with the constant efforts of ENTSO-E to improve the CBA Guideline, highlighted the need for a 3rd version of the CBA Guideline.

The 3rd CBA Guideline contains improved methodologies for already existing indicators and an introduction of new indicators. Among these, some new indicators stem from the lessons learnt from the ‘Missing Benefits’ process established for TYNDP 2018; however, the complexity of some of these new indicators does not enable a Pan-European assessment. For this reason, the 3rd CBA Guideline includes new ‘non-mature indicators’, the nature of which is clarified in **Chapter 3.4**. On 7 November 2017, ENTSO-E began to involve external stakeholders by hosting a public workshop to start the improvements which would lead to a 3rd edition of the CBA Guideline. Subsequently, three work streams under public participation, considering improvements on Security of Supply (SoS), Socioeconomic Welfare (SEW) and Storage Projects, were organised from December 2017 to May 2018. The outcomes from these work streams were considered for the drafting of the 3rd CBA Guideline which was presented at a public workshop on 18 December 2018. In 2019, ENTSO-E focused the work on the improvements on the 3rd CBA Guideline, together with ACER and the EC. The updated draft 3rd CBA Guideline was presented to the stakeholders during the open workshop on 8 November 2019 and released for public consultation on 9 November 2019. The Guideline was officially submitted to ACER on 11 February 2020. On 6 May 2020 ACER delivered their official opinion. ENTSO-E received the partial rejection of the 3rd CBA Guideline from the EC on 24 March 2022 and submitted the revised 3rd CBA Guideline to the EC on 27 October 2022 for approval.

The 4th CBA Guideline follows the main idea and structure of the 3rd CBA Guideline, while including corrections, clarifications, minor updates and some newly introduced concepts. A list of the main changes compared to the 3rd CBA Guideline is given within the ‘Accompanying Documents’ submitted together with the 4th CBA Guideline. Some were already included within the TYNDP 2022 Implementation Guidelines.

Why is the 4th CBA Guideline important?

- It is the only European guideline that consistently allows the assessment of TYNDP transmission and across Europe.
- The outcomes of the CBA Guideline represent the main input for the selection of Project of Common Interest and Projects of Mutual Interests lists under the TEN-E Regulation.
- The European CBA Guideline can also be used as a source for national CBAs.

Contents

1 Introduction

This Guideline for Cost Benefit Analysis of Grid Development Projects was prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) in compliance with the requirements of the EU Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure (referred to as 'the TEN-E Regulation'). This Guideline is therefore the first version that is based on the revised TEN-E Regulation with new requirements on strengthened stakeholder involvement and the need to ensure consistency with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective.

This Guideline is the fourth version of this document produced by ENTSO-E (referred to as the 4th CBA Guideline) and has been improved following the results of an extensive consultation process. The consultation process involved the public, stakeholder organisations, national authorities and their national regulatory authorities, the Agency for Cooperation of Energy Regulators (ACER), and the European Commission (EC), following the requirements as defined in the TEN-E Regulation (Article 11 2.). This updated version of the guideline (version 4.1) was sent to Member States (MS), the EC and ACER on 24 April 2023 following the TEN-E Regulation (Article 11 1.). After receiving the feedback from theses stakeholders, and after having received the official ACER opinion (No 07/2023) on 18.07.2023 ENTSO-E included amendments accordingly and submit the updated guideline (version 4.2) to the EC for approval.

The indicators that have been developed enable a harmonised, system-wide cost–benefit analysis (CBA) of projects. They facilitate a uniform approach in which all projects and promoters (either TSO or third party) are treated and assessed in the same manner.

The guideline's primary use is to describe the projects contained in the ENTSO-E Ten-Year Network Development Plan (TYNDP), including the Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI) that are identified from the list of TYNDP projects. It is also recommended to be used for the cross-border cost allocation (CBCA) process as required by the TEN-E Regulation (Article 16 4.(a)).[1]

The methodologies developed in this Guideline are of general relevance to the electricity industry and may therefore be useful to anyone seeking to assess transmission investments. Some of the indicators are developed to meet specific requirements of the TEN-E Regulation concerning market integration, security of supply (SoS) and sustainability, including the integration of renewable energy and energy storage among others. Of particular reference, the indicators are designed to comply with Article 4.3(a), Article 11, Annex IV and Annex V of the TEN-E Regulation.

1.1 Scope of the document

The TYNDP process consists of four main processes, illustrated in Figure 1: the building of scenarios, the project collection, the identification of system needs, and the CBA. This complies with the TEN-E Regulation, which requires projects to be assessed under different planning scenarios, each of which represents a possible future development of the energy system. Although project costs are scenario independent, the benefits strongly correlate with scenario-specific assumptions. Therefore, scenarios that define potential future developments of the energy system are used to gain insight into the future benefits of transmission projects.

A system-needs assessment determines the impact of those scenarios on the transmission system, identifying network bottlenecks and additional investment needs. This requires network power-flow, stability and market analyses.

This document aims to provide guidance for how to perform

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[1] Additional information can be found at the ENTSO-E's TYNDP website.

the last step: an energy system-wide CBA. Only where needed for the understanding of this CBA Guideline is general information on the other steps given, whereas more detailed information and guidance about the other processes can be found on ENTSO-E's website.

Figure 1: Overview of the assessment process inside the TYNDP and for identifying PCIs and PMIs

The aim of the 4th CBA Guideline is to deliver general guidance on how to assess projects from a CBA perspective. The Guideline describes the ENTSO-E's criteria for performing CBA in addition to the common principles and methodologies used in the necessary network studies, market analyses and interlinked modelling methodologies. Because of this general approach which allows for the application to different studies, not all study-specific details and requirements can be described in detail within the scope of this document. In addition to the 4th CBA Guideline, study-specific complementary Implementation Guidelines require publishing along with the respective TYNDP study, containing all relevant input data, data sources and assumptions utilised in the CBA implementation. An overview of the required complementary information, provided within the implementation guidelines and other documentation within the TYNDP, is given in Section 1.3. The implementation guidelines for the respective TNYDP will be part of the TYNDP package and will therefore also be publicly consulted on.

To ensure a full assessment of all transmission benefits, ENTSO-E applies a multi-criteria approach to describe the indicators associated with each project. To the extent possible the indicators are monetised, where this is not possible for justified reasons, indicators are quantified in their typical physical units (i. e. tons or GWh). The set of common indicators contained in this guideline form a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP as well as for project portfolio development in the PCI selection process.[2]

As the TYNDP is a continuously evolving process, this document will be reviewed periodically, in line with prudent planning practice and further editions of the TYNDP, or upon request (as foreseen by Article 11.13 of the TEN-E Regulation).

1.2 Overview of the document

This CBA Guideline uses a modular approach to enable more efficient updates of the Guideline and to allow stakeholders to better focus on specific content without necessarily going through the whole document.

To enable the modular approach, the 4th CBA Guideline is structured into six main chapters, supported by a number of detailed sections. Chapter 5 presents the indicator-specific information and provides a full description of all the indicators. It describes the methodology to be used and defines the principles and the requirements to properly assess the relevant indicator. Chapter 6 contains additional methodologies used in the CBA assessment but is not indicator-specific. The application for the TYNDP is further supported with supplemental implementation guidelines that will be provided separately.

Chapter 1 introduces the Guideline and provides a context to the indicators that have been developed for use in CBA.

Chapter 2 discusses general approach matters. This includes, among others, a discussion regarding scenarios and study horizons, cross-border and internal projects, reference network descriptions, and sensitivities.

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[2] It should be noted that the TYNDP does not select PCI projects. Regulation (EU) 2022/869 (art 4.5) states that 'each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria […] this assessment shall lead to a ranking of projects for internal use of the Group. Neither the regional list nor the Union list shall contain any ranking, nor shall the ranking be used for any subsequent purpose.'

A detailed description of the overall assessment, including the modelling assumptions and indicator structure, is given in Chapter 3. A general overview of the indicators is given in Section 3.3. This set of common indicators forms a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP and for project portfolio development in the PCI selection process.[3]

Chapter 4 concludes and provides a summary of the aim of the 4th CBA Guideline.

The benefit indicators, costs description and residual impacts are described in detail in Chapter 5. In Chapter 6, the details of the main concepts of the methodologies that are not indicator-specific are explained.

1.3 CBA Implementation Guideline and other complementary documents

As the CBA Guideline is a general guidance document for the assessment of projects, it would be impractical to include detailed methodologies, parameters or specific assumptions for the calculation of each indicator were in this document. Therefore, the CBA Guideline needs to be complemented by additional detailed information on how the simulations are to be performed. This additional information requires publishing within the respective TYNDP study and shall specify which method is to be used in the event the CBA Guideline allows for more than one possibility, as well as how to interpret the rules defined in the CBA Guideline.

For the CBA phase of the TYNDP process, Implementation Guidelines will be prepared that contain all of the necessary details required to calculate the indicators, considering the modelling possibilities and assumptions that can be applied in the relevant TYNDP. Together with the Scenario Report (where all the scenario-specific details not defined in the 4th CBA Guideline are given) and the Implementation Guideline, the CBA Guideline provides an exhaustive guidance on how to perform the project specific assessment within the TYNDP process. The Implementation Guidelines is considered a part of the TYNDP package, and will therefore be publicly consulted on, together with the rest of the package, every other year.

Table 1 contains a summary of details for certain indicators to be defined in complementary documents, which focus on the TYNDP process. If applied to other studies, these details must also be given within the respective study.

Indicator or rule	Information required to be provided
Defined in Implementation Guidelines	
Security of supply loop	Methodology to calibrate the adequacy of the scenarios before CBA assessment phase of TYNDP projects
Impact of third-countries	Method to remove the effects of non-European countries from the pan-European results and overview of the general perimeter used for the simulations and CBA evaluation
Assessment of commissioning years	Detailed explanation of the methodology and definition of needed parameters; the outcome of this assessment has to be given in the project sheets
Market simulations	Value of hurdle cost to be used Number of climate years to be used Sectors to be included in the simulations
Network simulations	Mapping the market results to the network model (nodal level) Load-flow method to be applied with explanation (whether AC or DC, year round or specific point in time)
Sensitivities	The applied sensitivities together with an overview of the assessment framework that are being applied (e. g. climate years, scenarios etc.) List of projects to which the respective sensitivities are being applied Motivation with explanation on the choice of the respective sensitivities

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[3] It should be noted that the TYNDP does not select PCI projects. Regulation (EU) 2022/869 (art 4.5) states that 'each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria […] this assessment shall lead to a ranking of projects for internal use of the Group. Neither the regional list nor the Union list shall contain any ranking, nor shall the ranking be used for any subsequent purpose.'

Indicator or rule	**Information required to be provided**
Transfer Capability Calculations	Steps of the NTC calculations process including for each step: input, modelling tools and output. The method for the selection of critical branches and critical outages For each project: the information whether power shift or load shift has been used For each project: the tool used for the calculation. For each project: information on whether year-round calculations or PiT have been used Information on the usage of TRM and TTC. Percentile value used as a threshold.
Geographical scope	An overview of the geographical scope on which the costs and benefits are applied needs to be given, e. g. how costs and benefits in non-EU MS are being considered and in- or excluded from the final results
B1. Socioeconomic Welfare	Method for reporting the part of SEW from fuel savings due to the integration of RES (SEW–RES) and the avoided CO_2 cost (SEW–CO_2) In the event of redispatch simulations, a detailed description of the methodology used. For each project: the methodology used to assess each project
B2. CO_2 Emissions	Societal cost to be used.
B3. RES Integration	How to report avoided RES spillage (dump energy) from the market simulation results.
B4. Non-direct greenhouse Emission	List of emission types and factors per generation category, with references or calculation details
B5. Variation in Grid Losses	Monetisation of losses on HVDCs between different market nodes Assumption to apply for the compensation of partial double counting with SEW Number of climate years to be used Information regarding whether points in time were used and the specific points in time used
B6. SoS – Adequacy to Meet Demand	Method for introducing peaking units in TOOT cases Definition of which sanity check method is to be used Details of the treatment of strategic reserves Details of Monte-Carlo approach Value of VOLL and CONE
B7.1 SoS – System Flexibility Benefit	Description of the methodology of how the qualitative indicators are defined
B8.1 Frequency stability	Detailed motivations and a clear descriptions of the chosen system splits, together with the formula and all relevant parameters for the RoCoF calculation
B8.2 Black start services*	Definition of the necessary assumptions
Project Costs	Definition of the costs delivered within the project sheets
CAPEX	Table of standard costs
OPEX	Definition of a yearly percentage of CAPEX for non-mature investments
Investment value calculation	The assessment period and real discount rate could be confirmed or updated with respect to what is indicated in the CBA Guideline
Sanity check for hybrid and radial projects assessment	Detailed methodology on how to apply the sanity check
Definition of what RES includes	To be applied for the calculation of B3 and the RES penetration ET3
Project Sheets	The content of the project sheet should be defined in the Implementation Guidelines
Storage	Information on how storage projects are modelled
Climate adaptation measures	Guidance on the reporting of cost of climate adaptation measures
Defined in Documentation of the respective study	
Simulation tools used to perform the assessment	List of tools used for Market, Network and Redispatch simulations For each project: tool(s) used to perform the calculation
Transfer Capability Calculations	Links to the databases used in the calculations
Database	Description of the main databases used for the CBA assessment
Defined in Reference network	
Specific document on the reference grid and Implementation Guidelines	Definition of the reference grid together with a justification for the chosen reference grid/s List of all projects within the reference grid Treatment of interdependent projects

* Or given by the project promoters

Table 1: Summary of indicators for which complementary documents are to be defined.

2 General approach

The general approach used to assess projects considers the following:

- **The range of future energy scenarios and study horizons;**
- **Internal and cross-border considerations;**
- **The modelling framework to be used in undertaking the analysis;**
- **The identification of a reference network used to assess the impact of the reinforcement against;**
- **The use of multi-case analysis to simplify analysis; and**
- **The approach to sensitivity studies.**

These are discussed in detail below.

2.1 Scenarios

Regulation (EU) 2022/869 states that ENTSO-E is required to use scenarios as the basis for the TYNDP and for the calculation of the CBA. The revised TEN-E Regulation introduces scenario guidelines to establish criteria for a transparent, non-discriminatory and robust development of scenarios. It requires that the scenarios are fully in line with the energy efficiency principle and with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objective taking into account the latest available Commission scenarios as well as, when relevant, the national energy and climate plans The scenarios are a description of plausible futures that can be characterised by: a **generation portfolio**; a **demand forecast** and power **exchange patterns** between the study region and other power systems. They provide the framework which the future is likely to occur within, but do not attach a probability of occurrence to them. The scenarios represent a means of addressing future uncertainties and the interactions between those uncertainties. Some TYNDP scenarios have a stronger national focus while others, called deviation scenarios, are there to capture uncertainties based on the trajectories of storylines. There is no right or wrong, likely or unlikely option; all scenarios have to be treated equally and, because of the uncertainties of the future energy sector, no scenario can be defined as a 'leading scenario'.

The objective of using scenario analysis is to construct sufficiently contrasting future developments that differ enough from each other to capture a plausible range of possible futures that result in different challenges for the grid. These different future developments can be used as input parameter sets for subsequent simulations.

The scenarios are constructed at the level of the European electricity system and can be adapted in more detail at a regional level. When constructed, the scenarios must reflect both European and national legislation that is in force at the time of the analysis and its effect on the development of these elements. The scenarios are, when possible, derived from official EU and Member-State data sources and are intended to provide a quantitative basis for the infrastructure investment planning. The scenarios need to comply with the requirements of the revised TEN-E Regulation as regards both the energy and climate targets and the energy efficiency principle.

One of the key principles of the EU energy policy is the Energy Efficiency First principle. Considering this principle in the scenarios will help implement it in products that build upon these scenarios. The scenarios are constructed so that they align with the energy efficiency targets as they are defined in the Energy Efficiency Directive (EU) 2018/2002 (EED). This can, for example, be observed in the level of energy demand. The scenarios aim to be in line with the final energy levels as defined in the EED or based on the latest figures available when the scenario project freezes the data.

As mentioned above, certain scenarios are strongly linked to national trends, which means that the scenario is built based on the National Energy and Climate Plans (NECP) from MS or based on national strategies if the latter is more up to date compared to NECP. All information related to the scenario building process are always detailed in the scenario report. According to the (EU) regulation 2018/1999, MS are required to establish a ten-year integrated NECP for 2021–2030, outlining how it intends to contribute, inter alia, to the 2030 target for energy efficiency. The EED states that MS should consider the Energy Efficiency First principle for all sectors and technologies defined and should be a part of the NECP. Consequently, the Energy Efficiency First principle is indirectly implemented via using the NECP inputs for the national trends scenarios.

For the deviation scenarios, the Energy Efficiency First principle is one of the high-level drivers and it is reflected within the demand forecast tool. Moreover, by implementing flexibility options such as DSR, V2G, storages and batteries within the scenario models, the energy reduction will be further helped.

The RES targets are set in the scenarios. Due to their property transmission projects cannot hamper pre-set RES investments, since there is no natural competition between them. A transmission project enables more RES integration which is clearly reflected in the B3 indicator. Thus, transmission projects should be seen as complementary to RES facilitating RES integration.

It is also to be noted that the CBA phase is based on adequate scenarios. If scenarios are not found adequate, a Security of Supply loop (described in the implementation guidelines) should be considered before the CBA phase.

Detailed information on the joint ENTSOG and ENTSO-E scenarios can be found in the respective scenario reports.[4]

2.2 Study horizons

Scenarios can be distinguished depending on the time horizon, as illustrated in Figure 2, and can be described as follows:

- Mid-term horizon (typically 5 to 10 years): mid-term analyses should be based on a forecast for this time horizon;
- Long-term horizon (typically 10 to 20 years): long-term analyses will be systematically assessed and should be based on common ENTSO-E scenarios.
- Very long-term horizon (typically 30 to 40 years). Analysis or qualitative considerations could be based on the ENTSO-E 2050-reports; and
- Horizons which are not covered by separate data sets will be described through interpolation or extrapolation techniques.

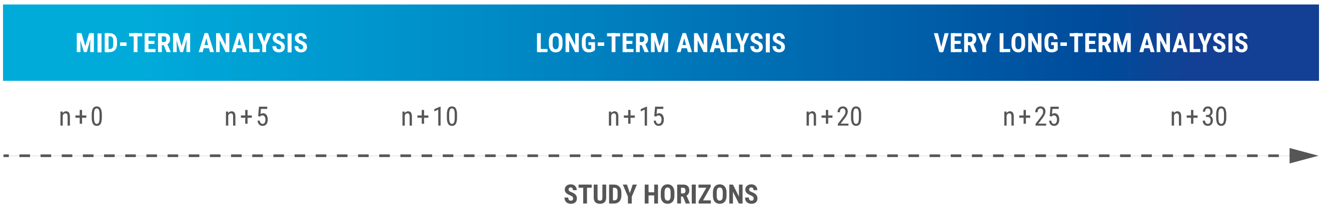

Figure 2: Continuous timeline with future study years and corresponding study horizons.[5]

As shown in Figure 2, the scenarios developed for the long-term perspective may be used as a bridge between the mid-term horizon and the very long-term horizon (i. e. n+20 to n+40). The aim of the perspectives beyond n+20 should be that the pathway realised in the future should fall within the range described by the scenarios with a reasonable level of likelihood.

The scenarios on which to conduct the assessment of the projects will be given for fixed years and rounded to full five years (e. g. 2025 instead of 2023 for n+5 in TYNDP 2018). For the mid-term horizon, the scenarios must be representative of at least two study years. For example, for the TYNDP 2020, the study years of the mid-term horizon are 2025 (n+5) and 2030 (n+10).

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[4] See **here**.

[5] There is no strict definition of the beginning and end of the horizons, and an overlap might appear, indicated by the gradual colour gradients used in the figure.

2.3 Cross-border versus internal projects

Assessing projects using only the impact on the transfer capacities across certain international borders can lead to an underestimation of the project-specific benefits as most projects also show significant positive benefits that cannot be covered by only increasing the capacities of a certain border. This effect is the strongest for, but not limited to, internal projects.

Internal projects do not necessarily have a significant impact on cross-border capacities, which makes it difficult to assess them using market simulations that consider only one node per country without a flow-based model.

Both internal and cross-border projects can be classified as having pan-European relevance. However, they all develop grid transfer capability (GTC) over a certain boundary, which may, or may not, be an international border (and sometimes several boundaries).

Depending on the types of project, a suitable method should be used. At this point, it is recognised that there is no unified method available that can address the specific aspects of all these projects adequately. Therefore, three alternative methods are given for the calculation of the benefits:

- Market simulations;
- Network simulations; and
- Redispatch simulations

Although these different alternatives exit, consistency across the methodologies is ensured thanks to the fact that they are all based on the same scenarios and even more, for each time horizon any type of CBA assessment starts with a same reference grid market simulation.

Both market and network simulations provide different types of information; they generally complement one another so they are frequently used in an iterative manner. These methods are discussed in detail in the following chapter.

2.4 Modelling framework

As the indicators described in Chapter 5 generally rely on different principles, they also need to be achieved under the use of different models. An overview of these models, i. e. **Market simulations**, **Network simulations** and **Redispatch simulations**, is given in this section.

It should be noted that most of the indicators can be achieved using more than one of the described models; this information will be given in an overview table at the end of the respective indicator.

2.4.1 Multi-sectorial market simulations

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

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

Projects that introduce mutual influences across sectors can undergo a multi-sector or multi-system CBA assessment. This guideline pursues a general approach to performing multi-sector CBA assessments. Without any limitation, any sector and/ or multiple sectors can be included. Sectors either represent energy carriers or end-use sectors associated with energy carriers comprising transport, industry or building sectors. Details on the sector inclusion will be drafted in the respective TYNDP Implementation Guidelines.

2.4.2 Power market simulations

Power market simulations incorporate solely the electricity sector. They can be considered a special case of multi-sectorial market simulations. Interactions with other sectors can be modelled exogenously. Power market simulations are used to calculate the cost-optimal dispatch of generation units. This is done under the constraint that the demand for electricity is fulfilled, considering demand-side response (DSR), in each bidding area and in every modelled time step.[6] In addition to the dispatch of generation and demand (if modelled endogenously), power market simulations also compute the market exchanges between bidding areas and corresponding marginal costs for every time step.

The simulations consider several constraints, such as:

- The flexibility and availability of thermal generating units;
- Hydrologic conditions impacting hydro generating units;
- Wind and solar generation profiles;
- Load profiles; and
- The occurrence of outages.

Power market simulations are used to determine the benefits of providing additional capacity, enabling more efficient use of the generation units available in the different locations across the bidding areas. They facilitate the measurement of savings in generation costs as a result of the investments in grid projects. The results of power market simulations, therefore, enable the computations of some of the indicators specified in this guideline.

The output of the power market simulations, i. e. the defined generation, consumption and power flowing across the transmission grid, is subsequently used as an input to the network simulations.

Different options represent the transmission network in market models, namely:

Net transfer capacity (NTC)-based market simulations

Bidding areas are represented as a network of interconnected nodes, connected by a transport capacity that is available for market exchanges using a simplified NTC model of the physical grid. These NTC values represent an approximation of the potential for market exchanges using the physical (direct or indirect[7]) interconnections that exist between each pair of bidding areas. Thus, the market studies analyse the cost-optimal generation pattern for every time step under the assumption of perfect competition.

Flow-based market simulations

Flow-based market simulation is a more complex and more granular approach for market simulations. In this approach, market exchange capabilities are represented by their real implication in physical transfer capacities in the meshed transmission grid. Flow-based market simulations consider the relationships between each potential market exchange and their corresponding utilisation of the physical grid capacities (cross-border as well as internal grid). Flow-based market simulations, therefore, use a representation of physical grid capacities (GTCs) to define the market exchange constraints rather than a set of independent NTC values.

2.4.3 Power network simulations

Power network simulations utilise models that represent the power transmission network in a high level of detail. They are used to calculate the power flowing on the power transmission network for a given generation–load–market exchange condition. Power network simulations enable the identification of bottlenecks in the grid corresponding to the power-flows resulting from the market exchanges.

The results of the power network simulations allow the computation of some of the indicators contained in this Guideline.

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[6] Typically, market simulations apply a one-hour time step, which is in accordance with the time step used in most electricity wholesale markets. However, this CBA Guideline is independent from the chosen time step.

[7] In general, the market flow is different from the corresponding physical flow, as getting the trading capacities e. g., ring flows, do not need to be considered. The important information is the trading capacity between two markets.

2.4.4 Redispatch simulations

Redispatch simulations compute the costs of alleviating constraints on the transmission network, identified by network simulations taken from market simulations, by adjusting the initial dispatch of generation. This is done while observing the same power plant-specific constraints that are applied to the market simulations, such as the minimum up- and down-times, ramp rates, must-run obligations, variable costs, etc. Redispatch simulations can, therefore, be considered a combination of both network and market simulations delivering the same indicators as the latter.

Redispatch simulations assist in the computation of indicators contained in this Guideline. They particularly relate to the evaluation of projects using the initial generation dispatch from NTC-based market simulations as a starting point.

More details on how to perform redispatch calculations are provided in Section 6.3 Redispatch simulations for project assessment.

2.4.5 Multi-case analysis

System planning simulations are conducted using the results of market simulations as an input. The network simulations produce load flow calculations for each time step for which the market simulations produce their results, typically hourly.

To simplify the volume of network calculations, network simulations may group results from several time steps into one planning case. This can only be done if the hours that are grouped together are sufficiently similar regarding the generation dispatch, load dispatch and market exchange within the area under consideration. These results for each planning case are then considered as representative for all the time steps linked to it.

It is crucial that the choice of planning cases and the time steps they represent are adequate, i. e. that the planning cases selected out of the available cases for each time step adequately represent the year-round effect. The process of obtaining a representative set of planning cases depends greatly on the combination of dispatch, load, exchange profiles, and especially on the availability profiles for variable RES.

2.5 Reference network

The reference network is the version of the network used to calculate the incremental contribution of the projects being assessed, and is used as the starting point for the computation. The reference network is therefore constituted of the already existing grid, and the projects that have a strong probability of being implemented by the dates considered in the scenarios.

To determine the incremental contribution of each project, market and network simulations are performed where the project is either included, or removed, from the reference grid (see section 3.2.2.). The results are then compared with the market and network simulations of the reference grid alone.

The incremental benefits would be the difference between the two results, and these are reflected in the indicators contained in this Guideline.

The selection of the projects that comprise the reference network directly impact the calculation of the indicators. Consequently, a clear explanation of which projects are considered in the reference network is required. This should also include an explanation of the initial state of the grid (i. e. the existing grid as defined in the year of the study). The Reference network shall be made available and accessible to the public.

2.5.1 Proof of maturity

A project should only be included in the reference grid when its capacity is available in the year for which a simulation is performed. Hence, only those projects whose timely commissioning is reasonably certain are to be included in the reference network. This can be assessed by considering the development status of the project and including the most mature projects that either:

1. Are in the construction phase; or

2. Have successfully completed the environmental impact assessments; or

3. Are in 'permitting' or 'planned, but not yet permitting', and their timely realisation is most likely (e. g. when the project is supported by country-specific legal requirements or the permitting and construction phase can be assumed to be short, such as for transformers, phase shifters etc.). This requirement can be strengthened by applying further criteria, such as:

   - The project is considered in the National Development Plan of the country where it is expected to be located;
   - The project fulfils the legal requirements as stated in the specific national framework where the project is expected to be located;
   - The project has a defined position with respect to the Final Investment Decision related to its implementation;
   - There is a documented reference to the request for permits;
   - A clearly defined system need, to which a project contributes, could help to identify the reference grid; and
   - Year of commissioning: chosen depending on the year of the study and the scenario horizon used to perform the study.

In general, it is reasonable to define different reference grids for different time horizons. Although the above given maturity criteria can be applied for all time horizons, the reference grid for the first study year of the mid-term horizon has to be based on the criteria given under a) and b). Based on this, the reference grid for the second year of the mid-term horizon and the long-term horizon can be defined by including projects following the criteria as given under c).

In cases where a cross-border project involves countries with different permitting processes and procedures, it would be advisable to use expert evidence-based judgement.

For interdependent projects it may be the case that, based on its respective realisation, one (or more) of the interdependent projects is (are) included in the reference grid although the project(s) it depends on is (are) not. In that case, the standard assessment methodology as described in section 3.2.2 cannot be applied and case-specific applications as also described in the same section need to be applied.

Whatever criteria have been chosen, the proof of maturity, and for interdependent projects additional concrete information on its treatment, needs to be given in the respective study specific Implementation Guidelines. It should also be mentioned that smaller projects (e. g. line upgrades) will most likely need less time to run through the approval process. This has to be considered when defining the reference grid. Ultimately, the reference grid should assume the most probable and realistic grid for the respective time horizon.

2.5.2 Commissioning dates

In addition to the above discussed maturity criteria, the assessment date of the projects also has to be considered when defining the reference grid. For this purpose, it can be assumed that only projects with commissioning dates equal to or earlier than the respective time horizon the reference grid is defined for can become part of the reference grid. As the development of new infrastructure projects is a complex process which might be subject to delays based on several factors, the commissioning dates have to be assessed after the project submission to the respective study. This assessment should not only be applied to possible reference grid candidates (before the reference grid definition) but also to all projects submitted to the CBA assessment. The results of the assessment of commissioning dates have to be used as follows:

1. For all projects falling under the category of reference grid candidates, the commissioning dates need to be agreed between the national TSOs and respective National Regulatory Authorities (NRAs). For this agreement, the result of the assessment of commissioning dates has to be used as additional source of discussion together with the information published in the actual network development plans and/or additional direct agreements between TSOs and NRAs.

2. For all projects submitted to the CBA assessment, the result of the assessment of commissioning dates has to be published within the study-specific project sheets as additional information giving an indication of whether the displayed commissioning date submitted by the project promoters appears realistic. There will be no approval of the commissioning dates or any project rejection based on this assessment. It should be seen as additional information and, in the event of discrepancies, as input for further discussions.

The detailed methodology and definition of parameters for the assessment of commissioning dates has to be given within the study specific Implementation Guidelines and should result in the definition of concrete commissioning dates based on the following principles:

- The starting point for the definition of the commissioning date has to be the year of the respective study
- The time **t** for the duration until projects submitted to the study will be commissioned can be calculated as:

$$t = (t_{pre-perm} + t_{perm} + t_{const}) \times f_1 \times f_2 \times f_3 \times f_4 \times f_5$$

Where:

- $t_{pre\text{-}perm}$ is the assumed mean standard time of all projects for entering the permission period;
- t_{perm} is the assumed mean standard time for the permitting process;
- t_{const} is the assumed mean standard time for the construction phase;
- f_1 is a standard factor indicating the complexity of the project with respect to its technology (AC or DC);
- f_2 is a standard factor indicating the complexity of the project with respect to its setup: whether it is an overhead line, cable, substation etc;
- f_3 is a standard factor indicating the complexity of the project with respect to whether it is an on- or offshore project;
- f_4 is a standard factor indicating the complexity of the project with respect to whether it is a completely new project or an update; and
- f_5 is a standard factor indicating the complexity of the project with respect to the environmental and social impacts of the project (see **sections 5.14**, **5.15** and **5.16**).

The duration times t_x are to be defined dependent on the respective project status (e. g. for projects in the construction phase $t_{pre\text{-}perm}$ and t_{perm} are to be set to zero) and have to consider the length of the projects (e. g. the construction time is assumed to take longer for a long project compared to a short project).

- The result of the assessment of the commissioning date can then be calculated by adding the duration time t to the year of the respective study.

2.6 Sensitivities

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

For its application a sensitivity analysis can be performed to observe how the variation of parameters, either one parameter or a set of interlinked parameters, affects the model results. This provides a deeper understanding of the system's behaviour with respect to the chosen parameter or interlinked parameters. It has to be noted that interdependencies between the below listed sensitivities can occur, e. g. the variation in CO¬2 costs will in general also have an impact on the installed generation units. However, as a robust investigation on these interdependencies can become very complex, this goes beyond the single treatment of sensitivities as addition to the CBA assessment and can instead be treated within specific studies. The aim of a sensitivity analysis is not to define complete new sets of scenarios but quick insights in the system behaviour with respect to single (few) changes in specific parameters. This would also help to better understand the impact of that single (or few) parameter which would not be possible when creating new scenarios based on the possible interdependencies of different parameter.

In general, a sensitivity analysis must be performed on a uniform level, i. e. the sensitivity needs to be applied to all projects under assessment in the respective study. However, in some cases the added value of the sensitivity might be given only for specific projects. In such cases it is, together with a sufficient argumentation within the study specific Implementation Guidelines, reasonable to apply the respective sensitivity only to the relevant projects. In principle, each individual model parameter can be used for a sensitivity analysis to obtain the desired information. Furthermore, different parameters can have a different impact on the results depending on the scenario; therefore, it is recommended to perform detailed scenario-specific studies to determine the most impacting parameters rather than just picking them. **For this purpose, detailed information explaining the criteria and methodologies used to select the parameters to conduct the respective sensitivity analysis must be given within the study-specific Implementation Guidelines.**

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

Fuel and CO_2-Price

A global set of values for fuel prices is defined as part of the scenario development process. A degree of uncertainty regarding these values and prices is unavoidable. Fuel and CO_2-prices determine the specific costs of conventional power plants and, thus, the merit order. Therefore, varying fuel and CO_2-prices impact the merit order, which in turn have an impact on the related indicators required to be reported on as part of this guideline.

New market simulations using the changed prices followed by network simulations have to be performed to properly evaluate this sensitivity.

Long-term societal cost of CO_2 emissions

The cost of CO_2 included in the generation costs may understate (or overstate) the full long-term societal value of avoiding CO_2. Therefore, a sensitivity study could be performed in which the cost of CO_2 is valued at a long-term societal price. To perform this sensitivity without introducing a risk of double-counting with the generation cost indicator, the following process is advised:

1. Derive the delta volume of CO_2;
2. Consider the CO_2 price internalised in the generation cost indicator; and
3. Adopt a long-term societal price of CO_2.

By multiplying the volume arising from (a) by the difference in prices described by (b) and (c), the monetisation of the sensitivity of an increased value of CO_2 can be calculated.

For this sensitivity, there is no adjustment in the merit order or the dispatch for the generation cost indicator for the higher carbon price and it can be applied as ex post calculation.

Climate year

Using different climate data for the creation of different climate years will most likely influence the benefits of a project. For example, the indicator RES-integration depends on the infeed of RES and weather conditions. For this reason, performing an analysis with different climate years would lead to a deeper understanding of how market results depend on weather conditions. This can be used to understand how the indicators are impacted by climatic conditions. For such sensitivity analysis it is recommended to consider extreme climate years (including extreme weather events) in order to cope with the expected climate change in the future.

For each climate year, new market simulations followed by network simulations have to be performed to properly evaluate this sensitivity.

Load

Regarding the development of load, two opposed drivers can be identified. On the one hand, energy efficiency will lead to decreasing load, but on the other hand, an increasing number of applications will be electrified (e. g. e-mobility, heat pumps, etc.), which will lead to an increase in load.

Technology phase-out/phase-in

Due to external circumstances, a phase-out/phase-in of a specific technology (e. g. nuclear or lignite) could occur and lead to a transition of the whole energy system within a member state. Such developments cannot be foreseen and are not considered within the scenario framework and can, therefore, be treated within sensitivity studies.

New market simulations using the changed load profiles followed by network simulations have to be performed to properly evaluate this sensitivity.

Must-run

If thermal power plants provide electrical power and heat, then thermal power ‘must-run’ boundary conditions are used in market simulations, i. e. these power plants cannot be shut down and have to operate in specific time frames, and at a minimum level, to ensure heat production. By assuming different must-run conditions for conventional power plants, market results will differ.

New market simulations using the changed must-run profiles, followed by network simulations, have to be performed to properly evaluate this sensitivity.

Installed generation capacity (including storage and RES)

The volume of installed generation capacity is defined within the scenarios. However, it may be, as past political discussions and decisions have shown, that changes to single generation categories such as coal or nuclear phase out can have an impact on the possible future scenarios also at relatively short notice. Furthermore, amendments to the national or EU-wide RES goals could lead to dominant impacts on the results of the CBA assessment. For this sensitivity, it is crucial to not overdo the changes in the generation portfolio, and it is advised to only change one generation category for each sensitivity – more fundamental changes would instead lead to the definition of new scenarios. If the changes in generation capacity would lead to unrealistic high or low adequacy levels, additional single measures could be applied carefully to reach reasonable adequacy levels in the respective sensitivity.

Sensitivity studies in which the installed RES capacity is varied could be performed to assess the impact of a delay or an advancement of RES capacity delivery on the indicators contained in this Guideline.

New market simulations using the changed capacities, followed by network simulations, have to be performed to properly evaluate this sensitivity.

Flexibility of demand and generation

This sensitivity needs to be clearly demarcated from B7 flexibility indicator, as here it is not the general system flexibility that is of interest. Flexibility in the context of this sensitivity must be understood as the change in possible flexible generation dispatch dependent on pre-defined demand and vice versa. This sensitivity could include the change in the behaviour of DSR or how electrolysers are modelled.

New market simulations using the changed DSR and electrolyser modelling followed by network simulations have to be performed to properly evaluate this sensitivity.

Availability of storage

The volume of installed storage capacity is defined for each scenario, and its variation as sensitivity is described under 'Installed generation capacity'. Sensitivity studies in which the availability of storage is varied could be performed to assess the impact of uncertainties to any future change of storage technologies, such as increased efficiency for batteries. It must be noted that a change in the availability of hydro storage needs to be discussed, together with the 'climate year' sensitivity.

New market simulations using the changed availabilities, followed by network simulations, have to be performed to properly evaluate this sensitivity.

The commissioning date of various projects

The projects to be assessed and the commissioning date related to these are information provided by project promoters during the data collection process. However, the timely commissioning of projects might be delayed due to several reasons (e. g. longer permitting phase, unexpected incidents while construction etc.). In the case of projects being in the reference grid of the study, this delay might result in the need to also adjust the reference grid. As delayed commissioning years are hard to predict in advance, such a sensitivity analysis could bring additional information. Whereas the variation of the commissioning year might directly impact the definition of the reference grid, it can also have an impact on the order of interdependent projects (assessed using the sequential TOOT/PINT application – see section 3.2.2).

New market simulations using the sequential assessment and/or an updated reference grid, followed by network simulations, have to be performed to properly evaluate this sensitivity.

Different assumptions in project specific data

In general varying the project specific data can have impacts on the assessment of the project but also on the assessment of other projects. Under this sensitivity only the pure project specific impacts will be considered and will mainly impact the investment value calculation as described in section 3.2.5 – the impact of assessing the commissioning years, that would impact the assessment of other projects, is given in a separate sensitivity.

Project specific sensitivities can be:

- Cost variation in both OPEX and CAPEX
- Applying different discount rates and residual value
- Variation of the assessment period

In any case, whatever project specific sensitivity will be applied, it needs to be clearly and transparently displayed and explained how it has been applied together with a clear argumentation for this choice.

Post process applied to the investment value calculation (section 3.2.5)

3 Project assessment

This chapter discusses the 'multi-criteria and cost benefit analysis' approach to be taken in the assessment of projects. It establishes a methodology for the clustering of investments into projects,[8] explains the TOOT and PINT approach, defines each of the cost and benefit indicators, and the project assessment required for each indicator.

ENTSO-E recognises that the primary goals of any project assessment method are:

- Transparency: the assessment method must provide transparency in its main assumptions, parameters and values.
- Completeness: all relevant requirements and indicators (reflecting EU energy policy, as outlined in Art. 4 and 11 as well as the criteria specified in annexes IV and V of the TEN-E Regulation) should be included in the assessment framework.
- Credibility/opposability: if a criterion is weighted, the unit value must stem from an external and credible source (international or European reference).
- Coherence: if a criterion is weighted, the unit value must be coherent within the area under consideration (Europe or Regional Group).

3.1 Multi-criteria and cost benefit analysis assessment

ENTSO-E favours a combined multi-criteria and CBA assessment that allows for a project evaluation based on the most robust indicators, preferably monetary values if an applicable and coherent unit value exists on a European-wide level. As stated in the EC Guide to Cost-Benefit Analysis of Investment Projects, Economic appraisal tool for Cohesion Policy 2014–2020 (2014): **'In contrast to CBA, which focuses on a unique criterion (the maximisation of socio-economic welfare), multi-criteria analysis is a tool for dealing with a set of different objectives that cannot be aggregated through shadow prices and welfare weights, as in standard CBA.'** This approach allows for a homogenous assessment of projects that is capable of supporting a comparison of those costs and benefits that can be monetised in the form of a conventional CBA, while recognising that other material benefits also exist that are not quantified.

The assessment includes both qualitative assessments and quantified and monetised assessments to ensure that the costs and benefits are represented, the characteristics of a project are highlighted and sufficient information to decision makers are provided. Such an approach recognises that, in this context, a fully monetised approach is not practically feasible as certain benefits and criteria specified in Annex IV and V of the TEN-E Regulation cannot be economically quantified in an objective manner. Examples of such benefits include:

- System safety and environmental impacts;
- High Impact Low Probability events, such as 'disaster and climate resilience' (multiplying low probabilities and very high consequences have little meaning);
- Other benefits may have no applicable monetary value today;
- Some benefits have applicable values at a national level, but no common value exists in Europe. This is the case with, for instance, the Value of Lost Load (VOLL), which depends on the structure of consumption in each country (tertiary sector versus industry, importance of electricity in the economy, etc.).

Some benefits (e. g. CO_2) are already partially internalised (e. g. in socioeconomic welfare). Displaying a value in tons provides additional information.

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[8] In general, a project can consist of only one investment. Obviously in this case no clustering rule needs to be applied.

Most indicators associated with the costs and benefits indicators are monetised and displayed in Euros. Other indicators are displayed using a calculated value in the most relevant and appropriate units of measure. By considering all the indicators described by the multi-criteria approach, comprising both monetised and non-monetised, the full benefit of a project can be described.

This approach also recognises that the importance of each indicator might be project specific, i. e. the main aim of one project might be to significantly integrate large amounts of RES into the grid, whereas the main focus of another project may be an increase in the SoS by means of connecting highly flexible generation units. In both cases, the monetised benefits (determined by the monetised indicators) may be the key driving indictors for making an investment decision, but they may not be the only ones.

Figure 3 displays a simplified overview of the entire project assessment process resulting in the set of CBA market and network indicators described in this Guideline.

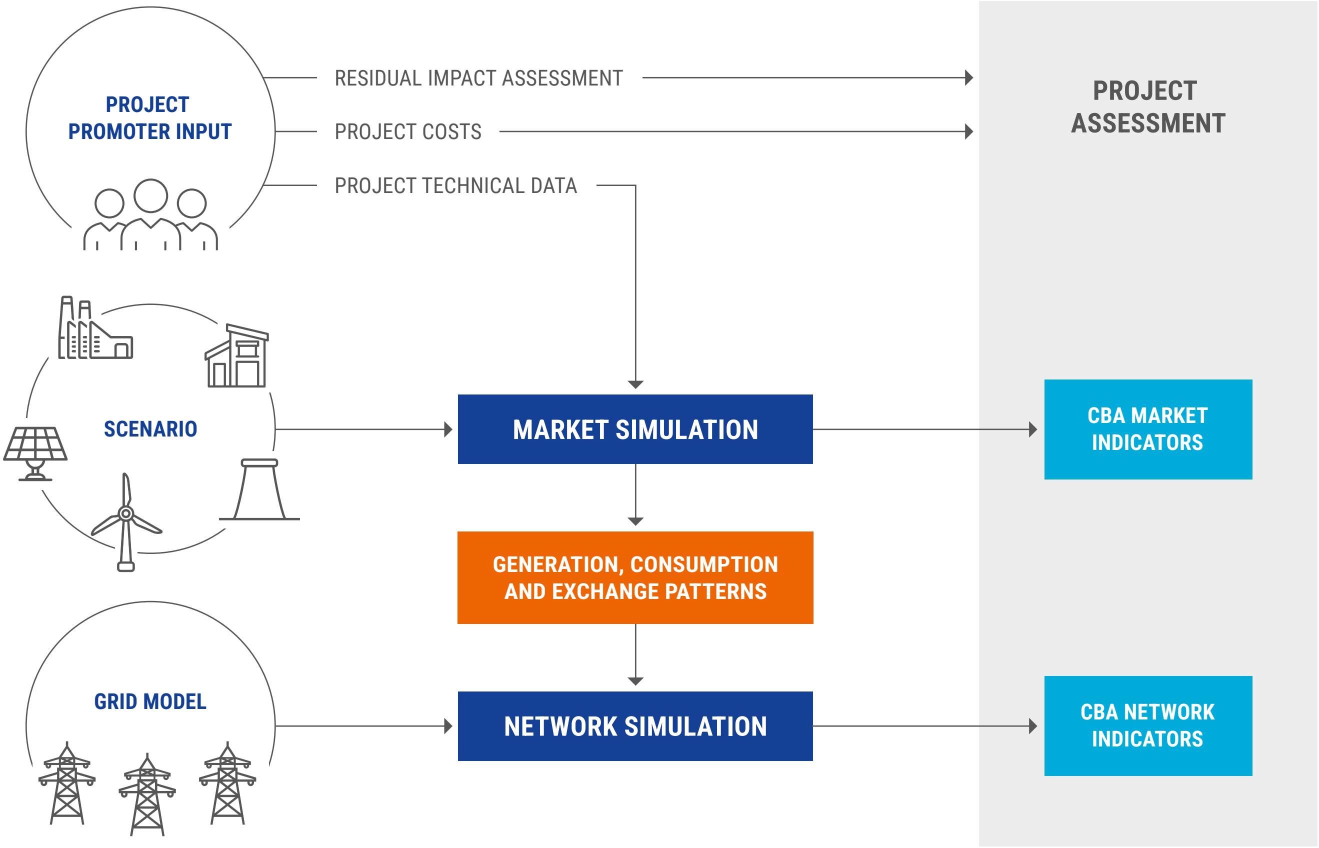


Figure 3: Schematic project assessment process. Whereas ‘CBA market indicators’ and ‘CBA network indicators’ are the direct outcome of market and network studies, respectively, ‘project costs’ (see 5.10 and 5.11) and ‘residual impacts’ (see 5.13, 5.14 and 5.15) are obtained without the use of simulations.

3.2 General assumptions

This section provides general guidance on the assessment of projects. It provides guidelines for the clustering of investment, the computation of transfer capability, the consideration of geographic scope, and the calculation of a net-present value on the basis of the (monetised) indicators.

3.2.1 Clustering of investments

In some cases, a group of investments may be necessary to develop transmission capacities (i. e., one investment cannot perform its intended function without the realisation of another investment). This process is referred to as the clustering of investments. In this case, the project assessment is done for the combined set of clustered investments.

When investments are clustered, it must be clearly demonstrated why this is necessary. Investments should only be clustered together if an investment contributes to the realisation of the full potential of another (main) investment. Investments that contribute only marginally to the full potential of the main investment will not be clustered together.

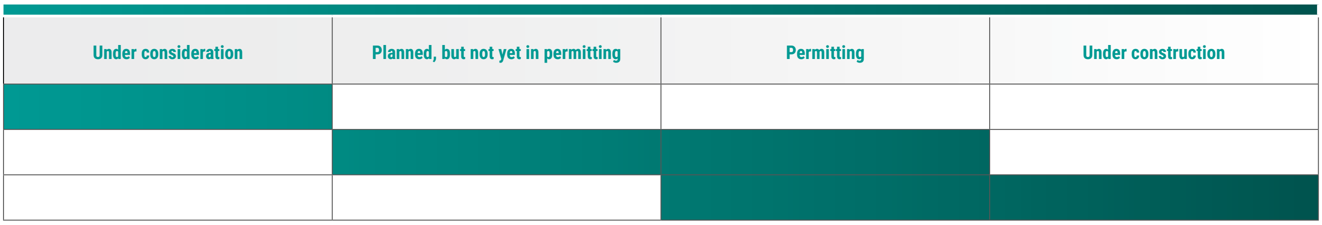
The full potential of the main investment represents its maximum transmission capacity in normal operation conditions. When clustering investments, one main investment (e. g. an interconnector) must explicitly be defined, which is supported by one or more supporting investments. A project that consists of more than one investment is defined as a main investment with one or more supporting investments attached to it.

Note that competing investments cannot be clustered together.

Further limitations are as follows:

- Investments can only be clustered if they are at maximum of one stage of maturity apart from each other, see Figure 4. This limiting criterion is introduced in order to avoid excessive clustering of investments that do not contribute to realising the same function because they are commissioned too far ahead in time.
- If an investment is 'under consideration', it can only be clustered with other investments in the same stage, i. e. an investment under consideration cannot be clustered with an investment in 'planned, but not yet in permitting'.
- If an investment is significantly delayed[9] compared to the previous TYNDP, it can no longer be clustered within this project. To avoid a situation whereby investments are clustered when they are commissioned far apart in time (which would also introduce a risk that one or more investments in the project are never realised), a limiting criterion is introduced that prohibits the clustering of investments that are more than one status away.

Figure 4 illustrates the categories of investments and which investments may be clustered. The categories marked in green in each row can be clustered. For example, a main investment with status 'permitting' can either be clustered together with investments that are 'planned, but not yet in permitting' (second row) or 'under construction' (third row).



Under consideration	Planned, but not yet in permitting	Permitting	Under construction
🟩			
	🟩	🟩	
		🟩	🟩

Figure 4: Illustration of the clustering of investments

The cost-benefit analysis should be related to the investments covered by the project and not the final outcome of the investments (in case of upgrades).

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[9] The term 'significant delay' has to be seen as case-specific; in relation to all investments in that project, the investment with the earliest commissioning date might be delayed further compared to that of the latest commissioning date. If two investments are more than 5 years apart, they will be considered as significantly delayed and can no longer be clustered together. Exceptions can be made if the project promoter provides a robust justification for the clustering.

3.2.2 TOOT and PINT

There are two methods that are used to assess a project's performance. These are illustrated in Figure 5 and are described as follows:

Take Out One at the Time (TOOT) method:

The reference network represents a future target network in which all additional network capacity is assumed to be in place (compared to the starting situation). The projects under assessment are then removed from the future target network, one at a time, to evaluate the changes to each of the indicators.

Put IN one at the Time (PINT) method:

The reference network represents the initial state of the network without the projects under assessment. The projects under assessment are then added to the reference network, one at a time, to evaluate the changes to each of the indicators.

Projects that are 'under consideration' are considered non-mature and, therefore, have to be excluded from the reference grid. These projects are assessed using the PINT approach, regardless of their position regarding any additional criteria.

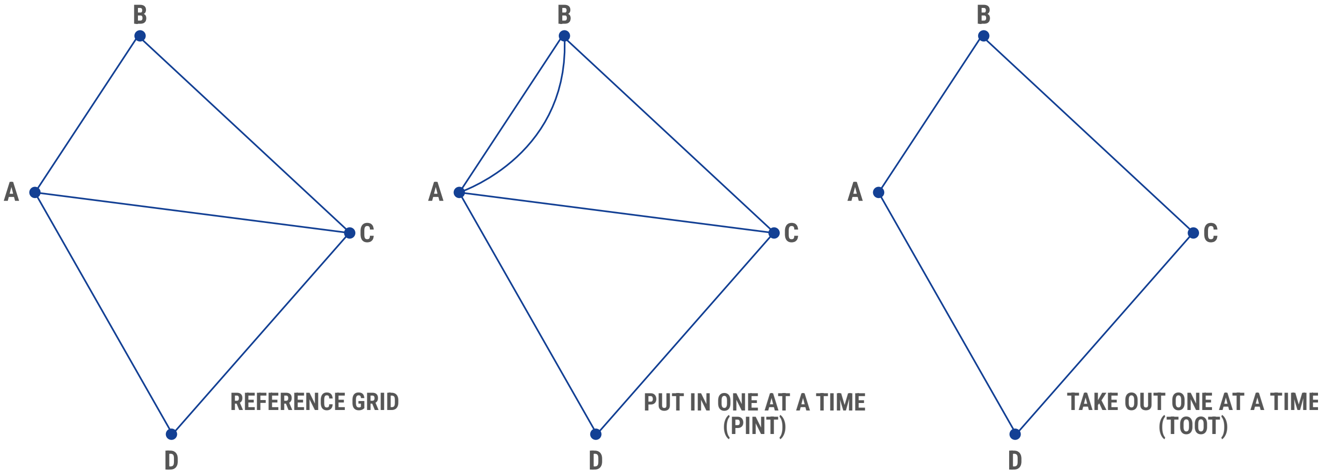

Figure 5: Illustration of TOOT and PINT approaches

The TOOT and PINT methods are to be applied consistently for both market and network simulations.

The TOOT method provides an estimate of the benefits for each project as if it were the last to be commissioned; i. e. it is evaluated as part of the whole forecasted network. The advantage of this analysis is that every benefit brought by each project is assessed together, without considering the order of projects. Hence, this method facilitates assessment at the aggregated TYNDP level, with the future power system and the evolution of every future network being considered.

For the PINT method, the reference network is clearly defined by the network model that is used; for market simulations, the reference network considers the exchange capacities between the defined market zones, including the additional capacity brought by the projects included in the grid. The PINT assessment is then applied 'on top' of all projects assessed using the TOOT methodology and thus provide an estimation of benefits for each project as if it were commissioned after all TOOT projects but is the first and only one to be commissioned compared to all PINT projects.

In general, the application of the TOOT approach has the potential to underestimate the benefits of projects because all project benefits are calculated under the assumption that the project is the final (marginal) project to be realised. However, the application of the PINT approach has the potential to overestimate the benefit of projects (compared to all other PINT projects) because all of the projects' benefits are calculated under the assumption that the project is the first project to be realised (after all TOOT projects have been realised). Project benefits are generally, but not necessarily always, negatively affected by the presence of other projects (i. e. if one project is built, a second one will have lower benefits). This effect is generally strongest when two (or more) projects are constructed to achieve a common goal across the same boundary, although it may also be present when projects are constructed along different boundaries.

Multiple applications of TOOT/PINT

For interdependent projects, the strict application of the TOOT or PINT methods may not fully reflect the benefits of the projects. Therefore, in addition to the project benefits calculated using the strict application of the TOOT or PINT methods, the benefits arising from the realisation of other projects on the same boundary can be calculated (i. e. multiple TOOT or PINT). When the multiple TOOT or PINT methods (or a combination of both) are applied, a detailed description of the sequence of projects must be given.

It should be noted that the reference for the second, third, etc. project in the sequence of the multiple TOOT/PINT needs to be taken correspondingly. Whereas the first project in the sequence can be assessed and compared against the reference grid (no change compared to the TOOT/PINT method as described above), the reference for the second project should be such that the first project has been taken out (for TOOT) or put in (for PINT). The third project needs to be assessed against the situation as defined by the second step and so on.

Example for three interdependent TOOT projects:

Commissioning date	Project number
2021	1
2022	2
2024	3

- project 3: assessment against the reference grid by taking the project out.
- project 2: assessment against the situation with project 3 already taken out.
- project 1: assessment against the situation with project 3 and project 2 already taken out.

3.2.3 Transfer capability calculation

There are two concepts of transfer capability, namely: **Net Transfer Capacity (NTC)** and **Grid Transfer Capacity (GTC)**. NTC that this Guideline refers to is related to the potential for market exchanges of electricity resulting in a power shift of dispatch from one bidding zone to another, and GTC is related to physical power-flows that can be accommodated by the grid.

It is important to note that the NTC defined in the present document corresponds to what is called cross-border grid transfer capacity in the TEN-E Regulation as it represents the capacity available for commercial flows between bidding zones. The NTC is defined in this document and further information on the calculation process are provided within the TYNDP specific Implementation guidelines.

Net Transfer Capacity

The **NTC** reflects the ability of the grid to accommodate a market exchange between two neighbouring bidding areas. An increase in NTC (ΔNTC) can be interpreted as an increased ability for the market to commercially exchange power, i. e. to shift power generation from one area to another (or similarly for load[10]). The physical power flow that is the result of this power shift may or may not directly flow across the border of the two neighbouring bidding areas in its entirety, but may or may not transit through third countries. The increase in the ability to accommodate market exchanges as a result of increasing physical transmission capacity may, therefore, be different from the capability of the grid to transport physical power across the border.

As the exchanges between bidding zones result in power-flows making use of the transport capacity across the different boundaries they impact, an increase in GTC across a specific boundary would correspond, **ceteris paribus**[11], to an increased exchange capability between these bidding zones.

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[10] Wherever the text refers to 'power shift', both the 'load shift' and the 'generation shift' can be applied.

[11] 'Ceteris paribus' acknowledges that in actual system operations, one single boundary is not exclusively influenced by only the exchanges between the bidding zones it relates to. The physical flow on the boundary can also be influenced by exchanges between other bidding zones which, for example, cause loop or transit flows. These influences are not considered when calculating the increased NTC delivered by a project in the context of this methodology.

Note that while the concept of NTC calculations in the context of long-term studies is similar to the operational calculation of NTC values on borders, the concept of NTC, as defined for the purpose of long-term planning studies, may show some differences in the sense that the approaches may not consider the same operational considerations to ensure a safe and reliable operation of the system. The NTC values reported in long-term studies are calculated under the 'ceteris paribus' assumption that nothing else in the system changes (e. g. generation and load in neighbouring zones, RES fluctuations, loop flows) and, therefore, does not have an impact on the calculated power shift made possible by the project (i. e. which equals market exchange). In the TYNDP, the assumed utilisation of the additional GTC delivered by a project will be reported in terms of the ability for additional commercial exchanges (i. e. ΔNTC) between the bidding zones that define the boundary in question. Very often, an increase in GTC would be synonym to an increase in NTC. However, it is to be noted that there is not a linear relationship between both elements, but they can rather be linked through Power Transfer Distribution Factors (PTDFs). Note that the ΔNTC is directional, which means that values might be different in either direction of the commercial power-flow across a boundary.

ΔNTC is calculated using network models by applying a generation power shift12 across the boundary under consideration. This figure applies to the year-round situation (i. e. 8,760 hours) of how the generation power shift affects the power-flow across the boundary under analysis. Calculating an ΔNTC value generally results in a different value for each simulated time step of the year under consideration. This year-round situation should be reflected in the load flow analysis either via a simulation of each individual time step or via a simulation of a set of points in time that are representative of the year-round situation. The annual delta NTC that is reported corresponds to the 70th percentile of the delta NTC duration curve (i. e. the value is reached for at least 30 % of the year). This is illustrated in Figure 6. In the event the reference NTCs used in the market simulations are time-dependent (e. g. seasonal values are used), the calculated delta NTCs could also be time-dependent, e. g. obtaining a different value for each season rather than a single annual NTC. In this latter case, similarly to what is done for the year-round situation, different delta NTC duration curves can be built for the different seasons and the 70th percentile can be reported for each season.

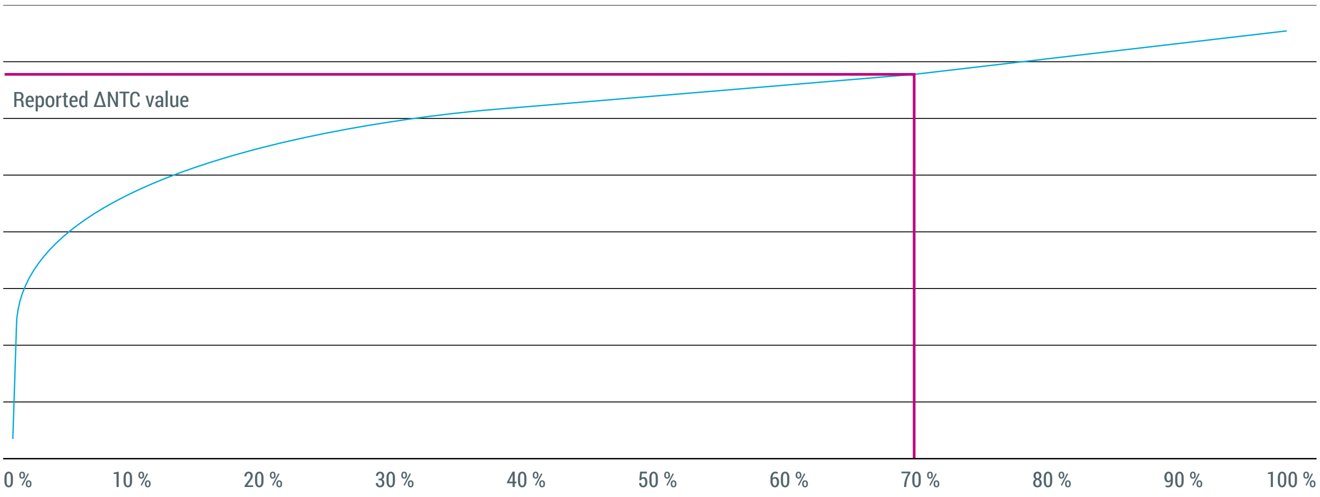

Figure 6: Duration curve of ΔNTC in one direction (blue) with 70th percentile (red): the reported ΔNTC at the 70th percentile needs to be reached at least 30 % of the time – to the right of the red line.

The calculation of the ΔNTC is based upon a reference network model in line with the scenario considered. As ΔNTC is the result of the possible power shift, the figure may differ between scenarios.

A detailed example of how the ΔNTC on one time step can be calculated is given in the Implementation Guideline for the respective TYNDP.

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[12] It should be mentioned that the methodology on how the generation power-shift is applied can have a significant impact on the results and must be clearly explained in the respective study. A consistent approach for the generation power shift must be applied for all assessments. The power shift method(s) are to be defined in the Implementation Guideline and reported on the project sheets.

Reporting on transfer capability

The impact on transfer capability must be reported on at the investment level for each project. This means that the reporting must be done for each investment and also for the project as a whole. In the case of a project with a cross-border impact, the figures to be reported are the ΔNTC of the project and the contribution of the investment(s). For an internal project, ΔNTC must be reported[13]. In any case, for each project it must be clearly displayed whether a cross-border transfer capacity, an internal transfer capacity, or a combination of both types of transfer capacities is provided.

The method used to perform the generation power shift has to be reported in the respective study, and the same method must be applied in a clear and consistent manner for all projects under assessment.

3.2.4 Geographical scope

The main principle of system modelling is to use detailed information within the studied area and a decreasing level of detail outside the studied area. As a minimum requirement, the study area should cover all MS and third countries on whose territory the project shall be built, all directly neighbouring MS, and all other MS significantly impacted by the project.[14] To consider the interaction of the pan-European modelled system in the market studies, exchange conditions with non-modelled countries will be fixed for each of the simulation time steps based on a global market simulation.[15] Practically, the market model should cover all European countries in addition to any third countries that host the assessed project. For network analysis, each synchronous zone relevant for the project should be modelled (generally, this means the synchronous zone in which the project is located; for HVDC projects between different synchronous areas, all synchronous areas should be modelled, except for third countries).

Project appraisal is based on analyses of the global (European) increase of welfare.[16] This means that the goal is to bring up the projects that are best for the European power system and, therefore, for European society. Therefore it might be necessary to reduce the CBA results only to EU MS by excluding costs and benefits located in third countries (non-EU MS). A detailed overview of the used perimeter applied for both the simulation and the CBA evaluation needs to be given within the study specific Implementation Guidelines. The defined perimeter has to fulfil the requirement to show what impact a project has on the EU MS[17]. Separate from this possible split of costs and benefits, all results always need to also be given for the full modelling perimeter.

3.2.5 Investment value calculation

The value of an investment is calculated using the discounted cash flow method. This method considers the timing of costs and benefits and recognises that the value of money changes over time, which is often referred to as the time value of money. The assumption is that the value of money changes at a constant annual rate, referred to as the discount rate. The future values of both costs and benefits can then be represented (or discounted) to present values using the discount rate.

The present value (PV) of a future cost or benefit (referred to as FV) in a given time period **n**, using a discount rate of **r** per annum, is described by the following formula:

$$PV(n) = \frac{FV_n}{(1+r)^n}$$

The main methods used to represent the value of an investment as a single value are Net Present Value (NPV) and

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[13] In case an internal project has a cross-border impact, the ΔNTC values have to be reported.

[14] Annex V, §1 Regulation (EU) 2022/869

[15] Within ENTSO-E, this global simulation would be based on a pan-European market data base.

[16] Some benefits (socio-economic welfare, CO_2 …) may also be disaggregated on a smaller geographical scale, like a member state or a TSO area. This is mainly useful in the perspective of cost allocation and should be calculated on a case-by-case basis, taking into account the larger variability of results across scenarios when calculating benefits related to smaller areas. In any cost allocation, due regard should be paid to compensation moneys paid under ITC (which is article 13 of Regulation 714 for caveats on Market Power and cost allocation).

[17] It is considered that societal impacts based on CO_2 emissions will occur independent of where the CO_2 is emitted. Therefore the B2 indicator might be still considered based on the whole perimeter, while other indicators are reduced just to the EU perimeter.

Benefit-to-Cost Ratio (BCR). Both methods assess the viability of the investment, and where there are a number of competing investments they are used to facilitate a comparison of competing investments where consistent assumptions are applied.

The NPV of an investment is the difference between the present value of benefits (i. e. cash inflows) and the present value of costs (i. e. cash outflows) over the economic life of the investment. A viable investment is usually indicated by a positive NPV, i. e. the present value of benefits is greater than the present value of costs.

The NPV of the investment assessed over the assessment period of **T** years is described by the following formula:

$$NPV = \sum_{t=t0}^{T} \frac{Benefit_t - Cost_t}{(1+r)^t}$$

Where **t0** calculates as the commissioning minus the year of the study and **T** is defined as the assessment period added to **t0**.

The BCR of an investment is the ratio of the present value of benefits to the present value of costs. A viable investment is usually indicated by a BCR greater than one, i. e. the present value of benefits is greater than the present value of costs.

The BCR of the investment is calculated over the assessment period of **T** years using the following formula:

$$BCR = \frac{\sum_{t=0}^{T} \frac{Benefit_t}{(1+r)^t}}{\sum_{t=0}^{T} \frac{Cost_t}{(1+r)^t}}$$

To enable the consistent calculation of either the NPV or BCR for an investment, a consistent set of assumptions must be applied. Given that both methods use the same calculations to determine the present value of benefits and costs, the assumptions apply equally to both methods.

The key assumptions are as follows:

The **assessment period** defines the period of time over which the investment will be evaluated. This may be different to the useful life of the investment's assets and represents the period over which it is reasonable, given the uncertainty, to expect value to be attributed to the investment. For the purposes of this guideline, the assessment period is 25 years[18].

Values are represented as real and constant values. This means that no inflation is considered and, therefore, no forecasts for future inflation are necessary. It also means that values are taken as fixed throughout the assessment by assuming constant year-of-study values. The year-of-study is taken as the year of the TYNDP, i. e. 2024 for the TYNDP 2024. The impact of taxation is not considered in the project assessments, so the values are represented as pre-tax values.

The **discount rate** used to calculate the NPV can differ between countries; however, for a fair assessment across projects, a common discount rate is required. For the purposes of this guideline, the discount rate should be given as a real value. The real discount rate to be used is 4 % per annum.

Future values are to be discounted to a common point in time, which is the year of the TYNDP, also referred to as the year-of-study above.

The forecasted costs and benefits for each investment are to be represented annually.

The year of commissioning is the year that the investment is expected to come into first operation.

The inception costs are to be aggregated and represented in the commissioning year of the investment as a single value.

Further capital costs incurred to sustain the investment during its lifetime are to be represented in real and constant year-of-study values in the year that they occur.

The benefits are accounted for from the first year after commissioning. To evaluate projects on a common basis, benefits should be aggregated across the years, as follows:

- For years from the first year after commissioning (i. e. the start of benefits) to the first mid-term: extend the first mid-term benefits backwards;
- For years between different mid-term, long-term and very long-term (if any): linearly interpolate benefits between the time horizons; and
- For years beyond the farthest time horizon: maintain benefits of this farthest time horizon.

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[18] The economical lifetime differs from the actual lifetime of transmission infrastructure assets which is longer than 25 years (rather towards 40 years and longer). This is also pointed out by the ESABCC in their recommendation on the CBA Guideline version 4.1 for ACER Opinion where it is stated considerable long-term benefits could be neglected when 25 years is assumed

To assess a project that is comprised of multiple investments, the annualised benefits, losses and operational costs for the project are accounted for from the commissioning of the latest investment, thus the commissioning of the complete project.

The residual value of the project at the end of the assessment period should be treated as having zero value.

3.3 Assessment framework

The assessment framework laid out in this Guideline is consistent with Article 11 and Annexes IV and V of the TEN-E Regulation, and describes the structure used to differentiate the range of indicators that comprise the project assessment.

The assessment framework comprises three main categories – costs, benefits and residual impacts – as illustrated in Figure 7. Within each of the three categories, there are a number of separate and distinct indicators that together represent the category. The composition of each of the categories is described in detail in Chapter 5.

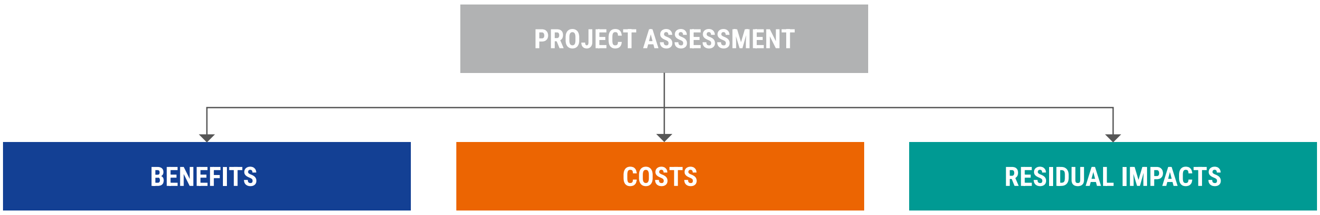

Figure 7: Overview of the main categories of CBA indicators

Benefits describe the positive contributions made by the project (or new functionalities/improvements in case of updates). The formalised indicators that comprise the benefits are supported by detailed methodologies that are captured in their corresponding sections in Chapter 5. Note that projects may also have a negative impact on some benefit indicators, in which case negative benefits are reported.

Costs describe the inception cost of the project or investment, i. e. CAPEX and the operating costs that incurred throughout the investment's lifecycle, i. e. OPEX. The CAPEX cost typically refers to the inception cost of the project and would also include the costs of implementing mitigation measures that address environmental and social constraints.

Residual impacts describe the impacts of investments that are not addressed by any of the identified mitigation measures that are contained within the cost category (typically as CAPEX). This ensures that all measurable costs associated with projects or investments are considered, and that no double-accounting occurs between any of the indicators.

3.4 Non-mature indicators

In some instances, there are costs or benefits that are relevant for a CBA, but it might not be possible to assess them at a pan-European level. This is the case when common applicable and on pan-European level agreed datasets are not available or when the methodological description has not achieved a sufficient level of maturity. However, for completeness reasons and to maintain consistency, all indicators, including the here mentioned non-mature indicators, are also displayed in this Guideline in Chapter 5, with a clear information about their non-mature status.

Although the Pan-European nature of these indicators is recognised, it is acceptable to assess them relying on a regional, or even national, perimeter to deal with their inherent complexity. In that case, additional information on the used tools, datasets, assumptions and a detailed description of the used methodology needs to be given within the respective study.

4 Concluding remarks

This guideline for the CBA of grid development projects was prepared by ENTSO-E in compliance with the requirements of the EU Regulation (EU) 2022/869. This guideline is the fourth version of the document produced by ENTSO-E and is built upon the 3rd CBA Guideline, which was the result of an extensive consultation process.

The document is a general guide to assist in the assessment of planned projects included in ENTSO-E's TYNDP. It describes the common principles and procedures for performing the analysis of costs and benefits for projects using network and market simulation methodologies. Following Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure, it also serves as the basis for a harmonised assessment of PCIs at the European Union level.

A multi-criteria approach is used to describe the indicators associated with each project. To ensure a full assessment of all transmission benefits, some of the indicators are monetised, whereas others are quantified in their typical physical units (i. e. tons or GWh). The set of common indicators contained in this Guideline form a complete and solid basis for project assessment across Europe, both within the scope of the TYNDP as well as for project portfolio development in the PCI selection process.

This CBA Guideline is drafted using a modular approach. The purpose of the modular approach is to enable more efficient updates of the Guideline by allowing stakeholders to better focus on specific content without necessarily impacting the whole document. This recognises that the Guideline is an evolving and living document that we endeavour to continually improve to meet the needs of our stakeholders.

The following sections give more concrete information on the single indicators and additional specific context.

5 Benefits, costs and residual impacts

The project assessment is conducted using the benefit, cost and residual impact indicators described in this Guideline. Although the benefits should be given for each study scenario (e. g. the TYNDP scenarios), costs and residual impacts are seen as scenario independent indicators.

The main project assessment categories are illustrated in Figure 8.

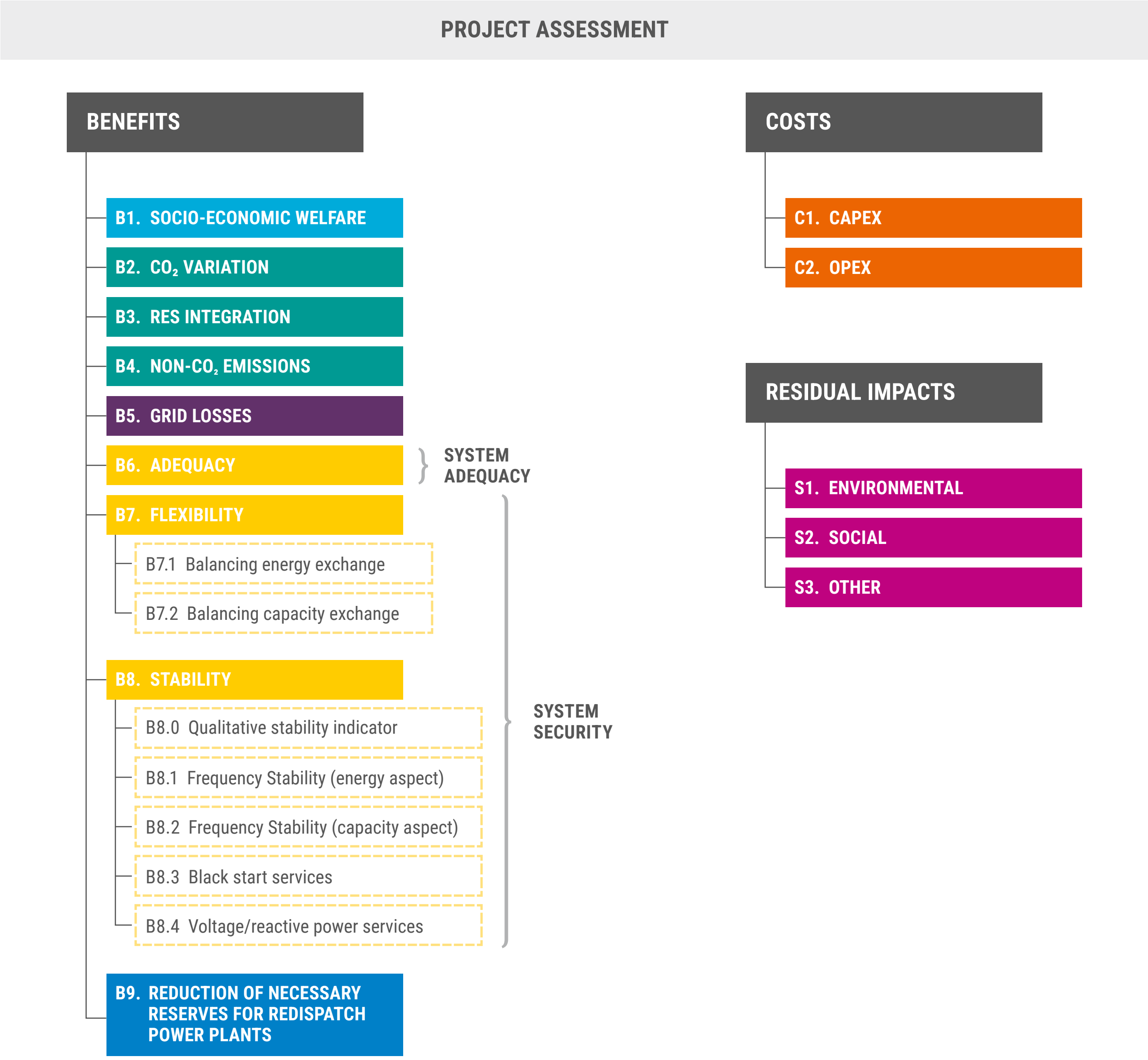

Figure 8: Illustration of the project assessment framework categories

The indicators have been selected on the following bases:

- They facilitate the description of the project costs and benefits in terms of the EU network objectives. These EU network objectives are:
  - to ensure the development of a single European grid, enabling EU climate policy and sustainability objectives (i. e. RES, energy efficiency, CO_2);
  - to guarantee SoS;
  - to complete the internal energy market, especially through a contribution to increased SEW and;
  - to ensure system stability.
- They provide a measurement of a project's costs and feasibility (especially environmentally and socially, as indicated by the residual impact indicators).
- They are as simple and robust as possible. This facilitates simplified methodologies where practical to do so.

The project assessment should reflect the average transfer capacity contribution of the project. The contribution to transfer capacity is time and scenario dependent, but a single or seasonal value should be reported for clarity reasons. A characterisation of a project is provided through an assessment of the directional ΔNTC increase and the impact on the level of electricity interconnection, relative to the installed production capacity in the MS.19 For those countries that have not reached the minimum interconnection ratio, as defined by the EC, each project must report the contribution to achieve this minimum threshold. However, the interconnection targets must not be considered as a technical criteria and therefore have to be treated differently from the indicators given in section 5 in order to avoid any double accounting.

The increased transfer capacity contribution and costs are given per investment, whereas the benefit indicators and residual impact indicators are provided at the project level.

For some of the indicators, it is not yet possible to deliver a mature methodology to assess them on a Pan-EU level. This 4th CBA Guideline introduces five non-mature indicators:

- B7.1 Balancing energy exchange (aFRR, mFRR, RR);
- B7.2 Balancing capacity exchange/sharing (aFRR, mFRR, RR);
- B8.1 Frequency Stability;
- B8.2 Black start services; and
- B8.3 Voltage/reactive power services

The **benefit indicators** are described as follows:

B1. Socioeconomic welfare (SEW from wholesale energy market integration),[20] in the context of transmission network development, is the sum of the short-run economic surpluses of electricity consumers, producers and transmission owners. The indicator reflects the contribution of the project or investment to increasing transmission capacity, making an increase in commercial exchanges possible so that electricity markets can trade power in a more economically efficient manner. It is characterised by the ability of a project or investment to reduce (economic or physical) congestion. Under multi-sectorial market coupling, the indicator can be augmented to the global SEW comprising the individual contributions of the different sectors.

B2. Additional societal benefit due to CO_2 variation is the change in CO_2 emissions produced by the power system due to the project. It is a consequence of changes in generation dispatch and the unlocking of renewable generation potential. This indicator is directly linked to the EU's climate policy goal of reducing greenhouse gas emissions by at least 55 % by 2030 relative to 1990 levels. As CO_2 emissions are the main greenhouse gas produced by the electricity sector, they are displayed as a separate indicator, and its monetary benefit is described using societal costs for carbon.

B3. RES integration defines the ability of the power system to connect new RES generation, unlock existing and future 'renewable' generation, and minimise the curtailment of electricity produced from RES.[21] The RES integration indicator is linked to the EU 2030 goal of increasing the share of RES to 32 % of overall energy consumption.

B4. Non-direct greenhouse emissions refer to the change in non-CO_2 emissions (e. g. COX, NOX, SOX, PM 2, 5, 10) in the power system due to the project. They are a consequence of changes in generation dispatch and the unlocking of renewable generation potential.

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[19] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action establishes, in article 23 (a), that '…the level of electricity interconnectivity that the Member State aims for in 2030 in consideration of the electricity interconnection target for 2030 of at least 15 % …'

[20] The reduction of congestions is an indicator of social and economic welfare assuming equitable distribution of benefits under the goal of the European Union to develop an integrated market (perfect market assumption). The SEW indicator focuses on the short-run marginal costs.

[21] This category corresponds to B3: Methodology for RES Integration Benefit.

B5. Grid losses in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. It is an indicator of energy efficiency[22] and is expressed as a cost in euros per year.

B6. Security of supply: Adequacy characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. Variability of climatic effects on demand and RES production is considered.

B7. Security of supply: Flexibility characterises the impact of the project on the ability to exchange balancing energy in the context of high penetration levels of non-dispatchable electricity generation. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mRR) and automatic Frequency Regulation Reserve (aFRR). Exchanging/sharing balancing capacity (i. e. RR, mFRR and aFRR) that requires guaranteed or reserved cross-zonal capacity is also considered. This indicator is considered as non-mature where further development is needed.

B8. Security of supply: Stability characterises the project's impact on the ability of a power system to provide a secure supply of electricity as per the technical criteria. This indicator (except of the qualitative part) is considered as non-mature where further development is needed.

B9. Redispatch Reserves or **Reduction of Necessary Reserves for Redispatch Power Plants** describes a project's impact on the required levels of contracted redispatch reserve power plants by assessing the maximum power of redispatch with and without the project. A prerequisite for this indicator is the use of redispatch simulations.

The **costs indicators** are described as follows:

C1. Capital expenditure (CAPEX). This indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, ground, preparatory work, designing, dismantling, equipment purchases and installation. CAPEX is established by analogous estimation (based on information from prior projects similar to the current project) and by parametric estimation (based on public information about the cost of similar projects). CAPEX is expressed in euros.

C2. Operating expenditure (OPEX). OPEX defines the annual operating and maintenance expenses associated with the project or investment. OPEX is expressed in euros per year.

Residual impact indicators refer to the impacts that remain after impact mitigation measures have been taken. Hence, impacts mitigated by additional measures should no longer be listed in this category. The indicators are defined as follows:

S1. Residual Environmental impact characterises the (residual) project impact on the environment, as assessed through preliminary studies, and aims to provide a measure of the environmental sensitivity associated with the project.

S2. Residual Social impact characterises the (residual) project impact on the (local) population affected by the project, as assessed through preliminary studies, and aims to provide a measure of the social sensitivity associated with the project.

S3. Other impacts provide an indicator of all other impacts of a project.

Although ENTSO-E intends to monetise as many of the indicators as possible, in some cases the required data are not always available (e. g. detailed emission prices per fuel type for non-CO_2 calculations). ENTSO-E seeks to deliver a uniform and objective CBA assessment and is reluctant to publish results if their uniformity and/or objectivity cannot be guaranteed. In such cases, it is more useful to publish indicator results in their original units than to unilaterally decide on their monetary value in an arbitrary manner.

It should be noted that for those indicators that require monetisation, the euro values are to be represented as real and constant values. This means that no inflation is considered and, therefore, no forecasts for future inflation are necessary. It also means that values are taken as being fixed throughout the assessment by assuming constant year-of-study values. The year-of-study is taken as the year of the TYNDP, i. e. 2024 for the TYNDP 2024. The impact of taxation is not considered in the project assessments, so the values are to be represented as pre-tax values.

Table 2 provides an overview of the status, regarding monetisation, of the benefit indicators included in this 4th CBA Guideline:

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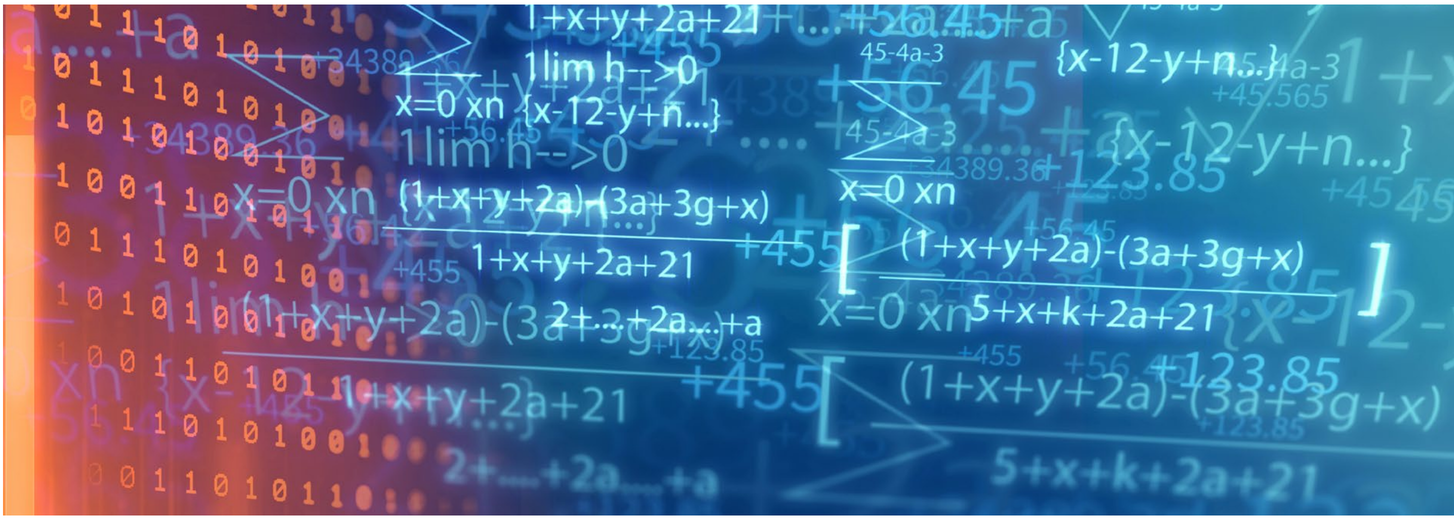
[22] This category contributes to B5: Methodology for Variation in Grid Losses Benefit.



Indicator	Unit	Monetisation status		Document location
B1. SEW	€/yr	Monetised by definition		B1. Methodology for Socioeconomic Welfare Benefit
B2. CO_2 emissions	Tons/yr and €/yr	Comprises two parts: (1) Fully monetised in B1, where the effects of CO_2 emissions are monetised and reported as additional information under indicator B1. (2) Related to the additional societal value, which is not monetised under B1.	Political CO_2 reduction targets are formulated as percentages of values, expressed in tons per year. The monetary effect is the topic of ongoing political debate. Therefore, the CBA Guideline requires that CO_2 emissions are reported separately (in tons).	B2. Methodology for Additional Societal benefit due to CO_2 variation
B3. RES integration	MW or MWh/yr	Fully monetised under B1, where the effects of RES integration on SEW, due to the reduction of curtailment and lower short-run variable generation costs, are monetised and reported as additional information.	Political RES integration goals are formulated and expressed in MW. The monetary effect (in addition to B1, B2) cannot be monetised objectively. Therefore, the CBA Guideline requires that RES integration is reported separately (MW or MWh/yr).	B3. Methodology for RES Integration Benefit
B4. Non-CO_2 emissions	Tons/yr	Not monetised		B4. Methodology for Non-Direct Greenhouse Emissions Benefit
B5. Grid losses	MWh/yr	Monetised using hourly marginal costs from the market simulations per price zone.		B5. Methodology for Variation in Grid Losses Benefit
B6. SoS: Adequacy	MWh/yr	Monetised. Is dependent on availability of VOLL-values. Additional adequacy margin may be conservatively monetised using investment costs in peaking units (provided figures are available).		B6. Methodology for Security of Supply. Adequacy to Meet Demand Benefit
B7. SoS: Flexibility (balancing energy exchange)	Ordinal scale	Not monetised.	Not monetised at present because of the unavailability of quantitative models. First development is to provide quantitative model results.	B7. Methodology for Security of Supply – System Flexibility Benefit
B8. SoS: Stability	Ordinal scale	Not monetised.	Not monetised at present because of the unavailability of quantitative models. First development is to provide quantitative model results.	Section 5.8: B8: Methodology for Security of Supply: System Stability Benefit
B9. Redispatch Reserves or Reduction of Necessary Reserves for Redispatch Power PlantsRedispatch Reserves	€/yr	Monetised using actual costs for allocation of redispatch reserves	This indicator is optional and can only be achieved when the SEW has been calculated using redispatch simulations	Section 5.9: Reduction of Necessary Reserve for Redispatch Power Plants (B9.)

Table 2: Overview of the status of indicator monetisation

5.1 B1: Methodology for Socioeconomic Welfare Benefit

Indicator definition:

- Definition: In power system analysis, SEW is typically defined as the sum of the short-run economic surpluses of electricity consumers, producers and transmission owners (congestion rent). In a multi-sector CBA project assessment, the SEW corresponds to the global SEW.
- Relevance: This indicator gives a direct measure for the monetary benefit and is therefore of great relevance for the CBA.

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on a system cost comparison with/without the project.
- Quantitative measure: this indicator is directly given in monetary values.
- Monetisation: per definition monetised and given in €/year

Interlinkage to other CBA indicators:

- B2, B3, B6

5.1.1 Introduction

In power system analysis, SEW is typically defined as the sum of the short-run economic surpluses of electricity consumers, producers and transmission owners (congestion rent). Transmission network projects, or investments, have an effect on the sum and the distribution of these surpluses. Investment in transmission capacity generally increases the total sum of the individual surpluses by enabling a larger proportion of demand to be met by cheaper generation units that were not available before because of a transmission bottleneck.

These surplus effects are only one part of the overall economic benefit provided by transmission investments that stem from wholesale energy market integration and do not capture other transmission-related benefits as described by the other indicators, as given in this guideline.

Calculations within the respective studies (e. g. the TYNDP) should be based on a set of scenarios, which are designed to represent future conditions with regard to generation and demand. The contents of the scenarios are carefully determined and consider a coherent set of assumptions with regard to possible developments in generation and load. This allows the marginal benefits of a transmission project to be assessed against a 'static' reference framework. In reality, the transmission project actually alters the reference framework itself – albeit with a (frequently significant) time delay. Considering that these longer-term effects make the modelling challenge considerably more complex and decrease the robustness of results, the strength of an approach based on reporting the marginal differences in short-run surplus lies in its unambiguity.

In the presence of sector coupling, the concept of SEW can be applied to multiple sectors. In this regard, those sectors represent different markets for different energy carriers e. g. electricity, hydrogen, methane, etc. Moreover, their contributions constitute the overarching global SEW that covers the entire energy system and captures cross-sectorial benefits. It is composed into the individual aforementioned standard surpluses and contributions stemming from the interlinkage of the involved sectors that are defined as cross-sector rents. They can be used to decompose the global SEW in its sectorial counterparts by attributing the benefits to the involved sectors. Their calculation is optional and can be considered an augmented and alternative approach to the standard economic welfare decomposition. Table 3 shows the different options for the SEW calculation depending on the project assessment type.

Indicator	Multi Sector Assessment	Single Sector Assessment
Global SEW	■	
SEW for electricity	■ *	■

* Calculation is only possible under the Total Surplus (TS) approach. This could be done in combination with the introduced cross-sector rent component.

Table 3: Options for SEW calculation under multi-sector or single sector project assessments

5.1.2 Methodology

The TYNDP reports changes to economic surpluses as a result of transmission projects, i. e. 'deltas' between situations with and without the project under consideration. It unambiguously reports the marginal change to the total economic surplus in the event of building a transmission project, without the need to further consider secondary consequences, which are usually not merely the result of constructing the transmission project but rather the result of (related and unrelated) further (political) decisions.

To calculate the change in short-term economic surplus, a perfect market is assumed. The perfect market assumes all market participants have equal access to information, no barriers to entry or exit, and no market power.

In general, two different approaches can be used for calculating the variation in SEW:

- The generation cost approach, which compares the generation costs with and without the project for the different bidding areas; and
- The total surplus approach, which compares the producer and consumer surpluses for both bidding areas, in addition to the congestion rent between them and potentially the cross-sector rents stemming from the interlinkage between the sectors, with and without the project.[23]

When measuring the benefits of transmission investments under the assumption of perfectly inelastic demand, the change in SEW is, by definition, equal to the reduction in total variable generation costs. Hence, if demand is considered as perfectly inelastic to price, both methods will yield the same result. This metric values transmission investment in terms of saving total generation costs as a project that increases the commercial exchange capability between two bidding areas allows generators in the lower priced area to export power to the higher priced area, as shown in Figure 9.

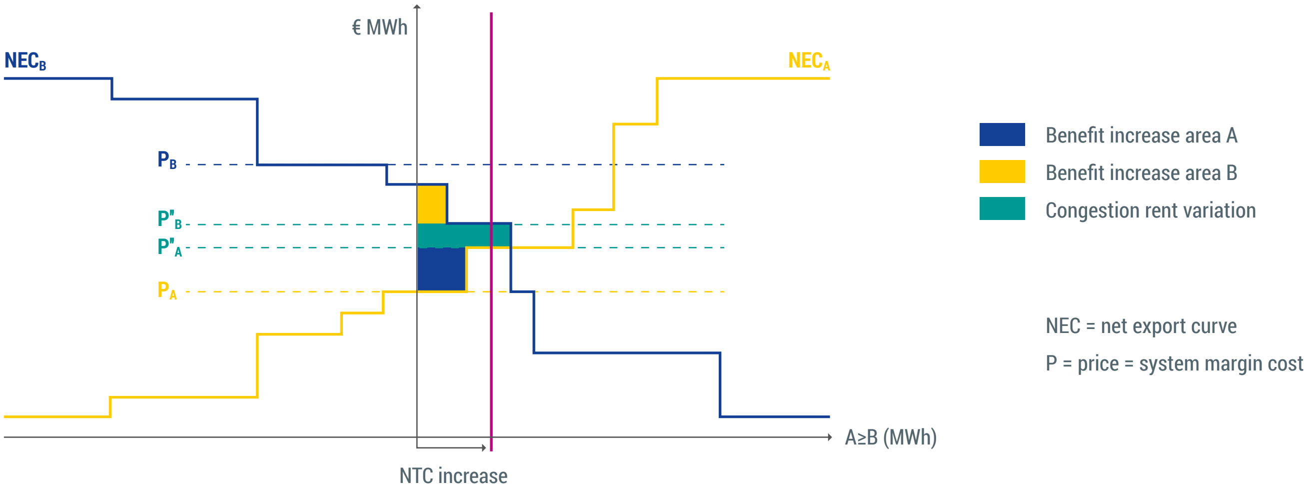


Figure 9: Illustration of benefits due to NTC increase between two bidding areas – +

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[23] More details about how to calculate surplus are provided in Annex II. Further calculation details under multi-sector project assessment will be given in the respective TYNDP implementation guidelines.

The new transmission capacity reduces the fuel and other variable operating costs and, hence, increases total SEW. Total generation costs are equal to the sum of thermal generation costs (fuel plus CO_2 ETS costs), and DSR costs. The different cost terms generally used in market simulations are shown in the Table 4: cost terms used in market simulations.

Cost terms in market simulations	Description
Fuel costs	Costs for fuel of thermal power plants (e.g., lignite, hard coal, natural gas, etc.).
CO_2-Costs	Costs for CO_2-emissions caused by thermal fired power plants. Depends on the power generation of thermal power plants and price of CO_2.
Start-up-costs/Shut-down costs	These terms reflect the quasi-fixed costs for starting up a thermal power plant to at least a minimum power level.
Operation and maintenance costs	Costs for operation and maintenance of power plants.
Demand Side Response (DSR) costs	Costs of DSR. DSR is the load demand that can be actively changed by a certain trigger.

Table 4: cost terms used in market simulations

If demand is considered elastic, modelling becomes more complex. Most European countries are considered to have price inelastic demand. However, there are a number of developments that appear to increase the price elasticity of demand. These developments include smart grids and smart metering, as well as a growing need for flexibility in order to accommodate the changing production technologies (i. e., more renewables, less thermal and nuclear).

The choice of assumptions regarding demand elasticity and the methodology for the calculation SEW benefit is left to ENTSO-E's Regional Group to decide. There are two recognised approaches considering greater flexibility of demand when assessing SEW, and these are listed below. The choice of the approach needs to be decided within the respective study, e. g. based on the respective Implementation Guidelines.

In the first approach, demand is estimated through scenarios, which results in a reshaping of the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles, etc. In this case, demand response is not elastic at each time step, but constitutes a shift of energy consumption from time steps with potentially high prices to time steps with potentially low prices (e. g. on the basis of hourly RES availability factors). The generation costs to supply a known demand are minimised through the generation cost approach. This assumption simplifies the complexity of the model and, therefore, the demand can be treated as a time series of loads that have to be met, while simultaneously considering different scenarios of demand-side management.

The second approach introduce hypotheses regarding the level of price elasticity of demand. To do this, there are two possible methods:

- **Generation cost method:** Using the generation cost approach, price elasticity could be considered via the modelling of curtailment as generators. The willingness to pay would then, for instance, be established at very high levels for domestic consumers and at lower levels for a part of industrial demand.
- **Total surplus method:** Using the total surplus method, the modelling of demand flexibility would need to be based on a quantification of the link between price and demand for each hour, allowing a correct representation of demand response in each area.

These methods are discussed in detail in the Annexes. Annex 7.1 addresses the generation cost method and Annex 7.2 addresses the total surplus method.

Changes in SEW must be reported in euros per year (€/yr) for each project, for a given scenario and study year. In addition to the overall SEW changes, the SEW changes that are the result of integrating RES and/or variations in CO_2-emissions must be reported separately as follows:

- Fuel savings due to integration of RES; and
- Avoided CO_2 emission costs.

5.1.3 Monetisation

This indicator is measured in €/yr and is, therefore, monetised by default.

The effects of CO_2 emissions, based on assumptions regarding emission costs, are monetised and reported as additional information under indicator B1.

The effects of RES integration on SEW due to the reduction of curtailment and lower short-run variable generation costs is monetised and reported as additional information under indicator B1.

Independent of the methodology used to calculate the SEW, the result will be given as a single value in €/yr as received by the respective methodology (i. e. no summation of the values achieved by the different methods) plus additional information on the RES and CO_2 impact on the SEW and in case of combined market and redispatch calculations (see **section 6.3** option 2) the SEW will be additionally displayed as SEW (cross border) and SEW (internal).

For cross-border projects, either the reduced generation costs/additional overall welfare or the combination with redispatch costs are calculated. For projects that have no cross-border capacity impact, only the redispatch methodology is used. The method used to calculate the SEW must always be reported.

5.1.4 Double-counting

The monetisation of RES and CO_2 under this indicator has to be seen as supplementary information and must not be added to the SEW figure. Furthermore, following the methodology used for monetising the RES part of this indicator (which has to be defined within the TYNDP-specific Implementation Guidelines), the sum over the monetary part of RES and CO_2 can exceed the total SEW delivered. This is because the assumptions behind evaluating the RES part are not included directly in the simulations calculating both the CO_2 emissions and the SEW. The RES impact is calculated as ex-post information. The fact that power dispatch changes also from the reference case to the TOOT or PINT case and the fact that we have non-linearities will impact also.

An overview of the different methods to calculate the SEW is given in Table 5.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
SEW: Reduced generation costs/ additional overall welfare	Market studies (optimisation of generation portfolios across boundaries)	€/yr	per definition monetary	European
SEW: Redispatch costs	Redispatch studies (optimisation of generation dispatch within a boundary considering grid constraints)			Regional/Project promoter (PP) level
SEW: Reduced generation cost/ additional overall welfare + Redispatch costs	Combination of both market- and redispatch-simulation			Regional/PP level

Table 5: Reporting Sheet for this Indicator in the TYNDP.

5.2 B2: Methodology for Additional Societal benefit due to CO_2 variation

Indicator definition:

- Definition: This indicator gives the change in CO_2 emission due to a new project or investment and is divided into two parts: the pure CO_2 emission in tons and additionally the societal costs in €/year. Both measures have to be displayed.
- Relevance: The European electricity system is a significant contributor to CO_2 emissions. In this context, grid development can play a role in modifying the level of carbon emissions. Due to the common goal to limit global warming and its harmful impact on the world, both measures of CO_2 (absolute and monetary) are given.

Indicator calculation:

- Model: Market simulations, Network simulations, Redispatch simulations; based on the CO_2 emissions comparison with/without the project.
- Quantitative measure: this indicator is for the first part given in tons
- Monetisation: the second part is monetised by the multiplication of CO_2 emissions [t] and a defined factor [€/t]

Interlinkage to other CBA indicators:

- B1, B3, B5

5.2.1 Introduction

As a signatory of the Paris Agreement, the European Union is committed to lower its carbon impact. In November 2018, the EC presented its strategic long-term vision for a prosperous, modern, competitive and climate-neutral Europe by 2050. This common goal aims to limit global warming and its harmful impact on the world. The European electricity system is a significant contributor to CO_2 emissions. In this context, grid development can play a role in modifying the level of carbon emissions. In particular, new interconnector projects enable cheaper generators to replace more expensive plants with potentially higher CO_2 emissions, leading to potentially lower CO_2 emissions.

To fully display the benefits of reducing CO_2 emissions due to a new project or investment, this indicator is divided into two parts:

- Part 1 refers to the change in pure CO_2[24] emissions given in tons; and
- Part 2 refers to its monetisation. The monetary part of CO_2 is partly considered within SEW and losses through the generation cost. The marginal cost for each power plant is the sum of the fuel cost and the CO_2 market price. This CO_2 price, which is paid for by the producers, is the forecast of the CO_2 price over the Emission Trading Scheme (ETS). Depending on the level of this market price, the forecasted price signal may be too low to give a sufficient price signal to lead to the investment level required to reach Europe's climate goal.

Thus, to appropriately assess investments in accordance with the European objective of CO_2 emission reduction, a specific indicator for monetising this additional impact is designed. For this purpose, the variation in CO_2 emissions is valued at the appropriate level of a societal cost. This cost represents the effort that should be made to reach the European climate-neutral goal.

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[24] All CO_2 values (in [t] and ETS costs) are considered being pure CO_2 without considering equivalents as coming from other emission types.

5.2.2 Methodology

The CO_2 emissions are computed with and without the project. The variations that are considered for this indicator are:

- Variations resulting from the change of generation plan; and
- Variations resulting from the change of losses volumes.

To avoid double accounting with the CO_2 variation already monetised into the SEW (B1) and the losses (B5), changes in CO_2 emission are then multiplied by the difference between the CO_2 societal cost and the ETS price used in the scenario. This benefit (B2) is to be added to the overall monetary benefit.

This is shown as follows:

$$B2 = CO_2variation \times (Societal\ cost\ of\ CO_2 - ETS\ CO_2\ price)$$

Where:

$$CO_2variation = -(CO_2variation_{from\ change\ in\ generation\ plan} + CO_2variation_{from\ change\ in\ losses\ volumes})$$

Note: this formula only applies when the ETS costs are lower than the defined societal costs. If the ETS costs are already above the societal costs, only the ETS costs are used, and this indicator does not bring additional monetary benefit.

Example: for a hypothetical project from A to B

The impact of the project is described as follows:

- Impact on CO_2 emissions on the generation plan (using market simulations): – 0.8 Mton/yr; and
- Impact on CO_2 emission of losses volume changes (using network simulations): + 0.2 Mton/yr

Given that the ETS price in the scenario is 27 €/ton; and

Societal cost is taken as 163 €/ton[25], the benefit is calculated as follows:

- B2 benefit = (0.8 – 0.2) × (163 – 27) = 81.6 M€/yr

5.2.3 Monetisation

The second part of this indicator is measured in €/yr and is, therefore, monetised by default.

The CO_2 cost used should be based on reputable scientific investigations and international studies. Because of the expected spread of values that typically arise from different sources, the costs that are used can be given as a range, e. g. by defining minimum, medium and maximum values, and should ideally be agreed between the main stakeholders and reflect the most recent values as given by the EC. The values used for the monetisation of this indicator have to be given within the study-specific Implementation Guidelines, together with a link to the scientific and agreed study. The societal cost of carbon can represent two concepts:

- The social cost that represents the total net damage of an extra metric ton of CO_2 emission due to the associated climate change;[26] and
- The shadow price determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint.[27]

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[25] This is only an example.

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

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

5.2.4 Double-counting

It is important to emphasise that this ‘societal cost of CO_2’ is a different concept to the price of CO_2 that is imposed on carbon-based electricity production, which may take the form of carbon taxes and/or the obligation to purchase CO_2 emission rights under the ETS. The cost of the latter is internalised in production costs and has a direct effect on SEW; hence, it is fully captured by indicators B1 and B5 (and also reported as such alongside the B1 and B5 indicators). However, the cost of CO_2 imposed on electricity producers does not necessarily reflect the total societal effect nor does it give the necessary incentive to reach the European climate goal. Setting the value of avoided CO_2 emissions is a political choice. Moreover, it is one that requires reliance on different, and potentially contradicting, reports on the actual long-term harmful effects of CO_2.

The reporting requirements are described in the reporting sheet in Table 6.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tons/yr	Per definition not monetary	European
CO_2 emission from losses variation	Network studies (losses computation)			
Societal costs of CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	€/yr	Societal costs decreased by ETS costs as used in the scenario (to avoid double accounting with B1)	
Societal costs of CO_2 emissions from losses variation	Network studies (losses computation)		Societal costs decreased by ETS costs as used in the scenario (to avoid double accounting with B5)	

Table 6: Reporting Sheet for this Indicator in the TYNDP

5.3 B3: Methodology for RES Integration Benefit

Indicator definition:

- Definition: This measures the reduction of renewable generation curtailment in MWh (avoided spillage) and/or the additional amount of RES generation that is connected by the project in MW.
- Relevance: As RES integration can be considered the main driver for reducing the CO_2 output, it will be given as stand-alone indicator.

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on the RES integrated in the system as comparison with/without the project; or: direct measure when directly connecting RES sources.
- Quantitative measure: this indicator is given in MWh/year for reduced RES spillage or in MW for direct connected RES sources.
- Monetisation: this indicator will not be monetised

Interlinkage to other CBA indicators:

- B1, B2

5.3.1 Introduction

The RES Integration Benefit indicator provides a stand-alone value for the additional RES available for the system as a result of the reinforcement project or investment. It measures the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the project. The volume of integrated RES (in MW or MWh) must be reported in any case. The integration of both existing and planned RES is facilitated by:

- The connection of RES generation to the main power system; and
- Increasing the capacity between one area with excess RES generation to other areas to facilitate an overall higher level of RES penetration.

5.3.2 Methodology

An explicit distinction is made between RES integration projects related to either:

- The direct connection of RES to the main system; or
- Projects that increase the capacity in the main system itself.

Although both types of projects can lead to the same indicator scores, they are calculated on the basis of different measurement units.

Direct connection is expressed in $MW_{RES\text{-}connected}$ (without regard for actual avoided spillage).

The capacity-based indicator is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system.[28]

Avoided spillage is extracted from the studies for indicator B1. Connected RES is only applied for the direct connection of RES integration projects. Both types of indicators may be used for the project assessment, provided that the method used is reported. In both cases, the basis of calculation is the amount of RES foreseen in the scenario or planning case.

5.3.3 Monetisation

This indicator is measured in MW or MWh; by default it is not monetised.

5.3.4 Double-counting

Indicator B3 reports the increased penetration of RES generation in the system. As this also affects the input parameters of the simulation runs, the economic effects, in terms of variable generation costs and CO_2 emissions, are already fully captured in other indicators (i. e. B1 and B2, respectively).

The reporting requirements are described in the reporting sheet in Table 7.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
Connected RES	Project specification	MW	Per definition not monetary	European
Avoided RES spillage	Market, or redispatch studies	MWh/yr	Included in generation cost savings (B1) and variation in CO_2 emissions (B2)	European

Table 7: Reporting Sheet for this Indicator in the TYNDP

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[28] Calculating the impact of RES in absolute figures (MW) facilitates the comparison of projects throughout Europe when considering the sole aspect of RES integration. Relative numbers (i.e. the contribution of a project compared to the objectives of the NREA) can easily be calculated ex-post for analysis at a national level.

5.4 B4: Methodology for Non-Direct Greenhouse Emissions Benefit

Indicator definition:

- Definition: This indicator gives the change in non-direct greenhouse emissions due to a new project or investment.
- Relevance: In addition to the B2 indicator, other non-CO_2 emissions must also be considered as they also have an impact on climate change and cannot be neglected. Pollution levels are increased via direct emissions, such as particulate matter and toxic elements, or via indirect methods that promote chemical reactions.

Indicator calculation:

- Model: Market simulations, Redispatch simulations; based on the non-CO_2 emissions comparison with/without the project.
- Quantitative measure: this indicator is given in tons/year
- Monetisation: this indicator will not be monetised

Interlinkage to other CBA indicators:

- none

5.4.1 Introduction

Following the Paris Climate Agreement, the goal of reducing greenhouse gases is focused on keeping the global temperature increase below two degrees Celsius relative to pre-industrial levels. The main focus in achieving this goal is the reduction in CO_2 emissions, which is described as a benefit indicator in B2: Methodology for Additional Societal benefit due to CO_2 variation .

In addition, other non-CO_2 emissions must be considered as they also have an impact on climate change and cannot be neglected. Pollution levels are increased via direct emissions, such as particulate matter and toxic elements, or via indirect methods that promote chemical reactions (e. g. cause acid rain). To properly consider the mitigation effects of transmission projects, specific efforts should also be taken for these non-CO_2 emissions. This should at least include the main emission types of CO, NO_2 (including NO that reacts to form NO_2 within the atmosphere), SO_2 and particulates (PM_2. PM_5 and PM_{10}).

5.4.2 Methodology

The quantity of each emission type can be calculated as a post process based on the year-round power plant dispatch produced by the market (redispatch) simulations. This is achieved by multiplying a specific emission factor in [t/MWh] by the yearly generation in [MWh] of a single power plant. In principle this must be done for each power plant and each emission type as the emission mechanism is specific for each single thermal power plant. As this is a very complex topic, for sake of simplicity, the emission model can be applied per technology type. It should be noted that, in general, these emission types can differ for different countries depending on the installed composition of power plants, e. g. more modern power plants will have a higher efficiency and, therefore, a lower emission factor, but old power plants can also install new technologies to reduce non-CO_2 emissions (e. g. low NOx burners). This needs to be considered when defining the fuel type specific emission factors. If this is not possible because of the lack of sufficient data availability, the reduction to one factor per emission type can also be accepted.

The non-CO_2 indicator/s can be calculated per fuel type by multiplying the specific emission factor (for all emission types) in [t/MWh] by the respective generation in [MWh]. The indicator will be given in tons per year [t/yr].

The used emission factors need to be given within the implementation guidelines of the respective study.

5.4.3 Monetisation

A monetisation of the non-CO_2 indicator is currently not proposed in this methodology. This is because it is unlikely that future improvements in emission reductions, because of filters or increases in efficiency, will have a comparable effect at lower costs. When monetising the non-CO_2 indicator, a project might become beneficial, or even non-beneficial, simply because of this impact, which is most likely not the main aim of building the project. Therefore, it can be strongly impacted by future technologies. However, currently no such future technologies are in place, the non-CO_2 indicator has to be shown on a quantified basis to complement the CBA assessment.

5.4.4 Double-counting

As there are no interlinkages to other indicators for this indicator, no double accounting can occur.

The reporting requirements are described in the reporting sheet in Table 8.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
Non-CO_2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tons/yr	Per definition not monetary	European

Table 8: Reporting Sheet for this Indicator in the TYNDP. Each single emission type has to be given separately

5.5 B5: Methodology for Variation in Grid Losses Benefit

Indicator definition:

- Definition: The Variation in Grid Losses Benefit indicator is used to reflect the changes in transmission system losses that can be attributed to a project or investment.
- Relevance: The energy efficiency benefit of a project is measured through the change of thermal losses in the grid. At constant power-flow levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load-flow pattern when they decrease the distance between production and consumption. Increasing the voltage level and the use of more efficient conductors also reduces losses.

Indicator calculation:

- Model: Network studies; based on the losses comparison with/without the project.
- Quantitative measure: losses are given in MWh/year
- Monetisation: amount of losses multiplied by marginal costs

Interlinkage to other CBA indicators:

- B1, B2

5.5.1 Introduction

The Variation in Grid Losses Benefit indicator is used to reflect the changes in transmission system losses that can be attributed to a project or investment.

The energy efficiency benefit of a project is measured through the change of thermal losses in the grid. At constant power-flow levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load-flow pattern when they decrease the distance between production and consumption. Increasing the voltage level and the use of more efficient conductors also reduce losses.

It should be noted that currently, the main driver for transmission projects is the need for transmission over long distances, which may increase losses. Although new interconnections generally decrease the electrical resistance of the grid and consequently the losses, the additional exchanges, resulting from the increase of the transfer capacities, and the change in generation size can lead to the increase. The precise location of generation units also has a significant effect on the amount of losses as generation at different nodes leads to different flows.

5.5.2 Methodology

The difference in losses (in units of energy [GWh][29]) and its monetisation is calculated for each project by calculating the grid losses in two different simulations, with the help of network studies, i. e. one simulation with the project and one simulation without the project.

Relevant geographical area/grid model

The calculated losses should be representative of Europe as a whole. However, they may be approximated by a regional losses-modelling approach for the time being. Thus, the minimum requirement should be to use **regional network model(s)**. These regional models should include at least the relevant countries/bidding areas for the assessed project, typically the hosting countries, their neighbours, and the countries on which the project has a significant impact in terms of cross-border capacity or generation pattern (as given by the market simulation). Practically, the model for the whole synchronous area in which the project is located should be used. In the case of HVDC projects that connect different synchronous areas, the losses need to be calculated in both synchronous areas (unless the HVDC project is connected to a third country).

By default, losses must be calculated using AC load-flow. If AC load-flow cannot be implemented in a reliable way (taking into account modelling assumptions, available input data, and calculation times), then exceptionally DC load-flow can be used to approximate the active power-flows.

When DC load-flow is used, the results of the calculations are the active power-flows on the AC lines and transformers. As the grid model contains the resistance values for all branches, the losses on each branch can be estimated using the following formula:

$$Losses\ [MW] = R\,\frac{P^2}{U^2 \cos^2 \varphi}$$

Where:

- P is the active power-flow from the DC calculation;
- R is the resistance of the branch;
- U is the voltage level; and
- Cos φ is an assumed power factor used to estimate the effect of reactive flows. For this, a common value (e. g. 0.95) is to be used for all calculations within a study.

The result of the losses calculation should provide an amount of losses **at least at a market node level** for the countries included in the model to monetise them.

Relevant period of time

A calculation over the complete year, with sufficiently small timesteps (typically one hour), should aim to be the closest to reality. The chosen methodology must be representative for the considered period of time, which must be verified within the study (e. g. in the current TYNDP scenarios, this means one complete calendar year).[30]

Market results/generation pattern with and without the project or in grid-stressed situations

As a TYNDP project will likely have an impact on internal or cross-border congestions, the generation pattern can differ significantly with and without the project, thus having an impact on losses. The change in generation can be considered through:

- A change in the NTC used for the market simulation, and/or
- For internal projects/generation accommodation projects, a re-dispatch methodology could be used.

In any case, the new generation pattern should not cause congestions elsewhere in the grid.

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[29] Due to possible magnitude, an appropriate representation should be used e.g., GWh.

[30] As a provisional exception, a computation of losses based on definite points in time can be used to approximate year-round losses. In such case, the chosen points in time should be sufficiently numerous to ensure representativeness and weighted in a correct manner.

5.5.3 Monetisation

When the losses (i. e. in MWh) are calculated, they can be monetised. It is important when calculating the monetised values that this is done in a consistent manner for all assessed projects. Generally, this should be assessed with the perspective of the cost that is borne by society to cover losses.

The approach is based on market prices that are taken from the marginal cost, as given by the market simulation. More precisely, for a given project, losses are calculated for each time step of the year, **h**, and each market zone, **i**:

- The amount of losses, $p'_{h,i}$ (with project) and $p_{h,i}$ (without project) in MWh after eventual measures for securing the grid situation; and
- The marginal costs, $s'_{h,i}$ (with project) and $s_{h,i}$ (without project) in €/MWh for a given time step.

The delta cost of losses should be calculated as the sum of h and i of the term $(p'_{h,i} \times s'_{h,i}) - (p_{h,i} \times s_{h,i})$. In this case, eventual re-dispatch costs are not considered.

The prerequisites for the calculation are the computation of the marginal cost and amount of losses for each market zone, with and without the assessed project.

The formula for losses monetisation is as follows:

$$Yearly\ cost\ C = \sum_i \left(\sum_h s_{h,i} \times p_{h,i} \right)$$

The yearly cost has to be calculated for the base case and the TOOT or PINT case (depending on the type of the project), using two market outputs. The final monetised result (i. e., delta cost) is the difference between the two cases.

The market simulations may contain extremely high marginal costs in certain hours for modelling reasons, such as in the case of ENS. Consequently, the marginal price during these hours does not represent the societal cost and, if used for monetisation, can distort the results. Therefore, for each market node, the market price used for the losses' monetisation should be capped to the most expensive generation category of the scenario.

It is important to note that the losses calculated with the project do include the losses on the project elements themselves.

Since the increase in losses is considered as costs, the monetised value have negative sign when reported as a benefit.

The reporting requirements are described in the reporting sheet in Table 9.

Parameter	Source of Calculation*	Basic Unit of Measure	Monetary Measure	Level of Coherence
Losses	Network studies	MWh/yr	€/year (market-based)	European

* Cf Annex IV, 2c.

Table 9: Reporting Sheet for this Indicator in the TYNDP

Double-counting

For the market simulations, demand curves are built to contain grid losses (i. e. using historical time series), which means that parts of the losses are already monetised under the B1 indicator SEW (namely, in the consumer surplus, which considers the effect of the change in marginal costs, brought about by the project, on the losses part of the demand).

This effect needs to be considered when monetising the losses from the network simulations.

There are two possible assumptions that can be made to deal with this issue:

Compensation assuming a given proportion of the demand as losses:

In this case, the compensation of the results with assumptions for the losses included in the demand in each market node is needed. As the typical grid losses may significantly vary among countries, it is recommended to not use a uniform European value. The following compensation term must be computed for both reference and TOOT/PINT cases, and then subtracted from the monetised losses:

$$Compensation = \sum_i \left(\sum_h K s_{h,i} d_{h,i} \right)$$

Where:

- **K** is the portion of the demand assumed to be losses, and
- **$d_{h,i}$** is the demand on the market node, **I**, in hour, **h**.

With this compensation, the monetised delta losses are:

$$Delta\ Losses\ (monetised) = \sum_i \left(\sum_h s'_{h,i} p'_{h,i} - s_{h,i} p_{h,i} - K d_{h,i} (s'_{h,i} - s_{h,i}) \right)$$

Generally, the K factor might come from the TSOs, or assumed centrally for each country, based on historical values.

Compensation with the computed losses:

Assuming that the losses computed in the reference case are included in the demand, the formula to monetise the delta losses simplifies to the following:

In the case of PINT projects:

$$Delta\ Losses\ (monetised) = \sum_i \left(\sum_h s'_{h,i} (p'_{h,i} - p_{h,i}) \right)$$

In the case of TOOT projects:

$$Delta\ Losses\ (monetised) = \sum_i \left(\sum_h s_{h,i} (p'_{h,i} - p_{h,i}) \right)$$

The advantage of this method is that no data collection from the TSOs, or any further assumptions, are necessary, but the computed losses might differ from the unknown losses included in the demand.

An example is provided below that demonstrates how the simplified formulas can be obtained.

Example: Illustration of the two assumptions used to deal with double counting using one hour and one market area.

A simple example is presented below for only one hour and one market area to demonstrate the double-counting problem and the two different assumptions for the compensation.

Starting from the original formula (for one hour):

- Delta monetised losses = p’ × s’−p × s

Now assume:

- A: being the general losses (e. g. 2 % of actual load)
  - A
- B: is the difference between A and the calculated losses in the reference case
  - B = p−A for PINT projects and B = p’−A for TOOT projects
- C: is the difference between the losses with and without the project
  - C = p’−p

Let us write **p** and **p’** using A, B and C (Although A and B are not known, C can be derived from grid simulations):

In the reference case, the losses are always equal to A + B (**p** in the case of PINT projects and **p’** in the case of TOOT projects).

Then, the PINT and TOOT cases need to be handled separately.

In the case of PINT projects:

$$p=A+(p-A)=A+B$$
$$p'=A+(p-A)+(p'-p)=A+B+C$$

In the case of TOOT projects:

$$p'=A+(p'-A)=A+B$$
$$p=A+(p'-A)-(p'-p)=A+B-C$$

The delta monetised losses will become:

$$p' \times s'-p \times s$$
$$(A+B+C) \times s'-(A+B) \times s \text{ for PINT projects;}$$
$$(A+B) \times s'-(A+B-C) \times s \text{ for TOOT projects.}$$

Simple equation transformation leads to:

$$A \bullet (s'-s)+B \times (s'-s)+C \times s' \text{ for PINT projects;}$$
$$A \bullet (s'-s)+B \times (s'-s)+C \times s \text{ for TOOT projects.}$$

Only the first term is already included in the SEW (delta in consumer surplus), therefore, only this part is double accounted and needs to be subtracted.

But as A is not known, one of the two assumptions needs to be made:

- Assume an estimate of A:

  After having calculated the change in losses as: p' × s'−p × s, a correction needs to be applied. Assuming that A is 2 % of the load, then the correction (to be subtracted from the final result) becomes:

$$0.02 \times load \times (s'-s)$$

- Assume that the calculated losses are equal to the assumed losses. In this case, B will equal 0, and the monetised change in losses is given by:

$$A \bullet (s'-s)+B \times (s'-s)+C \times s' \text{ or}$$
$$A \bullet (s'-s)+B \times (s'-s)+C \times s$$

  This will be reduced to C × s' for PINT projects and C × s for TOOT projects because B is 0 and the first term is already included in the SEW.

5.6 B6: Methodology for Security of Supply: Adequacy to Meet Demand Benefit

Indicator definition:

- Definition: Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand at any moment in time.
- Relevance: A new interconnector may help adequacy by pooling the risk of loss-of-load while simultaneously pooling the means (generation capacity) to deal with it. The interconnector can mitigate the adequacy risks among European countries and, in particular, the two linked by the interconnector.

Indicator calculation:

- Model: Monte Carlo-based Market simulations; based on the EENS comparison with/without the project.
- Quantitative measure: EENS avoided is given in MWh/year
- Monetisation: multiplying the EENS reduction by the VOLL

Interlinkage to other CBA indicators:

- none

5.6.1 Introduction

Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand at any moment in time, i. e. a sufficient volume of power is available and can be physically delivered to consumers at any time, including under extreme conditions (e. g. cold wave, low wind generation, unit or grid outages, etc.).

To achieve this, generation and transmission capacity are complementary elements: i. e. generation capacity requires a transmission grid for power to flow from the generation source to the load. This is particularly relevant in the context of geo-temporal fluctuations in intermittent RES, which may require certain areas to depend on generation that is only available in other areas at a certain moment. Transmission capacity makes it possible to meet demand in one area with generation capacity that is located in another area.

A new interconnector may help adequacy by pooling the risk of loss-of-load while simultaneously pooling the means (generation capacity) to deal with it. The interconnector can mitigate the adequacy risks among European countries and, in particular, the two linked by the interconnector. The less likely it is that the stressed events of the countries occur simultaneously, the higher the adequacy benefit of a new interconnector. Non-simultaneous stressed events mean that when one country is facing adequacy risks, the other could provide power.

Practically, the benefit can be seen in two ways:

- A decrease in the need for generation capacity: For an equivalent SoS level, in terms of LOLE[31] and EENS, an interconnector can decrease the peaking unit capacity needs; and
- A decrease in EENS volumes: When only one country is facing a loss of load, a new interconnector can help to import more, thereby reducing EENS.

More generally, the benefit could be a combination of the two effects (with the combination evolving over time).

The adequacy benefit of a project or investment can be assessed using two approaches. One approach uses the decrease in peaking unit investment needs (for the same SoS level). Another approach uses the reduction of EENS volume (installed capacity remaining constant). Some implementation difficulties favour the use of an EENS-based methodology. However, a sanity check based on investment saving is proposed to make the assessment more robust. This allows a link to be made with benefit that might be present for some countries that have capacity remuneration mechanisms in place for adequacy purposes.

Loss of load is a rare phenomenon, resulting from the combination of extreme events. Studying loss of load, therefore, requires a refined model of the hazards that could affect the power system. This refined model is essential to depict loss

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[31] LOLE represents the expected number of hours over a year when loss would occur (for each country it results from a comparison of load with available generation and possible exchange with neighboring countries).

of load characteristics, such as its deepness and simultaneity with other countries. **Several hundreds of Monte Carlo years are consequently necessary** using the several climate year datasets (to be applied using the principles as described in section 2.6 on climate years) combined with plant (and if possible grid) outage patterns.

In addition, studying adequacy requires generation portfolios to be adequate. This means that LOLE should be realistic and reasonable.[32] The scenario used to compute the SoS adequacy benefit must abide by this principle. It is advisable to ensure that such a setup is met without the studied project to avoid unrealistically high LOLE when removing the project. TYNDP scenarios are adequate under the reference grid; so for TOOT projects, a small adaptation could be necessary if the countries are no longer adequate when the project is removed. The adaptation would only consider the addition of a few peaking units.

5.6.2 Methodology

The methodology involves a number of steps, described as follows:

Step 1

If necessary, the scenario should be adapted to ensure realistic LOLE levels without the project. The LOLE is considered realistic if it is in a range of 1 hour lower or higher than the LOLE legal standard.

This step is only needed for TOOT projects as the scenarios should be already adapted for the reference grid. Thus, it might be necessary to add peaking power plants in certain countries to adhere to the adequacy standard without the project. If an adjustment must be made, its extent should be clearly reported.

This step is necessary because for some TOOT projects, removing the interconnector would lead to an unrealistically high LOLE and, consequently, unrealistically large values. This situation would not have occurred if the interconnector had not been commissioned, because the generation fleet would have increased to avoid such LOLE. Note that for the assessment, ENTSO-E generally makes the (simplified) assumption that generation is not dependent on the interconnector levels. This assumption cannot hold in the case of adequacy, which is directly impacted by both generation capacities and interconnector levels. Therefore, the slight adaptation may be needed for TOOT projects, making the assessment slightly conservative.

If such adaptations to the scenarios are needed, the respective actions must be given within the respective study.

Step 2: EENS saved

Perform two Monte Carlo simulations with and without the project and assess the EENS reduction. Monetise the benefit by multiplying the EENS reduction by the VOLL (both VOLL and LOLE have to be defined within the study specific Implementation Guidelines).

Step 3: Sanity check

A sanity check is performed to cap the value computed by EENS savings. This cap represents the value of the generation capacity that would have been necessary to reach an equivalent level of adequacy (compared with the addition of the project). Note that for an X MW interconnector, 2 × X MW of peaking unit capacity is an immediate cap. The details on how to perform the sanity check need to be given in the respective study (e. g. the Implementation Guidelines for TYNDP).

5.6.3 Monetisation

This indicator is measured in €/yr, so it is monetised by default.

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[32] Using national adequacy standard, for instance; if such standards don't exist, use 3h/yr.

5.6.4 Double-counting

As for this indicator, there are no interlinkages to other indicators, so no double accounting can occur. The reporting requirements are described in the reporting sheet in Table 10.

Parameter	Source of Calculation*	Basic Unit of Measure	Monetary Measure	Level of Coherence
Level of Adequacy	Market simulations	MWh/yr	€/year (market-based)	European

* Cf Annex IV, 2c.

Table 10: Reporting Sheet for this Indicator in the TYNDP

5.7 B7: Methodology for Security of Supply – System Flexibility Benefit

Indicator definition:

- Definition: The capability of an electric system to face the system-balancing energy needs in the context of high penetration levels of non-dispatchable electricity generation.
- Relevance: Cross-border interconnections can play a fundamental role in the integration of non-dispatchable energy generation as they support ramping where deviations are balanced over a power system covering a wider area. By balancing these fluctuations across larger geographic areas, the variability of RES effectively decreases and its predictability increases.

Indicator calculation:

- Model: B7.1: Market simulations; based on the projects impact on shared balancing energy. B7.2: qualitative description
- Quantitative measure: B7.1: ordinary scale ; B7.2: qualitative description
- Monetisation: monetisation is not recommended until dataset and assumptions are not consolidated

Interlinkage to other CBA indicators:

- none

This section describes the methodology for a quantitative assessment (non-monetised) of flexibility, pending methodology developments of B7.1 and B7.2.

The System flexibility indicator (B7) seeks to capture the capability of an electric system to face the system-balancing energy needs in the context of high penetration levels of non-dispatchable electricity generation. These changes are expected to increase in the future, which requires more flexible conventional generation to deal with the more frequent and acute ramping-up and ramping-down requirements.

Cross-border interconnections can play a fundamental role in the integration of non-dispatchable energy generation as they support ramping where deviations are balanced over a power system covering a wider area. By balancing these fluctuations across larger geographic areas, the variability of RES effectively decreases and its predictability increases. Transmission capacity thus provides a form of flexibility in the system by increasing the available flexible units that can be shared between different control areas. Storage technologies, DSR and the participation of RES can also play an important role in providing flexibility to the system.

The true valuation of system flexibility – within the limits of a Guideline on Electricity Transmission System Operation (SOGL) – is ultimately the valuation of the system needs and means for balancing energy exchanges, to which grid development (interconnections and internal reinforcements) will exert its influence.

The B7.1 indicator, and its methodology, might ultimately have to evolve in this direction –subject to satisfactory implementation, which is currently under development –in order to accurately calculate and reflect the SEW expected from the mandatory exchange of balancing energy products. In this sense, ENTSO-E has started acquiring necessary data, hypothesis development and analysis to investigate the setup of such market models.

5.7.1 B7.1: Balancing energy exchange (aFRR, mFRR, RR)

This indicator has to be considered a 'non-mature' indicator

Introduction

The exchange and sharing of ancillary services products, in particular balancing energy exchanges, is crucial to increase RES integration and to enhance the efficient use of available generation capacities.

The balancing services indicator shows welfare savings through the exchange of balancing energy and imbalance netting. Balancing energy refers to products such as RR, mFRR and aFRR.

New interconnectors and internal reinforcements with cross-border impact can enable the exchange of balancing energy across national balancing markets, where cross zonal capacity remains unused after market-closure in either direction (upward or downward activations). Exchanging balancing energy will enable cheaper bids from neighbouring markets to displace more expensive bids in the local balancing market, leading to cost savings and improvement in the net welfare.

The full assessment of balancing energy exchanges can only be realised when platforms for exchanging balancing energy exist. There is a challenge when it comes to choosing the right balance between the complexity and feasibility of completing assessments, timescales and resource levels. On the other hand, producing full models for balancing energy markets may be too time-consuming. For these reasons, this benefit is addressed by qualitative assessment, as indicated in table 11.

Available approaches	Source of Calculation	Basic Unit of Measure
Balancing Energy Exchanges	Qualitative studies or principles propose	0/+/++

Table 11: Reporting Sheet for this Indicator in the TYNDP

Where:

0: No change: the technology/project has no (or just marginal) impact on the Balancing Energy Exchanges indicator.

+: Small to moderate improvement: the technology/project has only a small impact on the Balancing Energy Exchanges indicator.

++: Significant improvement: the technology/project has a large impact on the Balancing Energy Exchanges indicator.

In addition, a detailed description of how the qualitative indicators have been defined is given within the study-specific Implementation Guidelines.

Methodology

The basic principle of this method is that increasing cross-border capacity could lead to an increase in balancing energy exchanges between control areas and, consequently, a reduction in balancing energy costs. The scope is to quantify this reduction in balancing cost. The expected outcome will eventually show an increase or decrease in the overall welfare of the system.

Common Platform

It is assumed that in the future, there will be platforms to exchange balancing energy products, such as 'EU imbalance netting', TERRE, MARIE and PICASSO[33] market. The balancing platforms presuppose that the settlement rules will be harmonised to marginal pricing across different markets.

The platform also presupposes that there will be standard balancing products to be exchanged. Common balancing platforms are expected to be rolled out as part of the balancing guidelines implementation. This assumption can be tested and adjusted for projects that do not have a foreseeable common platform.

Balancing Needs[34]

A system imbalance that needs to be resolved is assumed. The volume required varies across MS, and assumptions would be made about what this would be over the lifetime of the project being assessed. These needs are not easy to forecast as generation and consumption mix are evolving, and a cross-border project could itself increase the balancing needs across to bidding areas.

One option could be to use historical balancing needs, assuming that they will apply in the future. However, as the share of RES in the energy mix and the number of interconnectors is increasing, using historical data has the risk of underestimating future balancing needs. It is strongly recommended to study the effects of this type of assumption.

Cross-border Exchange Capacity

The available cross-border capacity after market-closure, which can be used to exchange balancing energy, will be determined. This capacity in both directions will be calculated as an output from the TYNDP market simulations with and without the project. The simulation results will show the remaining cross-border capacity for every hour in the modelled years that is available to exchange balancing energy between control areas.

Opportunity for Imbalance Netting

The opportunity for imbalance netting between control areas will be determined. The opportunity for imbalance netting in one direction does not necessarily require available cross-border capacity and can be achieved even if the link is fully congested for market flows. In situations where imbalance netting requires flows in the same direction as market flows, there is a need for available cross-border capacity. The model should calculate the volume of imbalance netting that is possible.

Balancing Bids and Offers[35]

The balancing bid prices stack for the different balancing markets will be established. There are four proposals to determine this, with increasing levels of complexity:

- Determine the seasonal average 'balancing bid prices' using historical data;
- Determine hourly national 'balancing bid price' curves, i. e. prices and volumes offered, using historical data;
- Determine historical 'balancing bid price' savings exchanged through a balancing platform; and;
- Determine hourly national 'balancing bid price' curves, i. e. costs and volumes offered, using forecast data that reflects changes to generation mix (considering the technologies available for participating in the balancing market).

Balancing Cost Savings

For imbalance netting, the cost savings will be calculated as the difference of the balancing costs with and without the project.

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[33] It is mandatory and required by Electricity Balancing Guideline (EBGL) to setup standard platforms for the exchange of balancing energy towards 2022–2023.

[34] Balancing needs for upwards and downwards reserves.

[35] Balancing bids and offers for upwards and downwards reserves.

Monetisation

Until the dataset and assumptions necessary for this indicator are not consolidated and tested, it is not recommended to assign a monetary value to this benefit. The reporting requirements are described in the reporting sheet in Table 12.

Parameter	Source of Calculation*	Basic Unit of Measure	Monetary Measure	Level of Coherence
Flexibility in terms of balancing energy exchange	Market simulations	Ordinal scale	Not monetised	Regional/PP level

* Cf Annex IV, 2c.

Table 12: Reporting Sheet for this Indicator in the TYNDP

5.7.2 B7.2: Balancing capacity exchange/sharing (aFRR, mFRR, RR)

This indicator has to be considered a 'non-mature' indicator

Qualitative description

This section describes the principles behind the aFFR, MFRR and RR flexibility services, but does not yet put forward a specific methodology to be applied for their quantification or monetisation. The production of such a methodology will require further analysis, investigation of hypotheses and testing within ENTSO-E. The final methodology should follow in a future updated version of this CBA Guideline.

These types of services are possible and allowed within, and between, synchronous areas (SAs), when operational limits are respected. The relevant operational limits are specified in Annex VII of the System Operation Guideline (SOGL), both between Load Frequency Control (LFC)-blocks and between LFC-areas of the same LFC-block and specifications of Art, 175-179. Both services require the exchange of balancing energy as a precondition (see B7.1).

In the event of balancing capacity exchange between LFC-blocks, for either FRR or RR, the total contracted balancing capacity remains equal in terms of total volume, but the final obligations are displaced to another asset that can deliver it more optimally from a price perspective (lower fuel costs).

In the event of balancing capacity sharing between LFC-blocks, for either FRR or RR, the total contracted balancing capacity is lower in terms of total volume. This implies that fewer volumes are blocked from participating in other markets (wholesale DA/ID, balancing, etc.), potentially contributing to increasing overall welfare.

Specific grid development projects[36] can increase these potential welfare benefits by giving access to potentially cheaper assets that can deliver the FRR or RR service, provided the SOGL rules are respected and available cross-border capacity is guaranteed. This can then, theoretically, result in a more optimal system operation and a reduction in overall system fuel costs. The net welfare effect is, however, to be calculated and compared with the welfare calculations in other markets (e. g. wholesale) because for balancing capacity exchange, XB-capacity needs to be reserved, which is then no longer available for the wholesale market.

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[36] Both XB-lines as internal reinforcements that resolve congestions, or limitations that would otherwise have resulted in an exclusion of this flexibility in the dimensioning or procurement stage, as described for FRR in Art 157 (g) & 159 §7 and for RR in Art 162 in SOGL.

5.8 B8: Methodology for Security of Supply: System Stability Benefit

Indicator definition:

- Definition: The objective of including a system-stability metric is to provide an indication of the change in system stability as a result of a reinforcement project, such as a new interconnection. The Security of Supply: System Stability Benefit indicator is addressed using four separate sub-indicators, namely: B8.0 Qualitative stability indicator; B8.1 Frequency stability; B8.2 Black start services; and B8.3 Voltage/reactive power services.
- Relevance: Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. The assessment of system stability typically requires significant additional modelling and simulations to be undertaken. The studies are by their nature complex and time consuming making them challenging to include within the TYNDP process. It is however practical to consider a simplified and generic representation of the potential impact of reinforcement on system stability based on the technology being employed.

Indicator calculation:

- Model: B8.0: qualitative measure; B8.1: based on the projects impact on RoCoF and NADIR and qualitative description; B8.2: Qualitative description; B8.3: qualitative description
- Quantitative measure: see under 'model'
- Monetisation: B8.0: not monetised; B8.1: not monetised; B8.2: not monetised; B8.3: not monetised

Interlinkage to other CBA indicators:

- none

The objective of including a system stability metric is to provide an indication of the change in system stability as a result of a reinforcement project, such as a new interconnection. The Security of Supply: System Stability Benefit indicator is addressed using four separate sub-indicators, namely:

- B8.0 Qualitative stability indicator;
- B8.1 Frequency stability;
- B8.2 Black start services; and
- B8.3 Voltage/reactive power services.

Each of these indicators is discussed in detail below.

5.8.1 B8.0: Qualitative stability indicator

Introduction

This section describes the methodology for a qualitative assessment (non-monetised) of stability, pending methodology development of B8.1–B8.3.

Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. Examples of physical disturbances could be electrical faults, load changes, generator outages, line outages, voltage collapse or some combination of these.

The assessment of system stability typically requires significant additional modelling and simulations to be undertaken, for which the supporting models would be required. The studies are by their nature complex and time-consuming, making them challenging to include within the TYNDP process. It is, however, practical to consider a simplified and generic representation of the potential impact of reinforcement on system stability based on the technology being employed.

Methodology

System stability is addressed by qualitative assessments of Transient Stability; Voltage Stability and Frequency Stability.

For each of the technologies, the generic impact on Transient, Voltage and Frequency Stability are indicated in Table 13.

Element	Transient Stability	Voltage Stability	Frequency Stability
New AC line	++	++	0
New HVDC	++	++	+ (between synchronous areas)*
AC line series compensation	+	+	0
AC line high temperature conductor/conductor replacement (e.g. duplex to triplex)	–	–	0
AC line Dynamic Line Rating	–	–	0
MSC/MSR (Mechanically Switched Capacitors/Reactors)	0	+	0
SVC	+	+	0
STATCOM	+	++	0
Synchronous condenser	+	++	++

* For the assessment of the impact of HVDC within one synchronous area on the frequency stability the B8.1 indicator has to be applied.

Table 13: Security of Supply: system stability indicator, given as qualitative indicator related to the different technologies

Where:

–: Adverse effect: the technology/project has a negative impact on the respective indicator.

0: No change: the technology/project has no (or just marginal) impact on the respective indicator.

+: Small to moderate improvement: the technology/project has only a small impact on the respective indicator.

++: Significant improvement: the technology/project has a large impact on the respective indicator.

N/A: Not relevant: if a particular project is located in a region where the respective indicator is seen as not relevant,[37] this should also be highlighted by reporting as N/A.

In addition to this qualitative stability indication, Table 13 can also act as an indication of where further investigations on transient, voltage and frequency stability might be interesting, on the one hand, and where no further information is expected on the other.

Where detailed stability simulations have been completed and the results of such technical assessments are available, they may be provided to supplement the results obtained using the qualitative table provided in Table 13. For such cases, the generic representation contained in Table 13 may be modified to appropriately represent the results of the technical studies. It is necessary that the supporting reports are provided to corroborate the assessments and any modifications to Table 13. Currently, this quantitative assessment has been made for the impact of a reinforcement project on the frequency stability.

Monetisation

This indicator is measured in qualitative measures; it is by default not monetised.

5.8.2 B8.1: Frequency Stability (energy aspect)

Introduction

Frequency stability is defined as the ability of a power system to maintain a steady frequency within a nominal range, following mismatches between generation and demand on a continuous basis or following a severe system contingency, resulting in a significant imbalance between generation and demand. Following this definition, it is in general not expected that, even in future scenarios, frequency stability will become a serious issue under ordinary contingencies but rather in severe events, such as system splits, during situations with high power flows in the AC system and low inertia. However, in such critical situations, changes in the frequency when exceeding critical values could lead to local and even total system blackouts.

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[37] This might be the case when previous to the project assessment (e.g. inside the scenario building) the needs for SoS in relation to a certain effect (transient, voltage, frequency stability), defined on a regional level, have been determined as not relevant for a certain region.

Methodology

To assess the impact of a reinforcement project improving the frequency stability, the drop of the frequency of the system with and without the reinforcement project is compared through the rate of change of frequency (RoCoF) after an imbalance in the system. Such a system split needs to be elaborated by proving that the respective RoCoF is higher than 1 Hz/s in each region after the split.[38] The limit of 1 Hz/s is considered as the operation limit where frequency stability can be ensured with the existing control schemes (LFSM-O/ LFSM-U, Load Shedding).

The computation of the delta RoCoF with and without the project is undertaken on an hourly basis over a timeframe of one year.

Detailed motivations and a clear descriptions of the chosen system splits, together with the formula and all relevant parameters for the RoCoF calculation[39], have to be given within the study-specific Implementation Guidelines.

Together with these information, for each project a justification of the chosen split on which the projects is assumed having impact on needs to be given within the project-specific reporting sheets.

Monetisation

This indicator is not monetised.

Double-counting

Indicator B8.1 reports the delta RoCoF based on a distinct formula that is not applied to any other indicator. Therefore, no double counting can occur.

The reporting requirements are described in the reporting sheet in Table 14.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
Reduction of the mean RoCoF	Market studies	Hz/s	Per definition not monetary	European
Number of hours with RoCoF > 1 Hz/s		Number of hours		

Table 14: Reporting Sheet for this Indicator in the TYNDP

5.8.3 B8.2: Frequency Stability (capacity aspect)

This indicator has to be considered a 'non-mature' indicator

Introduction

Frequency stability is defined as the ability of a power system to maintain a steady frequency within a nominal range, following mismatches between generation and demand on a continuous basis or following a severe system contingency, resulting in a significant imbalance between generation and demand.

Methodology

This section describes the principles behind these types of services, but does not yet put forward a specific methodology to be applied to arrive at quantitative/monetised results, which require further analysis and testing. The final methodology should follow in the Implementation Guideline or in a future version of the CBA Guideline.

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[38] Further descriptions and examples of such systems splits can be found in the ENTSO-E study 'Frequency Stability in long-term Scenarios and relevant Requirements' under this link.

[39] It is recommended to base the further definitions on the ENTSO-E study 'Inertia and Rate of Change of Frequency (RoCoF)' to be found under the following link.

Between Synchronous Areas (SAs), i.e. 'frequency coupling':

Between Synchronous Areas, frequency support services are officially known as 'frequency coupling services', as described in SOGL. From a legislative perspective, both frequency capacity exchange as well as frequency capacity sharing are allowed based on Art. 171/172 of SOGL. The allowed technical services, or products, across HVDC links between SAs are described in the ENTSO-E SOC approved paper[40] and consist of frequency netting (FN), frequency exchange (FE) and frequency optimisation (FO). These are illustrated in Figure 10.

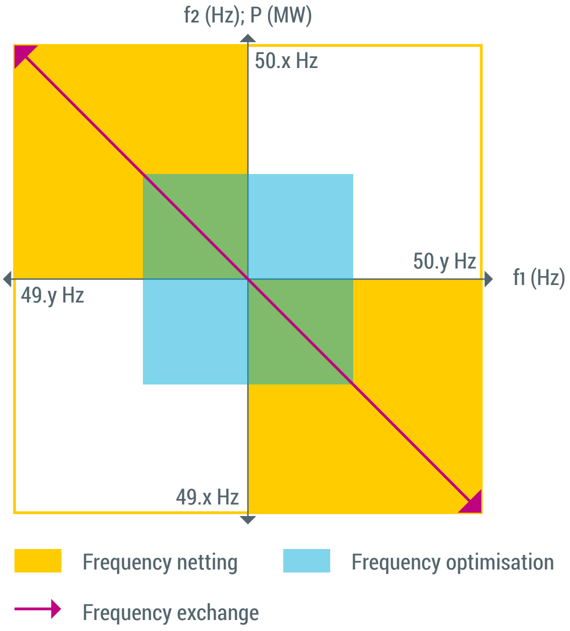

Figure 10: Illustration of the frequency netting and exchange

The specific limits and conditions to respect are described in the Synchronous Area Operational Agreements (SA-OA), which inherently cap the maximum potential of any benefits by setting up such services. The paper is in line with the stipulations set forward in Art. 171/172 of the SOGL. Across HVDC-cables, such services can indeed be implemented and unlock specific benefits that could theoretically be monetised (FCR capacity exchange or sharing) or non-monetised (general increase of frequency quality).

Frequency netting & optimisation contribute to the overall frequency quality of both connecting SAs. These benefits cannot be currently monetised in the CBA methodology as the direct relationship between frequency quality and the total amount of FCR reserves is not available. Only a qualitative assessment is possible, or quantification of the frequency quality indices. **Frequency exchange** requires physical FCR backup on the providing SA side and hence enables the exchange of FCR capacity, provided the service is 100 % available over the HVDC link. Such a setup could theoretically be monetised; however, a proper methodology cannot yet be proposed.

The benefits of the above-described services can be unlocked by certain grid development projects that enable additional HVDC links between SAs, provided the considered project has the technical capacity to enable such services (which should be included in the CAPEX). Pending further analysis and a final methodology in the Implementation Guideline or the next CBA version, the assessment of those benefits could work as follows:

For frequency netting and optimisation, in cases where the frequency quality contribution is systematic, both connecting SAs could agree in a sharing agreement to reduce the overall amount of FCR obligation. This is provided that the resulting frequency quality remains within the legal limits imposed by SOGL. In the event this volume could be accurately and realistically estimated, welfare benefits from other markets (SEW in DA/ID/balancing markets) can be calculated because of a reduced overall FCR obligation.

For frequency capacity exchange, the welfare benefits (SEW in DA/ID/balancing markets) are calculated by more optimally allocating the overall FCR obligation. As a cautionary note, this assumes that the allocation can be done in the most optimal manner; however, in practice FCR auction clearing happens before DA clearing. Therefore, the net effect can also be negative. Frequency exchange gives access to more (potentially cheaper) resources that can provide FCR.

Within a Synchronous Area:

Within a Synchronous Area, only frequency capacity exchange is allowed (not sharing), as described in Art. 163/164 of SOGL. Limitations for the capacity exchange (Annex VI of SOGL) stipulate fixed limits of 30 % of initial FCR obligations per LFC block for the CE SA, so theoretically there is no direct link to any grid development projects there – hence no direct benefits.

However, as described in other SAs (non-CE) or within LFC-areas of the same LFC-block within CE, cases where internal congestions would be alleviated, or a more even distribution of FCR can be obtained in the case of network

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[40] See here.

splitting, facilitated by those potential grid development projects, benefits could be present by giving access to more or cheaper assets that can then deliver the FCR service. This could theoretically result in a more optimal system operation (reducing overall system/fuel costs). The latter is also described in Art. 154 §4 of SOGL where geographic limitations could indeed apply that exclude certain units from participating, which would, if resolved by certain grid development projects, then increase the overall optimality of the system. To calculate or monetise such benefits, very specific localised information should be available and integrated with other welfare calculations in DA/balancing markets, in order to determine the effective monetised benefit.

5.8.4 B8.3: Black start services

This indicator has to be seen as 'non-mature' indicator

Introduction

This section proposes a methodology for how to assess black start services' contribution to the SEW of Europe.

Black start capability means that a power generating facility has the capability of recovering from a total shutdown through a dedicated auxiliary power source without any electrical energy supply external to the power-generating facility itself. For a power generating facility to provide black start services, there are certain criteria that need to be fulfilled, which are described in the connection code Requirements for Generators.

This type of service is normally contracted or imposed by TSOs to ensure that a minimum level of generation capacity is available for re-energising the power system after the event of a blackout in the entire, or part of, the control area. Such services are typically described and required by the network code on electricity Emergency and Restoration[41], and national legislation.

Certain grid development projects (internal or cross-border reinforcements) might reduce the need of the total required volume and/or unlock pathways for contracting more price-efficient units (lower fuel costs). This potentially reduces the overall system costs and contributes to overall welfare in other markets (e. g. wholesale or balancing markets) as more, typically peaking, units would consequently become available. They could also help to avoid new investments costs and reduce the blackout time.

5.8.5 B8.4: Voltage/reactive power services

This indicator has to be considered a 'non-mature' indicator

Qualitative description

Voltage or reactive power services/reserves are required from a TSO perspective to satisfy the SOGL regulation and are also described in national legislation. Typically, these services are contracted or imposed by TSOs, for a certain minimum level, on specific locations of the grid on existing market flexible units to ensure the voltage quality remains within the necessary system security limits. Alternatively, these services can also be ensured by investments in passive elements (capacitors/reactors) or active elements (power electronic devices such as STATCOMs).

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[41] See here.

5.9 B9: Reduction of Necessary Reserve for Redispatch Power Plants

Indicator definition:

- Definition: Change in needed reserves of redispatch power plants.
- Relevance: The maximum redispatch power is a direct indication of the need for reserve power plants and the difference (with and without the project) gives a direct indication of the change in needed reserve power plants.

Indicator calculation:

- Model: Redispatch simulations; based on a redispatch cost comparison with/without the project.
- Quantitative measure: this indicator is directly given in monetary values.
- Monetisation: per definition monetised and given in €/year

Interlinkage to other CBA indicators:

- B1, B2, B3, B4, B5

5.9.1 Introduction

This benefit indicator can only be calculated when applying redispatch simulations (for a detailed description on redispatch simulations see section 6.3) for the project assessment and must be added to the set of benefit indicators as described above.

The redispatch changes the cost-optimal dispatch by exchanging cheaper units for more expensive units. This leads to situations where more peaking units are more likely to be running. In some countries, the power plants necessary for providing the maximum redispatch capacity are provided for using specific contracts.

Therefore, the maximum redispatch power is a direct indication of the need for reserve power plants and the difference (with and without the project) gives a direct indication of the change in needed reserve power plants.

5.9.2 Methodology

The capacity of necessary reserves for redispatch (in MW) can be determined by performing the comparison of the maximum power of redispatch, with and without the project, as received from year-round redispatch simulations.

The maximum redispatch power is defined as the maximum of the hourly redispatch power that is calculated by summing up all redispatch actions within the respective hour.

Note: In principle, this methodology can only be applied for projects located in countries that have a specific mechanism for contracting redispatch reserve power plants or connecting countries where at least one country has such a mechanism. If such a mechanism does not exist for the respective countries, an assumption for the allocation-costs has to be made within the study-specific Implementation Guideline.

5.9.3 Monetisation

The quantification of the benefit is relative to the reduction of the maximum amount of necessary redispatch in MW and can be monetised using the statistical analysis of the costs of reserve from power plants, i. e., from changing capacity constraint payments.

5.9.4 Example: Internal project in country A

A fictitious example of this indicator is provided for an internal project in country A, as follows:

It is assumed that within country A, a mechanism for allocating redispatch power plants exists and that the assessment has been performed using redispatch simulations. The project is part of the reference grid so the TOOT method will be applied. The following process steps are adhered to:

1. Calculate the redispatch power with and without the project for each hour of the year
2. Find the maximum redispatch power for both cases (with and without the project):

   RD_{power}(with) = 16,000 MW, which appears in hour 3,465

   RD_{power}(without) = 18,000 MW, which appears in hour 5,687
3. Build the delta:

   RD_{power}(delta) = 18,000 MW – 16,000 MW = 2,000 MW
4. Monetise the benefit with 20 k€/MW of the allocated redispatch power plant:

   B11 = 2,000 MW × 20 k€/MW = 40 M€

5.9.5 Double-counting:

The risk of double accounting is not given because this benefit indicator can only be applied to projects located in countries where a specific mechanism for allocating redispatch power plants exists, and in reality the costs for allocating them must be paid independently if the respective capacity will be used or not. Furthermore, even when these redispatch reserves are needed payments, the allocation payments and the actual redispatch costs have to be taken. However, within the simulations, only the latter part is considered, and the reduction of allocation payments needs to be added to the overall project benefit.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
Reduction of necessary reserves for redispatch power plants	Redispatch studies (substitution effect)	MW	€/yr (market-based)	National

Table 15: Reporting Sheet for this Indicator in the TYNDP

5.10 C1: Methodology for CAPital EXpenditure (CAPEX)

Capital expenditure (i. e. CAPEX) is the cost of developing or delivering physical assets.

CAPEX figures are to be declared as real values (i. e. not considering inflation) for each investment. The CAPEX are expressed as constant year-of-study values. For example, for TYNDP 2024 the CAPEX are represented in constant 2024 values.

Where a project is comprised of several investments, the CAPEX for each investment as a year-of-study value and the year that the investment is to be commissioned should be provided.

The terminal values (i. e. the value of the assets at the end of the assessment period) are assumed to be zero.

The costs shall be reported according to the investment status and related uncertainties in the following manner:

- For mature investments with the status of ‘**permitting**’ or ‘**under construction**’, costs should be reported based on the current data of project promoters, together with a clearly explained uncertainty range.[42]
- For non-mature investments of a ‘**planned, but not yet in permitting**’ or ‘**under consideration**’ status, the following is relevant:

  1. If detailed project cost information is available, this should be used and the same principle applied as for mature investments.

  2. If detailed project cost information is not usually available, the project promoters will be required to use standard investment costs, which will be provided by ENTSO-E in the context of the TYNDP. To account for the specific circumstances and complexities of the project, these costs are to be multiplied by a clearly defined project-specific complexity factor.

Complexity factors are to be applied in the following manner:

a) To provide a range for the standard costs per group of assets, including a maximum and minimum value according to its expectations. In this case, the project promoter is required to provide an explanation (see Table 16 on the following page).[43]

b) In the case where the project promoter chooses complexity factors that exceed the previous ranges, the choice should be clearly explained. For example, applying complexity factors to account for different project characteristics, such as terrain, routing, presence of historical landmarks, presence of other infrastructure, population density, special materials and designs, protected areas, etc. The complexity factor should be unbundled and applied to the specific cost categories to build up the project cost.

c) In the case of early phase projects, where the project promoter has limited knowledge of the project investment costs (including the effect of possible project characteristic impacts), these costs should be equal to the standard investment costs using a complexity factor equal to 1.0.[44]

The methodology used for determining the projects costs, whether based on detailed information or taken from standard costs, has to be published.

Finally, the investment costs will be one value to which an uncertainty range is applied.

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[42] For example, information presented on National Investment Plans.

[43] Taken, for example, from the ACER report, with minimum and maximum interquartile.

[44] This information will be updated in future TYNDPs when project promoters have more detail.

The range of complexity factors to be applied per asset class is shown in Table 16.

Investment type	Maximum CF	Minimum CF
AC Onshore Overhead Lines (OHL)	1.30	0.50
AC Onshore Cable	1.20	0.70
Subsea Cables	1.10	0.90
AC Substation	1.30	0.60
Transformer	1.30	0.70
HVDC Converter Station	1.20	0.90

Table 16: Table of maximum and minimum Complexity Factors per group of assets

In this manner, the provision of the CAPEX expenses enables the project to be compared with other projects as they can be discounted using common assumptions to the point in time for which the assessment is needed (the year in which the study is performed).

CAPEX includes both the capital costs incurred at inception during the construction period; and capital expenditure incurred later in the project life-cycle. Therefore, two indicators, C1a and C1b, which represent the asset costs at inception and the ongoing asset costs during the original assets' operation respectively, represent CAPEX.

5.10.1 C1a: Inception CAPEX

Inception CAPEX is the capital costs incurred at the inception of the project (i. e. during the construction period). It includes the following cost categories:

- Costs for pre-feasibility studies, permits, feasibility studies, design and land acquisition;
- Costs for equipment, materials and execution (such as towers, foundations, conductors, substations, protection and control systems, machinery, construction supervision, project management, penalties);
- Costs for temporary solutions necessary to realise a project (e. g. a new overhead line required in an existing route, adaptation of the existing assets or the installation of a temporary circuit during the construction period); and
- Expected environmental and consenting costs (such as costs to avoid, environmental impacts or costs compensated under existing legal provisions, cost of planning procedures).

Example: Project X, which is a cluster of investments A, B and C

For each investment, the promoter should provide the aggregated real value (i. e. excluding inflation rate) of the expected capital expenditure for the investment and the year that the investment is to be commissioned. This is illustrated by Project X, which is a cluster of three investments: investment A, investment B and investment C. Investment A is expected to be commissioned in 2025, whereas investments B and C are expected to be commissioned in 2026 and 2027, respectively.

The project promoter should, therefore, provide the information as illustrated in Table 17.

Investment	CAPEX [M€]	Year of Commission
Investment A	40*	2025
Investment B	10*	2026
Investment C	20*	2027

* The investment costs are the "year-of-study" real values (e. g. 2024 for TYNDP 2024).

Table 17: Illustration of Capital Expenditure Information to be provided by Project Promoters

5.10.2 C1b: Sustaining CAPEX

Sustaining CAPEX is the capital expenditure incurred during the assessment period that is necessary to ensure that the functionality of the original assets realised by the inception CAPEX is maintained. This includes the following:

- Mid-life interventions or significant and scheduled upgrade of assets that are CAPEX in nature are also to be included in the evaluation. This would include the expected costs for devices that have to be replaced within the assessment period (consideration of project life-cycle); and
- Dismantling costs at the end of the equipment life-cycle, where relevant, are also to be included in the CAPEX cost figures.

All costs falling outside the assessment period are not to be considered. This impacts, for example, the dismantling costs for projects with lifetimes longer than the assessment period.

5.11 C2: Methodology for OPerating EXpenditure (OPEX)

OPEX is the ongoing cost of running the investment or project over the assessment period.

OPEX is represented as an annual average cost. It is applied annually from the first year after commissioning for the duration of the assessment period.

As mentioned in **Section 3.2.5**, the values are real values and are to be reported as constant year-of-study values. For example, for the TYNDP 2020 the values are to be represented as constant 2020 values.

The following costs are to be considered as OPEX:

- Expected annual maintenance costs; and
- Expected annual operation costs.

It is required that OPEX is reported per investment.

It is important to highlight that some annual costs can mistakenly be considered as a component of OPEX, but **do not** fall into this category, namely:

- System losses, as they are considered in a dedicated indicator.

5.12 Climate adaptation measures

Project promoters will be asked to state which climate adaptation measures have been taken by the project. Climate adaptation measures are defined as **'a process that ensures that resilience to the potential adverse impacts of climate change of energy infrastructure is achieved through a climate vulnerability and risk assessment, including through relevant adaptation measures.'** in Regulation (EU) 2022/869.

Climate change hazards can damage transmission lines or elements of the substation and hence cause power outages and black-outs, through direct impact or indirect impact (e. g. falling trees).

Tree fall, can be caused by several factors including strong winds, flooding, snow or ice accumulation or lighting.

A key driver for developing more sustainable transmission systems is to decrease the effects of climate change hazards (e. g. flooding, wildfire, extreme cold, storms, ground instability, etc.) by implementing the different climate adaptation measures as given following examples.

Most of the aforementioned hazards that transmission overhead lines are exposed to can be avoided by placing conductors underground.

Very high ambient temperatures, threaten transmission lines, causing lines to sag and fire. Sagging may also result in contact with trees or other structures, which could result in electrocution or fires. These impacts increase the risks of network failures. Adaptation options to deal with these impacts include:

- Installing higher power lines poles,
- Installing conductors with higher operating limits or implementing the use of 'low-sag' conductors.
- Software tool to optimise overhead line ratings

Impact of fires could be reduced with sustainable forest management, improving fire prevention measures and appropriate fighting systems.

Flooding may cause substations to lose the high voltage systems, telecommunications or battery systems. Water may damage protection, automation and control equipment. The following steps could help ensure substation flood safety:

- Installing flood monitoring devices. Float switches installed at various elevations throughout a substation, can inform operator when flooding first occurs and as flooding reaches critical stages.
- Equipment can be raised off the ground using elevated foundations or platforms. For high-risk areas, entire substations may need to either be elevated.

Project promoters should provide the information about the percentage of C1a and C1b that will be allocated to certain adaptation measures for climate hazard.

Climate adaptation measures cost will not be part of the NPV calculation.

5.13 General Statements on Residual Impacts

The main objective of transmission system planning is to ensure the development of an adequate transmission system that:

- Enables safe system operation;
- Enables a high level of SoS;
- Contributes to a sustainable energy supply;
- Facilitates grid access for all market participants;
- Contributes to internal market integration, and facilitates competition and harmonisation;
- Contributes to improving the energy efficiency of the system; and
- Enables cross-country transmissions.

The TYNDP highlights the manner in which transmission projects of European Significance contribute to the EU's overall sustainability goals, such as CO_2 reduction or the integration of RES. On a local level, these projects may also impact other EU sustainability objectives, such as the EU Biodiversity Strategy (COM 2011 244) and landscape protection policies (European Landscape Convention). Moreover, new infrastructure requires careful implementation though appropriate public participation at different stages of the project, considering the goals of the Aarhus Convention (1998) and the measures foreseen by the Regulation (EU) 2022/869.

As a rule, the first measure to deal with the potential negative social and environmental effects of a project is to avoid causing the impact (e. g. through routing decisions) whenever possible. Steps are also taken to minimise impacts through mitigation measures, and in some instances compensatory measures, such as the creation of a wildlife habitat, may be a legal requirement. When project planning is in a sufficiently advanced stage, the cost of such measures can be estimated accurately, and they are incorporated into the total project costs (listed under indicator C1).

As it is not always possible to (fully) mitigate certain negative effects, the indicators 'social impact' and 'environmental impact' are used to:

- Indicate where potential impacts have not yet been internalised, i. e. where additional expenditures may be necessary to avoid, mitigate and/or compensate for impacts, but where these cannot yet be estimated with sufficient accuracy for the costs to be included in indicator C1; and
- Indicate the residual social and environmental effects of projects, i. e. effects that may not be fully mitigated in the final project design and cannot be objectively monetised.

Particularly in the early stages of a project, it may be unclear whether certain impacts can, and will, eventually be mitigated. Such potential impacts are included and labelled as potential impacts. In subsequent iterations of the TYNDP, they may disappear if they are mitigated or compensated for or lose the status of potential impact (and become residual) if it becomes clear that the impact will not eventually be mitigated or compensated for.

When insufficient information is available to indicate the (potential) impacts of a project, this will be made clear in the presentation of project impacts in such a manner that 'no information' cannot be confused with 'no impact'.

In its report on **Strategic Environmental Assessment for Power Developments**, the International Council on Large Electric Systems (CIGRÉ, 2011) provides an extensive overview of factors relevant for performing a Strategic Environmental Assessment (SEA) on transmission systems. Most indicators in this report were already covered by ENTSO-E's CBA guideline, either implicitly via the additional cost their mitigation creates for a project or explicitly in the form of a separate indicator (e. g. CO_2 emissions). However, three aspects ('biodiversity', 'landscape' and 'social integration of infrastructure') could not be quantified clearly or objectively via an indicator or through monetisation. Previously, these were addressed in the TYNDP by an expert assessment of the risk of delays to projects, based on the likelihood of protests and objections to their social and environmental impacts. Particularly for projects in an early stage of development, this approach improves assessment transparency as it provides a quantitative basis for the indicator score.

To provide a meaningful yet simple and quantifiable measure for these impacts, the new methodology improves on this indicator by giving an estimate of the number of kilometres required for a new overhead line (OHL), underground cable (UGC), or submarine cable (SMC) that might have to be located in an area that is sensitive for its nature or biodiversity (environmental impact) or its landscape or social value (social impact; for a definition of 'sensitive' see below).

When first identifying the need for additional transmission capacity between two areas, one may have a general idea about the areas that will be connected, whereas more detailed information on, for instance, the exact route of such an expansion is still lacking as routing decisions are not

taken until a later stage. In the early stages of a project, it is often difficult to determine anything concrete about the social and environmental consequences of a project, let alone determine the cost of mitigation measures to counter such effects. Therefore, the quantification of these indicators will be presented in the form of a range, of which the 'bandwidth' tends to decrease as the project progresses in time and information increases. In the very early stages of development, it is possible that the indicators are left blank in the TYNDP and are only scored in a successive version of it when some preliminary studies have been conducted and there is at least some information available to base such scoring upon. A strength of this type of measure is that it can be applied at a rather early stage of a project when the environmental and social impact of projects is generally unclear and mitigation measures cannot yet be defined. In subsequent iterations of the TYNDP, as route planning advances and specification of mitigation measures becomes clearer, the costs will be internalised in 'project costs' (C1) or indicated as 'residual' impacts.

As soon as a global idea of the alternative routes that can be used has been determined, a range with minimum and maximum values for this indicator can be established. These indicators will be presented in the TYNDP along with the other indicators, as specified in ENTSO-E's CBA Guideline, with a link to further information. The scores for social and environmental impact will not be presented in the TYNDP by means of a colour code. These impacts are highly project-specific and it is difficult to express these completely, objectively and uniformly on the basis of a single indicator. This consideration has led to the use of 'number of kilometres' as a measure to provide information about projects in a uniform manner, while respecting the complexity of the underlying factors that compose the indicators. Attaching a colour code purely on the basis of the notion 'number of kilometres' would imply that a 'final verdict' has been passed regarding the social and environmental sensitivity of the project, which would not be correct because the number of kilometres that a line crosses through a sensitive area is only one aspect of a project's true social and environmental impact.

In the case of a replacement project, a residual impact indicator can also attain a zero or negative (i. e. having a beneficial environmental or social impact) when the affected sensitive area is reduced by the project, i. e. the 'number of kilometres' becomes zero or negative.

5.14 S1: Methodology for Residual Environmental Impact

5.14.1 Introduction

Environmental impact characterises the local impact of the project on nature and biodiversity, as assessed through preliminary studies. This indicator only considers the residual impact of a project, i. e. the portion of impact not fully accounted for under C1 and C2. It is expressed in terms of the number of kilometres that an overhead line or underground/submarine cable may run through environmentally 'sensitive' areas, as defined in 5.13 General Statements on Residual Impacts.

5.14.2 Methodology

The residual environmental impact is described using the following three descriptors:

- Stage: Refers to the stage of the project or investment. This is important as it gives an indication of the extent and accuracy at which the environmental impacts can be measured;
- Potential impact: Refers to the assessment of the potential effects that the infrastructure associated with a project or investment will have on nature and biodiversity.[45] It is measured by the distance (km) that the infrastructure will be located within an environmentally sensitive area; and
- Type of sensitivity: Defines why this area is considered sensitive.

The assessment of impacts that may qualify an area as environmentally 'sensitive' for the construction of overhead lines or underground cables, specifically with regard to biodiversity, are addressed by the following Directives or International Laws:

- Habitats Directive (92/43/EEC);
- Birds Directive (2009/147/EC);
- RAMSAR site;
- IUCN key biodiversity areas;
- Marin Strategy Framework Directive (2008/56/EC); and
- Other nature protection areas under national law.

Example: Assessment of hypothetical investments A, B, C, and D

The residual environmental impact of four hypothetical investments (i. e. A, B, C and D) is illustrated in Table 18.

Investment	Stage	Impact (Distance within environmentally sensitive area in km)	Sensitivity type	Further information (Link to be provided)
A	Planned	Yes (a. 50 to 75 km; b. 30 to 40 km)	a. Birds Directive; b. Habitats Directive	e.g. Big Hill SPA (www.…)
B	Permitting	No		(www.…)
C	Planned	Yes (20 km)	Habitats Directive	(www.…)
D	Under consideration	N.A.	N.A.	(www.…)

Table 18: Residual impact examples

For mature investments in the '**permitting**' or '**under construction**' status, the elements listed should be reported based on the current data of the project promoter, together with the reference to the environmental impact assessment performed to identify those elements.

For non-mature investments (classified as '**planned, but not yet in permitting**' and '**under consideration**'), two cases can be distinguished. If the elements mentioned are available because of an environmental assessment already performed by the promoter or competent NRA, they should be reported as in the case of mature investments. In all other cases where

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[45] The EC has formulated its headline target for 2020 as: 'Halting the loss of biodiversity and the degradation of ecosystem services in the EU by 2020, and restoring them in so far as feasible, while stepping up the EU contribution to averting global biodiversity loss.'

an environmental assessment study is not available or not fit to provide the necessary elements, in the context of the TYNDP, ENTSO-E should specify (in a dedicated space of the project sheet) that given that the actual route of the project might not be defined due to the low degree of maturity of its investment(s), an environmental assessment is not yet available.

5.15 S2: Methodology for Residual Social impact

5.15.1 Introduction

Social impact characterises the project impact on the local population, as assessed through preliminary studies. It is expressed in terms of the number of kilometres that an overhead line or underground/submarine cable may run through socially sensitive areas, as defined in section 5.13 General Statements on Residual Impacts. This indicator only takes into account the residual impact of a project, i. e., the portion of impact that is not fully accounted for under C1 and C2.

5.15.2 Methodology

The residual environmental impact is described using the following three descriptors:

- Stage: Refers to the stage of development of the project or investment. This is important as it gives an indication of the extent to which social impact can be measured at a particular moment.
- Potential impact: Refers to the assessment of the potential effects that the infrastructure associated with the project or investment will have on densely populated or protected areas in its proximity. It is measured by the distance (km) of the infrastructure that is located within socially sensitive areas.
- Type of sensitivity: Defines why this area is considered to be sensitive.

The following definitions provide an overview of impacts that may qualify an area as socially 'sensitive', with respect to the construction of an overhead line or underground cable:

Social impact

- Sensitivity regarding population density:
  - Land that is close to densely populated areas (as defined by national legislation). As a general guidance, a dense area is an area where population density is superior to the national mean.
  - Land that is near to schools, day-care centres or similar facilities.
- Sensitivity regarding landscape protected under the following Directives or International Laws:
  - World heritage;
  - Land within national parks and areas of outstanding natural beauty;
  - Land with cultural significance; and
  - Other areas protected by national law.

5.15.3 Example: Assessment of hypothetical investments A, B, C, and D

The residual social impact of four hypothetical investments (i. e., A, B, C and D) is illustrated in Table 19.

Investment	Stage	Impact (Distance within environmentally sensitive area in km)	Sensitivity type	Further information (Link to be provided)
A	Permitting	Yes (20 to 40 km)	Dense area	(www.…)
B	Planned	Yes (100 km)	European Landscape Convention	(www.…)
C	Planned	No	Submarine cable	(www.…)
D	Under construction	Yes (50 km)	Dense area, OHL	(www.…)

Table 19: Residual social impact example

For mature investments in the '**permitting**' or '**under construction**' status, the elements listed should be reported based on the current data of the project promoter, together with the reference to the social impact assessment performed to identify those elements.

For non-mature investments (classified as '**planned, but not yet in permitting**' and as '**under consideration**') two cases can be distinguished. If the elements mentioned are available because a social assessment already been performed by the promoter or competent NRA, they should be reported as in the case of mature investments. In all other cases, where a social assessment study is not available or not fit to provide the necessary elements, then ENTSO-E, in the context of the TYNDP, should specify this in a dedicated space of the project sheet. The note should state that given that the actual route of the project might not be defined yet because of the low degree of maturity of its investment(s), a residual social impact assessment is not yet available.

5.16 S3: Methodology for Other Residual Impact

The Other Residual Impact (S3) indicator lists the impact(s) of a project that are not covered by indicators S1 and S2. These impacts may be positive or negative.

Submitting these other impacts is the responsibility of the project promoter and will be included as a list in the TYNDP assessment results.

Impacts that are accounted for by indicators S1 or S2 should not be included under this indicator.

6 Supplemental methodologies

6.1 Contribution to Union Energy Targets (ET)

6.1.1 ET1: Interconnection Targets

The EC established the Expert Group on electricity interconnection targets in March 2016. The Expert Group's aim was to provide technical advice to the Commission on the extension of the 10 % electricity interconnection target (defined as import capacity over installed generation capacity in an EU country) to 15 % by 2030, while considering the costs aspects and the potential of commercial exchanges in the relevant regions. The Expert Group transmitted its report in October 2017.

The Expert Group recommends that the development of additional interconnections should be considered if any of the following three thresholds is triggered:

- Minimising price differentials: MS should aim to achieve yearly average of price differentials as low as possible. The Expert Group recommends € 2/MWh between relevant countries, regions or bidding zones as the indicative threshold to consider developing additional interconnectors.
- Ensuring that electricity demand, including through imports, can be met in all conditions: in countries where the nominal transmission capacity of interconnectors is below 30 % of their peak load, options for further interconnectors should be urgently investigated:

  nominal transmission capacity/peak load 2030

- Enabling export potential of excess renewable production: in countries where the nominal transmission capacity of interconnectors is below 30 % of their renewable installed generation capacity, options for further interconnectors should urgently be investigated:

  nominal transmission capacity/installed renewable generation capacity 2030

The Expert Group recommends that any project related to interconnection capacity, helping the MS reach any of the 30 % thresholds, must apply for inclusion in the TYNDP and future lists of PCI. In addition, countries above the 30 % but below 60 % thresholds in relation to their peak loads and renewable installed generation capacity are requested to regularly investigate possible options of further interconnectors regularly. In addition, as a condition sine qua non, each new interconnector must be subject to a socioeconomic and environmental CBA and implemented only if the potential benefits outweigh the costs.

6.1.2 ET2: Energy Efficiency

According to the EC, Europeans should lower their energy bills by saving energy. By using energy more efficiently, energy consumption can be reduced. The EC sets energy efficiency targets which translate to lower primary and final energy consumption. Energy efficiency (EF) can be defined as

$$EF = \frac{final\ energy\ consumption}{primary\ energy\ consumption}$$

Thereby, primary energy consumtion can be regarded as an input to the energy system and is the overall usage of all primary energy carriers that can be extracted from the market simulations (e. g. methane, hydrogen, etc.). The final energy consumption is the conventional demand of end-use appliances and can also be extracted from the market simulations. Any variation in energy efficiency unlocked by a project

$$ET2 = EF^{with} - EF^{without}$$

contributes to the overall European target and can be reported in the study-specific project sheets.

6.1.3 ET3: Renewable Penetration

The share of energy from renewable sources shall be calculated as the gross final consumption of energy from renewable sources divided by the gross final consumption of energy from all energy sources, expressed as a percentage[46].

$$ET_{res} = \frac{RES\ generation}{total\ consumption}$$

The numerator, 'gross final consumption of electricity from renewable energy sources', shall be calculated as the quantity of electricity produced in a MS from renewable energy, and the denominator 'gross final consumption of electricity' is, for the purpose of the calculations defined as the generation from all energy sources. For both numerator and denominator, a detailed overview of generation sources considered have to be defined within the respective study-specific implementation guidelines.

The evaluation of a project's impact on the renewable penetration ET3 will then be calculated as a delta comparison of the RES penetration with and without the project

$$ET3 = ET_{res}^{with} - ET_{res}^{without}$$

and can be reported in the study-specific project sheets.

6.2 Methodology for the assessment of Hybrid Projects

6.2.1 Context

Following the ongoing European decarbonisation targets and related EU legislation initiatives (Green Deal and FIT for 55 legislative package), a massive uptake in offshore RES (predominantly offshore wind technology) is expected now and in the upcoming decades, aiming at above 60 GW offshore wind + 1 GW ocean energy by 2030 and 300 GW offshore wind and 40 GW ocean energy by 2050 in European waters, following the EC's offshore RES strategy.

Historically, mostly radial connections to onshore bidding zones were developed near-shore, especially for offshore RES (short distances, AC-technology). For the near future, to fully exploit the energy potential of the European sea basins, far-out connections will be further exploited. A new set of technical setups will allow the interconnection-function between bidding zones (on- or offshore) to be combined with a facilitation of direct wind infeed (RES-connection). For these new configurations, which are defined below as (offshore) hybrid projects or dual/ multi-purpose interconnections, additional clarifications are necessary for proper CBA calculations to be performed in the framework of the European TYNDP.

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[46] Directive 2009/28/EC of the European Parliament and of the council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

6.2.2 Hybrid interconnector definition

The hybrid interconnector projects serve at least dual purposes within the electricity sector and constitutes a new project category related to CBA assessment, which project promoters need to indicate & provide correct parameters for to facilitate appropriate CBA calculation (see separate CBA section further). A further development of 'dual purpose' is 'multi-purpose' in cases the project integrates other sectors as well (e. g. via electrolysers). This multi-purpose project category, where other sectors are coupled, is not considered in this document.

The hybrid interconnection setup and dual purpose (see Figure 11) can be defined **as a project which enables an interconnector function between bidding zones (either onshore or offshore) while simultaneously facilitating a client connection with a certain technology (RES or non-RES; generation, load or storage; AC [e. g. Kriegers Flak] or DC [e. g. North Sea Windpower Hub])**. Hybrid interconnection projects are mainly expected offshore and are linked to the European Offshore RES strategy but, in theory, onshore cases could also exist: for instance, a wind farm in a mountain area with just 1 XB-interconnection (tie-line) passing by to which it could connect, rather than directly within the onshore bidding zones.

From the perspective of the client, for example an offshore wind project, the client connection will directly feed in or take off power off an otherwise direct cross-border interconnection (XB-IC) or tie-line/cable that connects MS bidding zones (BZs).

Based on how a hybrid interconnection setup is developed, two CBA options can be defined, as defined exhaustively in chapter 3.

- **CBA Case 1** expansion of an existing radial client connection through the inclusion of an XB interconnection (IC)
- **CBA Case 2** – project developed anew as a hybrid interconnector

The hybrid interconnection projects target the effective creation of a link between two or more BZs – meaning the project scope goes beyond anything that remains within one and the same BZ. General clustering rules should apply to effectively considering the multiple links & OWF(s) connections together in one project or whether multiple projects need to be created. Once more offshore hybrid interconnection projects are combined, they effectively result in a multi-terminal or offshore network setup.

The different project options that can be pursued by project promoters are listed in Figure 11 below, illustrating the cases for offshore development only – whereas the concepts can also apply onshore.

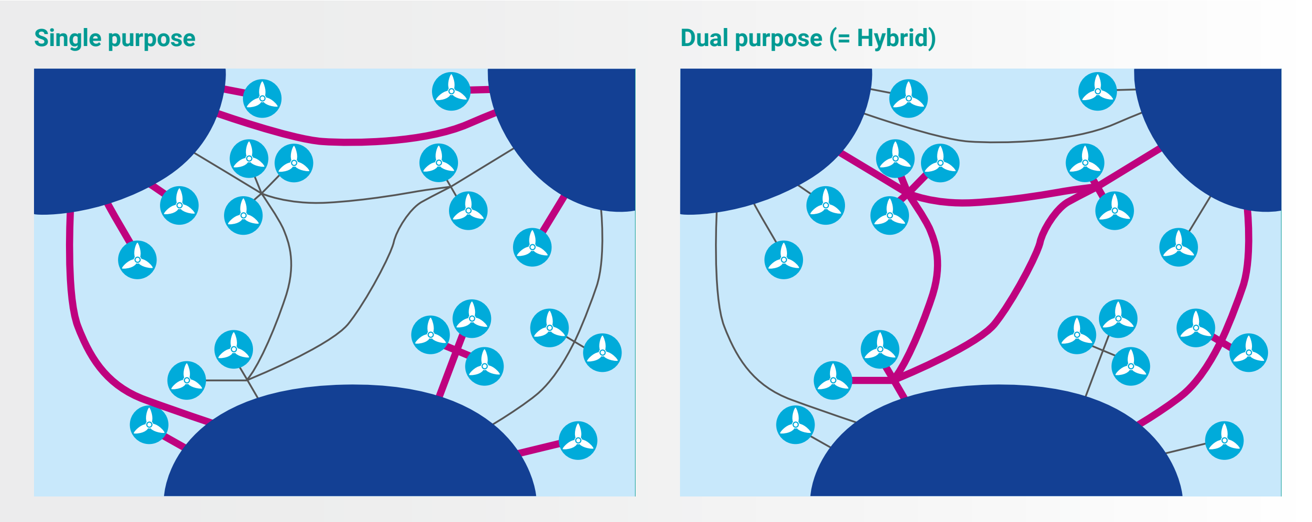


Figure 11: figure taken from ENTSO-E Position on Offshore Development – Summary of Recommendations, July 2021

6.2.3 Hybrid interconnection CBA configuration

Two CBA setups are possible for CBA analysis and are defined as CBA option 1 and option 2:

- Case 1: the project is built on top of an already existing or planned radial connected RES by enabling only an additional interconnector function (which consequently will then also host the existing or planned RES infeed from the initial radial connection)
- Case 2: the project enables both the RES-integration function (i. e. additional OWF capacity is integrated into the system through the project) and the additional interconnector function; and the project is developed anew as a hybrid interconnector

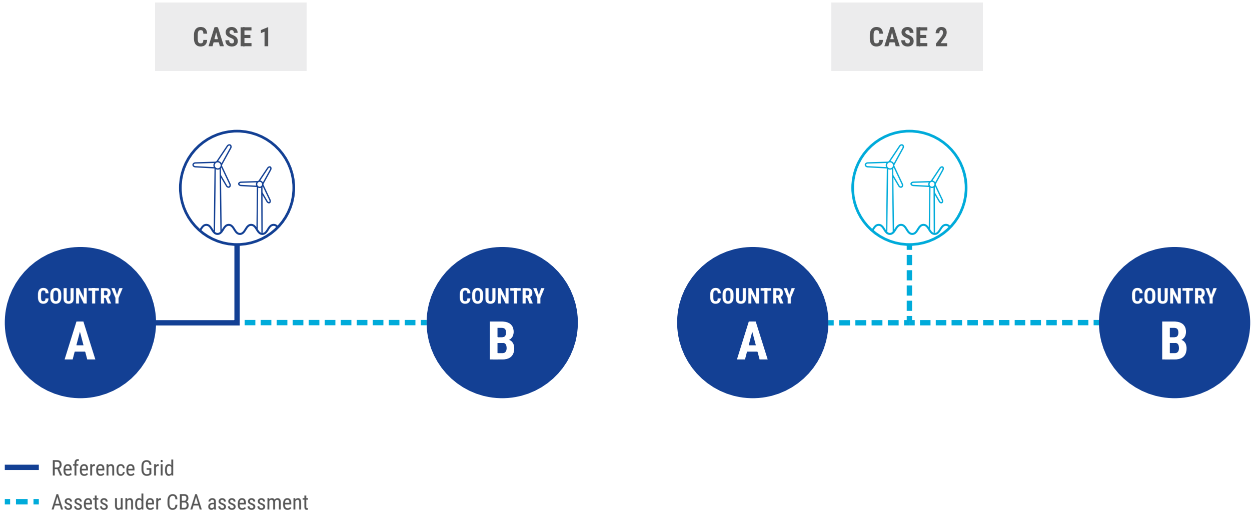


Figure 12: Hybrid CBA fundamental options

For illustration purposes, only the offshore wind technology setup will be illustrated. More complex variants, where multiple links are built to the same OWF or where meshing is introduced (either within same market or between BZs), can follow the same logic.

CBA Case 1

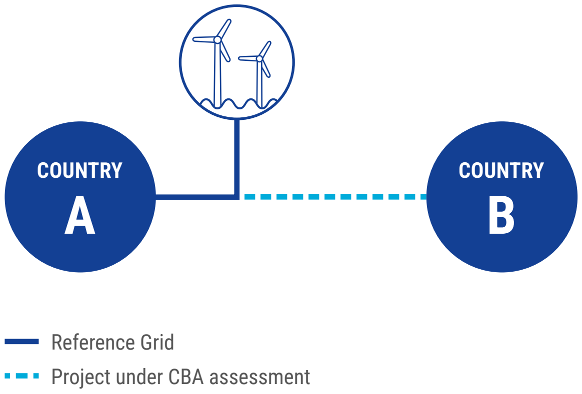
The project transforms the original client connection towards a cross-border (XB) line, by integrating the offshore RES through building the remaining leg to enable the XB function.

The benefits of market integration (relevant B1, B2, B4, B6 indicators) are enabled by increasing the transfer capacity between country A and B, as shown in Figure 13, enabled either in a home market (HM) setup or offshore bidding zone (OBZ) setup. In the case of a home market setup, RES is strictly allocated to either country A or B, and the created single NTC would be lower compared to the case of a direct connection between A and B without RES as the offshore RES energy will impact the options for remaining trade and congest the direct connection.

The costs (CAPEX) scope is defined as the asset of the 2nd leg and potential deltas of the targeted client connection.

CBA case 1 can be summarised in Figure 13.

CASE 1: ONLY INTERCONNECTOR BENEFITS (SECOND LEG)



Project Costs	Project Benefits	Assessment Type
2nd cross border Interconnector leg + Offshore substation delta's if applicable	Interconnector benefits from CBA guidelines (B1, B2, …) via indirect NTC A-B	**CBA case 1** No delta in total Offshore Wind Farm capacity

Figure 13: Project cost & benefit scope under CBA Case 1 assessment

CBA Case 2

The project builds the necessary leg(s) and simultaneously enables additional RES onto the resulting link, thereby enabling the dual function together i. e. the interconnection function and RES integration function. There are principally three different setups possible for CBA Case 2:

1. Either both legs plus access for the RES constitute the project entirely, which builds all anew.

2. Or, in the event a first leg with a radial RES connection is already planned, where on top of now a hybrid interconnection project will be added. The hybrid interconnection project scope itself for CBA assessment is then only constituted by the second leg and, crucially, also by additional RES facilitation on top of the initial radial RES amount. If the radial RES connection is not in the reference grid, then a sequential CBA assessment is required using both projects.

3. A radial RES connection is built on a planned or existing XB line, effectively yielding the same outcome i. e. a hybrid interconnector.

For the benefits and costs for setups 1/2/3, it should be acknowledged that between 1 and 2 there is only the difference in project cost scope, whereas for theoretical case 3 only RES-integration benefits would be present (with an impact on the remaining NTC between bidding zone A and B dependent on the chosen market setup HM or OBZ). For the remainder of the text, only setup 1 is illustrated.

The benefits of market integration (relevant B1, B2, B3, B4, B6 indicators) are enabled through the creation of:

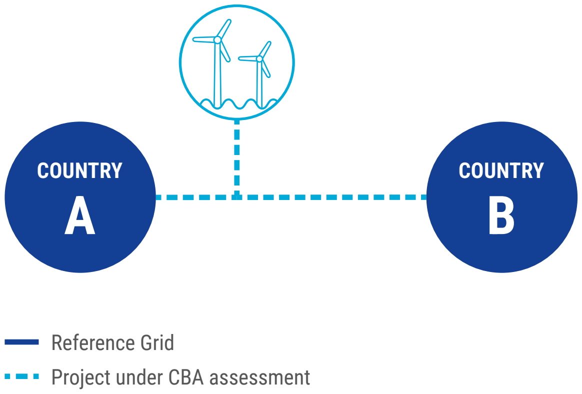
- A single NTC between A and B enabled in a home market setup (1 reduced NTC in total) and the creation of direct RES integration.

- Double NTC (2 NTCs in total i. e. 1 between country A and RES, and 1 between country B and RES) enabled in an OBZ setup and the creation of direct RES integration itself.
- Where the costs of additionally installed RES generation, which are per definition not included in the cost estimates by the TSO, need to be considered the producer surplus of the targeted RES itself needs to be removed from the EU–SEW as a proxy to warrant the required RES investment. The producer surplus can be calculated as the dispatched RES feed-in volume for all hours of the considered year, multiplied by the price the OWF gets, which is determined by the bidding zone in which it is considered. This calculation can be done ex-post and, in the event the RES is connected to 2 or more bidding zones onshore in a separate bidding zone setup, it will get the lowest price of all bidding zones to which it is linked. To verify that the assumed costs of the RES integration are in the same range as costs for RES assets, a sanity check needs to be applied. This sanity check will be described in detail in the study-specific Implementation Guidelines, together with a clear indication when this approach needs to be applied.

The costs (CAPEX) scope is defined as all legs part of the project scope required to enable the interconnection function and related substation to enable the RES infeed onto the interconnector (e. g. offshore this is typically a platform). The costs of the RES asset itself are excluded.

CBA case 2 is summarised in Figure 14.

CASE 2: INTERCONNECTOR + RES ADDITION BENEFIT (SETUP = BOTH LEGS + WIND)



Project Costs	Project Benefits	Assessment Type
Both legs + Substation platform	Interconnector benefits from CBA guidelines (B1, B2, …) via indirect NTC A-B Offshore Wind Farm integration benefits changing net Offshore Wind Farm capacity Perform sanity check	**CBA case 2** delta in total Offshore Wind Farm capacity

Figure 14: Project cost and benefit scope under CBA case 2 assessment

The choice between CBA case 1 vs case 2 is to be determined by the respective setup of the project based on the information delivered by the project promoter. For both cases the impact of the choice should be clearly described; for example, the consequences for the cost scope of the project (& related benefits), the implicit inclusion of the scope of the RES project and the need to respect the general CBA clustering rules when specifying a project and/or requesting a sequential CBA.

6.2.4 Radial projects:

To harmonise the methodology for hybrid and radial projects, the CBA case 2 approach could be applied to radial projects. The assessment of a radial project will consider only the RES integration benefits (no trade benefits).

The producer surplus of the targeted RES itself needs to be removed from the SEW, as a proxy to warrant the required RES investment. As for hybrid projects, to consider the benefits of RES integration, a sanity check needs to be applied. This sanity check will be described in the study-specific Implementation Guidelines.

The costs scope for radial projects only include the grid connection (cables and platforms); the RES assets themselves are excluded. This means, for example, for an offshore radial project, that the costs scope includes only the societal transmission grid assets but not the offshore inter array cables or the offshore wind farm itself.

6.2.5 NTCs

NTCs should respect the guidance, and hence can be different from the thermal capacity of the respective legs of the hybrid setup in general and clearly also when different leg sizing is applicable.

NTCs should reflect the HM or OBZ setup chosen, which mainly affects dispatch results in case of negative price occurrence in one or more bidding zones. As explained for both CBA option 1 and 2, for the HM setup a reduced NTC concept is to be applied, whereas for the OBZ setup separate traditional NTCs can be utilised.

The power rating of the different legs and the targeted voltage level are needed and need to be modelled to most accurately assess, among others, the B5 indicator (grid losses & related monetisation).

6.3 Redispatch simulations for project assessment

Assessing projects by only focusing on the impact of transfer capacities across certain international borders can lead to an underestimation of the project-specific benefits. This is because most projects also show significant positive benefits that cannot be covered by only increasing the capacities of a certain border, i. e. the reduction of internal congestions. This effect is strongest, but not limited to, internal projects that do not necessarily aim to increase the capacities across specific borders and, therefore, this makes it difficult, or even impossible, to solely assess them using market simulations.

According to the CBA, both internal and cross-border projects can be of pan-European relevance; however, they all develop GTC over a certain boundary (and sometimes several boundaries), which may or not be an international border.

Furthermore, as cross-border projects can also have an impact on internal congestions and on the redispatch, just as internal projects can have an impact on cross-border transfer capacities, the application of redispatch simulations also needs to be allowed for interconnectors whenever necessary.

The detailed description of the respective methodology is described below.

Generally, to perform the project assessment using redispatch simulations, the following simulation steps need to be performed:

- Simulation step 1: Perform market simulations to determine the cost-optimal power plant dispatch;
- Simulation step 2: Perform load-flow simulations based on the outcome from step 1 to determine the line loadings in the observed grid; and
- Simulation step 3: Perform redispatch simulations to identify opportunities to mitigate possible congestions[47] as achieved from step 2 by redispatching the initial power plant dispatch (taken from step 1).

These steps might be performed using a single tool or a combination of different tools, but none of them must be neglected.

6.3.1 Benefit calculation using redispatch simulations

To perform the redispatch simulations, the same delta approach used for market simulations can also be applied, i. e. the benefits are calculated using TOOT or PINT and multiple TOOT or PINT. The indicators that can be calculated using redispatch simulations are those defined under the respective indicator. Following this, the same indicators as for market simulations can be achieved using the redispatch simulations, i. e. B1, B2, B3, B4. by assessing the impact on the amount of redispatch to eliminate internal congestions with and without the project.

The redispatch simulations must be aligned with the market studies conducted using the respective scenarios. To meet this requirement, the market study results (e. g. hourly generation of the specific unit types) and market study inputs (e. g. capacities of generation types) must be used as an input for the redispatch assessment. This should include the same main input data-set used for market simulations, which is summarised below:

- Price assumptions (fuel prices, CO_2 price, and the marginal costs of thermal generation types calculated from these);

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[47] The check for whether the congestions have been mitigated by the redispatch needs to be achieved using load-flow simulations.

- Net-generating capacities for thermal generation types, RES (wind and solar), other RES, other non-RES and hydro categories (incl. pumping capacities);
- Must-run values of thermal generation types;
- Availability of generating units;
- DSR capacities;
- Demand time series; and
- Fixed exchanges with non-modelled countries.

The main datasets to be used from the market simulation results are as follows:

- Utilisation (hourly time-series) of thermal generation types, DSR and hydro categories (turbining and pumping);
- Dumped energy time series (on wind, solar, Other RES and Other non-RES generation categories combined);
- Hourly marginal costs on market nodes; and
- ENS (energy not served) time series.

There are a number of requirements for the grid or network simulations: The simulations should ideally be based on AC load flows. If this is not possible, or in order to reduce the simulation time to an accepted level, DC load-flows can be applied. The simulations should be made on a year-round basis. If this is not possible, representative points in time can be used, as is the case for the losses calculation. The method of mapping the market simulation results to the grid model (i. e. the distribution of market node level results to nodal level in the grid model) is to be defined in the Implementation Guidelines and must be consistent with other grid studies (e. g. the NTC, losses calculations).

Any thermal overloads identified from the network simulations could potentially be mitigated by employing redispatch simulations. The redispatch simulations should observe the following requirements:

- The balance of the system must be kept (i. e. the rise in generation must be covered by the same amount of reduced generation);
- The network, or at least pre-defined critical branches, must be free of congestion after the redispatch is implemented; and
- The redispatch must be implemented in a cost-optimal manner.

The perimeter of the redispatch simulations needs to be defined, and can be defined as follows:

- The perimeter should be chosen to cover the grid area influenced by the project. The decision depends on whether the project is internal or cross-border. For internal projects, the perimeter for internal projects without significant cross-border impact is typically the country that includes the project. For cross-border projects, the perimeter is typically the two countries that include the project on their common border.
- In cases where only part of the country (or countries) is influenced by the project, it is possible to reduce the perimeter to that part alone, on condition that the reduced perimeter includes all grid elements relevant for the redispatch analysis. The 'relevance' has to be clearly stated and reported.
- In cases where other surrounding countries are also supposed to be significantly influenced by the project, the perimeter should be extended to include those countries.

Optimisation measures are implemented according to a particular order. The order[48] (or sequence) that is to be applied and adhered to is as follows:

1. Apply operational measures (e. g. PST, HVDC);
2. Apply the pre-defined set of topological curative actions for each N-1 (or appropriate security criterion);
3. Optimise thermal power plants based on the dispatch costs of each generator;
4. Optimise storage devices (e. g. hydro generators, batteries, P2G, etc.);
5. Optimise RES;
6. Optimise cross-border power plants and cross-border HVDC links (depending on the perimeter); and
7. Address the overloading of transmission equipment.

As there are different project types, with different objectives, the simulation methods can also be different, depending on the objective. Although the objective of cross-border projects may be to increase the capacity between different countries and market areas, the objective of an internal project may not be to impact cross-border capacity. Therefore, it would make only little sense to assess these types of projects by comparing the two different market simulation runs.

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[48] No country-specific differences to this approach have yet been identified. If these are identified, they must be considered.

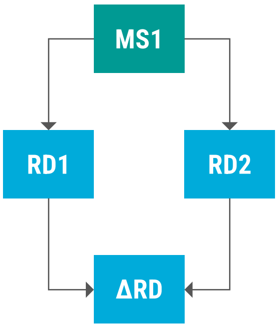
To account for different project types, there are two options for applying redispatch simulations:

The first option only uses redispatch simulations[49] to calculate the benefits, whereas the second option integrates both market and redispatch modelling. The decision regarding which methodology to apply depends on the case being assessed. In general, when assessing the market benefits of a project where the main aim of the project relies on a cross-border level, pure market simulations should be used. For projects where the main focus is on healing internal congestions, pure redispatch simulations should be used. Of course, there are also projects that are built to fulfil both needs. Therefore, to cover the full spectrum of benefits for different types of projects, a variation in methodologies or a combination of methodologies should be used. The choice of which method to use is for the project promoter to decide. However, the chosen method needs to be displayed with a justification of the respective choice. In cases where the assessment uses a combination of market and redispatch studies, the benefits must be displayed separately for market and redispatch studies.

Note: The following options are only related to the benefit calculation itself; to perform redispatch simulations, preceding market and network simulations are always necessary.

6.3.2 Option 1: Calculation of benefits using pure redispatch:

The benefits for projects with a focus mainly on internal impacts can solely be assessed by using redispatch simulations. Using a single market simulation output, two different redispatch simulations (i. e. one with the project and the other without the project) need to be performed (TOOT/PINT). The process needs to respect the conditions described above, and is illustrated below:

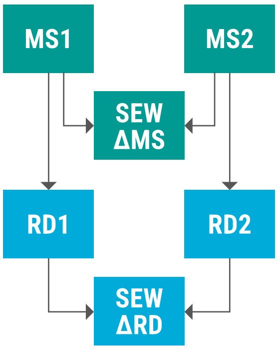


Where:

- MS1 refers to market simulation reference NTCs;
- RD1 refers to the redispatch run with reference network;
- RD2 refers to the redispatch run, with the project being assessed taken out/in (TOOT/PINT); and
- ΔRD refers to the difference between RD1 and RD2 unit commitment (different generation costs, different CO_2 outputs, etc.)

6.3.3 Option 2: Calculation of benefits using a combination of border-NTC-variation and redispatch:

The benefits of some projects mainly depend on internal bottlenecks, but can also have significant cross-border impact. In this case, a two-step approach can be used by combining the assessment using market simulations with redispatch simulations, with the final result being the sum of both. The process is illustrated below:



Where:

- MS1 refers to the market simulation with reference network;

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[49] The basis for the redispatch simulation under this option also relies on market simulations. In this case, the project has no NTC impact, therefore, only the reference market simulation output is used as an input. The different amounts of redispatch needed with and without the project (in the grid model) make the basis of the assessment.

- MS2 refers to the market simulation with the project being assessed taken out/in (TOOT/PINT);
- ΔMS refers to the difference between MS1 and MS2 unit commitment;
- RD1 refers to the redispatch run with reference network;
- RD2 refers to the redispatch run with the project being assessed taken out/in (TOOT/PINT);
- ΔRD refers to the difference between RD1 and RD2 unit commitment; and
- ΔTOTAL is given by the sum of ΔRD and ΔMS.

The application of redispatch enables the identification of a specific benefit indicator, B9: Reduction of Necessary Reserve for Redispatch Power Plants, which is discussed in section 5.9.

6.4 Value of Lost Load

VOLL is a measure of the costs for consumers associated with unserved energy (i. e. the energy that would have been supplied if there had been no outage), and is generally measured in €/kWh. It reflects the mean value of an outage per kWh (long interruptions) or kW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or nation considered. It is an externality as there is presently no market for SoS.

The value for VOLL used in project assessments should reflect the real cost of outages for system users, thereby providing an accurate basis for investment decisions. A level of VOLL that is too high would lead to over-investment, and a value that is too low would lead to under-investment. Under-investment would result in an inadequate SoS because the costs of measures to prevent an outage are erroneously weighed against the value of preventing the outage. The optimal level should correspond to the consumer's willingness to pay for SoS. Considering VOLL in project assessments requires that the right balance is struck between transmission reinforcements (which have a cost, reflected in tariffs) and outage costs. Transmission reinforcements generally contribute to improving the security and quality of the electricity supply, reduce the probability and severity of outages, and thereby reduce costs for consumers.

Experience has demonstrated that estimated values for VOLL vary significantly depending on geographic factors, differences in the nature of load composition, the type of consumers that are affected and their level of dependency on electricity, differences in reliability standards, the time of year, and the duration of the outage. Using a general and uniform estimation for VOLL would lead to inconsistency and less transparency and would greatly increase uncertainties compared to presenting the physical units.

Providing a reliable figure for VOLL, which reflects the actual societal costs of an outage, is vital for a proper project assessment with a monetised EENS component. When EENS is monetised, this is likely to shift the focus during interpretation of results away from the underlying values (i. e. a value in MWh that is different in each hour and in each price zone) because the monetised value is simply included in the summation of all monetised benefits and costs (e. g. to obtain a simple benefit–cost ratio). This is not problematic if an appropriate set of VOLL-values exists, which properly consider the spatial, temporal and actual characteristics associated with the cost of EENS. However, if the values used for VOLL in different situations are based on disparate calculation methodologies, which is the case under the present state of knowledge regarding economic valuation of outages, the credibility of the otherwise uniform and standardised project assessment results is undermined. ENTSO-E, therefore, considers the availability of a computation methodology that is approved by ACER and the EC as a prerequisite for reporting monetised values of EENS.

Note that in the absence of a uniform and standardised methodology to compute values for VOLL, EENS can nonetheless be monetised by stakeholders that make use of CBA results (e. g. the EC during the PCI process). The energy figure expressed in MWh, which ENTSO-E provides as the SoS indicator in the CBA evaluation for each project, allows all interested parties to derive a monetised value by using the preferred VOLL available. In any case, the VOLL values used in the assessment need to be transparently displayed within the study-specific Implementation Guidelines.

6.5 Climate resilience based on climate adaptation measures

Climate resilience based on climate adaptation measures provide better ability to anticipate and respond to climate hazards changing in practices and structures to moderate potential damages associated with climate change.

Climate resilience consists of following capabilities:

- Preventing damage;
- Dealing with extreme weather conditions and reduce damage during such conditions;
- Recovering transmission system back to a state equal to before the extreme event;
- Implementing interventions for transition to a climate-resilient society.

End note:

System development tools are continuingly evolving, and it is the intention that this document will be reviewed periodically pursuant to Regulation (EU) 2022/869, Art.11 §13 and in line with prudent planning practices and further editions of the ENTSO-E's TYNDP document.

7 Annexes

7.1 Generation cost approach

The economic benefit is calculated from the reduction in total generation costs associated with the NTC variation created by the project. There are three aspects to this benefit:

1. By reducing network bottlenecks that restrict the access of generation to the full European market, a project can reduce the costs of generation restrictions, both within and between bidding areas.

2. A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation. In the case of connection of renewables, this is also expressed by benefit B3, RES Integration.

3. A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers. The methods do not consider market power, and consequently the expression of socioeconomic welfare is the reduction in generation costs.

An economic optimisation is undertaken to determine the optimal dispatch cost of generation, with and without the project. The benefit for each case is calculated from the following relationship:

Benefit (for each time step) = sum of Generation costs without the project (sum over all time steps) over all sectors – sum of Generation costs with the project (sum over all time steps) over all sectors

The socioeconomic welfare, in terms of savings in total generation costs, can be calculated for internal constraints by redispatch (see Chapter 2.3 Cross-border versus internal. In any case, the method used for the SEW calculation must be clearly highlighted.

The total benefit for the horizon is calculated by summarising the benefit for all the hours of the year, which is done through market studies.

7.2 Total surplus approach

The global socioeconomic welfare is defined as the sum of the total surpluses stemming from the involved sectors. The total surplus approach takes the value of serving a particular unit of load into account. An economic optimisation is undertaken to determine the total sum of the producer surplus (difference between electricity price and generation cost), the consumer surplus (difference between willingness-to-pay the value of electricity and electricity price for a demand block), the change in congestion rent (difference in electricity prices between price zones), and possibly the change in cross-sector rent with and without the project. The total surplus of a specific sector is:

Total surplus = Producer Surplus + Consumer Surplus + Congestion Rents + Cross-Sector Rents

The economic benefit is calculated by adding the producer surplus (a measure of producer welfare), the consumer surplus (a measure of consumer welfare), the congestion rents for all price areas, as shown in Figure 16 on the following page, and possibly the cross-sector rents. The total surplus approach consists of the following three items:

1. By reducing network bottlenecks, the total generation cost will be economically optimised. This is reflected in the sum of the producer surpluses, which is defined as the difference between the prices the producers are willing to supply electricity and the generation costs.

2. By reducing network bottlenecks that restrict the access of import from low-price areas, the total consumption cost will be decreased. This is reflected in the sum of the consumer surpluses, which is defined as the difference between the prices the consumers are willing to pay for electricity and the market price.

3. Reducing network bottlenecks will lead to a change in total congestion rent for the TSOs.

A project with an NTC variation between two bidding areas with a price difference will allow generators in the low-price bidding area to supply load in the high price bidding area. In a perfect market, the market price is determined at the intersection of the demand and supply curves.

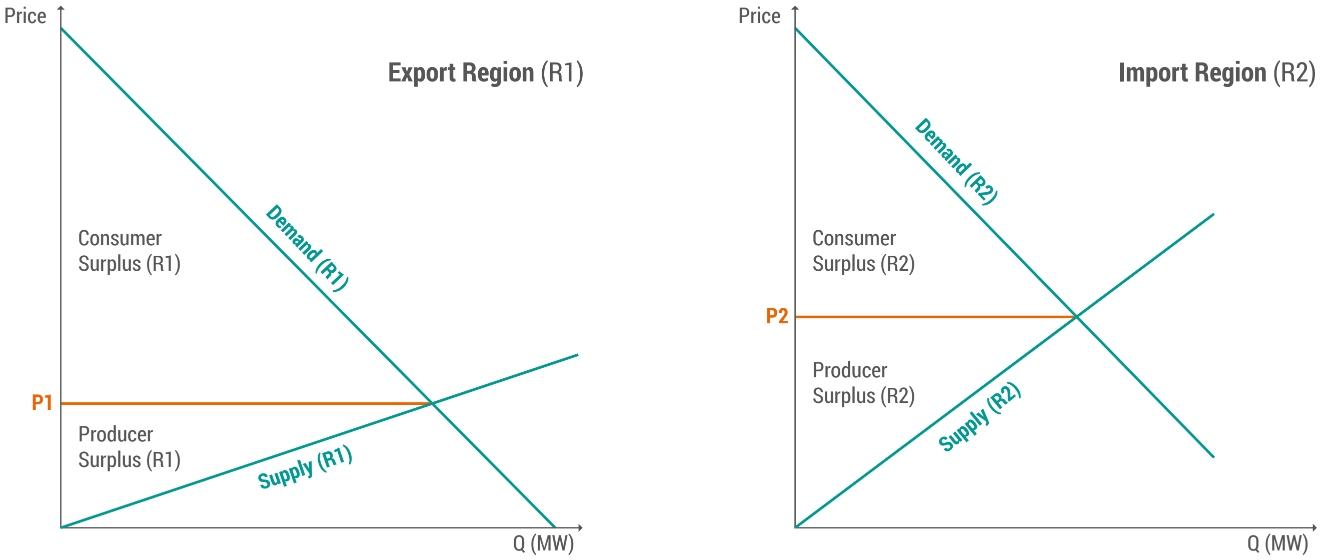

Figure 15: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity (elastic demand)

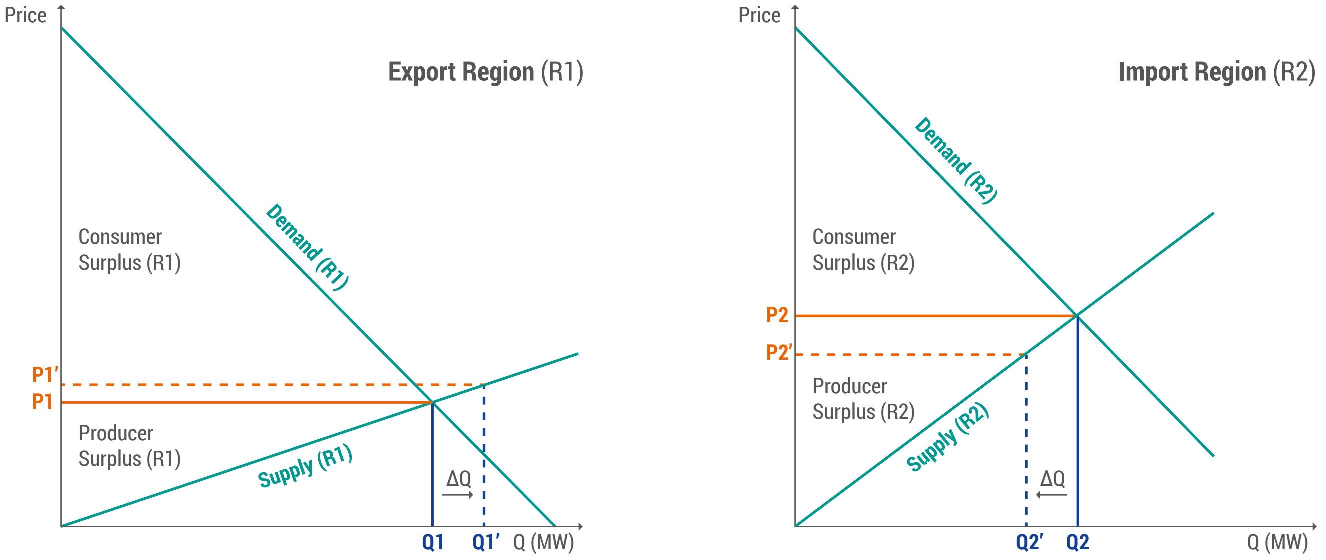

Figure 16: Example of an export region and an import region, with a new project increasing the GTC between the two regions (elastic demand)

A new project will change the price of both bidding areas. This will lead to a change in consumer and producer surplus in both the export and import areas. Furthermore, the TSO revenues will reflect the change in total congestion rents on all links between the export and import areas. The benefit of the project can be measured through the change in socioeconomic welfare. The change in welfare of a specific sector is calculated by:

Change in welfare = change in consumer surplus + change in producer surplus + change in total congestion rents + change of cross-sector rents

The total benefit for the horizon is calculated by summing the benefit for all time steps considered in that year. The total surplus is maximised when the market price is at the intersection of the demand and supply curves.

7.2.1 Inelasticity of demand

In the case of the electricity market, short-term demand can be considered as inelastic as customers do not respond directly to real-time market prices (no willingness-to-pay-value is available). The change in consumer surplus[50] of a specific sector can be calculated as follows:

For inelastic demand: change in consumer surplus = change in prices multiplied by demand

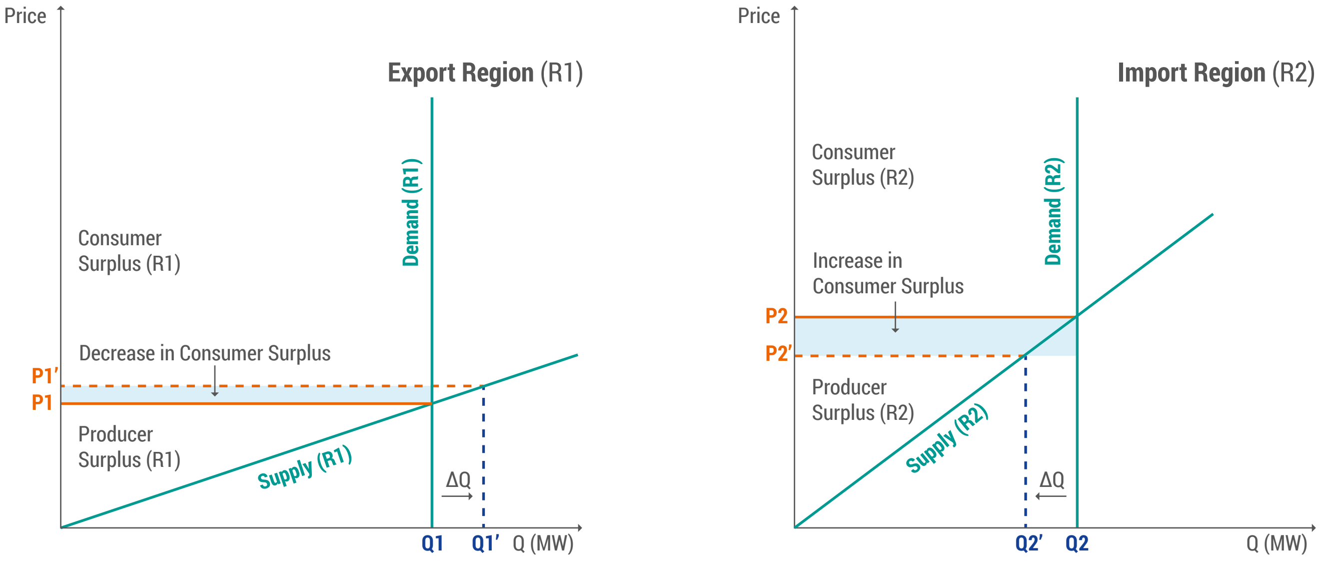

Figure 17: Change in consumer surplus

The change in producer surplus of a specific sector can be calculated as follows:

Change in producer surplus = change in generation revenues[51] – change in marginal generation costs

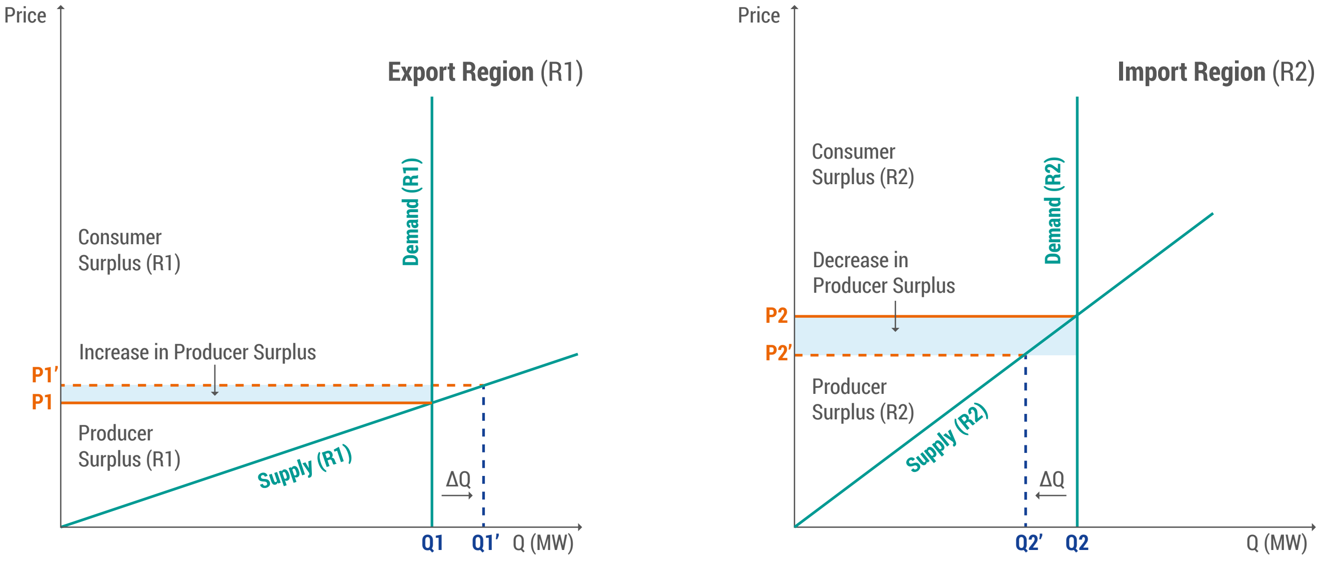

Figure 18: Change in producer surplus

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[50] When demand is considered as inelastic, the consumer surplus cannot be calculated in an absolute way (it is infinite). However, the variation in consumer surplus, as a result of the new project, can be calculated nonetheless. It equals the sum for every hour of the year of: marginal cost of the area x total consumption of the area (with the project) – marginal cost of the area x total consumption of the area (without the project).

[51] Generation revenues equal: (marginal cost of the area x total production of the area).

The congestion rents with the project can be calculated from the price difference between the importing and the exporting areas, multiplied by the additional power traded by the new link[52]. The change in total congestion rent for a specific sector can be calculated as follows:

Change in total congestion rent = change of congestion rents on all links between import and export areas

The cross-sector rent with the project can be calculated from the price difference between the coupled sectors, the energy conversion efficiency and the additional power required for the energy conversion from energy carrier A into B. The change in total cross-sector rent[53] for a specific sector is

Change in total cross sector rent = change of cross-sector rents between associated sectors

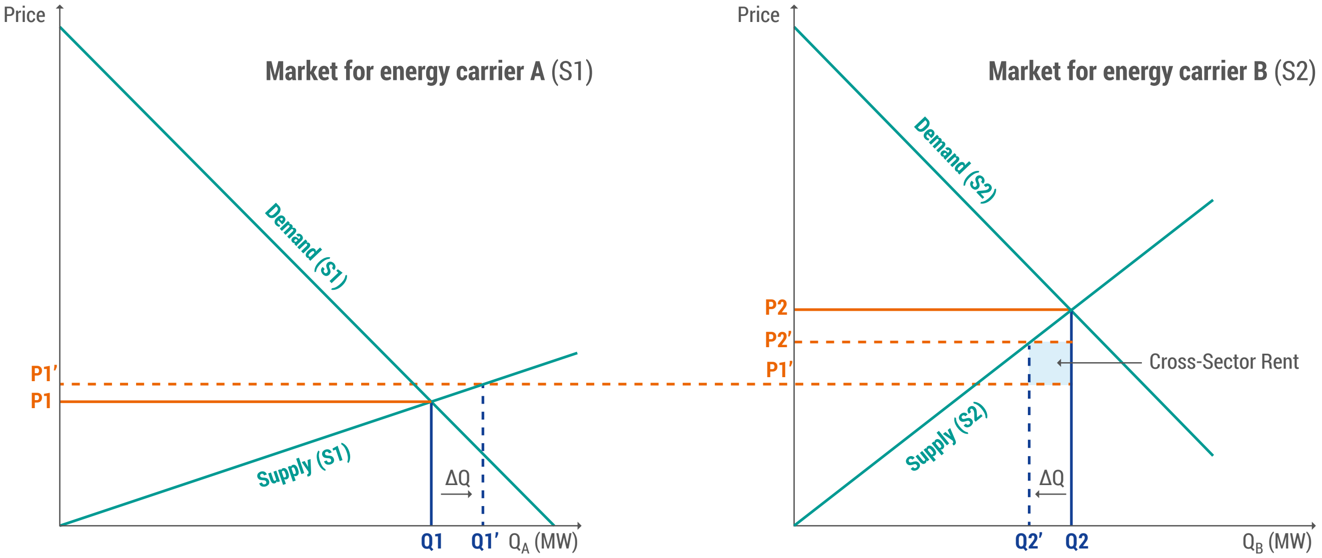

Figure 19: Illustration of sectorial market coupling. The cross-sector rent captures the benefit of sector coupling and describes the welfare movement from sector A to B. It can be regarded as an additional welfare component.

The global benefit for each case is calculated by:

Benefit (for each time step) = sum of Total surpluses with the project (sum over all time steps) over all sectors – sum of Total surpluses without the project (sum over all time steps) over all sectors

The total benefit for the horizon is calculated by summarising the benefit for all the hours of the year, which is achieved through market studies.

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[52] In a practical manner, it is calculated as the absolute value of (Marginal cost of Export Area – Marginal cost of Import Area) x flows on the interconnector.

[53] Further details on the calculation of cross-sector rents can be found in T. Felling and P. Fortenbacher, 'Extended Social Welfare Decomposition for Multi-Energy Systems,' 2022 18th International Conference on the European Energy Market (EEM), 2022, pp. 1-7, doi: 10.1109/EEM54602.2022.9921010.

7.3 Example of ΔNTC calculation

An example is provided below to illustrate how to calculate the ΔNTC. The example uses the TOOT approach for one time step. The PINT approach is similar; only the position of the project towards the reference network model changes.

The example is designed for a ΔNTC calculation across any boundary between bidding zones.[54] This methodology should be performed over all the time steps of the year to calculate an annual ΔNTC to be used for simulations.

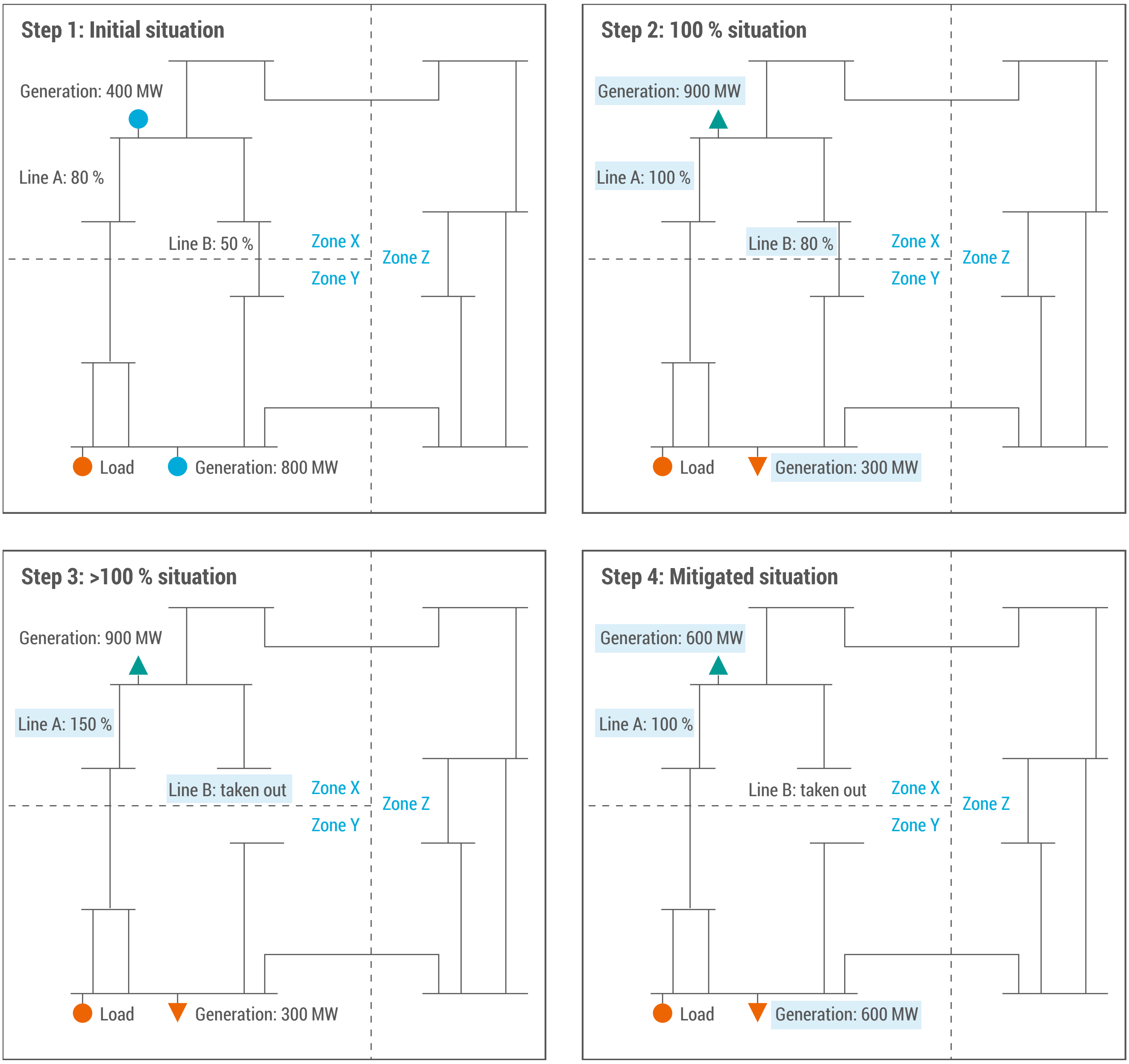

Figure 20: Qualitative example to illustrate the single steps, as described in the example above. It should be noted that the real physical flow will also have a component across the boundary between zones X–Z and Z–Y.

Consider the example system as presented above. The following steps must be followed:

- **Step 1:** Perform load flow analysis on the reference network model in line with the security criteria that consider the N-1 criterion.

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[54] In principle, the method can also be applied to any type of boundary.

- **Step 2:** Identify the total generation in zone X and Y (in the simple example, zone Z does not have any generation or demand), which corresponds with at least one line loaded at exactly 100 % under N-1 condition (100 % situation) in one of the areas around the border under consideration (i. e. X and Y in the example), and with no other congestion, under the assumption that there are no congestions in zone Z. The 100 % situation can be created by performing a generation power-shift[55] in zones X and Y (and vice versa).[56]
- **Step 3:** Repeat steps 1 and 2 on the reference network model from which the project has been removed (TOOT of the project for which the ΔNTC shall be determined). This will provide the values for generation in X and Y in the situation when one of the lines is loaded at exactly 100 % under N-1 without the project.
- **Step 4:** Calculate the ΔNTC as the difference between the generation situations that correspond with the 100%-situations: ΔNTC equals the power shift.
- **Step 5:** Apply this process to both directions of power-flow across the boundary under analysis.

The results of the calculations described in the steps above are illustrated in Table 20.

	Step 1	Step 2	Step 3	Step 4
Incident	Line B in	Line B in	TOOT line B	TOOT line B
Situation	initial situation	100 % situation	>100 % situation	mitigated situation, thus back to 100 %
Generation in zone X	400	900	900	600
Generation in zone Y	800	300	300	600
demand to be covered	1,200	1,200	1,200	1,200
Line loading at line A	80 %	100 %	150 %	100 %
Line loading at line B	50 %	80 %	–	–

Step 5
Δ NTC X > Y [MW]
300

Table 20: Simplified example of ΔNTC increase from direction X to Y across a boundary.

From Table 20 it can be seen that:

- Step 1 denotes the initial situation where all projects are put in (including line B). No overloads show up, illustrated by the line loadings in %.
- In Step 2, the generation power-shift has been done until one line is loaded at exact 100 % (line A in this example) under N-1 conditions. The power-shift-volume needed was 500 MW.
- In Step 3, line B is taken out as per the TOOT approach. The dispatch is fixed as it was after Step 2, with + 500 MW in zone X and – 500 MW in zone Y. The loading of line A became 150 % (N-1).
- In Step 4, the generation power-shift is done in the opposite direction to that done in Step 2. This reduces the load one line A to 100 % (N-1). The remaining power-shift, compared to the initial situation, is 200 MW. Hence, the project enables a power-shift increase of difference between initial dispatch and final dispatch; thus, 500 MW – 200 MW = 300 MW.
- Step 5 illustrates the corresponding ΔNTC in the direction of X > Y across the boundary.

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[55] Which generators to use for the generation power-shift is highly context-dependent. As many different methods for the generation power-shift can be applied without the possibility of identifying a preferable one, no favoured methodology for the generation power-shift is given in this Guideline. But it should be mentioned that the generation power-shift can have a significant impact on the results and should, therefore, be chosen carefully and with a detailed justification. In the likely case where the initial highest N-1 load may be higher or lower that 100 %, a power shift relative to the initial dispatch across the boundary is to be applied in order to reach 100% and find the corresponding power value. Depending on the initial conditions, this power-shift would increase or reduce the reference power-flow.

[56] If not possible, a load power-shift could also be performed.

General definitions

Boundary

A boundary represents a barrier to power exchange in Europe. It represents a section (transmission corridor) within the grid where the capacity to transport the power-flow related to the (targeted level of) power exchange in Europe is insufficient.

In this context, a boundary is referred to as a section through the grid in general. A boundary can:

- Be the border between two bidding zones or countries;
- Span multiple borders between multiple bidding zones or countries; or
- Be located inside a bidding zone or country, dividing the area into two or multiple sub-areas.

Competing transmission projects/investments

Two or more transmission projects are regarded as competing if they serve the same purpose.

- In cases where competing projects are proposed to achieve a transmission capacity increase, the projects typically (but not exclusively):
- Increase NTC on the same boundary; and

Their socioeconomic viability is reduced if assessed under the assumption that the other project is also realised. Therefore, the overall net benefit of realising both projects is lower than the sum of the individual net benefits.

Current grid (starting grid)

The current grid is the existing transmission grid and is determined at a specific date that is dependent on the point in time of the respective study. It can also be considered the starting point or initial state of building the reference grid by including the most probable projects as described in this 4th CBA Guideline.

Generation power shift

Generation power-shift is the deviation from the cost-optimal power plant dispatch (determined by market simulations) for the purpose of influencing grid utilisation.[57] It considers the loading of a line across a boundary that separates system A from system B (with energy transported from A to B), arrived at as a result of optimum dispatch. Generation is incrementally increased in area A and decreased in area B. This process is conducted up to the point where the line loading security criteria in System A or System B are reached. The volume of the power shift represents the additional market exchange possible between these systems and should be reflected by the variation in NTC that is assumed in market simulations. Generation power shift is used to modify the market exchange across a specified boundary to find the maximum change in generation made possible by the grid.

Grid Transfer Capacity (GTC)

The GTC is defined as the greatest (physical) power-flow that can be transported across a boundary without the occurrence of grid congestions, considering standard security criteria.

Hybrid Projects

A hybrid project is a project which enables an interconnector function between bidding zones (either onshore or offshore) while simultaneously facilitating a client connection with a certain technology (RES or non-RES; generation or load; AC or DC)

Interdependent Projects

An interdependent project is a project where its realisation is dependent on the realisation of another project, e. g. where a project needs to be built as a prerequisite before the interdependent project can fulfil its full potential. This might also apply to two or more projects interdependent from each other.

Interlinked Model

Interlinked (sector) models simulate energy market transactions and interactions with other sectors of different energy carriers. The interlinked model is necessary to assess projects from a 'one energy system' perspective.

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[57] This can also be seen as the definition of the re-dispatch. To avoid confusion in this case it is referred to generation power-shift as in reality the re-dispatch is used to reduce the grid utilisation and to heal congestions. However, as described in this guideline, the re-dispatch will also be used to determine the theoretical maximum grid utilisation by bringing the system to the edge of security.

Investment

An investment is the smallest set of assets that together can be used to transmit electrical power and that effectively add transmission infrastructure capacity. An example of an investment is a new circuit, the necessary terminal equipment and any associated transformers.

Investment need

The need to develop capacity across a boundary is referred to as an investment need. As different scenarios may result in different power flows, the amount of capacity required to transport these power flows across a boundary and, consequently, the amount of investment needed, is likely to differ from scenario to scenario.

Investment status

The investment status is defined depending on its stage of development, according to one of the following six options:

- Under consideration: Investments in the phase of planning studies and under consideration for inclusion in national plan(s) and Regional/EU-wide Ten-Year Network Development Plans (TYNDPs) of ENTSO-E.
- Planned, but not yet in permitting: Investments included in the national development plan and that have completed the initial studies phase (e. g. completed pre-feasibility or feasibility study), but have not yet initiated the permitting application.
- Permitting: Investments for which the project promoters have applied for the first permit required for its implementation and the application is valid.
- Under construction: The investment is in its construction phase.
- Commissioned: Investments that have come into first operation.
- Cancelled.

Main investment

In the case of a project that consists of a number of investments, one investment (e. g. an interconnector) is to be defined as a main investment with one or more supporting investments attached. This is required when clustering investments. The main investment is planned to achieve the specific goal, e. g. an interconnector between two bidding areas, with the supporting investments (as part of the project) required to achieve the full potential of that main investment. The full potential of the main investment represents its maximum transmission capacity in normal operation conditions.

Net Transfer Capacity (NTC)

The NTC is the maximum foreseen magnitudes of power exchange programmes that can be operated between two bidding zones while respecting the system security requirements of the areas involved. The NTC is used in market modelling to represent the power exchange capability between bidding zones.

Planning cases

The representation of how the power system (i. e. the generation and transmission system) could be managed at a point in time. They are used to represent a detailed model of the grid for that point in time, or a snapshot, and are used in network studies. Planning cases are selected inter alia based on:

- The outputs from market studies, such as system dispatch, frequency and magnitude of constraints;
- Regional considerations, such as wind and solar profiles or cold/heat spells; and
- Results of pan-European Power Transfer Distribution Factor (PTDF) analysis, when available.

Project

A project is defined as a single investment or group of investments. Therefore, it can comprise a main investment with supporting investments that must be realised together to enable the main investment to realise its intended goal, i. e. the full potential, which is defined as the capacity increase of the main investment. In cases where there are no supporting investments, the project consists of the main investment alone and will nonetheless be described as a 'project' in this CBA Guideline.

Put IN one at the Time (PINT)

A methodology that considers each new investment/project (line, substation, phase shifting transformer (PST), or other transmission network device) on the given network structure one-by-one and evaluates the load flows over the lines with and without the examined network investment/project reinforcement.

Radial Projects

A radial project enables the connection of a certain technology (RES or non-RES generation) to a bidding zone.

Reference network

The reference network is the version of the network used to calculate the incremental contribution of the project that is assessed. Therefore, it is used as the starting point for the computation of and the respective benefit indicators.

Renewable Energy Sources (RES)

RES means energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas ESAB. A detailed overview is also provided within the study specific Implementation Guidelines.

Respective study

The study in which the CBA assessment is performed, e. g. the TYNDP.

Scenario

A set of assumptions for modelling purposes related to a possible future situation in which certain conditions regarding demand, installed generation capacity, infrastructures, fuel prices and global context occur.

Societal cost of CO_2

The societal cost of carbon can represent two concepts:

- The social cost that represents the total net damage of an extra metric ton of CO_2 emissions due to the associated climate change;[58] and
- The shadow price that is determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint.[59]

Take Out One at the Time (TOOT)

A methodology that consists of excluding projects from the forecasted network structure on a one-by-one basis to compare the system performance with and without the project under assessment.

Ten-Year Network Development Plan (TYNDP)

The European Union-wide report examining the development requirements for the next ten years, carried out by ENTSO-E every other year as part of its regulatory obligations defined under Article 8, paragraph 10 of the Regulation (EU) 2019/943.

Time step

Simulation models compute their results at a given temporal level of detail. This temporal level of detail is referred to as the time step. Smaller time steps generally increase simulation run time, whereas larger time steps decrease simulation run time. Typically, simulations are done using hourly time steps, but this level of granularity may vary depending on the level of detail required in the results.

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[58] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

[59] IPCC Special report on the impacts of global warming of 1.5°C (2018) - Chapter 2

Abbreviations

ΔNTC	Increase in NTC
AC	Alternating Current
ACER	European Union Agency for the Co-operation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
BCR	Benefit-to-Cost Ratio
CAPEX	Capital Expenditure Cost
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CE	Continental Europe
CEER	Council of European Energy Regulators
CF	Complexity Factor
CIGRE	Council on Large Electric Systems
CONE	Cost of New Entrant
DA	Day-ahead Market
DC	Direct Current
DSR	Demand Side Response
EC	European Commission
EBGL	Electricity Balancing Guideline
EED	Energy Efficiency Directive
EENS	Expected Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ENS	Energy Not Served
EPRI	Electric Power Research Institute
ET	Energy Targets
ETS	Emissions Trading Scheme
EU	European Union
FCR	Frequency Containment Reserve
FE	Frequency Exchange
FO	Frequency Optimisation
FN	Frequency Netting
FRR	Frequency Restoration Reserve
FV	Future Value (Cost or Benefit)
GTC	Grid Transfer Capability
HVDC	High Voltage DC
ID	Intraday Market
ILM	Interlinked Model
IPS	Integrated Power System
LFC	Load Frequency Control
LOLE	Loss of Load Expectation
MES	Multi-Energy System
mFRR	Manual Frequency Restoration Reserve
MS	Member States
MSC	Mechanically Switched Capacitors
MSR	Mechanically Switched Reactors
NECP	National Energy and Climate Plan
NPV	Net Present Value
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OBZ	Offshore Bidding Zone
OHL	Overhead Line
OPEX	Operating Expenditure Cost
P2G	Power-to-Gas
PCI	Projects of Common Interest
PINT	Put IN one at the Time
PMI	Project of Mutual Interest
PP	Project Promoter

PST	Phase Shifting Transformer
PTDF	Power Transfer Distribution Factor
PV	Present Value
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
RR	Replacement Reserves
SA	Synchronous Area
SA-OA	Synchronous Area Operational Agreements
SEA	Strategic Environmental Assessment
SEW	Socioeconomic Welfare
SMC	Submarine Cable
SOC	System Operations Committee
SOGL	Commission Regulation (EU) 2017/1485: Establishing a Guideline on Electricity Transmission System Operation
SoS	Security of Supply
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TOOT	Take Out One at the Time
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TYNDP	Ten-Year Network Development Plan
UGC	Underground Cable
VOLL	Value of Lost Load
XB	Cross-border

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