European Network of Transmission System Operators for Electricity

IMPLEMENTATION GUIDELINES FOR TYNDP 2026 BASED ON 4th ENTSO-E GUIDELINE FOR COST BENEFIT ANALYSIS OF GRID DEVELOPMENT PROJECTS

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Contents

1. Introduction and scope

The TYNDP 2026 Implementation Guidelines provide complementary information to the 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Project (hereinafter: the '4th CBA Guideline'), as approved by the European Commission under Article 11(5) of the TEN-E Regulation[1]. The purpose of the TYNDP 2026 Implementation Guidelines is not to replace the 4th CBA Guideline, but to specify how cost benefit analysis is applied on projects included in the TYNDP 2026 cycle. For a full understanding of these Implementation Guidelines, it is strongly recommended that the reader familiarise themselves with the 4th CBA Guideline. Only in combination do both documents deliver the necessary information to practically perform a project CBA in the ENTSO-E Ten-Year Network Development Plan (TYNDP) 2026. Information not explicitly noted in the Implementation Guidelines has to be considered with respect to the 4th CBA Guideline.

These guidelines for the TYNDP 2026 are drafted under the requirement of being made public, together with the TYNDP 2026 package, as demanded by the 4th CBA Guideline. The structure of the 4th CBA Guideline follows a general and modular approach. It explicitly refers to and relies on the study specific implementation guidelines (i.e. for the TYNDP 2026 cycle the present Guidelines):

a. It is modular as each individual indicator or aspect within the 4th CBA Guideline is presented as an individual module. This approach allows ENTSO-E to include small changes or revise/add/revoke single indicators in a clearer manner without changing the entire document.

b. It is more general as very specific details or assumptions needed for applying the CBA Guidelines are specified in the Implementation Guidelines, whereas the CBA Guideline focuses on the main concepts.

Therefore, the Implementation Guidelines must fulfil different requirements, as described below.

For the application of the CBA, the reader should therefore also make use of:

4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (Approved by the European Commission)[2]

TYNDP 2026 Scenario Webpage

Key drivers of the methodology:

[1] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013

[2] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/news/2024/entso-e_4th_CBA_Guideline_240409.pdf

1. Complementing the guidance as provided in the 4th CBA Guideline
2. Delivering the methodology for assessing projects that have (or not) a major impact on cross border trading capacities
3. Alignment between results and tools in order to create comparable results
4. Transparency regarding the methods, assumptions and models used within the TYNDP project assessment

2. Changes compared to TYNDP 2024 Implementation Guidelines

ENTSO-E is constantly working on improving the methodologies, data etc. for the assessment of projects within the TYDNP project assessment. Although these Implementation Guidelines are based on the 4th improved CBA Guideline and therefore are to be considered as a mature document, the following main changes compared to the TYNDP 2024 need to be highlighted:

- Revised assessment definitions aligned with the TYNDP 2026 scenario framework
- Inclusion of a climate adaptation indicator
- Deleted sanity check for hybrids
- Central ENTSO-E dNTC calculations and verification of dNTC compliance
- Refinement of the methodology of the efficiency indicator (ET2) and renewable penetration indicator (ET3) to contribute to the European Energy targets
- Inclusion of Carbon Border Adjustment Mechanism (CBAM)

General error corrections, consistency changes and minor changes included based on increasing the understandability of the document are not listed above.

After public consultation:

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Updates since the latest draft version published in XX-XX-XX.

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3. Modelling frameworks

The Figure below outlines the project assessment process, including market and network simulations, and the link between the two.

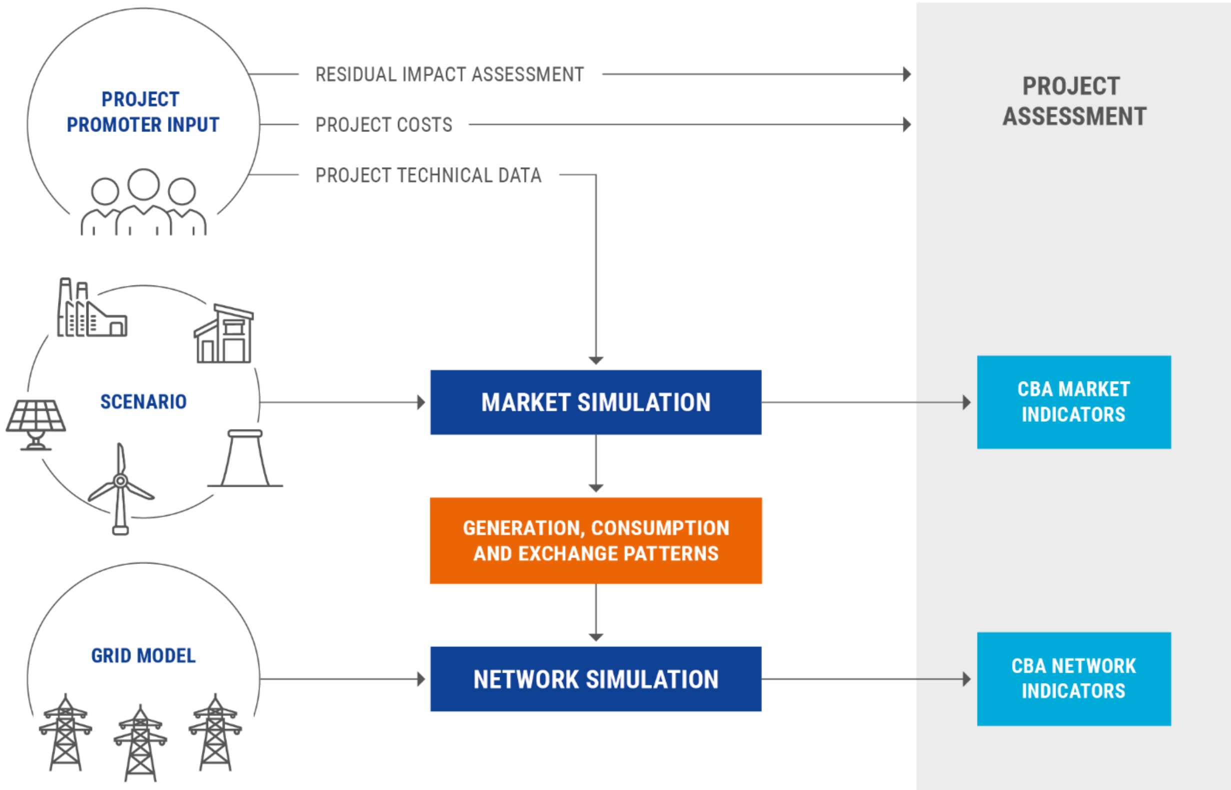

Figure 1 – Schematic project assessment process. Whereas 'CBA market indicators' and 'CBA network indicators' are the direct outcome of market and network studies, respectively, 'project costs' and 'residual impacts' are obtained from the promoters without the use of simulations.

This section delivers a detailed overview of the respective steps as shown in Figure 1.

In the scope of the TYNDP, the project assessment consists of appraising the impact of a project not only to the power system but also to the environment and to the society. Those impacts are characterised by a number of indicators that can either come from the project promoters themselves or can be extracted from market and/or network simulations. For each of the scenarios considered within the TYNDP study, the generation fleets and demand time series are defined. This feeds into the market simulation process together with the reference grid representative of the market exchanges capacities between different bidding zones. Project promoters have to submit technical data on their projects which can be taken into account or not in the reference grid depending on specific factors detailed in the 4th CBA Guideline.

To capture and assess the cross-sectorial coupling impacts in the infrastructures' assessment, the hydrogen and the electricity sectors are interlinked in the TYNDP 2026 cycle. All electricity projects undergo a dual-system assessment. This is shown in Figure 2, where the joint scenarios and reference networks are the inputs for the interlinked dispatch model. The dual assessment provides results for two classes of indicators:

a) **Energy system-wide indicators** encompass the cross-sectorial view. Those indicators incorporate the complete results from the interlinked model.
b) **Sector-specific indicators** among which some belong to the electricity sector. They are obtained from a subset of the results from the interlinked model and/or need to be further processed.

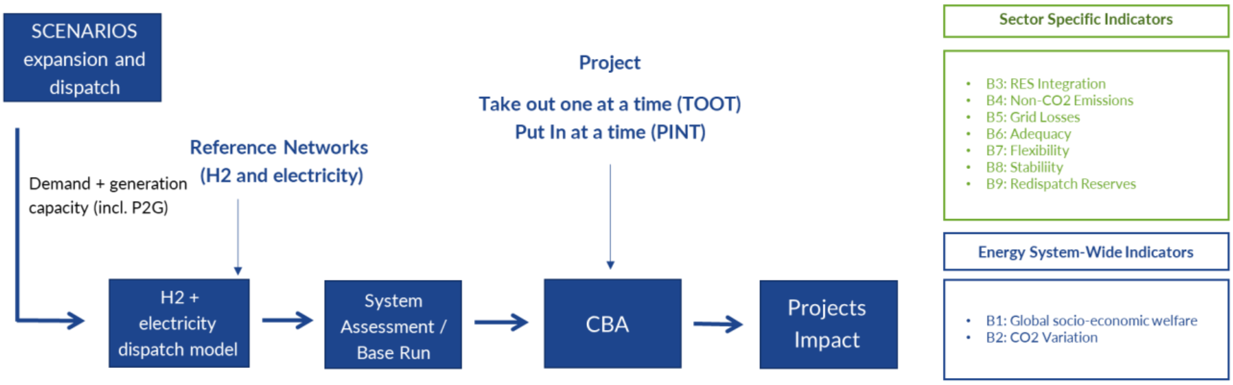

Figure 2 - Dual-(system) assessment of electricity projects in one overarching framework by interlinking the hydrogen and electricity sector.

3.1 Scenarios (section 2.1 of the 4th CBA Guideline)

An overview of the draft scenarios, their storylines, main data points and definitions as applied to the TYNDP 2026 can be found in the [LINK to Scenario 2026].

In the TYNDP 2026 the central scenario is "National Trends" (NT). For the NT scenario input data is directly collected from TSOs. Therefore, this scenario respects national energy and climate policies which are derived to implement the European energy and climate targets. The NT scenario is available for the target years: 2030, 2035, 2040 and 2050. The Market CBA is performed for all 4 target years (for 2030 only a combination of all projects is planned to be assessed).).). The Network CBA is performed based on the scenario NT target2035NTtarget years 2035 and 2040NT. For2040. Additionally, also high and low economic variants from the NT scenario are considered, which mainly differ in respect of the demand assumptions.

In order to cover the range of possible climatic futures, different "Weather Scenarios" are used. For the 4 target years 2030, 2035, 2040 and 2050 of the NT scenario, 30 weather scenarios are available each (PECD4.2). For each target year, the CBA is performed based on the 3 weather scenarios with the highest level of representativeness in combination (except for the B6 indicator which is calculated based on all 30 weather scenarios)..

An overview of the indicators calculated for the respective scenarios is provided in the table below:

Table 1: Overview of the scenarios considered for market and network CBAs

Scenario	B1, B2, B3, B4	B5 – Losses	B6 – Adequacy	ΔNTC
NT2030	Yes	No?	No?	Yes[3]
Weather scenario	WS003, WS021, WS029			
NT2035	Yes	Yes	Yes	Yes[3]
Weather scenario	WS032, WS037, WS059	WS032, WS037, WS059	All 30 WS from PECD	
NT2040	Yes	Yes	Yes	Yes[3]
Weather scenario	WS065, WS071, WS077	WS065, WS071, WS077	All 30 WS from PECD	
NT2050	YES	No?	Yes	Yes[3]
Weather scenario	WS091, WS092, WS106		All 30 WS from PECD	

[3] NT 2030 scenario from TYNDP 2024 is the one recommended in the present guidelines for the assessment of ΔNTC provided for the implementation of infrastructure projects.

3.1.1 Security of Supply loop (adequacy calibration of the Scenarios)

For the purpose of the CBA, it is necessary to modify the scenarios in order to ensure that all indicators can be calculated properly. These modifications mainly concern the Security of Supply (SoS) in the market models. The calculation of the SoS loop can be described in the following steps.

The SOS loop will be performed independently for the calculation of the:

To calculate B6 indicator in order to achieve the safety standard CBA models with 0 LOLE condition in order to eliminate undelivered energy.

The reference case scenario must have a realistic LOLE (Loss Of Load Expectation) level (maximum LOLE criteria with tolerance - 1h) for all countries without the project that is being assessed (mostly importantly, for projects initially included in the system).

The philosophy behind the scenario's adequacy calibration is either to:

- Add peaking generation capacities or demand side response (DSR) where LOLE exceeds SoS standard (LOLE < 3 h as default), or to
- Reduce installed capacities of peaking generation where LOLE < SoS standard.

For the purpose of the SoS loop (mainly), it should be ensured that the initial LOLE obtained is below the adequacy criteria of the country concerned and that it is not "over adequate".

SoS quantification is based on standard methodology similar to the one used in the European Resource Adequacy Assessment (ERAA) process conducted by ENTSO-E. For each country, it is assumed that the LOLE should be below or equal to the existing adequacy criteria (3 hours as default) and above 2 hours of LOLE (unless removal of capacities does not allow to reach it).

Further, the iterative process is performed until the criteria is satisfied for each country (or no more capacity of the pre-defined types can be added/removed).

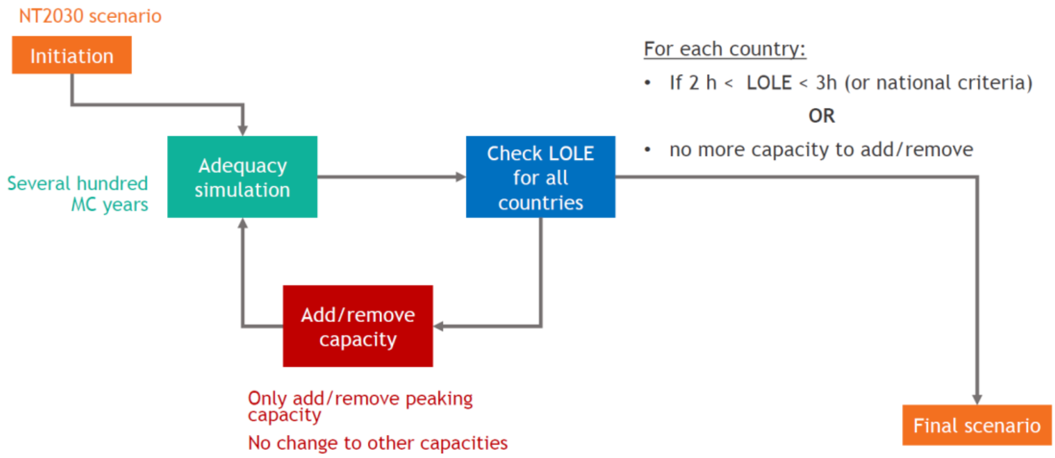

Figure 3 – SoS Loop Iterative Process Diagram in TYNDP 2026 process

The purpose of the mechanism is to develop realistic solutions. It should be emphasized that the problem of over or under estimation of adequacy is not symmetrical. Due to the high complexity of power systems and various requirements, generation capacity cannot be changed arbitrarily. Furthermore, the use of transport models may have bias, especially in the case of shortage events. Therefore, countries provide lower limits for power reduction in the SoS loop. Introducing these limits may lead to not meeting the criteria for every country but will provide scenarios that are closer to reality.

For the purpose of the CBA models, the process is exactly the same with the difference that the goal is to eliminate any unserved energy from the system. Unserved energy can lead to strong distortions of the Social Economic Welfare Indicator (B1).

For projects subject to a TOOT (Take Out One at the Time) assessment ('TOOT project'), it is necessary to verify this condition. If the model results without the project integrated does not respect the LOLE level, it might be needed to add some peaking power plants in the countries to reach the adequacy standard without the TOOT project. The maximum capacity added corresponds to:

- NTC (Net Transfer Capacity) to the country that sees SoS benefit (if only one side shows SoS benefit) or
- NTC direct + NTC indirect (if both sides show SoS benefit)
- Special case: Assessment of a TOOT project that adds a new interconnection between two market nodes, where in one market node there is no generation capacity nor other interconnections. In this case when a TOOT project is removed, the LOLE in isolated market node is equal to 8760 h. If NTC increase value of a new interconnection was to be added as peaking unit capacity in isolated country that has low average load, no delta ENS (Energy Non-Served) would be calculated. To avoid this situation in isolated market nodes, peaking unit capacity lower than the NTC increase of the TOOT project needs to be added. Added peaking unit capacity should be enough to meet the LOLE requirement in isolated market nodes (LOLE < 3h) without the TOOT project.

Therefore, for the purpose of CBA models, the SoS Loop analysis is performed on a system without TOOT projects (For borders with multiple TOOT projects it is sufficient to remove the project with the highest NTC increase).

A more detailed description of the calculations of the Security of Supply loop can be found in Annex G. In the TYNDP 2026 cycle, the SoS loop is applied before the calculation of the B6 indicator which assesses how a project supports the adequacy in the market zones where it is located. When a scenario is found non adequate before the CBA assessment phase, the first approach mentioned above consisting of DSR with cap price is considered which ensures that Energy Not Served is limited and the SEW (Social Economic Welfare) benefit is not distorted.

3.2 Market simulations (section 2.4 of the 4th CBA Guideline)

Modelling features The CBA assessment incorporates a dual system approach. In particular, the power market model is extended with a hydrogen market model. Both models are coupled by introducing sector coupling elements such as electrolysers[4]. Additional hydrogen market nodes with specific hydrogen demand are introduced to the models. This demand can be satisfied by steam methane reforming units (fossil), electrolyzes, exchanges between hydrogen nodes (pipelines) and imports from outside the modelled perimeter. This approach follows the scenario building process in most aspects. More information on this will be provided in the TYNDP 2026 scenario methodology report, accessible on the TYNDP 2026 Scenario website.

Flexibility influences the CBA outcomes and cannot be neglected. In addition to batteries, time shifting loads can be considered as an innovation which is used since the TYNDP 2024 edition. By including implicit Demand Side Response technology (iDSR) flexible demand can be shifted during the day based on the market needs. Currently, the demand portfolio for iDSR consists of certain shares of electric vehicles and heat pumps that are part of the scenarios.

3.2.1 Tools used for market simulations

The TYNDP project assessment should report costs and benefits on a pan-European level due to market and network simulations. The tools used for market simulations are:

- Antares link
- Plexos link
- BID3 link
- Promed (Not publicly available developed software)
- MARCO (Not publicly available developed software)

[4] Hydrogen gas turbines are however considered exogenously.

By using multiple different market modelling tools, the quality and robustness of the implemented models can be strongly improved. The goal is to have 3 different market modelling tools for each CBA indicator assessment (except B6 indicator). That way outliers of a single tool can easily be spotted and excluded.

All market modelling tools have individual approaches for modelling certain market characteristics. However, the fundamental underlying linear optimization problem (minimum of model-wide system costs) must be the same for all tools.

3.2.2 Generation cost and total surplus approach

Market simulations are used for assessing indicators B1-B2-B3-B4-B6. The assessment of the indicator B1 can rely on two possible approaches: the generation cost approach or the total surplus approach. An illustrated example for their calculation is provided in the Annex C. Both are elaborated in the 4th CBA Guideline in Annexes I and II and capture the global socio-economic welfare (SEW).

- The **generation cost approach** compares the generation costs with and without the project for the different bidding areas. This approach can be used for inelastic demand only (i.e. fixed demand in each time step) and is not the appropriate way to define the welfare gains from a project implementation when looking at a specific region smaller than the full domain modelled.
- The **total surplus approach** compares the producer and consumer surpluses for the different bidding areas as well as the congestion rents between them, with and without the project. When sectors are coupled, the cross sectoral rents with and without the project are also compared. This approach is capable of dealing with both elastic and inelastic demand and is the only approach that allows to compute welfare gains for a specific region such as the European Union. The global SEW along the sectors $S \in \{\text{electricity}, \text{hydrogen}\}$ is calculated as follows:

$$SEW_{\text{global}} = \sum_{j \in S} R_{\text{cons}}^{j} + \sum_{j \in S} R_{\text{prod}}^{j} + \sum_{j \in S} R_{\text{cong}}^{j} + R_{\text{CSR}}^{\text{electricity} \leftrightarrow \text{hydrogen}},$$

where R_{cons}^{j} is the consumer rent, R_{prod}^{j} is the producer rent, R_{cong}^{j} is the congestion rent of sector $j \in S$, and $R_{\text{CSR}}^{\text{electricity} \leftrightarrow \text{hydrogen}}$ is the cross-sector rent stemming from the interlinkage between the electricity and hydrogen sector.

Cross sectoral rent

Any component $c \in C$ of the energy system (e.g. electrolyser) that introduces a coupling between the electricity and the hydrogen sector belongs to certain market areas with market clearing price $mcp_{\text{electricity}}^{c,t}$ for electricity and $mcp_{\text{hydrogen}}^{c,t}$ for hydrogen. The cross-sector rent is dependent on the price difference between the sectors and is summed up over all timesteps $t \in T$ by applying

$$R_{\text{CSR}}^{\text{electricity}\leftrightarrow\text{hydrogen}} = \sum_{t\in T}\sum_{c\in C}\left|mcp_{\text{hydrogen}}^{c,t} * p_{\text{cs,hydrogen}}^{c,t} - mcp_{\text{electricity}}^{c,t} * p_{\text{cs,electricity}}^{c,t}\right|,$$

where $p_{\text{cs,hydrogen}}^{c,t}$ and $p_{\text{cs,electricity}}^{c,t}$ denote the component's output and input power respectively, referenced to the hydrogen and electricity side. Note that these powers are different as they are coupled with the component's efficiency for the conversion from one energy carrier into another.

Producer surplus (or rent)

The producer rent for sector $j \in S$ is composed by the contributions from the generation assets $c \in G$ and storage components $c \in S$:

$$R_{prod}^{j} = R_{prod}^{j,gen} + R_{prod}^{j,stor}$$

The producer rent from the generation portfolio is

$$R_{prod}^{j,gen} = \sum_{t\in T}\sum_{c\in G}(mcp_j^{c,t} - marginalCost^c) * p_{gen,j}^{c,t},$$

where $marginalCost^c$ is the marginal cost of the generation asset associated with $c \in G$, $mcp_j^{c,t}$ is the market clearing price at time step $t \in T$ to the corresponding market zone, and $p_{gen,j}^{c,t}$ denotes the generation output. For storage devices, we attribute the benefits of arbitrage to the producer rent by deducting the cost of stored energy. It is calculated by

$$R_{prod}^{j,stor} = \sum_{t\in T}\sum_{c\in S_t} mcp_j^{c,t} * p_{gen,j}^{c,t} - mcp_j^{c,t} * p_{load,j}^{c,t} ,$$

where $p_{load,j}^{c,t}$ corresponds to the demand of the storage component $c \in S_t$ at time step $t \in T$ of sector $j \in S$.

In the same straightforward way, the consumer rent is determined by

$$R_{cons}^{elec} = \sum_{t\in T}\sum_{c\in L}(elasticity^c - mcp_j^{c,t}) * p_{load,j}^{c,t} ,$$

where $elasticity^c$ is the strike price level for which a consumer or a demand side response (DSR) component $c \in L$ is willing to buy energy from the markets. Inelastic demands use the Value of Lost Load (VOLL) for the elasticity, whereas DSR units serve certain DSR bands as input for elasticity.

Finally, the congestion rent in sector $j \in S$ is summed up over all $c \in Lines$ and timesteps $t \in T$ by

$$R_{cong}^{j} = \sum_{t \in T} \sum_{c \in Lines} \left| \left(mcp_j^{from,t} - mcp_j^{to,t} \right) * p_{ex}^{c,t} \right| ,$$

where $mcp_j^{from,t} - mcp_j^{to,t}$ is the price difference between the two market areas connected by the power line (or the gas pipeline) and $p_{ex}^{c,t}$ is the exchanged power (or gas flow) between the interconnected market areas.

In the event of inelastic demand – which is the case for the modelling used in TYNDP 2026 – the two approaches give the exact same results when looking at the entire domain simulated. The elasticity of the demand is modelled as demand side response (DSR) in the same manner as generators are modelled – therefore, this does not impact the validity of the generation cost approach.

To compute the SEW for specific regions such as the European Union and the ENTSO-E area or even for third countries, the total surplus is the only approach to be considered as stipulated above. This is due to the fact that transmission projects (and others) influence the energy exchanges between the countries which affects the dispatch in each country. Typically, generation could be increased in a country to supply its neighbours' demand, therefore likely increasing its generation costs, but meanwhile likely reducing the generation costs in these neighbouring countries.

3.2.3 Treatment of 'third countries'

Geographical scope of the market model

In line with Annex V, point (1) of the TEN-E Regulation, the geographic perimeter modelled in the TYNDP is defined as covering countries from ENTSO-E (except for Iceland), as well as third countries (Algeria, Georgia, Egypt, Israel, Libya, Morocco, Moldova, Malta, Palestine, Tunisia, Turkey, Ukraine, United Kingdom, Saudi Arabia and Azerbaijan).

The ENTSO-E perimeter is connected to non-member countries – so called third countries – in which costs and benefits may arise. It is therefore necessary to properly consider the benefit allocation because project benefits that arise in third countries should, in principle, not be counted as a pan-European benefit and should be excluded from the TYNDP full domain results. The simulated costs and benefits may therefore need to be adjusted to account for the effects created in third countries.

For the reporting of the benefits assessment of TYNDP infrastructure projects, three levels of regional aggregation are considered:

1. The **full perimeter results** which encompass all the nodes, both onshore and offshore of the countries covering the ENTSO-E area and the third countries mentioned above.
2. The **ENTSO-E area results** where only the benefits observed in the countries that are part of the ENTSO-E area are accounted for.
3. The **EU27 area results** where only the benefits observed in the countries that are part of the European Union are accounted for.

For most of the benefits, this regional aggregation is straightforward as this would just mean summing up the contribution observed in each relevant market node. For the SEW benefit only the total surplus approach can be used, and an attention should always be put to the project configuration in the modelling.

Carbon Border Adjustment Mechanism (CBAM)

Not all modelled third countries are part of the EU Emission Trading System (ETS). Therefore, the Carbon Border Adjustment Mechanism (CBAM) Regulation[5] which will apply from fully 2026 has to be considered in the market models as well.

Under the Carbon Border Adjustment Mechanism (CBAM), importers of electricity produced in third countries are obliged, before any import into the EU takes place, to retain the status of authorised CBAM declarant and, after such import, to surrender CBAM certificates corresponding to the amount of the GHG emissions embedded in the imported non-EU electricity and declared in the CBAM declaration, as is the case for electricity producers inside the EU subject to the ETS. The prices of CBAM certificates are closely linked to the average of the closing prices of EU ETS allowances on the auction platform. The actual price of CBAM certificates paid by the importer is the difference between the CBAM certificates price (corresponding to the respective EU ETS allowance prices) and any reasonable carbon price paid in third countries. For the purpose of TYNDP 2026, one ETS price is assumed per year, on the basis of which the CBAM price per certificate can be set at the same value. For third countries, in line with the CBAM Regulation, default values of emissions for the generation mix for the countries, in principle, are assumed. Where an ETS system is established in a third country, the actual price and amount of CBAM certificates needed are reduced according to the prices and amounts surrendered in the third country.

3.2.4 Generation unit data

All assessments in the TYNDP 2026 use a common ENTSO-E database as defined within the Pan-European Market Modelling Database (PEMMDB). This data is directly collected

[5] Regulation (EU) 2023/956 of the European Parliament and of the Council of 10 May 2023 establishing a carbon border adjustment mechanism.

from TSOs. As the market simulations are carried out on the full pan-European perimeter plus third countries (see previous section), modelling complexity has to be reduced to optimise the memory usage during the computations and to avoid excessive computational time. Therefore, the modelling data from the PEMMDB extract with generator resolution (i.e. detailed information per generator) is reduced to generation categories resolution. This is done by merging each generator with comparable properties to single categories (e.g. Nuclear, Lignite old 1, Lignite old 2 etc.). The full list of used categories is provided in Annex C.

3.2.5 Modelling assumptions

The market simulation uses the following input data[6]:

- ENTSO-E's PEMMDB 2.5[7] package covering per target year:
    - Net generating capacities for all generating types (thermal, RES, hydro, Other Non-RES)
    - Net generating and pumping (charging) capacities for all storage units (PSP and batteries)
    - type specific unit characteristics
    - Electrolysers
    - Pre-defined generation time series
    - Must-run values of thermal generation types
    - Availabilities of thermal units
    - Demand side response capacities and offer prices

- Demand profile hourly time series for all market nodes, per weather scenario and target year
- Pan European Climate Database (PECD4) covering solar irradiance, wind generation, ambient temperature, hydro inflow data and hydro constraint data per weather scenario and target year, planned and forced outage time series or probabilities
- Costs for generation:
    - Variable fuel costs
    - Internalised cost of CO2 emissions
    - Marginal cost of thermal generation
    - Variable operation and maintenance costs
    - Start-up and shut-down costs

[6] This terminology is consistent with other ENTSO-E documents and published data. Wherever this document refers to a market model, it covers in general all these items.
[7] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/draft2024-input-output/PEMMDB2.zip

- Cross-border capacities (NTC values)
- Fixed exchanges with non-modelled countries

Hydrogen data containing:

- H2 demand
- Capacities for SMR (Steam Methan Reformation)
- Capacities for H2 imports
- H2 pipelines
- H2 storages

3.2.6 Time-resolution

The market simulations are performed for 8736 hourly steps starting with Monday to have exactly 52 weeks. This is useful as most tools apply weekly optimisations. Time coupled consideration is especially important for a proper modelling of storage units.

3.2.7 Weather Scenarios

The weather scenarios considered for TYNDP 2026 market are selected individually for each target year to achieve the best possible representation of the whole set of available weather scenarios.

Target Year	Weather Scenario (Weighting Factor)		
2030	WS003 (0.63)	WS021 (0.07)	WS029 (0.30)
2035	WS032 (0.24)	WS037 (0.43)	WS059 (0.33)
2040	WS065 (0.20)	WS071 (0.40)	WS077 (0.40)
2050	WS091 (0.23)	WS092 (0.57)	WS106 (0.20)

For each weather scenario, the factors from the Pan-European Climate Database (PECD) are used to calculate the production of Wind Onshore, Wind Offshore, Solar PV and Solar CSP on an hourly basis for each market node. These time-series are the input for the market simulations. PECD includes data from extreme weather events, which ensures that the simulations reflect a broad range of climatic conditions and their impact on renewable energy production. This renewable energy infeed may be restricted by the export capacities or demand during the market simulation, which can lead to dumped energy in the results. In the case of hydro power plants with natural inflow, hourly inflow data is used, which also depends on the weather scenario. In TYNDP 2026, demand, other non-RES generation and demand side response availability can also depend on the weather scenario.

3.2.8 Hurdle costs

A hurdle cost of 0.01 €/MWh is applied in TYNDP 2026, which is the same as in the previous TYNDP cycles in 2024, 20242 and 2020. As the hydrogen system is also now modelled, the same hurdle cost is applied to hydrogen pipelines.

Note: A hurdle cost is a cost over the energy flowing through a line (like a small fee) and could be used to incentivize the dispatch of local resources when thermal generators located in different zones have the same marginal costs. Most importantly, the hurdle cost is included as a model parameter to mitigate unrealistic high flows over long distances and facilitate the convergence of the model.

The hurdle costs need to be very small to avoid a distortive impact on the merit order of thermal units as well as system costs (the overall hurdle costs impact in the simulation should be negligible).

3.3 Network simulations (section 2.4 of the 4th CBA Guideline)

3.3.1 Merging of the Grid Models

All load-flow simulations for merging the grid models are performed on models collected from TSOs for the NT 2035 and NT 2040 scenario in ENTSO-E Common Grid Model Exchange Specification (CGMES)[8] format, for reference hours selected from a market simulation output for the given scenario. These national models are merged to larger regional models, which are used in the TYNDP network studies. The reference hour is selected with the aim of minimising the exchanges in Europe, in order to help the convergence of the merged models. These merged models can then be used for year-round CBA simulations in which generation and loads are redistributed for every point in time based on the market simulation results.

The collected grid models have to match the PEMMDB 2.5 installed capacities for every TSO and contain a mapping of each grid node to the corresponding market node. Merged models for the different synchronous areas are built by TSOs for their own simulation tools that participate in the CBA calculations in the Planning Study Team. The load-flow results are then compared, and necessary fixes are done in each tool in case of discrepancies before starting the simulations. The following tools are used:

Tool	Merged Model	Link to description
Convergence	Continental Europe	link

[8] https://www.entsoe.eu/digital/cim/cim-for-grid-models-exchange/

Integral	Continental Europe	link
Powsybl	Continental Europe	link
PSS/E	Continental Europe, Baltics, Nordics	link
PowerFactory	Continental Europe, Great Britain	link

Convergence is a network simulation tool developed and used by RTE. Powsybl is an open-source tool used also by RTE. Integral is used by the German TSOs and APG. The rest of the tools are commercially available and used by several TSOs. . The usage of these tools was determined by the available resources from the TSOs for participation in the calculations in the framework of the TYNDP Study Team.

3.3.2 Mapping the market simulation results to the network models

The market and network models applied in the TYNDP have a different geospatial granularity. The market models cover in general bidding zones (market nodes), but their outcome feeds into grid models which have a more detailed level and cover all individual nodes.

The network models collected by ENTSO-E contain all the information required to map the market simulation results, namely the identification of all grid parts corresponding to a market node, and the association of each generator to the relevant PEMMDB category. The market simulation results per hour are mapped in the following manner:

- **Mapping of generation for each modelled market node**: The market simulation results contain the total generation for each PEMMDB category (e.g. Combine Cycle Gas Turbine [CCGT] Present 1, Lignite Old 1, Wind Onshore etc., see section 3.2) per market node. Hence, it is not possible to directly allocate the generation pattern to each single generator – whereas the network model needs this information on a generator level/resolution. The PEMMDB categories are therefore mapped to all generators of the given category corresponding to the given market node in proportion to their maximum active power. In the case of pumping/charging, the negative generation is mapped to all such units within the given category in proportion to their (negative) minimum active power. Dump energy is reported for all renewable types as one value in the market outputs, therefore the order to subtract it from the generation from such types had to be defined for network simulations. The sequence is the following: wind onshore, wind offshore, solar PV, solar thermal, other RES, increase load.

- **Exchanges with non-modelled countries**: The exchanges with non-modelled countries are mapped directly to the appropriate boundary nodes as injections. Whether these connections are Alternating Current (AC) or High Voltage Direct Current Connections (HVDCs), the mapping to each boundary node per border is done in proportion of the capacity of each line.
- **HVDC setpoints**: In the case of HVDCs within a country (market node) or in the case of borders that consist of both AC lines and HVDCs, there are different options for the modelling of HVDCs in the TYNDP grid models. It is either using AC emulation (defined as a K [MW/°] factor provided by the TSO) or defining a formula to calculate the HVDC setpoints in function of the exchange value from the market simulation. If a border consists of HVDC(s) only, the exchange is mapped directly (in proportion of the capacities of the HVDCs, if there is more than one).
- **Balances**: As the demand for each market node in the market simulation contains losses, the demand values cannot be mapped to the loads in the grid model directly for AC load flows. Instead, the balance of each market node is set after fixing the generation and the directly mapped exchanges by scaling the loads. In this manner, the total load plus the losses remains equal to the demand value from the market simulation. Loads represented by the NonConformLoad[9] class in CGMES are to be kept at their initial value throughout the year, without taking part in the scaling. All other loads that are represented by ConformLoad or EnergyConsumer classes are to be scaled. When it comes to DC load flows, the losses are included in the load and therefore there is no need to scale the load.
- **Usage of representative Point-in-Time (PiT):** Although year-round simulations are to be seen as the standard, it is also allowed to use representative PiT instead in order to reducing the complexity of the simulations. However, when PiT are used a detailed proof of the representativeness of the PiT has to be given together with the respective modelling results.

The merged base case models (base case relates here to a specific reference PiT) are available in each simulation tool. However, beyond the computational limits, AC simulations present limits within the time steps where the convergence is not possible. For these time steps: i) a solution can only be found by installing reactive compensation that will enable the calculation. Nevertheless, these results are questionable because they depend on assumptions related to reactive compensations; and ii) it will not be possible to simulate entire years. A DC load flow approximation is convergent by definition and brings the complexity to a manageable level at a reasonable deviation in accuracy.

[9] *In the CGMES standard, the NonConformLoad class is used to represent loads that do not show a daily pattern, whereas ConformLoad is used to represent normally scaling loads. EnergyConsumer is a generic class to represent loads; in the TYNDP simulations, it is treated in the same manner as ConformLoads.*

3.3.3 Improving DC calculations using results from AC calculations

Some methods can be utilised to improve the accuracy of DC load-flow results, which were investigated and commonly agreed for TYNDP 2020. The applied methods are the following:

- Usage of voltages based on AC load-flow result in the formula for losses from DC results instead of base (nominal) voltages for the voltage levels that can be found commonly in the European grid. The values used are described in the section for losses calculations.
- The assumption of cos(ϕ) is verified by results from AC load-flow, performed by Integral. The value can be adjusted based on the results.
- Dispersal of losses in the loads is considered as the demand values from the market simulation already contain assumed losses for each market area.

After detailed load flow tests carried out in TYNDP 2020, it was identified that many other uncertainties are making the comparison between AC and DC load flow approaches very difficult. The comparison between the different network simulation tools showed that the issues in the modelling, topology, mapping of market outputs and specifics of the tools have an essential impact on the load flow results and, therefore, on losses results. The identification and fixing of these issues are crucial to ensure the robustness of the comparison of network calculations. The following tasks could be applied in the CBA process:

- Quality checks of prepared network models have to be performed before the CBA phase to identify the issues in the network models and ensure the good comparability of load flow results between network simulation tools used for the losses computations

- Improvement of voltage profiles:
    - The target voltage level should be harmonised in the considered areas to ensure realistic voltage profile compliant with operational rules
    - The parameters of voltage control mode have to be defined in the network model for AC load flow calculations (target value, min/max range etc.)
    - The DC voltage pattern should be customised using the results of AC load flow

Considering the recommendations above, the power flow results and thus the results of losses computations in AC and DC approaches should be well aligned. **The performed analysis proved that the DC power flow with customised voltage pattern approach is sufficient for long term studies as well as the AC power flow approach.**

3.3.4 Geographical scope of the grid models

As described in Section 3.3.2, the market simulation results are mapped to separate merged grid models representing different synchronous areas. The grid models are modelled per synchronous areas: The Continental Europe area, the Nordic area, the British area, and the Ireland and Northern Ireland area. However, the grid models do not contain the following European countries/areas: Cyprus (CY00), Corsica (FR15), Iceland (IL00), Malta (MT00), Turkey (TR00), Ukraine (UA00), Moldova (MD00), Georgia (GE00) and MedTSO countries.

3.3.5 Sanity check of the different tools

Before starting the load-flow calculations, all simulators for the same synchronous area must ensure that the AC load-flow results are adequately close[10] for the base case merged model. In addition, to ensure that all modelling rules for year-round calculations are implemented in the same manner, hourly load-flow results for a selected market simulation output need to be compared, as well as AC and DC load-flow results for selected hours of the same market output.

In the event the AC load-flow is used (only for Integral), the loads in each modelled market area have to be scaled to reach the correct balance from the market output as the demand values in the market simulations represent the actual loads plus the losses in the given area (meaning that the demand values cannot be used directly). The AC solution should be obtained by respecting the reactive limits of the generators.

In TYNDP 2026, AC load-flow can only be utilised for CBA calculations by Integral users (German TSOs and APG). To reach convergence, fictitious reactive compensator elements have to be added to the grid. The amount and placement of these elements may depend not only on the market simulation tool from which the output is used but also on the weather scenario.

3.3.6 Organisation of the modelling

The distribution of each project to a given simulator was done based on the available TSO resources. This is done centrally in the Planning Study Team, with results being directly reported to the Study Team, instead of running the simulations based on regional teams. Whereas the models for smaller synchronous areas outside Continental

[10] Tests have been performed to align the results from the models.

Europe (e.g. Nordics) are used by simulators from TSOs from those areas, the results were compiled for all synchronous areas centrally for each project.

3.3.7 Load-Flow calculations for the CBA-phase

All losses calculations are based on year-round simulations utilising the market simulation results for all 8736 hours for respective weather scenarios, as provided earlier in the table.

3.3.8 Load-Flow calculations for NTC calculations

For the project submission, project promoters can submit the project-specific dNTC values together with the respective explanatory documentation that undergoes a compliance check. In the TYNDP 2026 cycle, the methodologies followed by project promoters to compute the change in NTC brought by projects with cross-border impact were verified by ENTSO-E based on the criteria established in section 4.2.2.

A detailed description of a recommended methodology for the transfer capacity calculations is given in section 4.2.

3.4 Redispatch simulations (sections 2.4.4 and 6.3 of the 4th CBA Guideline4)

3.4.1 Introduction and purpose of redispatch

Assessing projects by just focusing on the impact of transfer capacities across certain international borders can lead to an underestimation of the project specific benefits because projects can 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, which makes it difficult or even impossible to solely assess them by market simulations. To close this gap of incomplete benefit calculation for internal projects, the use of redispatch simulations has been introduced in the 2nd CBA Guideline. The main aim of introducing this methodology was to get the best link to reality, as within some countries redispatch has already become a standard procedure for dealing with internal congestions.

Following its current application, the redispatch simulations must be based on detailed market and subsequent load flow simulations. As it is currently not possible to have the whole toolchain, especially the redispatch simulations itself, on a common tool and/or on ENTSO-E wide level, these Implementation Guidelines need to focus on a detailed methodology description, its main principles and an alignment of the most important parameters.

In TYNDP 2026, redispatch simulations will not be applied for interconnectors. They will be applied only for internal projects with or without cross-border impact, where the respective project promoter can prove that the tool and methodology used is compliant with the 4th CBA Guideline and the present Implementation Guidelines. The project promoter has to submit a written acknowledgement in the English language to ENTSO-E to prove compliance with the requirements of the 4th CBA guideline and the present Implementation Guidelines.

Note with respect to the *guidelines on project level indicators*:
Within section 10 Project Level Indicators, only specific indicators are described, whereas the redispatch methodology is used to achieve the same indicators as by the use of market simulations. It is thus not a description of how to assess specific indicators but instead on how the redispatch methodology can be applied to achieve the respective indicators.

3.4.2 Main objectives of the Implementation Guidelines of the Redispatch Assessment

As it is not yet possible to perform the redispatch simulations on a centralised level at ENTSO-E within the TYNDP 2026, the present Implementation Guidelines aim to provide all the necessary descriptions and definitions to allow project promoters to perform the redispatch simulations on their own (presupposing the respective tools are available). The Implementation Guidelines should thus provide all the necessary requirements for the modellers to be able to produce comparable results. The main goal should be to achieve the highest degree of comparability between the results achieved by the different tools and simulators.
It is, therefore, of major importance to define the **main parameters** and align them between the different tools and modellers. This is crucial as all models need to be based on a comparable data foundation, but on the other hand it might be the case that a specific parameter needed for the one tool might not be used in another. To find the best possible alignment, a detailed comparison between the different tools used for modelling the redispatch inside the ENTSO-E TSOs has already been performed in preparation for the TYNDP 2020. The results of this exercise are provided in the following chapters.

Project promoters aiming for redispatch calculations within the TYNDP 2026 that have not participated in the alignment process in TYNDP 2020 have to, in addition, prove their model compliance by performing the sanity check as described within section

3.4.4. In this case, the project promoter has to submit the results of the sanity check together with a written acknowledgement in English language to ENTSO-E to prove compliance with this requirement.

The definition of the **general principles** of the different tools is also part of the alignment process and will be presented here. This includes, e.g. the determination of the sequence of generation units to be used for redispatch.

For this purpose, in chapter 3.4.3 an overview of the general process is given. After giving the minimal requirements on quality in chapter 3.4.4 that need to be met, the participating tools are presented in chapter 3.4.6, together with a description of the test case to find alignment between the tools. As the redispatch methodology is based on market and network simulations, the needed input data is described in chapter 3.4.7, including a description of model specific data per simulation tool. An overview of the overall CBA assessment framework for the redispatch simulations, such as the number of weather scenarios, TOOT/PINT (Take out one at a time, put in one at a time) methodology etc. and the definition of the model perimeter, is given in chapters 3.4.8 and 3.4.9. A detailed overview of the optimisation measures, such as the order of sequence of generation units used for redispatch, possible penalty costs, the objective function etc. is given in chapter 3.4.10, followed by the definition of the critical branches to be considered when performing the redispatch simulations in chapter 3.4.11. The final two chapters, 3.4.12 and 3.4.13, give an overview of the results needed for a full CBA assessment and its monetisation.

Ultimately, in the best case, the present Implementation Guidelines might be seen as step-by-step guidelines for assessing projects using redispatch simulations, but at least they shall act as a source for all the needed information for simulators to perform the redispatch simulations in a consistent manner. This approach ensures the robustness of the redispatch simulations and permits the comparability of the produced results.

3.4.3 Overview of the simulation process

All redispatch calculations performed by the project promoters need to follow the principles laid out within the 4th CBA Guideline (section 6.3).

In this section, a short overview of the general simulation process of redispatch calculations is given. This does not include the detailed specifics that might be considered as defined by the respective tools. An overview of the used tools is given in section 3.4.6.

Although no interconnectors will be assessed using redispatch calculations within TYNDP 2026, both options as given in the 4th CBA Guideline (see also Figure 4) can be applied depending on the cross-border contribution of the respective project:

- Option 1: Calculation of benefits using pure redispatch
- Option 2: Calculation of benefits using a combination of border-NTC-variation and redispatch

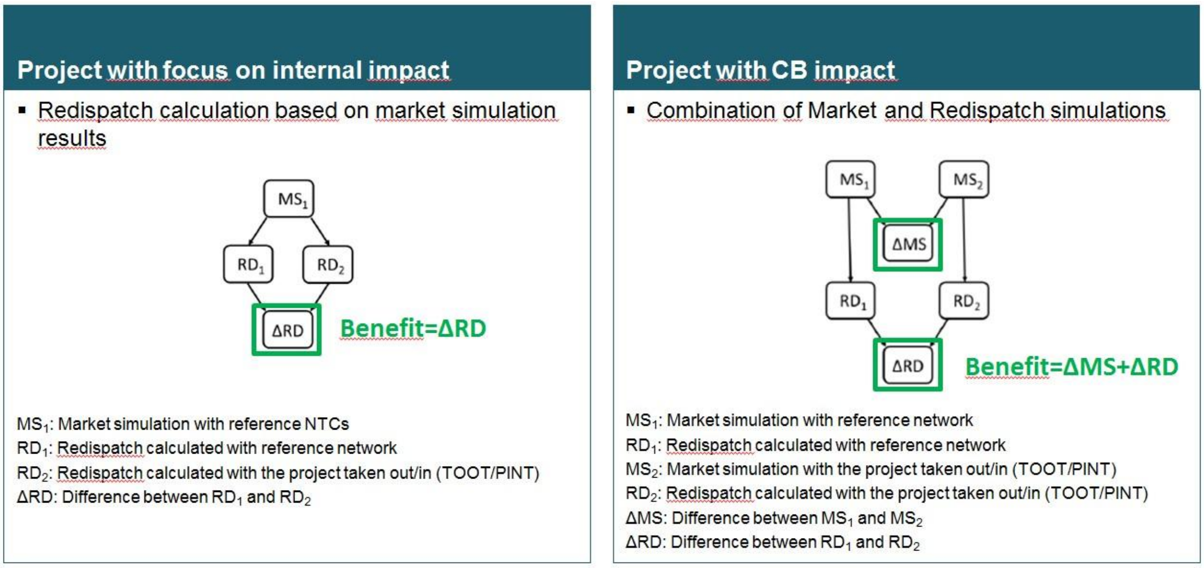

Figure 4 - Simplified presentation of the two options applied for projects with a focus on internal impact only and those with internal and cross-border impact respectively.

Choice of respective methodology:

The choice of the method to be used is for the project promoter to decide. However, in the end, in the TYNDP project sheets the chosen method needs to be displayed, together with a justification of the respective choice.

In general, projects with no cross-border contribution will be assessed using Option 1, whereas those with cross-border impact are assessed using Option 2. However, regarding the latter, project promoters might wish to only use redispatch calculations e.g. to reduce the complexity of the simulations, or as the focus relies on internal effects only. It should be noted that in that case, the cross-border part of the benefits will be lost, and the results can be seen as a lower bound. On the other hand, the application of Option 2 for projects with no cross-border impact will deliver the same results as when using Option 1.

Overview of the simulation process:

Generally, to perform the project assessment using redispatch simulations, the following simulation steps must be performed[11] - it has to be proven that all steps have to be performed in accordance with the guidelines:

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

1. **Market Simulations (see also 3.4.7):** all subsequent simulations must be based on the centrally performed market simulations by ENTSO-E. The respective data must be obtained from the TYNDP Study Team.
2. **Load Flow Calculations (see also 3.4.7):** the following load flow simulation must be based on the grid models as prepared by the TYNDP Study Team.
3. **Redispatch Simulations:** the redispatch simulations must be based on the principles and requirements as defined in these guidelines and executed by the respective project promoter.
   a. all grid models must be based on the models prepared by the TYNDP Study Team
   b. all market data must be in line with the data as used by the TYNDP Study Team
   c. the project promoter needs to prove the validity of the tool by having performed the sanity check (section3.3.45)3.4.4)

***Note*:** As for the load flow and redispatch simulations, a fuel type-based resolution is not sufficient, the market simulation from step 1 needs to be broken down on a generator level – whereby the infeed of each single generator/power plant is given and not its aggregation per fuel type. The geographical scope for this disaggregation has to be the same as defined for the redispatch simulations in this guideline.

3.4.4 Sanity check for minimum modelling requirements

The project promoter has to perform the simulations for the calculation of the indicators based on the redispatch method. The TYNDP Study Team does not perform calculations for projects based on the redispatch method. However, compliance with the redispatch guideline and a minimum quality of the calculations should be granted.

For this reason, the project promoter is requested to participate in the sanity check by performing detailed redispatch calculations using a highly simplified network model with a strongly reduced number of artificial market simulation results. The project promoter submits the results at least together with the final project results to ENTSO-E. The respective experts compare the results of the project promoter regarding the simplified model. The submission of the Sanity Check results should occur before the submission of the final project results to ENTSO-E. This is a recommendation as a recalculation may not be possible in the given timeframe of the publication process of the TYNDP. The approval process of the redispatch results by the project promoter will be communicated by ENTSO-E separately.

For tools that have already performed the sanity check in the TYNDP 2020, there is no need to re-submit the results from the sanity check to ENTSO-E.

The following tables give the description of the input data for the sanity check in the RD-Annex (section 3.4.14):

- Technical parameters
- Market Input Data
- Template for the results

The input data of the sanity check model covers all processes and methods necessary for the redispatch calculation. However, only minimal resources are required for the project promoter to generate it.

<u>A Brief description of the model:</u>

The sanity check model consists of six nodes (N=North, S=South, W=West & E=East). All nodes are connected by a double circuit 380 kV overhead line connection in ring topology. The phase shifter transformer (PST) NW_NE_1 is located between the nodes NW and NE. There are two HVDC connections (HVDC1, HVDC2) between node SW and SE. Four generation units or feeder and three load units are located in the model. Generation unit N_G is located in node N. Two generation units SW_G1 & SW_G2 and one load SW_L are located in node SW. Two load units SE_L1 & SE_L2 and one generation unit SE_G are located in node SE. (See also Figure 5)

Illustration of the Sanity Check model

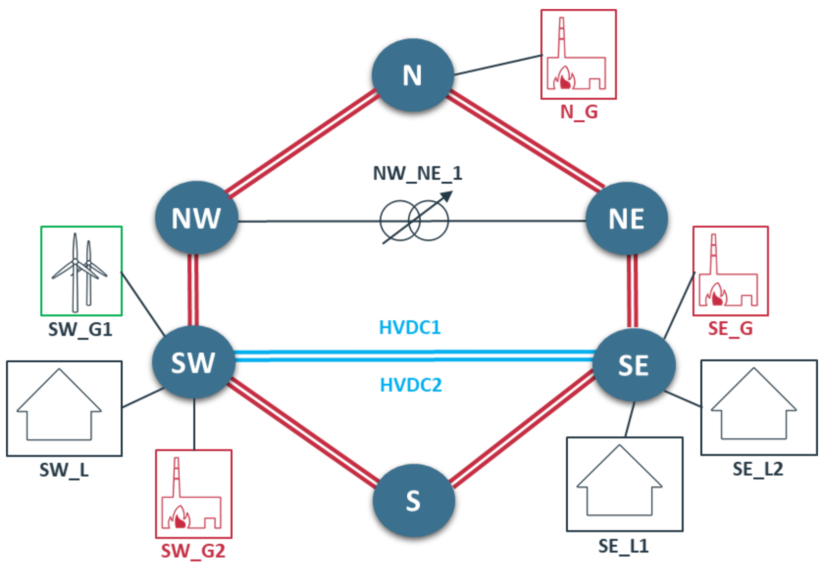

Figure 5 - Illustration of the Sanity Check model.

The generator SW_G1 is an onshore wind turbine. All other generation units are thermal power plants of type CCGT new. The HVDC connections and the PST have default penalty/ marginal costs too, see the RD-Annex (section 3.4.14). As the sanity check is a check of the detailed results for one day, only the order of the redispatch is important. All further input details can be taken from the guideline itself.

3.4.5 Additional information to be delivered by the project promoter

The project promoter needs to give a written statement regarding:

- The compliance with the 4th CBA Guideline and the TYNDP 2026 Implementation Guidelines for Redispatch calculations.
- If necessary, an explanation of a deviation from the guidelines due to special national regulatory conditions. A submission of these regulations to ENTSO-E for the authorisation process (e.g. RES Monetisation; Consideration of the n-2 criterion – Line Ratings etc.).
- The compliance with the TYNDP 2026 Input Data
- A description, which proposed options in the guidelines were chosen.
  - AC/DC
  - Number of weather scenarios and scenario variants
  - Multiple TOOT/PINT
  - Considered Branches Options (e.g.: 110 kV level)
- Additional information has to be delivered on:
  - Time granularity of studies (year-round or representative points in time)
  - Method of mapping market simulation results to the grid model
  - Geographical perimeter of the redispatch simulations
  - Optimization measures considered
  - Which market and network simulations were used as input for the redispatch simulations

3.4.6 Participating tools in the Redispatch Assessment

The use of redispatch calculations to assess projects is still relatively new and very resource intensive. An extensive software and hardware environment is necessary for this but currently not available at the ENTSO-E level for the purpose of centrally coordinated computations. Within the framework of these Guidelines, we strive to achieve a high standard by defining the main principles. Therefore, in this chapter we would like to clarify the generally accepted approach. However, it should be noted that the implementation of this assessment method can (and most likely will) lead to different approaches when considering the details, not only because of different national requirements and regulations but also because of the different tools used by different promoters.

General approach:

To perform the redispatch simulation, a market simulation is the first step. Based on the output of market simulation with the resulting cost optimal power plant dispatch, a load flow analysis is performed on the grid model to determine the utilisations of network elements in base case and (n-1) case. The line utilisations on (n-1) case resulting from the load flow analysis are evaluated within the redispatch simulation and possible bottlenecks are identified. The power flows, which exceed in the (n-1) case the thermal limits of respective network element (utilisation over 100%) represent the reason for redispatch interventions of generating units in order to ensure the (n-1) security criteria of the electricity grid. Their effect on the power flow on the lines is determined by linear sensitivity factors $PTDF$, so-called “Power Transfer Distribution Factors”. The nodal PTDF matrix does offer such a possibility as it translates nodal injections into individual line flows by explicitly stating the contributions of each nodal injection to a given line flow. Assuming a DC approach, PTDFs can be calculated directly from line parameters.

In the next step, the grid data will be reduced to all relevant grid areas and elements that have to be considered in the redispatch simulations (see sections 3.4.9 and 3.4.10). In addition, the cost-optimal redispatch optimisation will be performed to solve all respective congestions in the electrical grid.

The final step will be the monetisation of the redispatch outcomes (see also Figure 6).

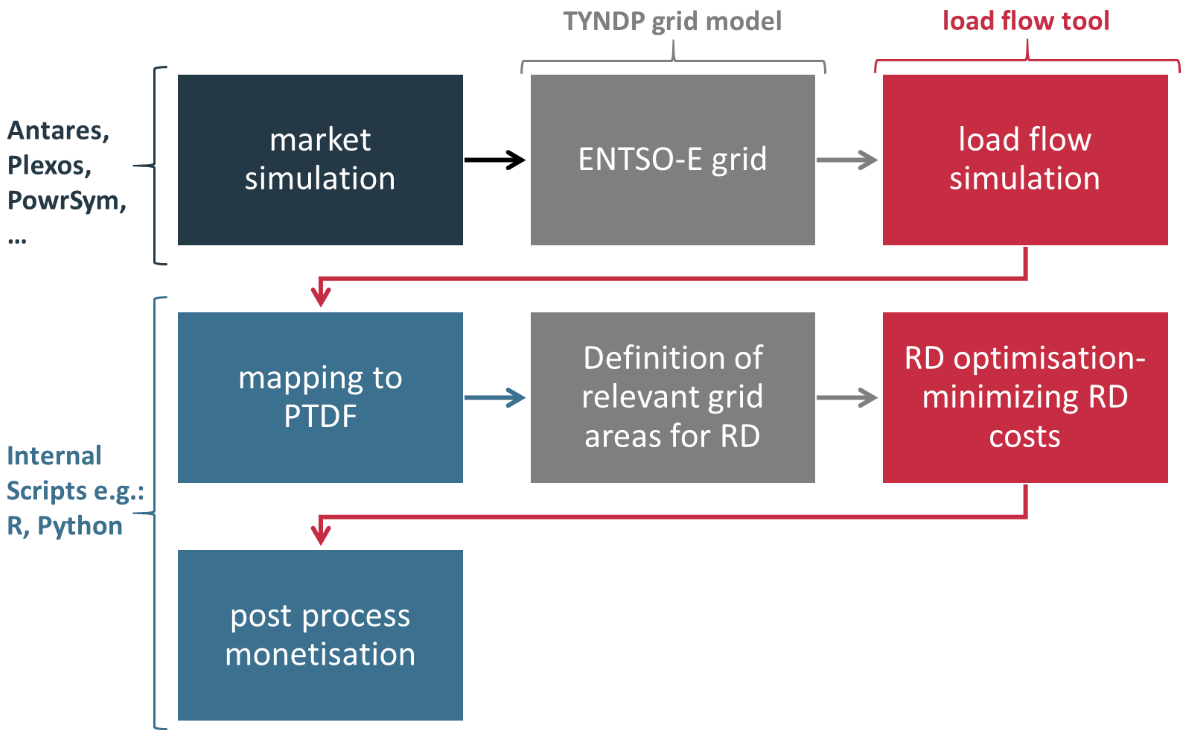

Figure 6 - General overview of the necessary steps to be performed to assess projects by use of redispatch calculations. The step of mapping to PTDF can be neglected in case where load-flow simulations are possible within the respective modelling tool.

3.4.7 Requirements for input data

To perform the redispatch calculation, the set of network and market data is required. As the results of the redispatch calculations are very sensitive to the input data used, the essential requirements for the content of the input data are defined in this chapter. Compliance with the defined requirements can ensure the consistency of the redispatch assessment runs and the comparability of results from different tools and promoters. Three data categories can be defined dependent on the confidentiality level:

1. Data publicly available
2. Data only available on request (due to data size)
3. Data for which an NDA is necessary

Market data

Redispatch simulations must be aligned to the market studies performed on the scenarios used in TYNDP 2026. To meet this requirement, the market model input data (see sections 3.2.4 and 3.2.6) as well as market model simulation results must be included in the dataset for the redispatch assessment.

The main datasets to be used from the market input are (the colour code denotes the confidentiality category as defined above in section 3.4.7):

- price assumptions (fuel prices, CO2 price and the marginal costs of thermal generation types calculated from these)
- net generating capacities for all generating types
- demand time series
- must-run values of thermal generation types (time series)
- availabilities of thermal units (time series)
- inflow profiles for Run-of-Rivers and pump storages
- DSR capacities
- cross-border capacities (NTC values)
- fixed exchanges with non-modelled countries

These data are based on the PEMMDB package per scenario per country and must be coherent with the input that was used for market simulations.

The market model simulation results, which are used as input for the power flow computations, also must be included in the input dataset for the redispatch calculations. This should include:

- Utilisation (hourly time-series) of thermal generation types, DSR and hydro categories
- dumped energy time series
- hourly marginal costs on market nodes
- ENS (energy not served) time series

The market simulation results are covered by the standard market modelling output file provided by the Planning Study Team per scenario and climate year.

The methodology for mapping the market dispatch results to the grid model depends on the modelling specific features of the individual grid models. In general, the mapping is based on the distribution of market hourly time-series proportionally to the installed capacity of network elements with corresponding fuel type code. Given the different requirements of the network models compared to those of the market simulations, certain technical restrictions and requirements can, to some extent, differ between both models (e.g. P_{max}, P_{min}, etc.). However, there must be an alignment process between the parameters used in both models. DSR is subtracted from the demand timeseries. Dumped Energy and Energy not Served are primarily subtracted from renewable energies and the demand.

Grid Model:

The grid model for the redispatch assessment must be aligned with the CGMES grid model submitted for network analysis as a part of TYNDP 2026, so that the installed capacities in the grid model are the same with market input data and the power flow results are consistent with other grid studies (e.g. the delta NTC, losses calculations).

Power flow analysis:

To determine the utilisations of the lines in the grid model in the base case and under contingencies (N-1 case), the power flow analysis should be performed on the grid model. The power flow simulations should be based either on a DC- or on AC- load flow approach. In the event the AC load flow approach cannot be applied by project promoters due to its complexity and lack of comparability between different tools, the use of a DC approach is allowed (see also section 3.3.3). The network analysis should be made on a year-round basis. If this is not possible, representative points in time can be analysed following the principles laid down in the 4th CBA Guideline.

Special input data provided by the TSO as part of the grid model:

Due to special national requirements and regulations, it is possible to deviate from the original TYNDP line ratings in the grid model and the n-1 principle based on them. The need to consider these exceptions such as Dynamic Line Rating or curative mitigation measures must be regulatory required and is provided by the respective national TSO. Due to the immense influence on the results, this approach must, at least, be described in the material sent to ENTSO-E for performing the compliance check.

3.4.8 Minimum requirements definition for the CBA Assessment

Compared to the TYNDP standard methodology, the assessment of projects with indicators determined using the Redispatch method is very computationally intensive. Nevertheless, a comparable minimum standard should be ensured. This chapter, therefore, addresses the question of the minimum level of detail and number of simulations required to calculate the indicators. However, the project promoter is free to carry out a greater number of simulations within the framework of the Guidelines or to increase the level of detail of the methods (e.g. more weather scenarios or additional TYNDP Scenarios). However, this must always strictly follow the assumptions of the TYNDP and the 4th CBA Guideline. It is not permissible to change any input data or mix scenario data. Otherwise, the comparability of the results would no longer be possible.

<u>Minimum number of TYNDP Scenarios and Time Horizons:</u>

As a minimum requirement, the central policy scenario **National Trends** must be used for project evaluation.[12]

Minimum number of weather scenarios:

The minimum requirement for project assessment is to use the most representative weather scenario of the three weather scenarios. In the case of TYNDP 2026, the most representative weather scenarios depend on the target year, as provided in section 3.2.7.

Minimum number of different Market tool results:

The minimum requirement is to use the results as input for the redispatch assessment of at least **one** market tool that participated in the TYNDP2026 CBA process. It is recommended that the same set of market tool input be always used for all projects within a bidding zone. This should increase the comparability of CBA redispatch results.

Minimum number of Points in Time:

It is recommended to calculate a complete year in hourly time steps. However, in line with the general network simulations (see section 3.3) it is also allowed to make use of representative points in time.

General:

A multiple TOOT/PINT approach is permitted under the 4th CBA Guideline and is not restricted by the present Implementation Guidelines. When the multiple TOOT/PINT method or a combination of both is applied, a detailed description of the sequence of projects must be given in a disclaimer. To ensure comparability, the project assessment approach regarding multiple TOOT/PINT should correspond to the approach chosen in the CBA.

These specifications apply to all project types (overhead line, HVDC, storages...). The description of the selection of input data must be communicated in the project sheet in a disclaimer.

3.4.9 Definition of the perimeter

The minimum perimeter considered in the calculation has to be chosen to cover all relevant grid areas influenced by the project, which depends on whether the project's contribution is considered as mainly internal or also contains a major cross-border impact (CB impact).

[12] It has to be noted that for projects applying for the PCI status it is not up to ENTSO-E to define on which scenarios and/or climate years the simulations have to be carried out. This will be decided by the EC within the PCI process. It is therefore recommended to perform the simulations on all available TYNDP 2024 scenarios and horizons, in line with the centrally performed project assessment.

Internal projects (without significant CB impact)

The minimum perimeter for internal projects without significant cross-border impact to be monitored during the redispatch calculations is typically the country that includes the project. However, as the European grid is generally highly meshed, it is recommended to include at least the neighbouring countries. In any case, the border flows to the non-modelled countries should be mapped from a full grid model covering the entire synchronous area that the country of the project is part of.

Internal projects (with significant CB impact)

The minimum perimeter for internal projects (with significant CB impact) to be monitored during the redispatch calculations is typically the two or more countries affected by the project on their common border, but the considerations described for internal projects without significant cross-border impact are also valid in this case: it is recommended to also include at least the neighbouring countries to the ones hosting the project.

Typically, the grid model used for the calculations should be the same full European merged grid model used for other calculations in the CBA process. If the full model cannot be utilised in the tool used for redispatch, the smaller perimeters defined above can be used, but the effects of the excluded network parts must be demonstrated (e.g. by showing that all LODF factors in the excluded part to the critical branches are below a certain limit, e.g. 3%).

3.4.10 Order of optimisation measures – Penalty costs

The order of selection of the measures taken by the tool to resolve the bottlenecks on the critical elements depends essentially on two factors:

- Effectiveness of the measure
- The cost of the measure

To define the effectiveness of different measures on the bottleneck in the electrical grid, the PSDF/PTDF sensitivity factors are calculated using a DC load flow assumption. These factors describe the change of utilisation of each line or transformer by adjustment of initial setpoint of controllable units in the electrical grid (powerplants, storages, PSTs, HVDCs etc.).

The costs of the individual measures are insufficiently defined by the scenario and market data. On the one hand, the marginal costs of certain elements such as renewable energy are per definition 0; on the other hand, there are measures for grid optimisation that cannot be captured by the market. Furthermore, there is the possibility that regulatory restrictions may specify a certain sequence of redispatch measures. For reasons of security of supply, certain measures are also kept in reserve so that they can be made available in the event of an emergency. All these additional artificial costs are described here as "Penalty Costs".

The corresponding costs of redispatch consist of the costs for up/down regulation of all units K involved in the redispatch across all time steps T. The objective function of the underlying optimisation problem is shown below:

$$\min f = \sum_{t=1}^{T} \sum_{k=1}^{K} c(k,t) \cdot \Delta p(k,t)$$

The above formula only applies to the time coupled approach. Without time coupling, the minimum costs for each hour are defined as a target function. As the time coupled approach quickly becomes very complex with increasing number of time steps within one closed optimisation problem, without dramatically increasing the accuracy, the approach without time coupling can also be applied without losing the significance of the results.

Basically, the costs *c(k, t)* picture the coefficients in the objective function of the optimisation problem and depends on the technology/ fuel type of each measure. They determine how and in which sequence the conventional power plants, renewable energy, storage, foreign generation units and power flow controllable devices (PST, HVDC etc.) can be used to cure line bottlenecks. If the costs of the individual units (ex. conventional power plants) are defined by market data, they have to be used as costs coefficient of these units in the optimisation for the redispatch calculation.

Due to this methodically necessary intervention, the sequence of the measures and thus the reduced redispatch quantity (e.g. GWh or CO_2 tons) corresponds to the operational experience of the TSOs, but the Penalty Costs of these measures cannot be used for the project assessment. For this reason, post-monetisation must be implemented (see also chapter 3.4.13).

Furthermore, it must be ensured that in the case of a positive redispatch (power increase), the cheapest measure is always taken first, and in the case of a negative redispatch (power decrease), the most expensive measure is always taken first. This can already be determined by the tool itself or also by suitable penalty costs.

Accordingly, for each time step, the best measures will be implemented, from a set of measures listed below. In principle, the sequence of this measure is driven by the two types of costs: the “real” costs, also referred to as generation costs, defining the marginal costs of the conventional power plants; and the Penalty Costs that can be interpreted as the model parameter to ensure the desired order of sequence within the redispatch. No country-specific differences to this approach have yet been identified. If these are identified, they must be considered and reported accordingly.

1. network-side measures

   a. topological actions
   b. power flow controllable devices (PST, HVDC, FACTS)
2. weather-dependent line operation curative actions (generating units decrease) included in the ratings (see above)
3. Thermal Power plants based on the dispatch costs of each generator
4. Storages (Hydro, Batteries, P2G)
5. RES
6. Cross Border Power plants and Cross Border HVDCs (depending on the perimeter)
7. Very Last Step: (2 Possibilities with very high penalty cost)
   1. Load Shedding (ENS)
   2. Remaining Overloading (Branch Slack)

All redispatch measures need to ensure that the total balance is kept before and after the respective measure. Thus, for each measure impacting the generation of the system a respective measure needs to be applied as a counterpart.

3.4.11 Considered branches

The planning and operation of electrical transmission networks considers the so-called (n-1)-criteria. The (n-1)-criteria ensures that the operating limits of the lines in the system are not violated even in case of single failures of circuits and transformer (busbars overloadings not considered). Using the market related measures, such as redispatch, TSOs adjust the feed-in of power plants in order to shift the power flow from the overloaded branches and therefore ensure the (n-1) security of the system. Hence, the monitoring and identification of relevant branch overloadings has a huge impact on the redispatch results.

Using the AC or DC load flow approach, a set of single outages is simulated on the grid model and the power flow on other branches in the system in each considered (n-1) case are calculated. A branch is said to be overloaded when the actual power flow post contingency exceeds the operational line limit that depends on the protection relay settings and weather conditions. Some TSOs investigate not only single failures but also certain failure combinations, i.e. “(n-2)”-outages or exceptional contingencies.

Generally, the (n-1)-utilisation of all branches in the grid should be considered in the redispatch analysis but, in the context of network development studies, some assumptions are made. The exclusion of certain elements from the optimisation problem helps to avoid an overestimation of redispatch values and obtain more robust and realistic results. Moreover, it can simplify an optimisation problem and reduce the calculation time. Thus, a reasonable and consistent approach to the monitoring of relevant elements is necessary.

Like the generating units, the considered branches must be reduced to the relevant grid area influenced by the project (see chapter 3.4.9). This means that only the branches within the defined perimeter as well as the corresponding interconnectors must be considered in the (n-1)-calculation and redispatch simulation. As the focus of the TYNDP is on the analyses of the transmission network, the monitored branches can be filtered *per se* based on the voltage level (e.g. only 220-/380-kV). It is generally assumed that failures and overloading of transformers are not considered in the redispatch analysis, but the decision of whether transformers should be considered is optional and up to project promoters.

Due to necessary simplifications in the model and the network reductions made, artificial overloads and thus artificially high redispatch needs can occur. If such cases are identified, the affected branches should be removed from the observation. Whereas the outages of HVDC lines have a big impact and can seriously increase the utilisation of the AC network, it is necessary to include them into analysis.

3.4.12 Definition of the results for CBA from the Redispatch Assessment

In general, the indicators assessed using the redispatch methodology are the same as when using market simulations as both simulation methods deliver the power plant dispatch, which is the driver for most of the CBA indicators. Below is a list with all CBA indicators as defined in the 4th CBA Guideline that can be achieved by using the redispatch methodology applying the (multiple) TOOT/PINT approach (all other indicators are not foreseen as being calculated using redispatch):

- **B1 - SEW:** can be achieved by the generation cost approach the same way as for market simulations (including cross-border costs and start-up and shut-down costs)
- **B2 - Societal costs of CO_2**: can be achieved the same way as for market simulations as post process
- **B3 - RES integration**: can be achieved the same way as for market simulations by the change in needed reduction in RES generation due to redispatch
- **B4 - non-direct greenhouse emissions:** can be achieved the same way as for market simulations as post process
- **B5 – Losses**: can be calculated the same way as for market simulations using the dispatch taken from the redispatch calculations as input for the losses calculations
- **B9 – Reduction of Redispatch Reserves:** the only way to calculate this indicator is by nature the use of redispatch simulations

The presentation of the results within the project sheets needs to follow the definitions and requirements as defined within the present Implementation Guidelines in the same way as when using market simulations.

3.4.13 Monetisation and quantification of the redispatch results

In principle, the monetisation of the redispatch results can be carried out directly by the simulation tool using the generation cost approach as also applied within the market simulations, as each redispatch of conventional power plants is accompanied by a change in fuel consumption which will naturally impact the system costs. This difference in costs then delivers the benefits (which might also be negative) of the assessed projects.

If this automated monetisation is not available by the respective tool, the final step of the redispatch assessment will be the monetisation of the simulation results. This step is a post process calculation. The redispatch results are added to the standard CBA results (in line with the 4th CBA Guideline).

First, a clarification is needed for the energy amount differences per type of power plant between the calculations with/ without the project. For each type of power plant:

For TOOT: $\Delta energy = \ energy_{ref.case-project} - \ energy_{ref.case}$

For PINT: $\Delta energy = \ energy_{ref.case} - \ energy_{ref.case\,+\,project}$

B1: SEW – Social Economic Welfare

SEW is defined as the yearly energy difference amount per power plant type (without RES) times the power plant specific marginal costs

$$SEW\ [\frac{€}{yr}] = \sum_{plant\ type} \Delta energy_{type} \left[\frac{MWh}{yr}\right] * marginal\ cost_{type} \left[\frac{€}{MWh}\right]$$

The marginal costs of RES technologies are assumed to be zero.

SEW_RES

Same application as described in section 5.1 of the present Implementation Guidelines.

SEW_CO2

Same application as described in section 5.1 of the present Implementation Guidelines.

B2: Societal costs of CO2

In the event the specific tool does not directly deliver the CO_2 emissions, to calculate the yearly CO_2 emissions, the energy of the emitting power plant times the specific emissions per energy (see RD-Annex 2) is used.

$$\Delta CO_2\ [\frac{t}{yr}] = \sum_{plant\ type} \Delta energy_{type} \left[\frac{MWh}{yr}\right] * CO_2\ emissions_{type}\ [\frac{t}{MWh}]$$

A monetisation is done with the CO_2 prices as described in section 5.2.

B3: RES integration

Same application as described in section 5.3 of the present Implementation Guidelines.

B4: Non-direct greenhouse emissions

Same application as described in section 5.4 of the present

Implementation Guidelines.

B5: Losses

This indicator will be calculated with the same procedure described in the CBA 4th Guideline.

B9 – Reduction of Redispatch Reserves:

Same application as described in section 5.9 of the present Implementation Guidelines.

3.4.14 RD-Annex 1: Data for the quality check for minimum modelling requirements

Table of technical parameters

		Feeder				Load		
Unit name	**Unit**	**N_G**	**SW_G1**	**SW_G2**	**SE_G**	**SW_L**	**SE_L1**	**SE_L2**
U	kV	380	380	380	380	380	380	380
Q	MVar	7.48158	2.35231	2.35231	6.45498	4.8	4.8	4.8

Lines							
Unit name	**Unit**	**L_SW_NW**	**L_SW_S**	**L_S_SE**	**L_NE_SE**	**L_NW_N**	**L_NE_N**
Un	kV	380	380	380	380	380	380
R1	Ohm	0.01	0.01	0.01	0.01	0.01	0.01
X1	Ohm	1	1	1	1	1	1
Ir	A	600	500	500	600	600	600

HVDC			
Unit name	**Unit**	**HVDC1**	**HVDC2**
Ur	kV	400	400
Pr	MW	500	500
rdc	Ω	1	1
voltage-angle-control:			
headend station (SE)			
AC-angle control	MW/degree	-1260	-1260
AC-voltage control		OFF	OFF
DC-voltage control		ON	ON
U_{dc}	kV	400	400
headend station (SO)			
AC-angle control	MW/degree	0	0
AC-voltage control		ON	ON
$U_{setpoint}$	kV	380	380
DC-voltage control		OFF	OFF

Phase-shifting transformer		
Unit name	**Unit**	**PST_NE_NE_1**
Ur1 (NO)	kV	380
Ur2 (NE)	kV	380
Sr	MVar	263.272
ukr	%	0.18233
Pk	kW	4.80001
Poc	kW	100
io	%	0.1
vector group		DD4
tap changer		
max.		11
main		6
min.		1
additional voltage		
max. position	%	0.17453
min. position	%	-0.17453
angle	°	90

Table of Market Input

	Feeder				Load		
PIT	**N_G**	**SW_G1**	**SW_G2**	**SE_G**	**SW_L**	**SE_L1**	**SE_L2**
	P [MW]	**P [MW]**	**P [MW]**	**P [MW]**	**P [MW]**	**P [MW]**	**P [MW]**
1	0	-960	0	0	0	0	960
2	0	-800	-100	0	450	0	450
3	0	-600	-200	0	400	0	400
4	-600	0	0	-600	1200	0	0
5	0	-600	-600	0	600	0	600
6	-600	-2000	-2000	0	0	2000	2600
7	0	-800	-800	0	800	0	800
8	0	-2000	-2000	-600	0	2000	2600
9	-600	-1000	-1000	-600	1000	1200	1000
10	0	-900	-900	0	900	0	900
11	0	-1000	-1000	0	1000	0	1000

12	0	-1100	-1100	0	1100	0	1100
13	-600	0	0	0	0	600	0
14	-600	-2000	-2000	-600	0	2600	2600
15	-600	-2000	-2000	0	0	2000	2600
16	-600	0	-1000	-600	1100	0	1100
17	0	-1200	-1200	0	1200	0	1200
18	0	-2000	-2000	0	0	2000	2000
19	0	-1400	-1400	0	1400	0	1400
20	0	-1300	-1300	0	1300	0	1300
21	0	-1100	-1100	0	1100	0	1100
22	0	-900	-900	0	900	0	900
23	0	-700	-700	0	700	0	700
24	0	-500	-500	0	500	0	500

Template of Table of Results

	Feeder				Phase-shifting transformer		HVDC	
PIT	N_G	SW_G1	SW_G2	SE_G	PST_NW_NE_1	PST_NW_NE_1	HVDC1	HVDC2
	dP [MW]	dP [MW]	dP [MW]	dP [MW]	dSteps []	dAngle [°]	dP [MW]	dP [MW]
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
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3.5 Reference grid (section 2.5 of the 4th CBA Implementation Guidelines)

Based on the guidance in the 4th CBA Guidelines, for the purpose of TYNDP 2026, 4 different reference grids are defined for the corresponding time-horizons 2030, 2035, 2040 and 2050. The reference grid for the 2030 time-horizon, which corresponds to the mid-term horizon, is based on proof of maturity criteria under categories a) and b) as defined in section 2.5.1. of the 4th CBA Guideline. This means that only projects which, at their time of submission to the TYNDP, are in the construction phase or those which have successfully completed their environmental impact assessment can be part of the 2030 reference grid. The reference grids for the long-term horizons (2035, 2040 and 2050) include additionally projects fulfilling the criteria listed under category c) as defined in section 2.5.1 the 4th CBA Guideline and which are expected to be commissioned by the target year of each respective time-horizon.

In addition to the above given maturity criteria, a cut-off for the commissioning years has been set. This choice deals with the uncertainties in the planning and construction, ensuring that only projects with a strong chance of being commissioned at the dates of the respective time-horizons are part of the reference grid. The cut-off has been set to 31 December of each target year, excluding all projects with planned commissioning dates later than these cut-offs. The commissioning years submitted by the project promoter need to be agreed between the respective NRA and TSOs where the project submitted to the reference grid is located.

Given that the UK must be treated as third country and not all projects connect the UK to an EU Member State or an ENTSO-E member country, the respective projects need to be included in the network development plan of the Member State or the ENTSO-E member country connecting to the UK in order to meet the criterion for becoming part of the reference grid. If this is not the case, although the other maturity criteria and commissioning dates might fulfil the requirement as set out within the 4th CBA Guidelines those projects cannot become part of the reference grid.

A list of projects which are part of the respective reference grids is given in Annex B.

3.6 Assessment of the commissioning dates (section 2.5.2 of the 4th CBA Guideline)

The 4th CBA Guideline addresses the need to assess the expected commissioning years of the submitted projects. The result from this assessment will be shown as additional information within the project specific project sheet. The respective commissioning years will not be changed as the submission of the commissioning lies within the responsibility of the project promoters.

The methodology for the assessment of commissioning dates has to meet the following principles:

- The starting point for the definition of the commissioning date has to be the 31.12.2026.
- The period of time *t* for the duration until a project submitted to the TYNDP 2026 will be commissioned can be calculated based on the characteristics of each individual investment:

$$\Delta T_{Commissioning,Investment} = \left[\begin{matrix} (\boldsymbol{\Delta t}_{\boldsymbol{Status}} + \boldsymbol{\Delta t}_{\boldsymbol{Length}}) * \\ \boldsymbol{f}_{\boldsymbol{technology}} * \boldsymbol{f}_{\boldsymbol{type,\,project}} * \boldsymbol{f}_{\boldsymbol{type,\,Investment}} * \boldsymbol{f}_{\boldsymbol{geography}} \end{matrix} \right] \left[\begin{matrix} (\boldsymbol{\Delta t}_{\boldsymbol{Status}} + \boldsymbol{\Delta t}_{\boldsymbol{Length}}) * \\ \boldsymbol{f}_{\boldsymbol{type,Investment}} * \boldsymbol{f}_{\boldsymbol{type,\,project}} * \boldsymbol{f}_{\boldsymbol{type,flow}} * \end{matrix} \right.$$

With:

Parameter	Description	Unit
$\boldsymbol{T}_{\boldsymbol{Start,Assessement}}$	Reference Starting Point of the Assessment	[Date]
$\boldsymbol{\Delta t}_{\boldsymbol{Status}}$	Classification based on the status of the project, this equals to the **mean standard time until the construction of the project. If a project passed already the permitting stage, this value is set to 0.**	[years]
$\boldsymbol{\Delta t}_{\boldsymbol{Length}}$	**Classification of the mean standard time needed for construction based on the length of the project. If the project has no length (e.g. A substation), this value is set to 0.**	[years]
$\boldsymbol{f}_{\boldsymbol{type,\,Investment}}$	standard factor indicating the complexity of the project with respect to its setup whether it is an overhead line, cable, substation etc. on investment level	-
$\boldsymbol{f}_{\boldsymbol{type,\,project}}$	**standard factor indicating the complexity of the project with respect to whether it is a completely new project or an update**	-
$\boldsymbol{f}_{\boldsymbol{type,flow}}$	standard factor indicating the complexity of the project with respect to its technology (AC or DC)	-
$\boldsymbol{f}_{\boldsymbol{geography}}$	standard factor indicating the complexity of the project with respect to whether it is an on- or offshore project	-

- The commissioning year on investment level then can be calculated by adding the period of time to the starting point:

$$\mathbf{T}_{\boldsymbol{Commissioning,Investment}} = \boldsymbol{T}_{\boldsymbol{Start,Assessment}} + \Delta\mathbf{T}_{\mathbf{Commissioning,Invesrment}}\mathbf{T}_{\mathbf{Commissioning,Investment}}$$

- The assessed project commissioning year then corresponds to the maximum commissioning year assessed for all investments included in the project:

$$T_{C,Assessment,Project} = \max(T_{Assessment,Investment})\ \forall\ Invesment \in Project$$

- The outcome from this assessment could however be used as starting point for discussions, where project promoters in case of a mismatch between submitted and assessed commissioning years on project level will have to explain their submission.

$$\Delta\boldsymbol{T}_{\boldsymbol{C,Project}} = \boldsymbol{T}_{\boldsymbol{C,Assessment,Project}} - \boldsymbol{T}_{\boldsymbol{C,\ Promoter,Project}}$$

Disclaimer: All values used for the assessment of commissioning years are based on expert knowledge and might be changed in future editions of the TYNDP. It is therefore not foreseen to use this methodology to actually approve or disapprove any commissioning years.

The distinct values for the factors can be found in the **Error! Reference source not found.** A nnex.

Example:

Assuming a fictive sample projects with the following data submitted by the project promoter:

	Status	Length	Technology		Overhead/ cable	On-/ offshore	New or upgrade
Input	planned, but not yet permitting	250 km	DC	Cable	offshore	upgrade	
Times and	t = 5 years	mid: t = 3 years		$f_{type,\ flow}$ = 1.1	$f_{type,\ Investment}$ = 1.2	$f_{geography}$ = 0.9	$f_{type,\ Project}$ = 0.5

fact ors

The expected commissioning year following the formula above in this case would calculate as:

$$t = 2026 + (5 + 3) \cdot 1.1 \cdot 1.2 \cdot 0.9 \cdot 0.5 = \ 2030$$

The commissioning year in this example would therefore be calculated as the year 2030.

4. General concepts and assumptions

In this chapter a few important considerations for the clustering of investments are first defined. More details are provided in section 3.2.1 of the 4th CBA Guideline on the different rules regarding this. Then, in section 4.2. of the present Implementation Guidelines, further guidelines are provided of the methodology to compute the ΔNTCs of projects having cross-border impact. It starts with the definition of the input data required and the options for the computation and it ends up with the guidance on how to report the ΔNTCs.

4.1 Clustering of investments (section 3.2.1 of the 4th CBA Guideline)

Following the 4th CBA guideline, only investments that strongly rely on each other may be clustered. A limiting criterion is that clustered investments can at most be one project status level apart from each other. A justification is required whereby the full potential of the main investment can only be achieved after realisation of the supporting investment(s).

Re-clustering for projects from the former TYNDP:

In general, it is of course permissible to use the same projects from the former TYNDP.

However, special attention must be given to investments with commissioning dates that are significantly delayed compared to the previous TYNDP.

The interpretation of "significant delay" and the decision of whether it is still permissible to cluster the investments may be case-specific but must nevertheless be directly linked to the required justification, as for any clustering. In this respect, it might be the case that the clustering of one project is allowed, whereas for the other one, e.g. where the investment with the earlier commissioning date is strictly necessary for the realisation of the second one (related to the dates as given in the previous TYNDP), it is not, although the respective investments of both projects have the same commissioning dates.

In any case, when the project status also changes due to a delay, the abovementioned rules must be applied.

4.2 Transfer capability calculation (section 3.2.3 of the 4th CBA Guideline)

The Transfer Capability concept at a system boundary is defined by two related concepts, a Net Transfer Capacity (NTC) and a Grid Transfer Capacity (GTC), and their variation enabled by a project, respectively ΔNTC and ΔGTC. The NTC concept stems from market simulations, whereas the GTC refers to physical flows in grid studies. Both are assessed by network studies which take input from market studies.

In a CBA assessment for a project with a cross-border impact (whether the project itself is cross-border or internal), the ΔNTC must be reported. For an internal project without cross-border impact ΔGTC can be reported; however, in TYNDP 2026, such projects are to be assessed by redispatch simulations, which do not require the knowledge of the GTC impact of the project.

For TYNDP 2026, transfer capability calculations are performed within ENTSO-E through a NTC toolchain based on the methodology defined in this section. Project promoters also have the opportunity to submit their own values, if compliant with the methodology, values below ENTSO-E calculations can be used. This compliance will be verified by ENTSO-E through compliance checks., as described further.

4.2.1 Net transfer capacity

The NTC is defined as the maximum admissible power shift (as defined in the 4th CBA Guideline) across the boundary between two market areas while respecting the capacity and security criteria (e.g. N-1) of the physical assets.

To get the delta NTC in a given hour and direction, two different calculations must be made (one with the project included and one without the project):

$$\Delta NTC = NTC_{with} - NTC_{without}$$

The NTC values must be calculated using a generation or load power shift:

- Getting the line loadings from load flow calculations under N-1 security criteria
- Achieving the 100%-situation (N-1 secure) by using the generation or load power shift (see below)

This must be done in a manner that is representative for each time-step (in general 8736 hours equivalent to one year, or representative points in time).

The reported ΔNTC value equals the 70th percentile of the year round ΔNTC duration curve of the project. This means that the reported ΔNTC value can be sustained for 30% of the time steps in the simulated period.

Input data required for the calculations

For TYNDP 2026, the ΔNTC calculations of all projects are based on the hourly market simulation results for the TYNDP 2024 NT2030 scenario from one market tool and one climate year. The selection of the climate year will be based on the highest representativeness of the three used in TYNDP 2024, i.e. climate year 2009. The mapping of market simulation results on the grid model to obtain the starting point for transfer capacity calculation is done as described in Chapter 3.3.

The NTC is derived as follows:

$$TTC = BCE + \Delta E_{max}$$

$$NTC = TTC - TRM$$

where:

- TTC: Total Transfer Capacity,
- NTC: Net Transfer Capacity,
- BCE: Base Case Exchange (which is the initial exchange between the two market areas before applying any additional power shift),
- ΔE_{max}: the maximum additional power shift respecting the N-1 criterion,
- TRM: Transfer Reliability Margin.

The BCE values are known from the market simulation results. However, they can be volatile due to the optimisation algorithms used in the market simulators. In the case of AC projects, to avoid using the BCE values, the ΔNTCs will be calculated using the market simulation output for the reference case only, meaning that the TOOT/PINT will only be applied in the grid model. This means that the BCE value is the same with and without the project; therefore, it is eliminated from the calculation. As the TRM values may not be known for the reference NTCs, and the changes in TRM resulting from projects are not known either, the ΔNTCs will be approximated by the change in TTCs (by calculating the change of the maximum possible power shift, ΔE_{max}).

The selection of **critical branches** and **critical outages (CB/CO)** for each examined border is done by filtering based on their sensitivity (PTDF values) to the given exchange. The default threshold for PTDF is 5% (in the event there is an agreement established by NRA within a country, a different threshold could be used). This filtering may not be sufficiently accurate for all borders and projects: in such cases, manual addition or removal of network elements from the CB/CO lists needs to be consulted on with the relevant TSOs.

In terms of line ratings, the grid model must include both winter and summer values, at least for the critical branches, to consider the seasonality for the different points in time.

Power shift

The power shift to be applied may be done by changing the generation or the load in the examined market areas. Although the default method is generation power shift, in certain cases load shift is easier to use to get meaningful results (e.g. if there is insufficient dispatchable generation in the examined areas). In should be remarked that in any case, for many projects, through power generation should be used requiring further developments on the current adopted NTC tool.

In the event generation power shift is used, it can be distributed among the generators in the following ways:

- in proportion to their maximum active power,
- in proportion to their available power margin (maximum active power-actual active power)
- in proportion to their actual active power
- based on the generation costs.

Given that different modelling tools are used, it is not possible to be restricted to one single methodology for the generation power shift. Within the TYNDP process, the different models are therefore harmonised such that comparable results can be expected.

In each case, the technical limits of the generators must be respected. The chosen method may be dependent on the project and/or border.

In the event load power shift is used, the active power of each load is shifted in proportion of their initial value in each hour. Only loads of ConformLoad or EnergyConsumer classes (see section 3.3) are to be shifted.

Other considerations

In the event the examined border includes PSTs, their tap positions must be optimised in each hour within the power shift optimisation process, or at least before applying the power shift steps, in order to avoid sub-optimal outcomes.

In the event the examined project is between non-synchronous areas, a calculation must be performed independently in the two non-synchronous countries: the powershift is simulated by changing setpoints of HVDCs of the border and compensating with internal load or generation. If the border already has one or more HVDCs, then the powershift is proportional to HVDC Pmax and the areas or lines/contingencies is extended in accordance with HVDC.

location. The minimum value of both should be selected. Further improvements are required in order to extend the optimization to the case of more HVDCs consisting of other borders between non-synchronous areas.

There are still avenues for further improvement. As a limitation in this cycle, the internal grid impact of cross-border HVDC projects is not taken into account. As a simplification made in this cycle their thermal capacities correspond to the dNTC values. Moreover, the dNTCthe dNTC methodology for projects having mutual multi-border impacts, connecting small energy isolated systems (i.e. islands) or imposing unidirectional power flows will be further elaborated in the upcoming TYNDP cycles.

Selection of the reported values

When the ΔNTC values are obtained for all hours, a duration curve is constructed. A separate duration curve is made for each border (in case the project has an NTC impact on more than one border) and both directions. Separate curves are made for each direction.

The value to be reported from each duration curve is the 70th percentile (meaning that this value is reached at least 30% of the year). This is illustrated in the following diagram.

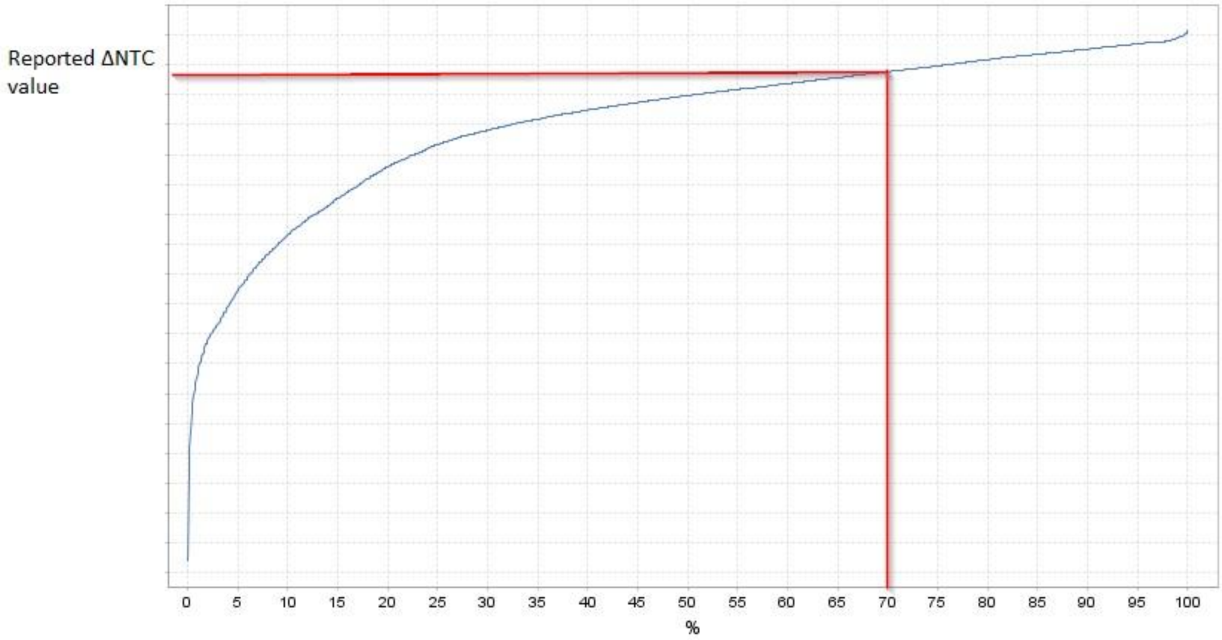


Figure 7 - Sample of a reported ΔNTC value as the difference in boundary exchange in a specific direction that can be supported for 30% of the year due to the project

Note that in exceptional cases, a project can decrease the NTC, at least in a small number of hours. This does not signify any problems with the calculation, but it is inherent to meshed systems. At year-round view when selecting the 70th percentile value, any investment deemed necessary should of course not have a negative value.

In the event representative points in time are used for the calculation (instead of calculating for every hour of the year), the representativeness of each hour has to be weighted when plotting the approximate duration curve.

Summary: steps of the calculation

Based on the detailed descriptions above, the main steps of the ΔNTC calculation are summarised here.

- definition of the CB/CO lists: either by PTDF-filtering, based on expert judgement, or the combination of both
  - Tool: load-flow tool for PTDF-filtering
  - Input: merged grid model
  - Output: list of relevant combinations of branches and outages
- initial load-flow calculations: using a market simulation output for the reference case, running year-round load-flow calculations (or for representative points in time)

  - Tool: load-flow tool
  - Input: results from market simulations, grid model
  - Output: initial flows before any power shift
- PST optimisation: depending on the assessed border(s), optimisation PSTs for each hour
  - Tool: load-flow tool
  - Input: initial flow, PST parameter, grid model
  - Output: PST angles, new load-flows
- calculation of the maximum power shift (in N-1) for each hour (or relevant PiT): for all assessed borders independently, in both directions, with and without the project in the grid model
  - Tool: load-flow-tool or specific script
  - Input: initial flows (including PST optimisation), grid model
  - Output: maximum power shift in both directions, per hour, with and without the project
- calculation of the difference of the maximum power shifts for each hour (or relevant PiT)
  - Tool: post-processing script
  - Input: maximum power shifts
  - Output: ΔNTC per hour (weighted if PiT are used)
- construction of the duration curves for ΔNTCs
  - Tool: post-processing script
  - Input: ΔNTC per hour; if PiT are used, the weights of the PiT are required
  - Output: duration curve
- obtaining the value at the 70th percentile from each duration curve.
  - Tool: post process
  - Input: duration curve
  - Output: ΔNTC to be reported

4.2.2 Compliance checks

Project promoters' ΔNTC values are submitted to compliance checks by ENTSO-E, on the basis of criteria including the following:

- Scenario(s) and climate year(s) used as input, must be provided: specify which TYNDP scenarios (e.g. National Trend, Distributed Energy or Global Ambition), climate years (1995, 2008 or 2009) were used.

- Information on the grid model used: indicate the version of the ENTSOE-E grid model used and/or any modification made compared to the standard model.
- Consideration of the n-1 criterion,
- Information on the N-1 criterion must be considered in the analysis: The N-1 criterion must be considered to ensure that the network remains secure and fully operational even in the event of a single component failure. This criterion is essential for assessing the critical elements of the grid and evaluating system performance following specific critical contingencies.
- The power shift approach considered, must be indicated: indicate which approach was adopted between Generation or Load power shift.
  - In case of generation shift, provide a short description of the methodology for the power shift and a confirmation that all technical limit of the generators were respected.
  - In case of load shift, provide a short description of the methodology for the load shift and confirm that only permitted load types were modified (only ConformLoad and EnergyConsumer allowed)
- Information on the critical elements monitored in the calculation must be provided. At least all elements with a sensitivity of minimum 5% need to be considered,
- Information whether year-round simulations or PiT were applied. In case PiT were applied, total number of PiT used and proof of representativeness must be provided,
- Information on the consideration of application the optimisation of the PST and HVDC set points if applicable,
- The 70th percentile (per direction) of the duration curve must be applicated for the final dNTC reporting, as described in 5.2.1.

• More detail on these criteria can be found in the TYNDP2026 dNTC compliance verification template. ENTSO-E provided a template for promoter to submit their dNTC documentation, accessible on the website here: TYNDP2026 dNTC compliance verification template[13].

[13] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2026/TYNDP2026%20dNTC-compliance-verification-template.docx

5. Benefit indicators (B1 – B9)

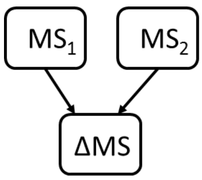
This section delivers additional information in order to complement the 4th CBA Guideline with insights into the benefits assessment within the TYNDP 2026. All sections are directly linked to the respective sections within the 4th CBA Guideline. Even in the event that no additional information is needed to be delivered in this document, the respective indicator is nonetheless displayed for reasons of completeness.

5.1 B1 – SEW (section 5.1 of the 4th CBA Guideline)

Cross-border projects increase the commercial exchange capability between two bidding areas, allowing generators in the lower priced area to export power to the higher priced area. Their SEW can be calculated using the **generation cost approach** or **total surplus approach** by applying two simulations with and without the project. Refer to the 4th CBA Guideline for the general methodology and section 3.2.2 in this document for the specific approach in TYNDP 2026. **Internal projects** can have significant cross-border impact as interconnection projects and/or can solve internal bottlenecks, leading to large internal benefits being obtained by reducing the redispatch cost generation. Their SEW assessment can be calculated using the **redispatch methodology** set out in section 3.4. of the present Implementation Guidelines, applying two distinct simulations with and without the project.

Method 1: Using market simulations

For projects whose main impact is cross-boundary, such as interconnections and internal projects which affect the NTC between market zones, the assessment can be done using two market simulations:

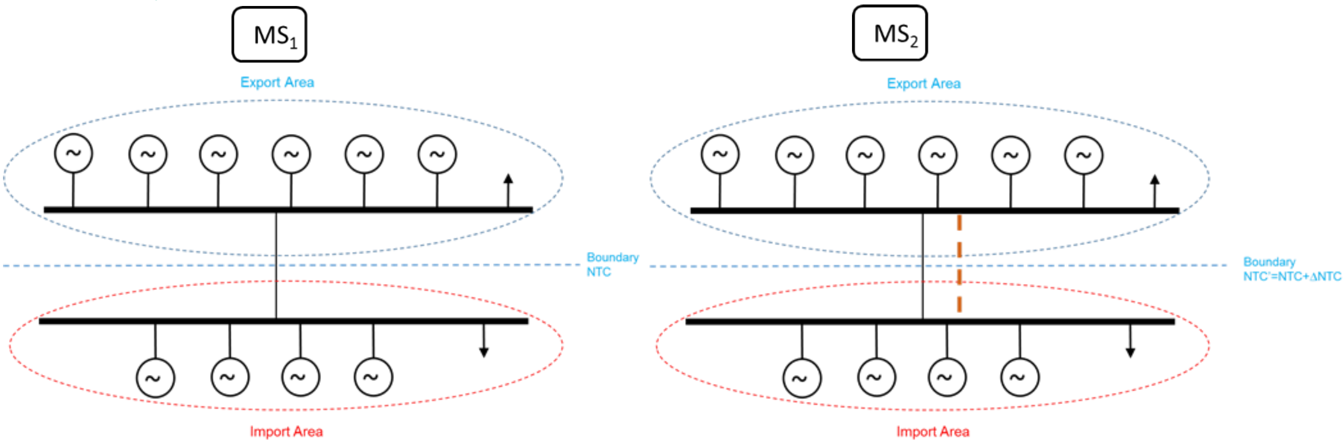


MS_1: Market simulation without the project

MS_2: Market simulation with the project

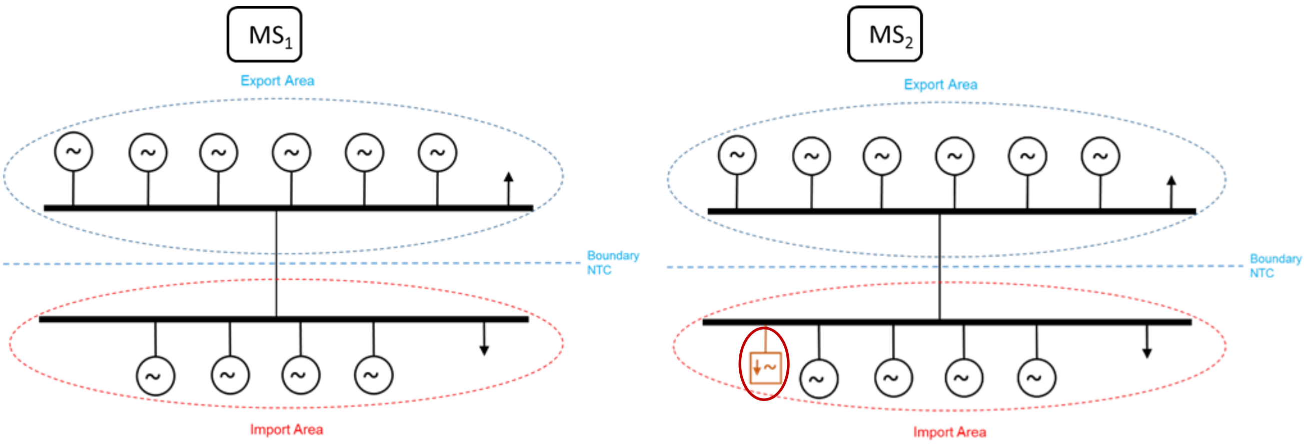
ΔMS: Difference between MS1 and MS2

<u>Interconnection project</u>



MS_1: Market simulation with NTC (= NTC $_{initial}$) between bidding zones without the project. MS_2: Market simulation with NTC' (= $NTC_{initial}$ + $\Delta NTC_{project}$) between bidding zones with the project

Storage project

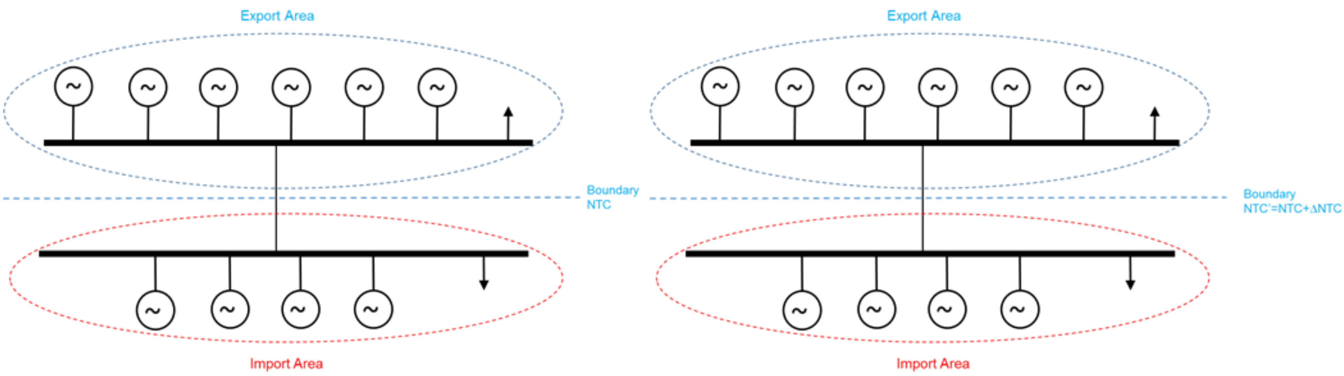


MS_1: Market simulation without the storage project

MS_2: Market simulation with the storage project

Internal project: cross-border impact is the main driver

In this case, there is no physical reinforcement between the bidding zones, but there is an increase in NTC, facilitated by an internal reinforcement.



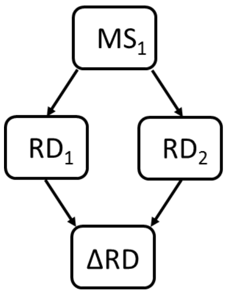
MS_1: Market simulation with NTC (= NTC $_{initial}$) between bidding zones without the project
MS_2: Market simulation with NTC' (=NTC$_{initial}$ + ΔNTC$_{project}$) between bidding zones obtained with the internal project

The total benefit (SEW) is calculated by summarising the difference in total generation costs or total surplus (ΔMS) obtained from market studies for all the hours of the year.

$$SEW = \Delta MS$$

Method 2: Using redispatch simulations, with a market simulation result as a base

For internal projects without significant cross-border impact but with large internal benefits, a combination of market and network studies can be performed:

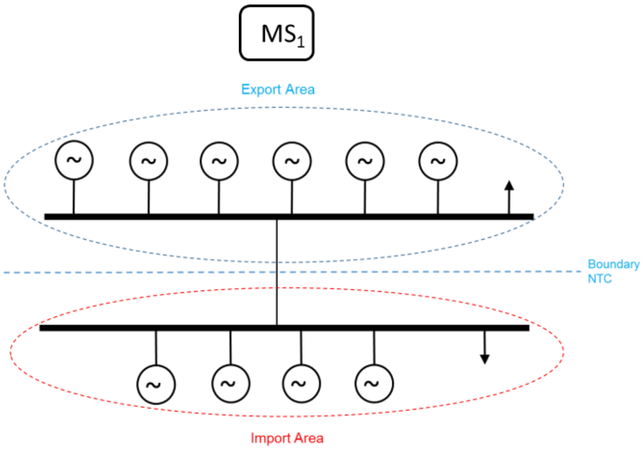


MS_1: Market simulation with reference NTCs

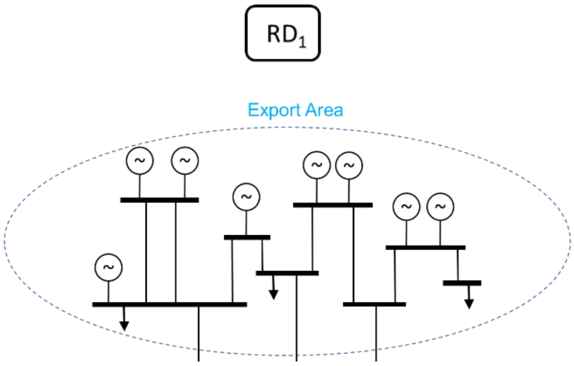
RD_1: Redispatch calculated without the internal project

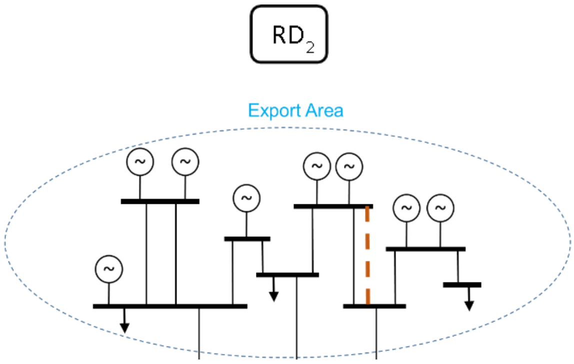
RD_2: Redispatch calculated with the internal project

ΔRD: Difference between RD_1 and RD_2



MS_1: Market simulation with reference NTC between bidding zones





RD_1: Redispatch calculated without the internal project
RD_2: Redispatch calculated with the internal project

With the dispatch taken from MS_1 the load flow within the region where the internal project will be installed has to be calculated.

If congestions are detected in the network studies, the redispatch has to be done (see section 3.4)

The redispatch is calculated with (RD_2) and without (RD_1) the internal project for each time step during one year. In cases where the annual calculation is not possible, representative points in time can be analysed following the principles described in section 7.3 of the 4th CBA Guideline.

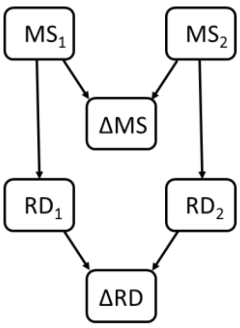
The redispatch costs are defined by the fuel costs of the respective scenario.

The total benefit (SEW) is calculated by summarising the difference in total generation costs (ΔRD) obtained from redispatch for all hours of the year.

$$SEW = \Delta RD$$

Method 3: Using a combination of market and network (redispatch) simulations

For internal projects with (significant) cross-border impact and with large internal benefits, a combination of market and network studies can be performed:



MS_1: Market simulation without the internal project

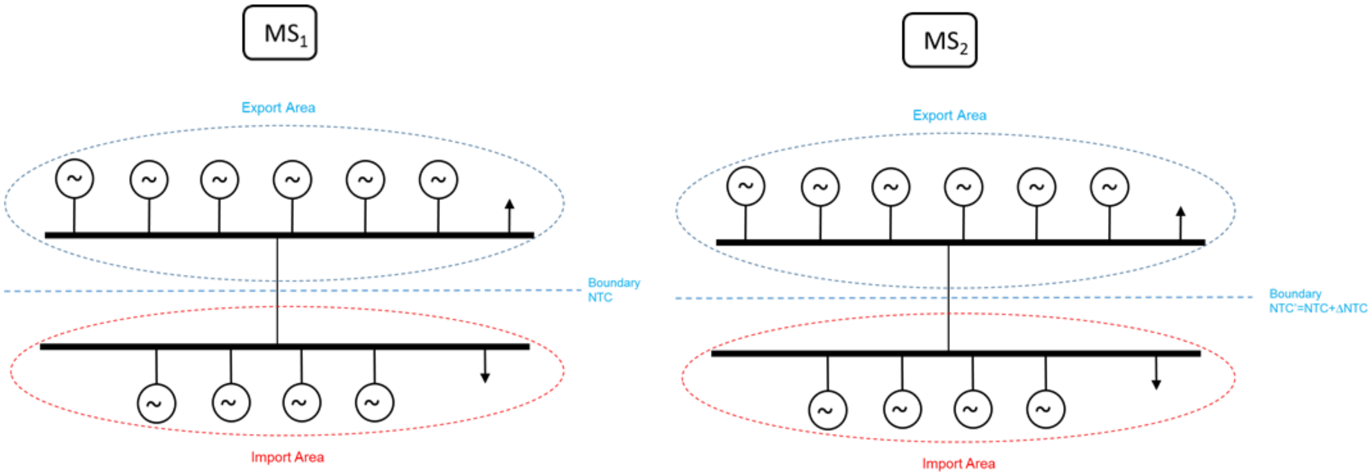
RD_1: Redispatch calculated without the internal project

MS_2: Market simulation with the internal project

RD_2: Redispatch calculated with the internal project

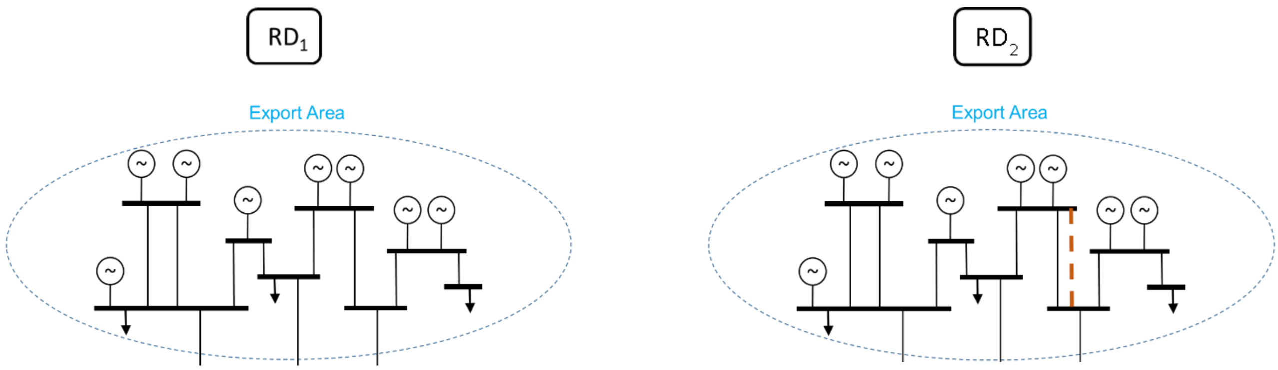
ΔMS: Difference between MS1 and MS_2

ΔRD: Difference between RD_1 and RD_2



MS_1: Market simulation with NTC (= $NTC_{initial}$) between bidding zones without the project

MS_2: Market simulation with NTC' (= $NTC_{initial}$ + $\Delta NTC_{project}$) between bidding zones obtained with the internal project



RD_1: Redispatch calculated without the internal project using the dispatch taken from MS_1

RD_2: Redispatch calculated with the internal project using the dispatch taken from MS_2

The total benefit (SEW) is calculated by summarising the difference in total generation costs or total surplus (ΔMS) obtained from market studies for all the hours of the year and the difference in total generation costs (ΔRD) obtained from redispatch.

$$SEW = \Delta MS + \Delta RD$$

The market simulations give the benefit related to a change in market capacity between market nodes and the redispatch simulations give the benefit related to a change in line loadings. The change in dispatch from the market studies will influence the line loadings, but this is not considered in the market studies but only in the redispatch. Double counting can therefore not show up, because redispatch just gives the additional benefit that comes from the internal line loadings. This is because of the determination of the system costs without consideration of compensation costs:

- $costs_{MS1}$ = dispatch costs from MS1
- $costs_{RD1}$ = re-dispatch costs from RD1 (only the change in dispatch compared to MS1 is considered)

Therefore, the total system costs of the situation 1 sum up as

$$costs_{MS1} + costs_{RD1}$$

The same consideration can be done for situation 2. Applying this to the calculation of the SEW, which is the difference of costs of situation 1 and two, leads to:

$$SEW = (costs_{MS1} + costs_{RD1}) - (costs_{MS2} + costs_{RD2})$$

This leads to:

$$SEW = (costs_{MS1} - costs_{MS2}) + (costs_{RD1} - costs_{RD2})$$

which is the same as

$$SEW = \Delta MS + \Delta RD$$

5.1.1 Fuel savings due to integration of RES (SEW RES)

A project impact on RES integration due to reduction of curtailment and lower short-run variable generation costs is part of the general SEW benefit (B1). In line with the 4th CBA Guideline, it is explicitly monetised and reported as additional information under indicator B1. This additional information must not be seen as an additional benefit. The monetised benefit RES integration, accounted under SEW, is not an individual indicator and must not be added to the SEW.

As the market tools do not directly monetise the effect of integrating RES within the system, its monetisation must be performed as a post process. The RES integration is monetised by multiplying the annual avoided curtailed RES (in MWh) by the average marginal price (€/MWh), as follows for each weather scenario:

1. Calculate the demand weighted average marginal price (the hours of ENS [10000€/MWh] will be excluded of the computation) from market studies output (reference case – with/without project case) per area q, per hour n.
2. Average over all areas c (number of countries) to obtain a Pan-European value.
3. Multiply this average marginal price value [€/MWh] with the annual avoided RES curtailment [MWh] (B3. RES Integration benefit).
4. The results are then weighted onto the base of the weather scenario's weighted factors to get the monetary value of RES, accounted under SEW, per scenario.

These steps lead to the following formula for the RES monetisation for each weather scenario:

$$RES_{monetary} = \frac{1}{c} * \frac{1}{h} * \left[\sum_{q=1}^{c} \sum_{n=1}^{h} \frac{demand_{q,n}}{demand_q} * MC_{q,n} \right] * RES$$

where:

$MC_{q,n}$: Marginal cost at node q in hour n [€/MWh]

$demand_q$: yearly native demand at node q [MWh]

q: runs over all countries considered within the calculations (*c* being the number of countries)

n: runs over all hours h considered within the calculations (*h*=8736)

RES: Annual total avoided RES curtailment [MWh]

5.1.2 Avoided CO_2 emission costs (SEW CO_2)

The avoided CO_2 emission costs can easily be extracted from market simulations by multiplying the difference in CO_2 emissions (in *tons*) by the CO_2 costs used in the different scenarios (in *€/tons*). These costs can be seen as the costs of CO_2 linked to the costs created by the ETS market. It must be noted that in addition to these costs, CO_2 creates additional costs due to the damage it causes to health and the environment. These costs are described in the following chapter. Specific attention must be paid to the risk of double accounting with these societal costs of CO_2 emissions. This is also described in the following chapter.

As with the fuel savings due to RES integration, this monetised avoided CO_2 emission cost is part of the SEW benefit (B1) already. Even when it is reported separately, it should not be added to B1 to avoid double counting.

5.1.3 Relation of the SEW-sub indicators to the total SEW

The total SEW is derived from the cost terms as shown within the 4th CBA Guideline in table 3, of which the CO_2-costs are one. The RES integration is implicitly already monetised within the SEW as an increase in RES generation will reduce the need of conventional electricity generation, which will lower the overall generation costs. In addition, the CO_2 output is (most likely) to be decreased under higher RES integration. With this in mind, the total SEW can expressed as:

$$SEW_{total} = SEW_{CO2} + rest$$

5.2 B2 – Additional societal benefit due to CO_2 variation (section 5.2 of the 4th CBA Guideline)

Variation of CO2 emission

The variation of CO_2 emissions comes from two effects

1. The change of generation plans: $\Delta CO2_{generation\ plan}$
2. The change of the losses volumes: $\Delta CO2_{losses}$

CO_2 emissions variation from the change of generation plans

The variation of CO_2 emissions resulting from the change of generation plans is computed through two market simulations: one with and one without the project. For each situation, the generation dispatch is assessed during the simulation. The system wide CO_2 emissions are based on the annual dispatched energy of each plant category and their corresponding CO_2 emission factor. The difference between the total CO_2 emissions of the two simulations gives the variation resulting from the change of generation plans.

***CO_2* emissions variation from the change of losses volumes**

In the market simulations, losses are considered via a fixed load demand time series. The addition (or the withdrawal) of a new project can have an impact on the hourly losses volumes and, as a consequence, on the hourly total energy generation, and finally on the CO_2 emissions. The change of the hourly generation is not considered in market simulation because load time series are identical in both simulations with and without the project. The CO_2 emissions variation resulting from this change of total generation is computed through the following process.

For both simulations with and without the project:

a. For each hour and for each bidding zone, assess the losses volume via network studies. In order to avoid double counting the part of the losses already within the load curve, only the additional part should be used for the following steps of the process (see the double counting methodology section on losses chapter)
b. For each hour and for each bidding zone, assess the marginal power plant. To assess the marginal power plant per bidding zone, compare the marginal price of the bidding zone to the marginal cost of each fuel type (or cluster of fuel types, see below). The fuel type (or cluster) which has the closest marginal cost is the marginal power plant.
c. For each hour and for each bidding zone, assess the CO_2 emission of losses by using the additional part of losses (step a.) and the CO_2 emission factor of the marginal power plant (step b.).

Finally, the difference of the CO_2 emission of losses in the case with and without the project aggregated over a full year gives the variation due to the addition of the project.

Note: Some power plant types have very close marginal costs even though their CO_2 emission factor might differ significantly. Hence, to avoid some edge effects, plant types that have close marginal costs (delta < 2€/MWh) are grouped together into a cluster for step b and c. The equivalent marginal cost of the cluster is the average (weighed over the total installed capacity) of the marginal costs of the power plant types that compose it. Similarly, the equivalent CO_2 emission factor of the cluster is the weighted average of the ones of the power plant types that compose it. Note that different scenarios can have different clustering because of the change of marginal costs.

Monetisation

The variation of CO_2 emission is monetised through a societal cost. Indeed, the CO_2 ETS market price used in the marginal cost of power plants does not fully capture the cost that CO_2 emission has on society. The societal cost of carbon can represent two concepts:

1. The social cost (or damage cost) that represents the total net damage of an extra metric ton of CO_2 emission due to the associated climate change
2. The shadow price (or avoidance cost) that is determined by the climate goal under consideration. This can be interpreted as the willingness to pay for imposing the goal as a political constraint.

In general, the avoidance cost approach is preferred to guide investments. The literature reports numerous studies of both social cost and avoidance cost. This results in a broad range of possible values. For the TYNDP, the values (avoidance cost) based on European Commission's (DG MOVE) *Handbook on the external costs of transport*[14] are used to define the low and central values[15]. The high value in the table below is derived from the European Investment Bank (EIB) Climate Bank Roadmap Progress report[16] (also updated from $€_{2016}$ to $€_{2026}$ values using the HICP from Eurostat). These avoidance costs are aligned with policies to reach the Paris agreement. To represent the uncertainty surrounding these costs within the TYNDP 2026, the societal value of CO_2 is calculated using the Low, Central and High value[17].

Table 2: Low, central and high values for social cost of carbon in horizons 2035,5,2040 and 2050 (figures in $€_{2026}$ values)

	Low value	Central value	High value
CO_2 cost (2035) €/t			
CO_2 cost (2040) €/t			
CO_2 cost (2050) €/t			

The societal cost of carbon emissions is considered an absolute given, which does not depend on the scenario that is assessed. Note that, compared to what can be found in literature, these values – even the high one – are rather in the low part of the CO_2 societal cost projections. Care is needed in interpreting these societal costs and comparing them with other monetised costs. Also note that these societal costs are not factored in the market study runs where dispatch is still optimised based on other/lower carbon price, which reflects an effective monetary flow related to the EU ETS scheme.

<u>Double counting</u>

Part of the CO_2 emission variation benefit is already computed within the SEW and the losses cost through the inclusion of the EU ETS CO2 price in the generation cost. Hence, the B2 indicator should only report the additional part of the CO_2 benefit that is not already captured in the context of the other indicators.
Consequently, the formula for this indicator is the following:

[14] *https://op.europa.eu/es/publication-detail/-/publication/9781f65f-8448-11ea-bf12-01aa75ed71a1/language-es*
[15] The Low and Central values considered in this implementation guideline corresponds respectively to the Central and High values considered in the DG MOVE Handbook on the external costs of transport, updated from $€_{2016}$ to $€_{2026}$ values based on the Harmonized Index of Consumer Prices from Eurostat.
[16] https://www.eib.org/attachments/lucalli/20240145_eib_group_2023_climate_bank_roadmap_progress_report_en.pdf
[17] It can happen that in a scenario the ETS cost is higher than the low societal costs for 2030. In this case, the monetisation of the B2 benefit indicator is set to 0€ for that low value.

$$B_2 = (\Delta CO2_{generation\ plan} + \Delta CO2_{losses}) * (CO2_{societal\ cost} - CO2_{ETS\ price})$$

In this calculation, $CO2_{ETS\ price}$ refers to the carbon cost as applied in the market simulations and given in the TYNDP scenario report.

5.2.1 Different parts of the CO_2 emissions calculation

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence of Monetary Measure
CO2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tonnes/yr	per definition not monetary	European
CO2 emission from losses variation	Network studies (losses computation)	Tonnes/yr	per definition not monetary	European
Societal costs of CO2 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 counting with B1)	European
Societal costs of CO2 emissions from losses variation	Network studies (losses computation)	€/yr	Societal costs decreased by ETS costs as used in the scenario (to avoid double counting with B5)	European

5.3 B3 – RES Integration (section 5.3 of the 4th CBA Guideline)

The integration of RES can be facilitated by a new project in two ways:

1. By directly connecting RES capacity to the main power system that is not already connected without the project.
2. By increasing the capacity between areas with excess of RES generation and other areas, which facilitates the integration of both existing and new planned RES.

Depending on the type of the project, either one or both ways can play a role. The monetised value is already fully included in the B1 indicator (SEW). This indicator B3 provides the benefit of RES integration in quantitative MW or GWh figures

Two indicators are used to quantify this impact:

a. For projects directly connecting RES such as offshore wind parks: **the generation capacity of the integrated RES**, in MW.

b. For all kind of projects (i.e. directly connecting RES or not): **the additional amount of RES energy used in the power system** as a consequence of the change on the generation dispatch, in GWh/year. This additional RES energy displaces non-RES energy from the power system.

Therefore, the benefit of RES integration is computed as the additional yearly RES energy of the newly connected generation capacity (if any), reduced by the additional dumped energy in the system resulting from the addition of the project:

$$RES = E_{project} - (E_{dumpwith} - E_{dumpwithout})$$

With

- $E_{project}$: the yearly energy produced by the connected RES source
- $E_{dumpwith}$: the yearly dump energy with the project included
- $E_{dumpwithout}$: the yearly dump energy without the project included

To directly connecting RES projects, this indicator is necessary because the connected RES might not always be available due to the RES curtailment caused by congestions somewhere in the grid.

For non-directly connecting RES projects, this indicator measures the reduction of curtailed energy allowed by the addition of the new connection of area with the excess of RES generation with other areas.

The calculation should be performed as year-round market simulations.

Internal congestion can also lead to RES curtailment. In that case, redispatch simulations are necessary to calculate the RES integration indicator which will be given as the difference of the RES curtailment (energy) with and without the project.

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, network or redispatch studies	GWh/yr	included in generation cost savings (B1)	European

5.4 B4 – Non-direct greenhouse emissions (section 5.4 of the 4th CBA Guideline)

Grid reinforcements can lead to additional benefits via emission reductions for all greenhouse gases other than CO_2 as well as particulate matters. A dedicated module is used in the TYNDP market studies to track these emissions based on dispatch profiles.

This benefit indicator corresponds to the avoidance of externalities due to NH3, SO2, NOx, PM 5, PM 10 and NMVOC. The benefits of these avoided emissions and how they should be considered in infrastructure projects assessment are described in a study by the European Investment Bank: The Economic Appraisal of Investment Projects at the EIB.

These emissions are derived from the TYNDP market simulations, providing the annual generation by PEMMDB generation category (see Annex C.) multiplied by the emission type specific emission factor as given in annex A.3. It must be noted that the emission factors are given in [kg/GJ] thermal, which makes it necessary to apply the given standard efficiency in order to derive the emission factors in [kg/GJ] electrical.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary Measure	Level of Coherence
Non-CO2 emissions from market substitution	Market or redispatch studies (substitution effect)	Tonnes/yr	per definition not monetary	European

5.5 B5 – Variation in losses (section 5.5 of the 4th CBA Guideline)

The losses calculations are generally performed by comparing the network simulation results using two market simulation outputs: with and without the project, to consider the change of flows due to the differences in generation dispatch caused by the NTC increase of the project in the market assessment. Whereas the general rules of the load-flow simulations were described in section 3.3, there are some additional ones that are only relevant for losses calculations, which are described below.

DC load-flow improvements

In case DC load-flow analysis are used to calculate the active power flows, the losses on each network branch are estimated by the following formula:

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

Generally, voltage levels of 110 kV and above are to be considered. To better approximate the voltage pattern of AC load-flow, the voltage values to be used in the formula for the most frequent voltage levels are not the base voltages of the nodes but were determined using the AC load-flow results of selected points in time. The estimated losses' results with these values were also compared to the losses from the AC solution. The values to be used per voltage level are the following:

Voltage level [kV]	Value for U [kV]
380-400	405
220–225	237
150	152
120–132	128
110	115

A common value of cos(ϕ) = 0.95 to approximate the effect of reactive flows is confirmed by the statistical screening of the branch flows of AC load flow simulations.

Monetisation

The demand curves used in the market simulations for TYNDP 2026 are constructed to cover estimated losses. Therefore, to avoid partial double counting with the B1 benefit (SEW), one of the two possible assumptions described in the 4th CBA Guideline must be taken. Starting with TYNDP 2020, the assumption that the losses computed in the reference case are included in the demand was made, which means that the double counting compensation is done with the calculated losses results. This leads to the following monetisation formulas:

In the case of PINT projects:

$$Delta\ Losses\ (monetized) = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s'_{h,i}(p'_{h,i} - p_{h,i})\right)$$

In the case of TOOT projects:

$$Delta\ Losses\ (monetized) = \sum_{market\ node\ i} \left(\sum_{time\ step\ h} s_{h,i}(p'_{h,i} - p_{h,i}) \right)$$

where $p'_{h,i}$ (with project) and $p_{h,i}$ (without project) are the losses in MWh, and $s'_{h,i}$ (with project) and $s_{h,i}$ (without project) are the marginal costs (taken from the market simulation outputs) in €/MWh for each market node and time step (hour).

To get meaningful monetised results, the marginal costs must be capped to the highest generation cost of the given scenario. This avoids occasional/exceptional marginal costs of 10000 €/MWh in the case of ENS, which would strongly distort the results. The following values are applied:

Scenario	Cap price [€/MWh]
NT 2030	212.86
NT/DE 2040	236.04

The cap prices correspond to the Light Oil category in all scenarios.

In TYNDP 2026, two network models will be built for the target years 2035 and 2040.

Losses on HVDCs are to be calculated using a linearised model (Idle Loss+K*Setpoint), for which the parameters are provided by the TSOs and the relevant project promoters. In the event of cross-border HVDCs, the losses are split equally between the two market areas.

Parameter	Source of calculation	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Losses	Network studies	MWh/yr (positive sign means increase in losses)	€/year (market based) (positive sign means increase in benefits at a decrease in losses)	European

5.6 B6 – Security of Supply – Adequacy to meet demand benefit (section 5.6 of the 4th CBA Guideline)

The adequacy benefit is estimated through the assessment of the Expected Energy Not Supplied (EENS), saved by the addition of the project. This value is monetised via the Value of Lost Load (VoLL) then capped by a sanity check that assesses the amount of generation capacity that would have been necessary to get the same Security of Supply (SoS) level.

Prerequisite (more details in Annex H.)**:**

- To properly model the loss of load probabilities, the hazards must be simulated in detail. This is achieved through a Monte Carlo (MC) analysis, requiring a large number of years to be modelled in order to reach the convergence of the outputs. Consequently, for the TYNDP, adequacy simulations must be performed with hundreds Monte Carlo samples, resulting from the matching of the full set of the 35 PECD climate years and outage patterns time series. These times-series are randomly created through a Monte Carlo (available generations, RES, demand).
- The scenario is built to be realistic in terms of loss of load (see Annex G. on the Security of Supply loop): for each country, Loss of Load Expectation (LOLE) should be within 1h of its reliability standard criteria[18], except for countries where there are too many base and semi base generations (in which case LOLE could be down to 0).
- From the above-mentioned scenarios, scarcity events are selected, and using the MC method, samples for analysis are prepared.

The following process is applied:

1. Step 1: Check scenarios (apply the SoS-loop to the scenarios as describe in section 3.1.1 of the present Implementation Guidelines).
2. Step 2: Assess avoided EENS
    a. Preliminary
        i. For a transmission project, if the project links two countries with no loss of load (LOL) in the situation without it, then its adequacy benefit is equal to 0.
        ii. For storage and RES generation project, if the project is connected to a country with no LOLE in the situation without it, then the adequacy benefit of the project is 0.
    b. Assess the EENS without the project. More detail on the computational process of this step is provided in Annex H.

[18] *By default, 3h/year (if no official value)*

c. Add the project and assess the EENS with it. If an adjustment had been made (for TOOT projects), keep the added generation peaking units in the situation with the project.

d. Compute the difference of EENS between both situations. Report this value

e. Monetise this difference using the VoLL of each country.

3. Step 3: Sanity check[19]
    a. Transmission project
        i. If the addition of the project decreases the LOLE in the two countries directly linked by the project, then the sanity check capacity is equal to the sum of the direct and indirect ΔNTC of the project
        ii. If the addition of the projects only decreases the LOLE in one of the two countries, then the sanity check capacity is equal to the ΔNTC in the direction that goes to this country.
    b. For RES project
        i. The sanity check is equal to the load factor of the project multiplied by the installed capacity if the addition of the project decreases LOLE in the country and would not be required when there is no LOLE decrease due to the project.
    c. Particular projects
        i. For project with several contributions (in transmission or RES generation), the sanity check is the sum of the sanity checks of each contribution
        ii. For a project that has an effect on the exchange capacities of more than 2 countries, the sanity check is the sum of the ΔNTC in the direction that goes to countries whose LOLE has decreased by the addition of the project.
    d. Report the sanity check capacity.
    e. Monetise the sanity check with the Cost of New Entry (CONE) value for each country.
4. Monetisation
    a. **VOLL**: as required in the Clean Energy Package, ENTSO-E is working on the definition and the application of a methodology to estimate the VoLL for each country. For TYNDP 2026, the results of this study will be used if available. For countries where it is not yet available, the VoLL will be based on expert judgement at 10 k€/MWh for the monetisation of B6 indicator, in line with common values found in the literature.

[19] *This is a simplified sanity check, to be used for the TYNDP. In more advance studies, this sanity check can be refined.*

b. **CONE**: as required in the Clean Energy Package, ENTSO-E is working on the definition and the application of a methodology to estimate the CONE for each country. For TYNDP 2026, the results of this study will be used if available. For countries where it is not yet available, the value will be set at 42 k€/MW/yr for the monetisation of B6 indicator, in line with what is commonly used in the Scenario Building process.[20]

5. Final value
   a. The adequacy benefit is the minimum between the monetisation of the EENS avoided by the project and monetisation of the sanity check.

Parameter	Source of calculation	Basic unit of measure	Monetary measure	Level of coherence of monetary measure
Level of Adequacy	Market simulations	MWh/year	€/year (market based)	European

[20] *This value relates to that of a OCGT installation cost spread over 25 years with a 6% discount rate, in line with costs of generation as given in the TYNDP 2022 Scenario Building Guidelines (2022.entsos-tyndp-scenarios.eu)*

5.7 B7 – Security of Supply – Flexibility benefit (section 5.7 of the 4th CBA Guideline)

5.7.1 B7.1 - Balancing energy exchange

This indicator is part of the Project Level Indicators and can be delivered by the relevant project promoter. A detailed description of the used methodology needs to be submitted, following the principles of the 4th CBA Guideline.

It has to be noted that 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. As the aforementioned issues could lead to high uncertainties in the delivered values, this indicator will be addressed by qualitative assessment only. Therefore, although the methodology described in the 4th CBA Guideline predicts monetary results, the value submitted by the promoter will not be published in the TYNDP 2026 project sheet. This value, after validation by ENTSO-E, will be converted into a qualitative indicator, applying the following equivalences:

Value submitted within the range	Corresponding qualitative indicator shown as published in the Project Sheet
< 2.4 M€	0
[2.4 M€; 19 M€]	+
≥19 M€	++

To ensure the indicator is statistically meaningful, the range thresholds are set based on the TYNDP 2022 results and public studies on market integration benefits:

- Definition of the ratio of the social welfares from:

$$\frac{balancing\ market\ integration}{Long\ Term + Day\ Ahead\ "crossborder"}$$

- Relationship between the SEW of TYNDP 2022 projects for all 2030 scenarios (NT and DE) and the expected ratio between Long Term + Day Ahead cross-border trade social welfare (associated to SEW) and the social welfare of balancing market integration;

- This relationship was calculated by applying the ratio equal to 7.5% for all SEW values of all TYNDP 2022 projects for 2030 scenarios (source: social welfare benefits already obtained and to be obtained from various actions intended to increase EU market integration, ENTSO-E, NRAs, NEMOs, Vulcanus and ACER calculations for 2018);

- Subsequently, using this relationship and the ratio equal to 7.5%, ENTSO-E calculated the probability associated with the expected balancing energy exchanges benefit of each project;
- Finally, the probability of balancing energy exchanges benefit being below 2.4 M€ is 35% and below 19M€ is 87.5% (see Figure 8 below)

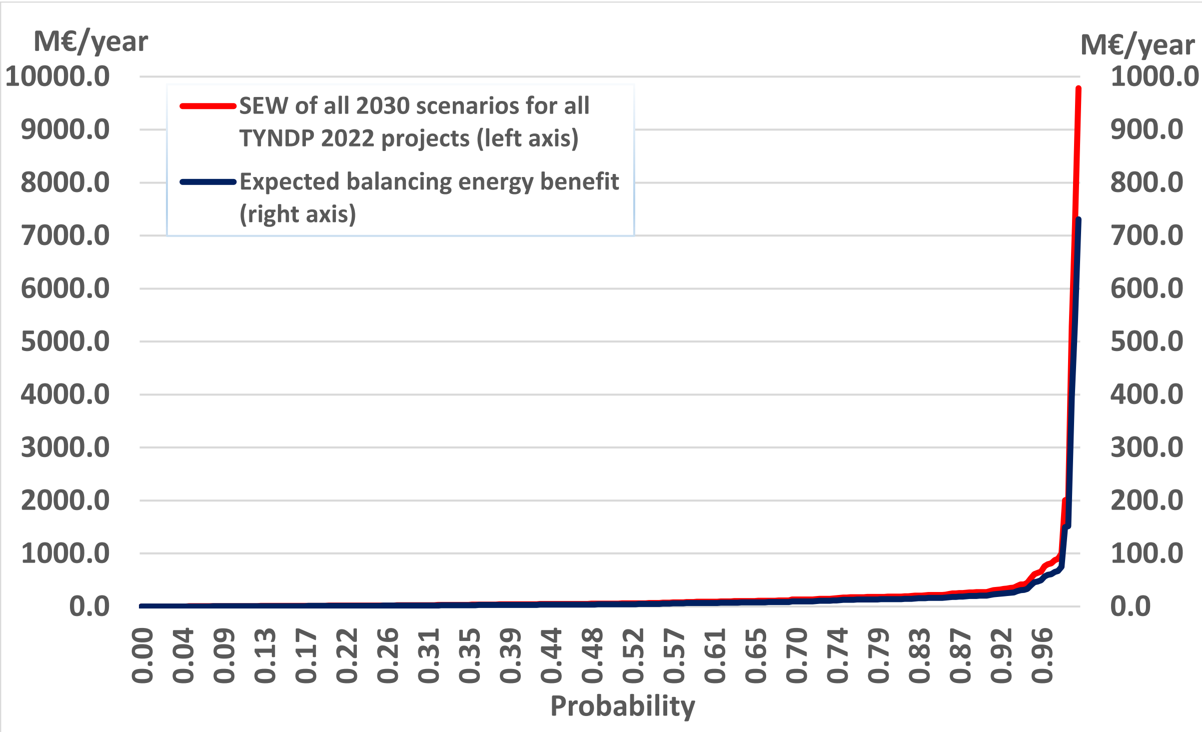


Figure 8 – Illustrative view on how TYNDP 2022 project SEW benefits can be mapped to contributions in balancing energy benefits to come to reasonable thresholds

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

The basic principle of the balancing services indicator is that increasing cross-border capacity could lead to a reduction in balancing energy costs. The scope of the methodology included in the 4th CBA Guideline aims to quantify this reduction in balancing cost.

In Annex E.1. an example is included to further clarify the explanation of this indicator. The values included refer to the TYNDP 2022 Implementation Guidelines[21]; however, the application of the methodology is unchanged.

5.7.2 B7.2 - Balancing capacity exchange/sharing

As this indicator has been introduced to the 4th CBA Guideline for completeness reasons, just giving a qualitative description without delivering a concrete guidance, *the balancing capacity exchange/sharing is not computed within the TYNDP 2026.*

This indicator is associated with the increase of balancing energy exchange volumes on a cross zonal border. The impossibility of delivering a unique and universal methodology is related to the high number of variables associated with this indicator.

[21] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2022/public/CBA-IG.pdf

5.8 B8 – Security of Supply – System stability benefit (section 5.8 of the 4th CBA Guideline)

System stability reflects the project's impact on the ability of a power system to provide a secure supply of electricity as per the technical criteria (such as voltage, frequency and/or black start). In the 4th CBA Guideline, the System Stability indicator is addressed using four separate sub indicators: B8.0 - Qualitative stability indicator; B8.1 - Frequency stability; B8.2 - Black start services; and B8.3 Voltage/reactive power services.

5.8.1 B8.0 Qualitative stability indicator:

This indicator must be implemented following the guidance given within the 4th CBA Guideline.

5.8.2 B8.1 Frequency stability:

Following the principles given in the 4th CBA Guideline for this indicator the rate of change of frequency (RoCoF) is calculated with and without the project in a system situation that occurs directly after an imbalance in the system. The indicator is referred to HVDC projects within a synchronous area and complements B8.0.

This indicator is listed as one of the PLIs and can be provided by the relevant project promoter. A detailed description of the used methodology has to be submitted, following the principles given in the 4th CBA Guideline and within this Implementation Guidelines in this section.

It is not expected that, even in future scenarios, frequency stability will become a serious issue under ordinary contingencies in the interconnected system but rather in severe events, like system splits, during situations with high power flows in the AC system and low inertia. Therefore, in the ENTSO-E study "*Frequency stability on long-term scenarios and relevant requirements*"[22] global severe splits were identified in which a RoCoF higher than 1 Hz/s is reached in each region after the system split. 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). This must be distinguished from the RoCoF withstand capability of generation units (2-2,5 Hz/s) which is specified in the Connection Network Codes.

In the TYNDP 2026, the assessment of the B8.1 indicator is evaluated on a selected global sever split, that was identified in the ENTSO-E Frequency Stability study.

The instantaneous RoCoF just after an imbalance is an important quantity for the robustness and resilience of an electrical grid. It is calculated from the active power

[22] https://eepublicdownloads.azureedge.net/clean-documents/Publications/ENTSO-E%20general%20publications/211203_Long_term_frequency_stability_scenarios_for_publication.pdf

imbalance ($\Delta P_{imbalance}$), the system load (P_{Load}) and the inertia constant (H) at system frequency (f_0):[23]

$$RoCoF = \frac{\Delta P_{imbalance}}{P_{Load}} \cdot \frac{f_0}{2H}$$

The inertia constant of a single generation unit (H_G) is the ratio of energy stored in the rotating parts ($E_{kin,G}$) related to the generators rated power (S_G). For a synchronous electrical grid, the Inertia H_{synch}^{gen} can be calculated from the sum of the stored energy in all rotating masses of the generators connected to the grid ($\sum_i^N H_{G,i} \cdot S_{G,i}$) in relation to the system load (P_{Load}):

$$H_G = \frac{E_{kin,G}}{S_G}, H_{synch}^{gen} = \frac{\sum_i^N H_{G,i} \cdot S_{G,i}}{P_{load}}$$

Additional inertia is provided by the rotating masses of the loads to the system. Since this share is rather small and there is a trend of decoupling the rotating loads from the system via power electronics this is neglected in the study.

All input parameter for the RoCoF calculations have to be obtained from the TNYDP 2026 market simulations. The active power imbalance $\Delta P_{imbalance}$, inertia H are calculated for the reference case and the project case at any point in time. In both cases, $\Delta P_{imbalance}$ corresponds to the scheduled market power flow minus the power flow capcacity of the HVDC lines between the split areas. The inertia H is also calculated from the market results by taking the hourly generator outputs of the rotating masses into account. P_{Load} is the total system load and can be extracted from the market results. It is recommended to calculate the RoCoF for all defined scenarios, but as a minimum requirement the RoCoF has to be calculated based on the NT2030 scenario. Two indicators are assessed:

- Mean RoCoF Reduction [Hz/s]: For all point in times the mean RoCoF is calculated for the reference case and the project case. A project contributes to frequency stability if it reduces the mean RoCoF.
- Reduction of critical RoCoF situations >1Hz/s [hours/year]: By constructing of RoCoF duration curves, the hours of critical situations >1Hz/s can be identified. If a project reduces these situations it contributes to frequency stability.

[23] Inertia and Rate of Change of Frequency (RoCoF) – 2020. Online available under https://eepublicdownloads.azureedge.net/clean-documents/SOC%20documents/Inertia%20and%20RoCoF_v17_clean.pdf

5.8.3 B8.3 Black start services

The Black start services sub-indicator is contracted or imposed by TSOs to ensure that a minimum level of existing market flexible units is available for re-energising the power system after an event that results in the loss of power supply to the entirety, or part, of a bidding zone or LFC block.

However, this indicator is non-mature, and no qualitative or quantitative methodology has been developed yet. *The indicator is therefore not assessed in the TYNDP 2026.*

5.8.4 B8.4 – Voltage/reactive power services

This indicator is not assessed in the TYNDP 2026.

5.9 B9 – Reserves for redispatch power plants (section 5.9 of the 4th CBA Guideline)

Although not listed as one of the non-mature indicators in the 4th CBA Guideline, this indicator is listed as one of the PLI and can be provided by the respective project promoter as within the TYNDP 2026 no centralized redispatch calculations are to be performed. A detailed description of the used methodology has to be submitted, following the principles in the 4th CBA Guideline and in these implementation guidelines. The project promoter has to prove compliance by delivering the requested information linked to each step, as given in the example in the 4th CBA Guideline. For this purpose, for each of the steps as shown below, the compliance of the study must be given. The simulations must be carried out with and without the project as follows:

- without the project:
    - market simulation to get the initial dispatch (year-round)
    - load-flow simulation to get the initial line loadings (year-round)
    - redispatch calculation to mitigate congestions (year-round)
        - from this, for each hour of the year the power activated due to redispatch has to be extracted
- with the project:
    - market simulation to get the initial dispatch (year-round) (if there is no major cross-border impact by the project, the same market simulation as without the project can be used)
    - load-flow simulation to get the initial line loadings (year-round)
    - redispatch calculation to mitigate congestions (year-round)
        - from this, for each hour of the year, the power activated due to redispatch has to be extracted.

A simple example of how to achieve this indicator can be found in Annex E.

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

6. Contribution to Union Energy Targets (section 6.1 of the 4th CBA Guideline)

6.1 ET 1: Interconnection Targets

According to the Expert Group on electricity interconnection targets recommendations, the contribution to Union Energy Targets is computed through three different indicators: price differentials, security of supply and renewable energy integration.

- Price differentials: Market studies simulations will serve to account price differentials per border as the yearly average of absolute hourly price differentials.
  This indicator is computed per border in €/MWh. In those borders where this indicator is greater than 2 €/MWh will mean that further interconnectors should urgently be investigated.

- Security of supply: Ensuring that electricity demand, including through imports, can be met in all conditions in a country the ratio of the sum of nominal transmission capacity of all interconnectors of country i divided by the peak load 2030 of country i, as presented in the following formula should be used:

$$\frac{\sum NTC_{Nominal,Interconnectors,country\ i}}{Load_{peak,country\ i}}$$

  Where:

  Nominal transmission capacity: Reflects the physical capacity for which the interconnector was designed. It corresponds to the maximum power flow that the cross-border asset can transmit in summer in accordance with the system security criteria. Nominal transmission capacity is not influenced by market design, mechanisms and rules.

  This indicator is computed by country. In those countries where this indicator is below 30% will mean that further interconnectors should urgently be investigated.

- Renewable energy integration: to account for the contribution of interconnectors to integration of renewables the following formula is used:

  Sum of nominal transmission capacity of all interconnectors of country i / installed renewable generation capacity 2030 of country i

  Where:

  Nominal transmission capacity: Reflects the physical capacity for which the interconnector was designed. It corresponds to the maximum power flow that the cross-border asset can transmit in summer in accordance with the system security criteria. Nominal transmission capacity is not influenced by market design, mechanisms and rules.

This indicator is computed by country. In those countries where this indicator is below 30% will mean that further interconnectors should urgently be investigated.

The interconnection levels in the EU member states can be represented in a map with colours per country/border whenever the thresholds are not met.

6.2 ET 2 Energy Efficiency

Energy efficiency can be regarded as the ratio of output of energy to input of energy[24]. In energy system analysis applications, the energy efficiency (EF) is given by:

$$EF = \frac{E_{final}}{E_{primary}} ,$$

where $E_{primary}$ denotes the primary energy consumption (input of energy) and E_{final} is the final energy consumption of the energy system (output of energy).

As the final demand is already defined by the scenario building process[25], the indicator ET2 specifies any variation on the primary consumption influenced by a project and can be interpreted as a direct contribution of the related to the European energy targets on the primary consumption in 2030[26]. It is given by the following equation:

$$ET2 = \frac{E_{primary}^{woP} - E_{primary}^{woP}}{E_{primary}^{EU\ targets}} , ET2 = \frac{E_{primary}^{wP} - E_{primary}^{woP}}{E_{primary}^{EU\ targets}} ,$$

where E_{wP}, E_{woP} are the primary energy consumptions with and without the project. A positive value would indicate that a project contributes to the European targets.

[24] Gregor Erbach, Understanding energy efficiency, European Parliamentary Research Service, 2015, available at https://www.europarl.europa.eu/RegData/etudes/BRIE/2015/568361/EPRS_BRI(2015)568361_EN.pdf
[25] end user appliances are already linked with certain energy efficient technologies following the energy efficiency first principle
[26] Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency and amending Regulation (EU) 2023/955

Primary energy consumption is defined as the energy input to supply the energy system. It reflects all energy carriers that feed the energy system in the form of imports or domestic provision. It can be calculated as

$$E_{primary} = \sum_{c \in G_{th}, G_{RES}, G_{H2}} \frac{E^{c}_{supply}}{\eta_c},$$

where E^{c}_{supply} is the yearly energy output of the generator $c \in G_{th}, G_{RES}, G_{H2}$ obtained from the market dispatch simulation. The geographical perimeter is specified in Section 3.2.3 and the market model includes the electricity and hydrogen sector. To calculate the primary energy usage, we need to divide the energy output by the energy efficiency η_c of the generation device. G_{th} is the setting of all thermal generation units that are coupled with the electricity sector for exogenously treated primary energy carriers e.g. power plants fueled with methane, oil, coal or nuclear power G_{RES} comprises all renewable energy sources that convert renewable energy to electricity or hydrogen. Note that for the renewable and nuclear energy sources an efficiency of 100% is assumed. Lastly, G_{H2} includes all units that are coupled with the hydrogen sector for exogenously treated primary energy carriers. These units are hydrogen import terminals or steam methane reformers.

Components that couple endogenously treated energy carriers, e.g. electrolysers or hydrogen gas turbines are not subject to primary energy providers. These units are indirectly fed by primary energy sources reflected in G_{th}, G_{RES}, G_{H2} . In addition, flexibility devices e.g. batteries, closed pumped storage plants or iDSR units that solely shift energy on timescale, do not provide primary energy. Those units are excluded from the calculation. Note that the contributions from open loop pumped storage plants are split into an eligible RES and a non-eligible flexibility part for primary energy consumption.

The final energy consumption is calculated as:

$$E_{final} = \sum_{c \in L_{el}, L_{H2}} E^{c}_{demand},$$

where E^{c}_{demand} denotes the energy demand for the components $c \in L_{el}, L_{H2}$. The set L_{el} specifies all electric conventional and switching DSR loads connected to the energy system and L_{H2} contains all conventional loads of the hydrogen sector.

6.3 ET 3 Renewable Penetration

The definition of the share of renewables in the energy mix is the ratio of renewable energy consumed in the country/region to the total amount of energy consumed by the country/region[27]. The renewable penetration (ET_{res}) is calculated as the yearly energy gross consumption from renewable energy sources (E_{RES}) of energy divided by the gross primary energy consumption (E_{final}):

$$ET_{res} = \frac{E_{RES}}{E_{primary}} ,$$

where E_{RES} corresponds to the yearly energy output from renewable generators providing electricity. Following units should be extracted from market results: Run-of-River and pondage, Reservoir, Wind Onshore, Wind Offshore, Solar (Photovoltaic), Solar (Thermal), Solar (Rooftop), Others renewable. The calculation of the primary energy consumption is specified in the Section 6.2. Any variation in ET_{res} is reported as ET3 by taking the difference of ET_{res} with and without the project. As we only partially model the energy system, this indicator is not able to fully capture the contribution on the energy targets. Therefore, it can serve a lower bound on the contribution of the energy targets.

[27] UN Department of Economic and Social Affairs Statistics Division, International Recommendations for Energy Statistics (IRES), New York, 2018
available at https://unstats.un.org/unsd/energystats/methodology/documents/IRES-web.pdf

7. Project costs

The costs are presented with two main indicators C1 (CAPEX) and C2 (OPEX) for every investment in the price base year as defined within the 4th CBA Guideline. C1 and C2 need to be reported within the project sheets separately.
All costs must be provided by the Project Promoter based on the guidance given within the 4th CBA Guideline. Any uncertainties (e.g. based on delays) must be considered by applying the uncertainty range respectively.

7.1 CAPEX (C1) (section 5.10 of the 4th CBA Guideline)

Project Promoters need to provide C1 for each investment. C1 includes capital costs incurred at the inception of the investment (C1a) and capital expenditure incurred during the assessment period (C1b).

For non-mature investments, the standard costs must be taken from the table in Annex **Error! Reference source not found.** if detailed investment cost information is not available. If there are some specific circumstances or complexity of the investment these costs are to be multiplied by specific complexity factor as defined within the 4th CBA Guideline.

7.2 OPEX (C2) (section 5.11 of the CBA Guideline)

All expected maintenance and operation costs must be delivered by the Project Promoter based on the guidance given in the 4th CBA Guideline.

8. Climate adaptation measures

A key driver for developing more sustainable transmission systems is to mitigate the effects of climate change. Extreme weather events have a significant impact on transmission systems and are among the leading causes of large-scale electrical disturbances. Weather-related power interruptions often tend to be severe and with sustained duration, ranging from hours to days, due to large damage on transmission system elements. Hence, strengthening grid resilience against such events is becoming increasingly important.

According to Article 2(19) of Regulation (EU) 2022/869, climate adaptation means a process that ensures that resilience to the potential adverse impact of climate change of energy infrastructures is achieved through a climate vulnerability and risk assessment, including through adaptations measures.

In the context of the energy transition, and specifically infrastructure planning, climate adaptation measures are any action (progressive or ultimate) taken in order to make infrastructure assets and the whole energy system less vulnerable to the intensity and prevalence of the direct and indirect climate change impacts, including both extreme weather events (high-impact low-probability events) and alteration of weather patterns. Common primary climate change impacts are changes in temperature, precipitation, sea level, wind speed, humidity and solar radiation. In terms of the CBA framework, climate adaptation measures are to be assessed as quantitative information.

Integrating climate adaptation measures in energy system planning aims at reducing the system vulnerability and enhancing its resilience to climate change, by better anticipating, mitigating, absorbing, accommodating and recovering from the effects of potentially hazardous events related to climate change. Therefore, resilience measures are all measures that help improving the security of supply, affordability and sustainability in the system. In terms of the CBA framework, climate resilience measures have to be given as quantitative indication. Climate adaptation measures often lead to higher investment costs (CAPEX). Hence, projects incorporating such measures could appear less beneficial if the added value of climate resilience is not adequately captured in the CBA.

In the TNYDP 2026 project promoters will be asked to provide information about adaptations to an investment to cope with possible extreme weather conditions caused by climate changes, as a percentage of CAPEX in the following table. In addition to information on investments costs, project promoters need to deliver input on rebuild cost in case of outage.

From its nature, the general logic of calculating the climate adaptation indicator as presented in this section differs from the calculation of benefit indicators B1-B9, although monetised, the climate adaptation benefit must not be added on top of the other benefits. This becomes clear when considering that the climate adaptation benefit is calculated based on the probability of an outage based on the benefits as described above. The probability is introduced by applying NPV calculations over the assessment period under the assumption of an outage – in that case the benefit is assumes to be zero – and an NPV calculation where no outage is assumed. In contrast to the "standard" benefit indicator calculation, that give the benefits of the project (comparison of with and without the project), the climate adaptation indicator gives the comparison of with and without adaptation. It is thus not directly comparable with the other benefits, but can, and should, be seen as additional information for the decision making.

Information about the portion of the CAPEX allocated to climate adaptation measures:

Hazards	Explanation of adaptation	Climate adaptation cost (% of CAPEX)	Benefit
Ocean PH	foundation is protected against corrosion and structural failure		Corrosion resistance

Wildfire	forest management to reduce impact on OHL, stronger tower foundations, higher towers, protection of equipment against exposure to fire		prevention against inclination or collapse of equipment
Storms, including storm surge	extra-sturdy power lines that can withstand strong winds, designing the line to fail at controlled points		reduce the number of towers from toppling over
Flooding/Sea level rise	underwater drainage, extra-sturdy power lines that can withstand flooding, entire SS may need to be strategically elevated, flood barriers, pumping stations, flood storage reservoirs, flood monitoring devices		to avoid damage of HV equipment, operators can notify when flooding first occurs
Soil/costal erosion	retaining wall, maintaining the natural vegetation and taking up plantation near tower foundations, type of foundation structure that is used in ground improvement and stabilization		prevent tower collapse
Ground instability/landslides/avalanches	modifying slopes geometry, using chemical agents to reinforce slope material, inspection system for remotely identifying high-risk towers		prevent equipment damage
Ice jam	usage of materials and structures with low ice adhesion deicing properties		prevent equipment damage

8.1 Calculation of Climate adaptation benefit

To assess the value of climate adaptation measures, it is necessary to compare scenarios that justify higher capital expenditures (CAPEX) for climate-resilient infrastructure by quantifying the benefits of avoided service disruptions.

For the adapted project, the Net Present Value (NPV) is calculated over a defined time horizon (25 years), using the standard discount rate as defined in the 4th CBA Guideline. The calculation considers: benefits from the measure, costs (CAPEX and OPEX), potential outages and rebuild costs if infrastructure is damaged.

By including the duration of outages and the probability of damage, the method quantifies how much more valuable a climate-adapted project is compared to a non-adapted one. This provides a numerical basis for assessing climate adaptation investments.

As for the final benefit calculation, two NPV values need to be calculated. The difference between them gives the climate adaptation benefit. For this purpose, the NPV needs to be calculated for the situation with consideration of the additional costs because of the adaptation and the NPV for the case where no adaptation is considered. Both NPV calculations are described below:

NPV for project with adaptation:

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

$Cost^A$: Cost Adapted (CAPEX + OPEX)
r: Discount rate
T: Maximum year of NPV approach (25 years)

This formula equals the calculation as described within the 4th CBA Guideline, while only the Costs have been increased by the part of the additional costs that come from the climate adaptation.

NPV for non-adapted project (with outage)

$$NPV(N)_{non-adaptation} = \sum_{t=t0}^{T} \frac{Benefit_t \cdot (1-d_t) - Cost_t^B - Cost_t^R \cdot f_t}{(1+r)^t}$$

$$NPV_{Non-adaptation} = \frac{1}{T}[* \, [NPV(1) + NPV(2) + \cdots + NPV(T)]$$

d: Duration of outage (between 0 and 1)
$Cost^B$: Cost: Non-adapted (CAPEX + OPEX)
$Cost^R$: Rebuild Cost (CAPEX required to restore damaged infrastructure)
r: Discount rate = 4%
T: Maximum year of NPV approach = 25

f_t: model factor to include the rebuild costs into the formula (f_t= 1 for t= N and f_t = 0 else)

For the case without adaptation measures, the approach assumes that an outage of the project occurs due to hazard impacts once within the 25 years assessment period. While the point of time of the outage is not clear, the outage and corresponding NPV is calculated assuming the occurrence in each assessment year N.. This assumed outage is transferred to a loss of benefit within the NPV calculation which is indicated by the factor d. The factor d is defined within the range of [0,1] while 1 stands for a whole years outage (the benefit is then multiplied by a 0 in the formula) and 0 stands for no outage at all. For the TYNDP 2026 the information about the duration d is based on expert knowledge, e.g. through submissions by project promoters.

In comparison to the NPV calculation for the adapted case, the NPV here is calculated using the costs without consideration of the adaptation. Furthermore, this approach takes into consideration the costs of rebuilding the damaged asset. This is achieved within the formula by the factor f which is to be considered as 0 for all years except for the year N in which the outage is assumed – in this case the factor equals 1.

As this methodology evaluates an outage in each of the 25 assessment years the average NPV value has to be calculated in order to compare the mean impact of non-adaption on the project.

Considering these two NPV values, the benefit of climate adaptation can be achieved as:

Benefits of Climate adaptation

$$Benefit_{Adaptation} = NPV_{Adapted} - NPV_{Non-adaptation}$$

9. Residual impacts (5.13-5.16 in CBA4)

In the TYNDP 2026, the Project Promoter will directly deliver the Residual Impacts S1, S2 and S3 following the guidance given in the 4th CBA Guideline.

The values for the residual impacts must be determined in line with the line-routing of the projects as given in the TYNDP 2026.

10. Project level indicators

Project level indicators are indicators given within the 4th CBA Guideline, whereby it is not yet possible for ENTSO-E to assess certain benefits at a pan-European level within the TYNDP process. This can be due to the lack of tools available at ENTSO-E level or common input data specifically required for the respective indicator, or where the methodology is not yet sufficiently mature to get a full assessment on ENTSO-E level (see section 3.4 in CBA 4 on non-mature indicators).
Competent project promoters can submit the project level indicators within the TYNDP process. It should be noted that the submission of project level indicators does not guarantee their inclusion as they may be assessed and determined to be not valid. The validity of the project level benefit will be verified by ENTSO-E during a review process as part of the wider TYNDP process.

Except for two detailed examples of the B7.1 and B9 indicator given in the annex, it is not foreseen to define within this Guideline a more detailed picture of the PLI in addition to the main principles as defined within the 4th CBA Guideline. However, project promoters applying for PLI within the TYNDP 2026 need to give a detailed description of the methodology used.

The project level benefits identified within the TYNDP 2026 are as follows:

- B7.1: Balancing Energy Exchange
- B8.1: Frequency Stability
- B9: Reduction of necessary reserve for re-dispatch power plants

The other indicators presented in this guideline, which have not been listed above, are not treated as project level indicators.

All indicators calculated based on redispatch simulations within the TYNDP 2026 are to be seen as project promoter based. As the indicators determined by redispatch are the same as from market simulations (except for the B9 indicator), where the detailed methodology is defined within the 4th CBA guideline, they are not called project level indicators. However, their inclusion in the TYNDP 2026 has to be followed in the same manner as for PLI together with the specific written compliance acknowledgement, as highlighted in section 3.4.5.

For the indicators to be accepted in the TYNDP project sheets, project promoters should provide the following justification elements:

1) **Information on the study performed to assess the project level benefit:**

    a. Title of the study;

    b. Year of the study;

c. Name of the company that has performed the study; and

d. A link or copy of the study should be made available according to the terms of the TYNDP process.

2) The study shall contain the following information:

a. The assumptions made, together with a detailed explanation. The assumptions required for each project level benefit are detailed in the respective section of these Implementation Guidelines dedicated to that benefit;

b. Data source (if requested, the promoter should also be able to provide the dataset that was used);

c. Details of the tool(s) used to compute the benefit;

d. A clear explanation of how the methodology illustrated in this guideline has been implemented and applied to perform the study; and

e. A clear demonstration that the figures provided in the study relate to countries within the ENTSO-E perimeter only.

ENTSO-E will review the information provided by the promoter (PLIs and supporting documentation) with respect to compliance with the 4th CBA Guideline. Subject to there being no objections, the indicators will be implemented in the TYNDP as valid indicators while clearly indicating the origin of the results.

11. Modelling of storage

As per the TEN-E Regulation, the guidance for the assessment of energy storage projects has been written by the European Commission[28]. This Guidance is the one implemented in the TYNDP 2026 cycle for the CBA assessment of energy storage projects.

Following the aforementioned Guidance labelling, indicator B1 through B5 and B8 are computed by ENTSO-E, same as for transmission projects. Indicators B6 and B11 of that same guidance are analogous to indicator B7.1 and B9 of this TYNDP 2026 CBA Implementation guidelines. The remaining indicators are left to the discretion of the project promoter to compute.

Storage projects are modelled in the market simulation tools with respect to their technology type. A hydro storage technology will be modelled as hydro pump unit connected to the corresponding node. This means that for those projects, there are two reservoirs: one upwards of the generation/pumping unit and another reservoir downwards. The storage capacity of the upward reservoir corresponds to the storage capacity of the storage project. Then, pumping and turbine capacities, together with the round-trip efficiency of the storage project, correspond to the ones given by the project promoter. Depending on the information provided by the project promoter, additional weekly constraints can be considered. These are: Natural inflow, Maximum/Minimum Generated energy, Maximum/Minimum Pumped energy, Maximum/Minimum Generation, Maximum/Minimum Pumping, Reservoir level at the beginning of each week and Maximum/Minimum Reservoir levels at the beginning of each week. These constraints can also vary depending on the weather scenario used or they can be constant.

After the project is modelled in the market tool, simulations are performed to calculate the market CBA indicators and simultaneously extract the time series for the network calculations.

In the network model, the node(s) to which the unit(s) associated to the project under assessment are to be connected must be given by the project promoter. For the case with the project, the unit(s) are connected, and the separate time series from the market simulation associated to the project are directly mapped to the corresponding unit(s) (pumping and turbines). Subsequently, the losses are calculated in the same manner as for the standard project assessment.

28 https://energy.ec.europa.eu/document/download/63685051-41d2-4932-8921-b044d39172a5_en?filename=Electricity_storage_CBA_methodology_FINAL.pdf

12. Assessment of hybrid projects (6.2 in CBA 4)[29]

The CBA methodology application requires clarifications on several points for offshore hybrid interconnection projects to ensure suitable implementation in the short term – for application as of TYNDP 2026 by the ENTSO-E TYNDP team, based on available data to be provided by project promoters – and a fair CBA comparison between project promoters within the TYNDP framework to support the PCI process.

In general, the additional guidance for offshore hybrid projects, other than being compliant with the principles of the 4th CBA guideline (e.g. clustering rules, no double counting of benefits…) should:

1. **Explain which cost components and benefits are to be considered, in which reference grid and with which transfer capacities,** so that the implementation is sufficiently clear both for the project promoter (TSO or third-party promoter) and for the TYNDP Study Team who are effectively performing the market and technical simulations (ENTSO-E).
2. **Ensure consistency with the targeted RES capacity levels** defined in the TYNDP scenarios and related reference grid as well as the targeted Offshore Wind Farms (OWFs) capacity in expected future strategic Offshore Network Development Plans (ONDP) at sea basin level, to be defined by the involved MS on different target years towards 2050, following TEN-E regulation and Fit-for-55 package. The necessary consistency will drive the proper CBA setup and ensure the realism of the CBA analysis performed.

12.1 Out-of-scope

Neither national benefits nor cost sharing elements are elaborated on given the European angle of the TYNDP; this implies that there is no need to know the effective RES target contributions at MS-level nor subsidies (if any). The responsibility for complying with cross-border cost allocation (CBCA) requirements and considering the outcome of the European business case lies at the project promoter level.

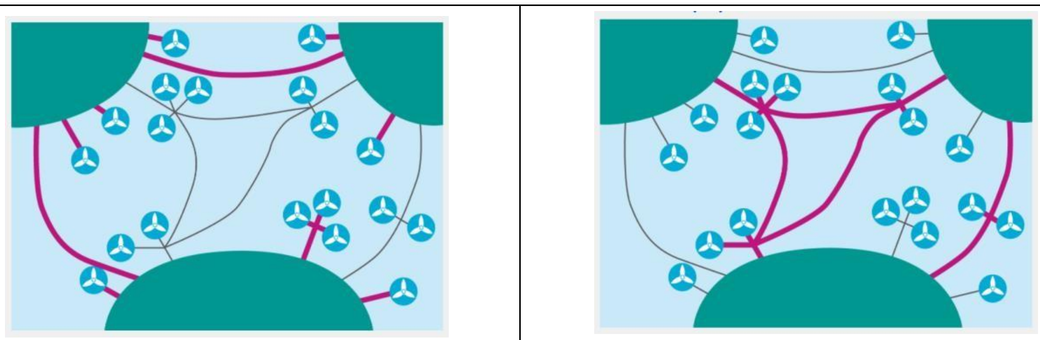
It is important to clarify that **the 4th CBA Guideline and TYNDP 2026 Implementation Guidelines are not designed to facilitate "grid variant comparison & dimensioning".** This is a task for the project promoters (TSOs or third parties) to perform, prior to choosing the best setup which will become their reference solution for both the CBA analysis within the TYNDP framework and the potential submission to the subsequent PCI process.

[29] The assessment of hybrid projects is in line with the definition provided in the 4th CBA Guideline and is limited to the current TYNDP 2026 cycle.

The “best feasible solution” could be multiple things:

- a direct point-to-point interconnector,
- a direct radial connection of offshore RES,
- a hybrid (dual-/ multipurpose) interconnection setup
- meshing between existing radial connections or interconnectors

These key setups are highlighted below in Figure 9 – illustrated for offshore grid development setups only. Each of these setups could be assessed in the TYNDP, following the project promoter choice of the best feasible solution for their project.



Single purpose	Dual purpose (= Hybrid)

Figure 9 – figure taken from ENTSO-E Position on Offshore Development - Summary of Recommendations, July 2021

In general, clustering rules apply as specified in the 4th CBA Guideline in order to determine separate offshore hybrid interconnection projects and their scope. The respect of clustering rules should be monitored in the TYNDP process.

12.2 Hybrid interconnector definition

The hybrid interconnector projects serve at least dual purposes, providing cross-border transmission capacity and generation connection 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). TYNDP projects are expected to contribute substantially to the cross-border transmission capacity of connected systems. Where projects include transmission infrastructure connected to third countries, promoters shall ensure early and sustained coordination with the relevant third country TSO to ensure consistency of network assumptions and cross-border capacity treatment across all participating systems. 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.**

Two CBA cases were defined in the CBA 4th (Section 6.2):

- **CBA Case 1** expansion of an existing radial offshore RES connection through the inclusion of an XB interconnection (IC) to turn them into a hybrid interconnector. The project is built on top of an already existing or planned radially connected offshore RES by enabling only an additional interconnector function (which will then also as a result host the existing or planned RES infeed from the initial radial connection).
- **CBA Case 2** – project developed anew as an offshore hybrid interconnector. The project enables both the RES-integration function (i.e. additional OWF capacity is integrated into the system through the infrastructure project) and the additional interconnector function.

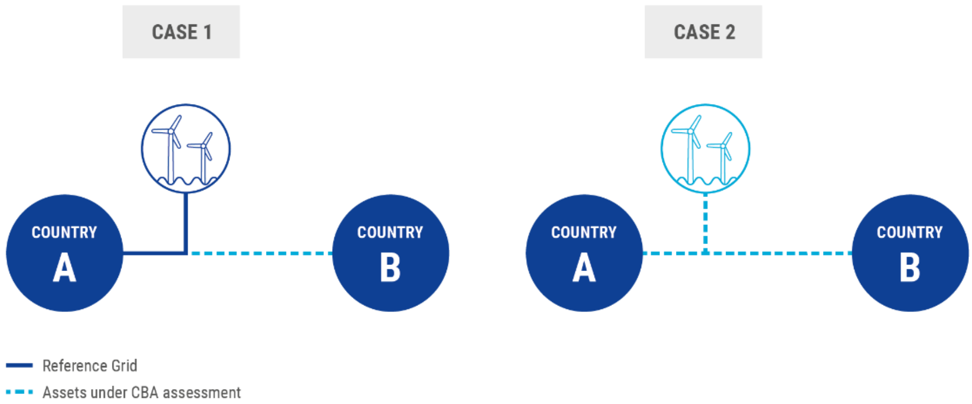


Figure 10 - schematic display of the two fundamental cases/setups of offshore hybrid projects as applied to the CBA assessment

For illustration purposes, only the offshore wind technology setup will be given & discussed in the Implementation Guidelines. However, the same rules apply in case that other offshore RES technologies are connected. 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.

12.2.1 CBA Case 1

The project transforms the original radial connection of offshore RES into an offshore hybrid project by building the remaining leg to another country to enable the XB function.

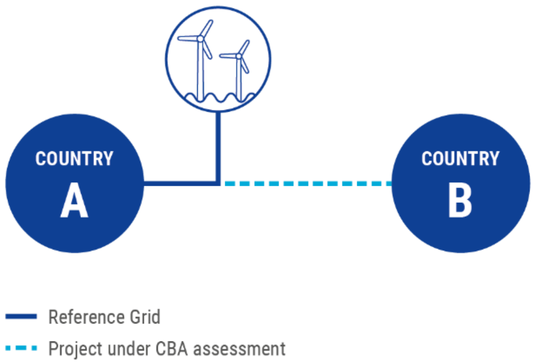
The benefits are enabled by increasing the transfer capacity between country A and B, as shown in Figure 11. In the case of a home market setup, RES is strictly allocated to either country A or B, and the created single NTC would be lower compared to the case of a direct connection between A and B without RES, as the offshore RES energy will impact the options for remaining trade and congest the direct connection.

- 2 NTCs in total are created, 1 between country A and the OWF and 1 between the OWF and country B. The 2 created NTCs can differ between each other and are linked to the leg size in transport capacity terms.

The costs (CAPEX see section 7.1) 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 11 below.

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 11 - Project cost & benefit scope under CBA Case 1 assessment

12.2.2 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 indeed principally three different setups possible for CBA case 2.

(1) Either both legs + 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, on top of which 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 additional RES facilitation on top of the initial radial RES amount. If the initial radial RES connection is not in the reference grid, then a sequential CBA assessment is required using both projects.
(3) If 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 theoretic case 3 only

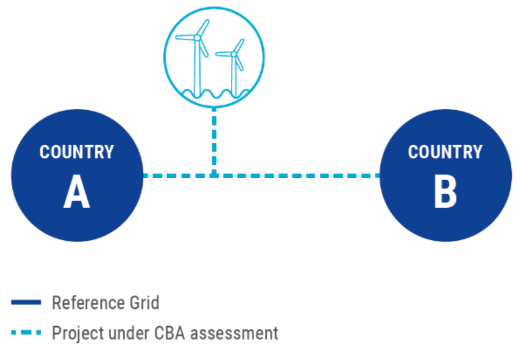
RES-integration benefits would be present (with an impact on the remaining NTC between bidding zone A and B). For the remainder of the text, only setup 1 is illustrated.

The benefits of market integration (relevant B1, B2, B3, B4, B6 indicators) are enabled through the creation of double NTC (2 NTCs in total i.e. 1 between country A and offshore RES, and 1 between country B and offshore RES) and the facilitation of direct offshore RES integration itself.

The costs (CAPEX see 7.1) scope are 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 12 below.

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 12 - Project cost and benefit scope under CBA Case 2 assessment

Since the calculated *benefit* includes both the benefit coming from the interconnection and the additionally included RES generation capacity, the project *costs* must also include the costs from both the interconnection and the CAPEX for the installed OWF. In other words, in order to not overestimate the benefit of the offshore hybrid project assessed using Case 2, the CAPEX for the additional RES generation assets should be considered in the final evaluation.
In practical terms, this means for the assessment of hybrid Case 2 and radial projects requires that the producer surplus be removed from the Social Economic Welfare (SEW) obtained in the market results from the implementation of the project. With this removal, the monetary benefits brought to the system other than the generation asset earnings can be better compared to the costs of the related transmission assets, which ensures consistency with other transmission infrastructures and thus non-discrimination (equal treatment) of transmission infrastructures connecting nodes in the system and transmission infrastructures connecting generation capacity (partially/only).

For keeping focus on the transmission assets only, which ensures consistency and fairness with the assessment performed for the other transmission assets submitted to the TYNDP, the adjusted SEW can be compared with the transmission assets costs linked to the project[30].

12.2.3 Radial projects:

To harmonise the methodology for offshore hybrid and radial offshore RES connection projects, the CBA case 2 approach could be applied to radial offshore RES connection projects. The assessment of a radial offshore RES connection project will consider only the RES integration benefits (no trade benefits). As mentioned above, to ensure consistency with the assessment of other transmission assets, the producer surplus is removed from the calculated benefit.

The costs scope for radial offshore RES connection projects only includes the grid connection (cables and platforms); the RES assets themselves are excluded. This means, for example, for a radial offshore RES connection 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.

12.2.4 NTCs

NTCs should respect the guidance as given in section 4.2 and hence can be different from the thermal capacity of the respective legs of the offshore hybrid setup in general and clearly also when different leg sizing is applicable.

Power rating of the different legs and the targeted voltage level are needed and need to be modelled, in order to most accurately assess amongst others the B5 indicator (grid losses & related monetization).

[30] With this approach, the economic viability of the RES generation asset is not questioned, as this lies fully within the responsibility of the promoter and the stakeholders of the project. **For transparency reason, both the adjusted SEW and the producer surplus of the targeted RES capacity are explicitly reported to give full view on the project market outcomes.**

12.3 Direct project promoter input

12.3.1 Determination of CBA Case 1 versus 2

The determination between CBA case 1 vs case 2 is fully defined by the project setup.

Additional information to justify the project setup must be given by the project promoter. The determination of whether applying case 1 or 2 needs to be supported by the following information:

- For CBA Case 1 – objective information from the involved countries or MS supporting the starting point on which project promoters want to build further and including consistency in future with the expected ODPs & targeted (offshore) RES capacities. This objective information should be published or endorsed by a competent authority (National Ministry or Regulator, EU agency etc.) or be the result of a legally binding process, e.g. grid connection contract, licence award or auction result. Sources could include from National Development Plans (NDPs), strategic offshore network development plans (ONDPs), granted offshore concessions, etc. This implies that the starting point (initial RES connection) is either already existing, or known to be coming, or submitted separately within the TYNDP portfolio framework.
- For CBA Case 2, for TYNDP 2026 it is assumed to either add/remove RES capacity on top of/out of the capacities in the market scenarios in case of PINT/TOOT assessment and this is strictly linked to the reference grid position for each targeted time horizon 2035 2040 and 2050. Project promoters should specify the targeted location & technology, if possible, in order to perform sanity checks where and if necessary.

12.3.2 Data required for TYNDP 2026

This section focusses on offshore RES and typically OWFs, but the described principles & data required can also hold for other technologies used in the hybrid CBA assessments. Project promoters therefore need to submit the following specific information for the hybrid project assessment:

1. Targeted RES location (minimally the target country/EEZ), installed capacity [MW], technology – with best accuracy possible
2. Indication of the project (in particular for the RES project) is part or not of the NECP (National Energy Climate Plan) and/or the NDP (National Development Plan)
3. Sizing of power rating of different legs between onshore bidding zones and OWF
    a. Needed to correctly reflect in NTC estimations
4. Voltage level and estimation of related no load & full load losses

   a. Needed for B5 – grid losses

5. The project promoter may give indication of the ‘hybrid interconnection CBA assessment type’ and related choice between CBA case 1 and case 2 and complementary information to justify the starting point and to improve the CBA quality. However, the final conclusion must strictly be related to the project description and will be done by ENTSO-E under communication with the project promoter.

APPENDIX

A. QUANTITATIVE ASSUMPTIONS

A.1. General Assumptions

Quantitative measure	Value
Hurdle costs	0.01 €/MWh
Cost for ENS in the market models	10000 €/MWh
Societal values of CO_2 emissions (2035)	
Societal values of CO_2 emissions (2040)	
Societal values of CO_2 emissions (2050)	
Cap of marginal costs for losses calculations	212.87 €/MWh (*NT2030*) 236.05 €/MWh (*NT2040*)
Value of Lost Load (general assumption)	10000
Cost of new entrant (general assumption)	42000 €/MW/yr
Economic Lifetime of Assets	25 years
Weighted Average Cost of Capital (WACC)	4%

The Table below gives an overview of the VOLL and CONE used within the TYNDP 2026.6The values are taken from the yearly ACER Security of Electricity Supply 2023[31], and for some countries updated to the latest value available, as indicated in the table .

Country	Value of Lost Load [€/MWh]	Cost of new entrance 2030 [€/MW/yr]	Cost of new entrance 2040 [€/MW/yr]	Reliability standard [h]
Belgium	12,832	30,000	30,000	3
Cyprus	-	-	-	3

[31] The values can be found in table 11 on page 66 and 67 here: ACER Security of EU electricity supply 2023

Czech Republic	16,003 [32]	105,800[32]	105,800[32]	6.7[32]
Estonia	7,300	63,000	63,000	9
Finland	8,000	17,000	17,000	2.1
France	33,000	-	60,000	2
Germany	12,240	57,067	-	2.77
Greece	6,838	18,735	18,735	3
Ireland (SEM)	17,909[32]	115,990[32]	115,990[32]	3[32]
Italy	20,000	53,000	53,000	3
Lithuania	-	-	-	8
Luxemburg	12,240	33,905	33,905	2.77
Netherlands	68,887	-	-	4
Poland	17,173[32]	119,256[32]	-119,256[32]	3[32]
Portugal	-	-	-	5
Slovenia	10,700	21,753	21,753	-
Sweden	7,065[32]	7,873[32]	7,873[32]	1[32]
Spain	6,350	-	-	3
All other countries	10,000	42,000	42,000	3

The Table below summarizes the information needed for the assessment of commissioning years as described in section 3.5

Factor_Class	Factor_Name	Factor_Value	Factor_Unit
$T_{Start,Assessement}$	Reference Starting Point of the Assessment	31/12/2026	[Date]
Δt_{Status}	**Under consideration**	8	[years]
	Planned but not yet permitting	5	[years]
	In permitting	2	[years]

[32] Where applicable, values were updated by the latest version of the ACER report while drafting this document. The numbers are provided in table 1 on page 10 here:::: ACER Security of EU electricity supply 2024

	Under construction	0	[years]
	Commissioned	0	[years]
	Completed	0	[years]
Δt_{Length}	**Short**	2	[years]
	Mid	3	[years]
	Long	4	[years]
	No Length	0	[years]
$f_{type,\ Investment}$	**Overhead line**	1	-
	Substation	0.5	-
	Transformer	0.5	-
	Cable	1.2	-
	Reactive Compensation Device	0.5	-
$f_{type,\ project}$	**New**	1	-
	Upgrade	0.5	-
	MostlyNew	0.8	-
	MostlyUpgrade	0.6	-
$f_{type,flow}$ $f_{type,flow}$	**AC**	1	-
	DC	1.1	-
$f_{geography}$	**Onshore**	1	-
	Offshore	0.9	-

A.2. CO2 emission per type

Category #	Fuel	Type			CO_2 emission factor		
			Original	NT2030	NT2035	NT2040	NT2050
					kg / Net GJ		
1	Nuclear	-	0.00	0.00	0.00	0.00	0.00
2	Hard coal	old 1	94.00	94.00	94.00	94.00	94.00
3	Hard coal	old 2	94.00	94.00	94.00	94.00	94.00
4	Hard coal	new	94.00	94.00	94.00	94.00	94.00
5	Hard coal	CCS	9.40	9.40	9.40	9.40	9.40
6	Lignite	old 1	101.00	101.00	101.00	101.00	101.00
7	Lignite	old 2	101.00	101.00	101.00	101.00	101.00
8	Lignite	new	101.00	101.00	101.00	101.00	101.00
9	Lignite	CCS	10.10	10.10	10.10	10.10	10.10
10	Gas	conventional old 1	57.00	52.44	48.45	41.04	15.39
11	Gas	conventional old 2	57.00	52.44	48.45	41.04	15.39
12	Gas	CCGT old 1	57.00	52.44	48.45	41.04	15.39
13	Gas	CCGT old 2	57.00	52.44	48.45	41.04	15.39
14	Gas	CCGT present 1	57.00	52.44	48.45	41.04	15.39
15	Gas	CCGT present 2	57.00	52.44	48.45	41.04	15.39
16	Gas	CCGT new	57.00	52.44	48.45	41.04	15.39
17	Gas	CCGT CCS	5.70	5.24	44.85	4.10	1.54
18	Gas	OCGT old	57.00	52.44	48.45	41.04	15.39
19	Gas	OCGT new	57.00	52.44	48.45	41.04	15.39
20	Light oil	-	78.00	78.00	78.00	78.00	78.00
21	Heavy oil	old 1	78.00	78.00	78.00	78.00	78.00
22	Heavy oil	old 2	78.00	78.00	78.00	78.00	78.00
23	Oil shale	old	100.00	100.00	100.00	100.00	100.00
24	Oil shale	new	100.00	100.00	100.00	100.00	100.00
25	Hydrogen	Fuel cell	0.00	0.00	0.00	0.00	0.00
26	Hydrogen	CCGT new	0.00	0.00	0.00	0.00	0.00
27	Hydrogen	OCGT new	0.00	0.00	0.00	0.00	0.00

A.3. Non-CO2 emission factors

Fuel	Type	Standard efficiency in NCV terms	NOx emission factor [33]	NH3 emission factor	SO2 emission factor [20]	PM2.5 and smaller emission factor[34]	PM10 emission factor [20]	NMVOC emission factor [35]
		%	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ
Nuclear	-	33%	0	0	0	0	0	0
Hard coal	old 1	35%	0,072	0,0017	0,071	0,0025	0,0048	0,0007
Hard coal	old 2	40%	0,072	0,0017	0,071	0,0025	0,0048	0,0007
Hard coal	new	46%	0,072	0,0017	0,071	0,0025	0,0048	0,0007
Hard coal	CCS	38%	0,072	0,0017	0,071	0,0025	0,0048	0,0007
Lignite	old 1	35%	0,084	0,001	0,16	0,0042	0,0057	0,0009
Lignite	old 2	40%	0,084	0,001	0,16	0,0042	0,0057	0,0009
Lignite	new	46%	0,084	0,001	0,16	0,0042	0,0057	0,0009
Lignite	CCS	38%	0,084	0,001	0,16	0,0042	0,0057	0,0009
Gas	conventional old 1	36%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	conventional old 2	41%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT old 1	40%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT old 2	48%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT present 1	56%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT present 2	58%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT new	60%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	CCGT CCS	51%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	OCGT old	35%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Gas	OCGT new	42%	0,019	0,0060	0,00056	0,00016	0,00016	0,0021
Light oil	-	35%	0,24	0	0,16	0,0062	0,0086	0,0023
Heavy oil	old 1	35%	0,24	0	0,16	0,0062	0,0086	0,0023
Heavy oil	old 2	40%	0,24	0	0,16	0,0062	0,0086	0,0023
Oil shale	old	29%	0,24	0	0,16	0,0062	0,0086	0,0023

33 Values taken from EEA Industrial report: https://www.eea.europa.eu/data-and-maps/data/industrial-reporting-under-the-industrial-7

34 Values taken as average from Emission Factor Database, European Environment Agency (2019), OMINEA, CITEPA (2022) and Updating the Emission Factors for Large Combustion Plants, Umwelt Bundesamt (2019):
https://www.eea.europa.eu/publications/emep-eea-guidebook-2019/emission-factors-database
https://www.citepa.org/fr/ominea/
https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2019-11-29_texte_141-2019_emissionsfaktoren-grossfeuerungsanlagen-en.pdf

35 Values taken as average from Emission Factor Database, European Environment Agency (2019), OMINEA, CITEPA (2022) – Links see footnote above.

Oil shale	new	39%	0,24	0	0,16	0,0062	0,0086	0,0023
Other non-RES	-	-	0,052	0,012	0,038	0,00320	0,00320	0,0039
Lignite biofuel	-	35%	0,084	0,001	0,160	0,0042	0,0057	0,0009
Hard Coal biofuel	-	35%	0,072	0,0017	0,071	0,0025	0,0048	0,0007
Gas biofuel	-	36%	0,019	0,006	0,001	0,00016	0,00016	0,0021
Light oil biofuel	-	35%	0,24	0	0,160	0,0062	0,0086	0,0023
Heavy oil biofuel	-	35%	0,24	0	0,160	0,0062	0,0086	0,0023
Oil shale biofuel	-	29%	0,24	0	0,160	0,0062	0,0086	0,0023

B. Reference grid: List of projects

In the table below you will find the projects included in the reference grids for the 2030 and 2040 horizon. The commissioning years are estimated by the project promoters. The status ID of the project is defined as the following; 1: *Under consideration*, 2: *In planning, but not permitting*, 3: *In permitting*, 4: *Under construction*. The maturity criteria are given based on the definitions within the 4th CBA Guideline. Additional information of the projects together with the explanation why the projects are to be considered for the respective reference grid can be found within the project sheets.

Table 3: Overview of the projects included in the reference grids for 2030 and 2040 time horizons

ID	Project name	Direction 1	Direction 2	TYNDP2026 Dir 1 NTC	TYNDP2026 Dir 2 NTC	Status. Status ID 1 : Under Consideration, 2 : In Planning but not permitting, 3 : In permitting, 4 : Under Construction	2030 network assessment UTILISED IN CBA 2030	2035 network assessment UTILISED IN CBA 2035, 2040 and 2050 (market and network) AND IOSN 2035 and 2040	Commissioning Year
1	RES in north of Portugal	internalPT00	0	0	0	4	TOOT	TOOT	2026
4	Interconnection Portugal-Spain	ES00-PT00	PT00-ES00	1800	700	4	TOOT	TOOT	2025
16	Biscay Gulf	ES00-FR00	FR00-ES00	2200	2200	4	TOOT	TOOT	2028
28	Italy-Montenegro	ITCS-ME00	ME00-ITCS	600	600	4	PINT	TOOT	2032
29	Italy-Tunisia	ITSI-TN00	TN00-ITSI	600	600	4	TOOT	TOOT	2028
33	Central Northern Italy	ITCN-ITN1	ITN1-ITCN	500	500	4	TOOT	TOOT	2026
33	Central Northern Italy	ITCN-ITCS	ITCS-ITCN	400	400	4	TOOT	TOOT	2026
35	CZ Southwest-east corridor	CZ00-DE00	DE00-CZ00	500	500	3	TOOT	TOOT	2029
47	Westtirol (AT) - Vöhringen (DE)	AT00-DE00	DE00-AT00	750	250	2	PINT	TOOT	2030
81	North South Interconnector	IE00-UKNI	UKNI-IE00	981	993	4	PINT	TOOT	2031
85	Integration of RES in Alentejo	internalPT00	0	0	0	3	TOOT	TOOT	2026
107	Celtic Interconnector	FR00-IE00	IE00-FR00	700	700	4	TOOT	TOOT	2028
120	Princess Elisabeth Island (MOG 2)	internalBE00	0	0	0	3	PINTPINT	TOOTTOOT	2032
121	Nautilus: multi-purpose interconnector Belgium - UK	BE00-UK00	UK00-BE00	1400	1400	2	PINTPINT	TOOTTOOT	2032
127	Central Southern Italy	ITCS-ITS1	ITS1-ITCS	500	500	3	TOOT	TOOT	2029
130	HVDC SuedOstLink Wolmirstedt to area Isar	DE00-PLI0	PLE0-DE00	150	250	3	TOOT	TOOT	2027
130	HVDC SuedOstLink Wolmirstedt to area Isar	CZ00-DE00	DE00-CZ00	350	100	3	TOOT	TOOT	2027

130	HVDC SuedOstLink Wolmirstedt to area Isar	CZ00-PLI0	PLI0-CZ00	0	150	3	TOOT	TOOT	2027
130	HVDC SuedOstLink Wolmirstedt to area Isar	AT00-CZ00	CZ00-AT00	50	400	3	TOOT	TOOT	2027
132	HVDC Line A-North	BE00-DE00	DE00-BE00	1400	0	3	TOOT	TOOT	2027
132	HVDC Line A-North	DE00-NL00	NL00-DE00	250	400	3	TOOT	TOOT	2027
138	Black Sea Corridor	BG00-RO00	RO00-BG00	300	200	4	TOOT	TOOT	2026
144	Mid Continental East corridor	RO00-RS00	RS00-RO00	900	800	3	TOOT	TOOT	2029
144	Mid Continental East corridor	HU00-RO00	RO00-HU00	450	1650	3	TOOT	TOOT	2029
170	Baltic States Synchronization with Continental Europe	LT00-PL00	PL00-LT00	700	700	3	PINT	TOOT	2030
187	St. Peter (AT) - Pleinting (DE)	AT00-DE00	DE00-AT00	2500	2500	3	TOOT	TOOT	2030
210	Würmlach (AT) - Somplago (IT) interconnection	AT00-ITN1	ITN1-AT00	150	150	3	TOOT	TOOT	2029
219	Great Sea Interconnector	CY00-GR03	GR03-CY00	1000	1000	4	TOOT	TOOT	2029
219	Great Sea Interconnector	CY00-IL00	IL00-CY00	1000	1000	4	TOOT	TOOT	2029
227	Transbalkan Corridor	BA00-RS00	RS00-BA00	1050	450	3	TOOT	TOOT	2028
227	Transbalkan Corridor	ME00-RS00	RS00-ME00	600	550	3	TOOT	TOOT	2028
228	Muhlbach - Eichstetten	DE00-FR00	FR00-DE00	300	300	3	TOOT	TOOT	2030
231	Beznau - Tiengen	CH00-DE00	DE00-CH00	100	450	2	PINT	TOOT	2035
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-DKW1	DKW1-DE00	550	1750	3	PINT	TOOT	2028
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-NL00	NL00-DE00	0	500	3	PINT	TOOT	2028
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-FR00	FR00-DE00	1300	300	3	PINT	TOOT	2028
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	AT00-DE00	DE00-AT00	0	200	3	PINT	TOOT	2028
244	Vigy - Uchtelfangen area	DE00-FR00	FR00-DE00	1500	1500	3	TOOT	TOOT	2029

254	HVDC Ultranet Osterath to Philippsburg	DE00-FR00	FR00-DE00	650	100	3	TOOT	TOOT	2026
259	HU-RO	HU00-RO00	RO00-HU00	2150	1050	2	PINT	TOOT	2030
260	Project 260 – Multi-purpose HVDC interconnection between Great Britain and The Netherlands	NL00-UK00	UK00-NL00	1800	2000	2	PINT	TOOT	2032
280	FR-BE: Lonny-Achene-Gramme	BE00-FR00	FR00-BE00	1000	1000	3	PINT	TOOT	2032
299	SACOI 3	FR15 - ITCO	ITCO-FR15	100	100	4	TOOT	TOOT	2029
299	SACOI 3	ITCO-ITSA	ITCO-ITSA	100	100	4	TOOT	TOOT	2029
299	SACOI 3	ITCN-ITCO	ITCO-ITCN	400	400	4	TOOT	TOOT	2029
309	NeuConnect	DE00-UK00	UK00-DE00	1400	1400	2	TOOT	TOOT	2027
313	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	AT00-DE00	DE00-AT00	1400	1400	3	TOOT	TOOT	2027
323	Dekani (SI) - Zaule (IT) interconnection	ITN1-SI00	SI00-ITN1	40	7	3	PINT	TOOT	2026
324	Redipuglia (IT) - Vrtojba (SI) interconnection	ITN1-SI00	SI00-ITN1	65	93	3	PINT	TOOT	2026
328	Interconnector DE-LUX	DE00-LUG1	LUG1-DE00	1000	800	2	PINT	TOOT	2029
329	Stevin-Izegem/Avelgem (Ventilus): new corridor	internalBE00	0	0	0	3	TOOT	TOOT	2029
338	Adriatic HVDC link	ITN1-ITCN	ITCN-ITN1	600	1000	4	TOOT	TOOT	2029
338	Adriatic HVDC link	ITCN-ITCS	ITCS-ITCN	1000	1000	4	TOOT	TOOT	2029
339	Tyrrhenian link	ITCS-ITSIvirt	ITSIvirt-ITCS	1000	1000	4	TOOT	TOOT	2029
339	Tyrrhenian link	ITSA-ITSIvirt	ITSIvirt-ITSA	1000	1000	4	TOOT	TOOT	2029
339	Tyrrhenian link	ITSI-ITSIvirt	ITSIvirt-ITSI	1500	1500	4	TOOT	TOOT	2029
340	Avelgem-Courcelles (Boucle du Hainaut): new corridor	internalBE00	0	0	0	3	PINT	TOOT	2032
341	North CSE Corridor	RO00-RS00	RS00-RO00	850	550	3	TOOT	TOOT	2029
342	Central Balkan Corridor	BG00-RS00	RS00-BG00	550	350	2	PINT	TOOT	2034
343	CSE1 New	BA00-HR00	HR00-BA00	450	850	2	PINT	TOOT	2035
346	ZuidWest380 NL Oost	BE00-NL00	NL00-BE00	1074	447	4	PINT	TOOT	2031
349	MaresConnect	IE00-UK00	UK00-IE00	750	750	3	TOOT	TOOT	2029

350	South Balkan Corridor	AL00-MK00	MK00-AL00	298	581	4	TOOT	TOOT	2027
1034	HVDC corridor from Northern Germany to Western Germany	BE00-DE00	DE00-BE00	0	100	2	PINT	TOOT	2032
1034	HVDC corridor from Northern Germany to Western Germany	DE00-NL00	NL00-DE00	500	0	2	PINT	TOOT	2032
1046	Finnish North-South reinforcement	internalFI00	internalFI00	0	0	3	PINT	TOOT(2035 NT)/TOOT(2040NT)/TOOT(2050NT)	2032
1052	Lienz (AT) - Malta (AT) - Obersielach (AT)	AT00-SI00	SI00-AT00	1000	450	2	PINT	TOOT	2034
1052	Lienz (AT) - Malta (AT) - Obersielach (AT)	AT00-ITN1	ITN1-AT00	500	500	2	PINTPINT	TOOTTOOT	2034
1054	220-kV Westtirol (AT) - Zell/Ziller (AT)	AT00-DE00	DE00-AT00	750	250	2	PINT	TOOT	2032
1059	Southern Italy	ITCS-ITS1	ITS1-ITCS	200	200	3	PINT	TOOT	2032
1059	Southern Italy	ITS1-ITCA	ITCA-ITS1	900	900	3	PINT	TOOT	2032
1074	Pannonian Corridor	HU00-RS00	RS00-HU00	250	500	3	PINT	TOOT	2030
1086	Internal grid reinforcements in Estonia to increase RES connection capability (RRF project)	EE00internal	EE00internal	0	0	4	TOOT	TOOT	2026
1088	Latvia and Estonia Hybrid Off-Shore interconnector	EE00-OBZ	OBZ-EE00	1000	1000	2	PINTPINT	TOOTTOOT	2035
1095	Aurora line 2 (4th AC Finland-Sweden north)	FI00-SE01	SE01-FI00	701	883	2	PINT	TOOT	2034
1096	Beznau - Mettlen	CH00-DE00	DE00-CH00	200	1300	3	PINT	TOOT	2033
1098	Offshore Wind LT 2	LTOffshore	LTOffshore	1466	0	2	TOOT	TOOT	2030
1100	Reinforcement of the existing CZ-DE interconnector (Hradec - Röhrsdorf) on the CZ side	CZ00-DE00	DE00-CZ00	500	500	3	TOOT	TOOT	2028
1103	Bickigen - Chippis	CH00-DE00	DE00-CH00	400	400	3	PINT	TOOT	2031
1104	Bauler - Roost	DE00-LUG1	LUG1-DE00	800	800	2	PINT	TOOT	2027
1106	Bornholm Energy Island (BEI)	DE00-BolEnergy	BolEnergy-DE00	0	0	2	PINT	TOOT	2033
1110	Sicily - Calabria	ITCA-ITSI	ITSI-ITCA	450	700	3	TOOT	TOOT	2027
1112	GRITA 2	ITS1-GR00	GR00-ITS1	1000	1000	2	PINT	TOOT	2033

1121	220-kV Hessenberg (AT) - Weißenbach (AT)	ATInternal	ATInternal	0	0	2	PINT	TOOT	2031
1122	Offshore Wind connection Centre Manche 1	FROffshore	FROffshore	0	0	3	PINT	TOOT	2032
1123	Offshore Wind connection Centre Manche 2	FROffshore	FROffshore	0	0	3	PINT	TOOT	2033
1124	Offshore Wind Connection South Brittany	FROffshore	FROffshore	0	0	3	PINT	TOOT	2032
1125	Offshore Wind Connection Occitanie (Narbonnaise)	FROffshore	FROffshore	0	0	2	PINT	TOOT	2032
1126	Offshore Wind Connection PACA (Golfe de Fos)	FROffshore	FROffshore	0	0	2	PINT	TOOT	2032
1127	Offshore Wind Connection South Atlantic Oléron 1	FROffshore	FROffshore	0	0	2	PINT	TOOT	2033
1138	400 kV OHL Suceava (RO) - Balti (MD)	MD00-RO00	RO00-MD00	300	300	2	PINT	TOOT	2030
1153	PST romands	CH00-FR00	FR00-CH00	800	800	2	PINT	TOOT	2033
1155	380-kV Burgenland North (AT) - Sarasdorf (AT) - Greater Vienna (AT)	ATInternal	ATInternal	0	0	2	PINT	TOOT	2033
1157	HG North Tyrrhenian Corridor	ITCS-ITN1	ITN1-ITCS	2100	2100	2	PINT	TOOT	2034
1157	HG North Tyrrhenian Corridor	ITCS-ITCN	ITCN-ITCS	800	0	2	PINT	TOOT	2034
1159	220-kV Bisamberg (AT) – Wien Südost (AT)	ATInternal	ATInternal	0	0	2	PINT	TOOT	2027
1160	PST Riddes	CH00 - ITN1	ITN1 - CH00	150	100	4	TOOT	TOOT	2029
1161	Offshore Wind Connection South Atlantic Oléron 2	FR00Offshore	FR00Offshore	0	0	1	PINT	TOOT	2035
1162	Offshore Wind Connection Fécamp-Grand Large 1	FR00Offshore	FR00Offshore	0	0	1	PINT	TOOT	2035
1166	HG Adriatic Corridor	ITCN-ITN1	ITN1-ITCN	700	700	2	PINT	TOOT	2034
1166	HG Adriatic Corridor	ITCS-ITS1	ITS1-ITCS	600	600	2	PINT	TOOT	2034
1166	HG Adriatic Corridor	ITS1-ITN1	ITN1-ITS1	2100	2100	2	PINT	TOOT	2034
1167	HG Central link	ITCS-ITCN	ITCN-ITCS	600	600	2	PINT	TOOT	2031
1182	EHV S/S Thesprotias and its connection to the 400 kV System	AL00-GR00	GR00-AL00	1160	1590	2	PINT	TOOT	2031

1183	New interconnection line 400 kV Greece - Albania	AL00-GR00	GR00-AL00	160	590	2	PINT	TOOT	2031
1185	Powering Up Offshore South Coast project	IE00Offshore	IE00Offshore	0	0	2	900 MW Wind Offshore/ PINT	900 MW Wind Offshore/ TOOT	2033
1209	Latvia and Lithuania cross-border strengthening project	LT00-LV00	LV00-LT00	949	1570	2	PINT	TOOT	2035
1219	Bofferdange- Bertrange	LUG1INternal	LUG1INternal	0	0	3	PINT	TOOT	2035
1229	Rhein-Main-Link	BE00-DE00	DE00-BE00	700	450	3	PINT	TOOT	2035
1229	Rhein-Main-Link	DE00-DKW1	DKW1-DE00	850	700	3	PINT	TOOT	2035
1234	220-kV Reitdorf (AT) - Weißenbach (AT)	ATInternal	ATInternal	0	0	4	TOOT	TOOT	2027
1235	Second circuit of the 400 kV OHL Sajóivánka (HU) – Rimavská Sobota (SK)	HU00-SK00	SK00-HU00	100	1137	2	PINT	TOOT	2030
1256	Limitations removal on the Italian - Slovenian border	SI00-ITN1	ITN1-SI00	600	600	2	PINT	TOOT	2030

C. PEMMDB GENERATION CATEGORIES

Nuclear
Lignite old 1
Lignite old 2
Lignite new
Lignite CCS
Hard coal old 1
Hard coal old 2
Hard coal new
Hard coal CCS
Gas conventional old 1
Gas conventional old 2
Gas CCGT old 1
Gas CCGT old 2
Gas CCGT new
Gas CCGT CCS
Gas OCGT old
Gas OCGT new
Gas CCGT present 1
Gas CCGT present 2
Light oil
Heavy oil old 1
Heavy oil old 2
Oil shale old
Oil shale new
Fuel cell Hydrogen
Hydrogen CCGT
Hydrogen OCGT
Run-of-River and pondage
Reservoir
Pump Storage - Open Loop (turbine)
Pump Storage - Open Loop (pump)
Pump Storage - Closed Loop (turbine)
Pump Storage - Closed Loop (pump)
Wind Onshore
Wind Offshore
Solar (Photovoltaic)
Solar (Thermal)
Solar (Rooftop)
Others renewable

Others non-renewable
Lignite biofuel
Hard Coal biofuel
Gas biofuel
Light oil biofuel
Heavy oil biofuel
Oil shale biofuel
Battery Storage discharge (gen.)
Battery Storage charge (load)
Power to Gas (generation)
Power to Gas (load)
Demand Side Response

D. POINTS IN TIMES FOR LOAD-FLOW CALCULATIONS

In case points in time are used instead of year-round calculations, the selection of representative hours must be ensured. The method applied is based on a clustering algorithm, which identifies 100 clusters of points in time by default – with the optimal number of clusters depending on the number and distribution of the chosen variables – and a representative hour for each. The choice of variables to be used for clustering (which may be both from a market simulation output and a base case year-round load-flow) can be different for each project assessed for points in time. This is due to different parts of the grid being sensitive to different variables (e.g. wind production is an important variable only for countries with a significant amount of installed capacities; or the loading of certain lines in the base case load-flow results may be important for a given area). In case points in time were used, the chosen points in time must be given within the documentation of the TYNDP 2026.

E. EXAMPLES OF PROJECT LEVEL INDICATORS CALCULATIONS

E.1. B7.1 BALANCING ENERGY EXCHANGE

Example: Computation of indicator B7.1 for a project of interconnection between two countries, A and B

- **First Step – Common Platform**

  It is assumed that in the future there will be platforms to exchange balancing energy products such as "EU imbalance netting", TERRE, MARI and PICASSO.

  The first step consists of extracting data of exchange balancing energy products from the balancing platforms mentioned in the event they are available, or historical ones in the event such platforms are not available yet.

  For this example, historical data of hourly Replacement Reserves (RR) and manual Frequency Restoration Reserves (mFRR) have been used for two countries (country A and country B) for one year (2019 year) and for upwards (UD) and downwards (DD) needs.

- **Second Step – Balancing Need**

  One option proposed within the 4th CBA Guideline consists of using historical balancing needs, assuming that they will apply in the future. This option is considered a very conservative approach as the historical values do not reflect the evolution of the energy mix and it is expected that reserve needs will be increased due to the growth of RES. Nevertheless, it will be a valid option in the event there is no estimation of future balancing needs available.

		STEP 2			
		BALANCING NEEDS			
Date	Hour	Type	Total Quantity RR+mFRR (MW) country A	Type	Total Quantity RR+mFRR (MW) country B
2019.01.1	1	UD	800	DD	282.1
2019.01.1	2	UD	344.6	DD	379.25
2019.01.1	3	DD	1362.8	DD	5.01
2019.01.1	4	DD	922.4	UD	0.75
2019.01.1	5	DD	809.8	UD	0
2019.01.1	6	DD	680.3	UD	0
2019.01.1	7	DD	753.5	UD	0
2019.01.1	8	DD	786.7	UD	0
2019.01.1	9	DD	493.3	UD	144.13

- **Third Step – Cross-border Exchange Capacity**

In this step, the available hourly cross-border capacity after market-closure between country A and country B, which can be used to exchange balancing energy, will be determined in both directions, both with and without the project, as an output from the TYNDP market simulations (each climate year for each time horizon).

For this example, the maximum transfer capacities between country A and B are as follows:

Maximum Transfer Capacity between country A and B (MW)		
	A -> B	**B -> A**
Without the project	**2300**	**2500**
With the project	**4200**	**3500**

Considering the above maximum values of transfer capacity between countries A and B and the market simulations, with and without the project, the available capacity for each hour of the time horizon considered can be computed. Results are shown in the last four columns of the following Figure:

STEP 3							
		Flows (MW) from market simulation country A-> country B WITHOUT the project (2030 NT - 1982 Climate Year) if flows > 0 direction A -> B if flows < 0 direction B -> A	Flows (MW) from market simulation country A-> country B WITH the project (2030 NT - 1982 Climate Year) if flows > 0 direction A -> B if flows < 0 direction B -> A	Available Cross-Border Capacity WITHOUT the project (2030 NT - 1982 Climate Year)		Available Cross-Border Capacity WITH the project (2030 NT - 1982 Climate Year)	
Date	Hour			A -> B	B -> A	A -> B	B -> A
2019.01.15	5	-2500	-3500	4800	0	7700	0
2019.01.15	6	-2500	-3500	4800	0	7700	0
2019.01.15	7	-2500	-3500	4800	0	7700	0
2019.01.15	8	-2500	-3500	4800	0	7700	0
2019.01.15	9	-2500	-3500	4800	0	7700	0
2019.01.15	10	-2500	-3500	4800	0	7700	0
2019.01.15	11	-2500	-3295	4800	0	7495	205
2019.01.15	12	0	37	2300	2500	4163	3537
2019.01.15	13	-2500	82	4800	0	4118	3582
2019.01.15	14	-2141	272	4441	359	3928	3772
2019.01.15	15	-818	-818	3118	1682	5018	2682
2019.01.15	16	-2500	-3500	4800	0	7700	0
2019.01.15	17	-2500	-3500	4800	0	7700	0

- **Fourth Step – Opportunity for Imbalance Netting**

  Determine the opportunity for imbalance netting between control areas: In situations where imbalance netting requires flows in the same direction as market flows, there is need for available cross-border capacity.

  The volume of imbalance netting between country A and country B is calculated, whenever the type of the balancing needs (UU/UD) is not the same in both countries and those needs are not 0, as the minimum of total quantity RR+mFRR in country A and country B:

STEP 4											
		Balancing Need direction	Available Cross Border Capacity for Netting WITHOUT the project	Netting (MW)	Demand after Netting WITHOUT the project						Available Cross Border Capacity after Netting WITHOUT the project
Date	Hour	A-->B B-->A			Country	Type	Quantity Total	Country	Type	Quantity Total	
2019.01.1	1	B-->A	2500	282.1	A	UD	517.9	B	DD	0	2217.9
2019.01.1	2	B-->A	2500	344.6	A	UD	0	B	DD	34.65	2155.4
2019.01.1	3	0	0	0	A	DD	1362.8	B	DD	5.01	0
2019.01.1	4	A-->B	2500	0.75	A	DD	921.65	B	UD	0	2499.25
2019.01.1	5	A-->B	2500	0	A	DD	809.8	B	UD	0	2500
2019.01.1	6	A-->B	2500	0	A	DD	680.3	B	UD	0	2500
2019.01.1	7	A-->B	2500	0	A	DD	753.5	B	UD	0	2500
2019.01.1	8	A-->B	2500	0	A	DD	786.7	B	UD	0	2500
2019.01.1	9	A-->B	2500	144.13	A	DD	349.17	B	UD	0	2355.87

STEP 4												
		Balancing Need direction	Netting (MW)	Available Cross Border Capacity for Netting WITH the project	Netting (MW)	Demand after Netting WITH the project						Available Cross Border Capacity after Netting WITH the project
Date	Hour	A-->B B-->A				Country	Type	Quantity Total	Country	Type	Quantity Total	
2019.01.1	1	B-->A	282.1	3500	282.1	A	UD	517.9	B	DD	0	3217.9
2019.01.1	2	B-->A	344.6	3500	344.6	A	UD	0	B	DD	34.65	3155.4
2019.01.1	3	0	0	0	0	A	DD	1362.8	B	DD	5.01	0
2019.01.1	4	A-->B	0.75	3500	0.75	A	DD	921.65	B	UD	0	3499.25
2019.01.1	5	A-->B	0	3500	0	A	DD	809.8	B	UD	0	3500
2019.01.1	6	A-->B	0	3500	0	A	DD	680.3	B	UD	0	3500
2019.01.1	7	A-->B	0	3500	0	A	DD	753.5	B	UD	0	3500
2019.01.1	8	A-->B	0	3500	0	A	DD	786.7	B	UD	0	3500
2019.01.1	9	A-->B	144.13	3500	144.13	A	DD	349.17	B	UD	0	3355.87

- **Fifth step – Balancing Bids and Offers**

  Establish the balancing bid price stack for the different balancing markets.

  The 4th CBA Guideline gives four proposals to determine this, with increasing levels of complexity:

  i) Determine a seasonal average balancing bid price using historical data

  ii) Determine hourly national balancing bid price curves, i.e. price and volume offered, using historical data

  iii) Determine historical balancing bid price savings exchanged through a balancing platform

  iv) Determine hourly national balancing bid price curve, i.e. costs and volume offered, using forecast data that reflects changes to the generation mix

  In the current example, a conservative approach is applied by determining the hourly balancing bid price, applying the 2019 relation between the average market price and the RR/mFRR price to the marginal cost resulting from the TYNDP market studies.

Country A			Country B		
Average market price (€/MWh)	RR+mFRR Upwards (€/MWh)	RR+mFRR Downwards (€/MWh)	Average market price (€/MWh)	RR+mFRR Upwards (€/MWh)	RR+mFRR Downwards (€/MWh)
47.71	56.775	32.21	47.86	57.65	32.17
Country A ratio	1.19	0.68	Country B ratio	1.20	0.67

- **Sixth Step – Balancing Cost Savings**

  Balancing costs with and without the project are calculated, considering whether the balancing needs are coming from the interconnection (the reserve price used will be the minimum of the country A and country B) or coming from the own country (the reserve price of the own country is used)

  Finally, for imbalance netting, the cost savings are calculated as the difference of the balancing costs with and without the project.

E.2. B9 REDUCTION OF NECESSARY RESERVE FOR RE-DISPATCH POWER PLANTS

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 following the principles given in section 3.4. The project is part of the reference grid, so the TOOT method will be applied. The following process steps are adhered to:

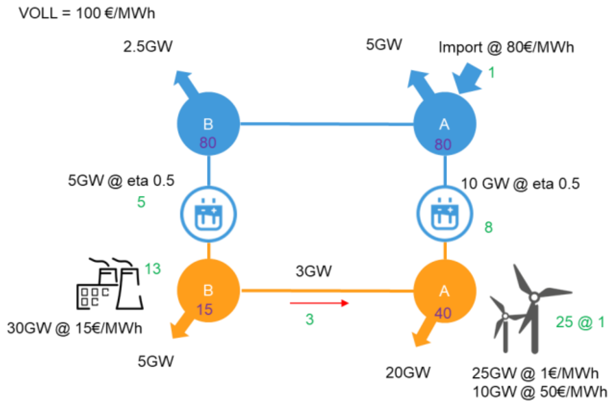
1. Calculate the redispatch power with and without the project for each hour of the year
2. Find the maximum redispatch power for both cases (with and without the project):
3. $P_{RD\ (with)} = 16000\ M$, which appears in hour 3465
4. $P_{R(without)} = 18000\ MW$, which appears in hour 5687
5. Build the delta:
6. $\Delta P_{RD} = P_{RD(without)} - P_{RD(with)} = 18000\ MW - 16000\ MW = 2000\ MW$
7. Monetise the benefit with 20k€/MW of allocated redispatch power plant:

$$B11 = \Delta P_{RD} \times Cost\ of\ Redispatch = 2000\ MW * 20k€/MW = 40\ M€$$

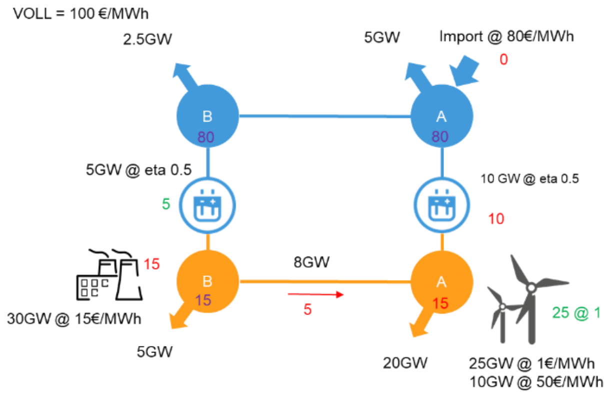
F. Illustrative example for Global SEW calculation

Section 3.2.2 Generation cost and total surplus approach presents the method to calculate the global SEW for TYNDP 2026 under a multi-sectorial scope. The following example illustrates how the derived equations are applied step-by-step based on a simple example. As shown in the illustration below it couples the hydrogen (blue nodes) and power markets (yellow nodes) of two countries A and B over electrolysers. The individual markets are coupled over a dedicated transmission infrastructure e.g. over a power transmission line and a pipeline. Importantly, the example confirms that after a PINT of 5 GW additional power transmission capacity both approaches (Total Surplus and Generation Cost Approach) yield the same delta SEW.

Reference Case



PINT Case Additional Transmission Capacity of 5 GW



Total Surplus Approach

Reference Case:

$R_{CSR}^{elec\leftrightarrow h2} = (80*2.5-15*5)+(80*4-40*8) = 125$

$R_{cons}^{elec} = (100-15)*5+(100-40)*20 \ = 1625$

$R_{cons}^{h2} = (100-80)*2.5+(100-80)*5 = 150$

$R_{prod}^{elec} = (15-15)*13+(40-1)*25 = 975$

$R_{prod}^{h2} = (80-80)*1 = 0$

$R_{cong}^{elec} = (40-15)*3 = 75$

$R_{cong}^{h2} = (80-80)*0 = 0$

$SEW = \sum R = \ 2950$

PINT Case:

$R_{CSR}^{elec\leftrightarrow h2} = (80*2.5-15*5)+(80*5-15*10) = 375$

$R_{cons}^{elec} = (100-15)*5+(100-15)*20 \ = 2125$

$R_{cons}^{h2} = (100-80)*2.5+(100-80)*5 = 150$

$R_{prod}^{elec} = (15-15)*15+(15-1)*25 = 350$

$R_{prod}^{h2} = (80-80)*0 = 0$

$R_{cong}^{elec} = (15-15)*8 = 0$

$R_{cong}^{h2} = (80-80)*0 = 0$

$SEW = \sum R = 3000$

Delta SEW = 3000-2950 = 50

Generation Cost Approach

Reference Case: Generation $Cost = 13*15+25*1+1*80 = 300$

PINT Case: $Generation\ Cost = 15*15+25*1+0*80 = 250$

Delta SEW = 300-250 = 50

G. Security of Supply Loop – detailed methodology

G.1. Context and Background

The aim of this study was to develop a methodology that identifies the level of necessary generation capacity needed to fulfill LOLE Standard. The changes of the generation capacities as the outcome of the study are incorporated into the market models used to perform the B6 indicator calculations. The occurrence of imbalances may significantly impact CBA indicators.

The goal of Security of Supply adaptation process (SoS loop) is to achieve realistic levels of LOLE in the starting results of market models to be used for the B6 indicator calculations.

The presented description concerns the SoS loop for B6, for CBA analyses the mechanism is identical, with the difference that it is performed with the 0 LOLE target for each country, and on a specially prepared model without TOOT projects.

G.2. Methodology & General assumption

Due to the high complexity of the problem, it has been decided to use an iterative approach. This approach will allow to achieve reliable results while maintaining a very complex connection structure of the electricity system (grid structure). Moreover, it is currently difficult to indicate available analytical solutions that could help to solve the problem.

Run SoS Loop to Identify „over and under adequate countries" with:

- reasonable computational time,
- reliable environment that allows automation of the calculation process.

To achieve this goal, it has been decided to adopt the following simplifying assumptions:

- Generation
    - In case of scarcity events, economic dispatch (costs, like emission, fuel price, SRMC) can be neglected, because cost driven by VOLL would be much higher. The marginal costs of the generators are also neglected; thus, a price of 0€/MWh is assumed.
    - Generation is aggregated to single one in each market node.
    - Instead of running several loops with different outage patterns, the installed capacity of the power plants (excluding RES) is multiplied by a capacity factor. The capacity factor is

an average of the available capacity over different outage patterns. Capacity Factors used are from the ERAA study.
    - Starting point of SoS Loop is linked to installed capacity of the power plants (excluding RES) multiplied by capacity factor.
    - The capacity factor is derived from National Grid ESO Capacity Market Auction Guidelines and ELIA PRODUCT SHEET CAPACITY REMUNERATION MECHANISM documents.
- Storages
    - Storages (DSR, hydro storages etc.) are treated as generators - they always give their power during scarcity events which leads to faster computation due to lack of optimization.
    - The power is calculated by the maximum power of the storages multiplied with a capacity factor. This accounts for the fact that the storages might not be fully available in each hour (e.g. when multiple scarcity hours appear in a row).
    - The capacity factor are derived from National Grid ESO Capacity Market Auction Guidelines and ELIA PRODUCT SHEET CAPACITY REMUNERATION MECHANISM documents.
    - Different capacity factors for hydro pump storages and battery storages are used.
    - IDSR is excluded from the study.
- Demand
    - Demand is decreased by generation of generators that operate using fixed profile (Onshore, Offshore, PV, Other RES).
    - During these scarcity situations (2-3 hours per year) the market price would be very high. The assumption is that electrolysers would not be used because of these high prices. Thus, electrolysers are removed from the model.

G.3. Tools and optimization

In order to develop and verify the methodology, simulations were conducted using PLEXOS. The automatization of the iterative approach is made by python through Application Programmable Interface of PLEXOS software. Other parts like data preparation (pre-processing) or definition of the merit order visualization (post-processing) are prepared using R. This combination allows us to effectively perform all tasks. Data preparation and visualization preparation are very quick. A single run of the one step in the iterative approach takes around 2 minutes. Hence, the loop for one CY could take around 1-2 days (approximately 2 minutes x approximately 700 iterations). Full automation allows for easy implementation for other weather scenarios, target years and scenarios.

G.4. Algorithm

The proposed algorithm enables SoS Loop to be performed. In the first steps, preparation of the data and the model in PLEXOS is required. Further, iterative calculations are performed which allow to estimate the necessary generation available in any given node to meet the reliability standards (LOLE of two or three hours per year). The last stage includes graphical presentation of the results and interpretation of the data. Figure 13 shows algorithm scheme.

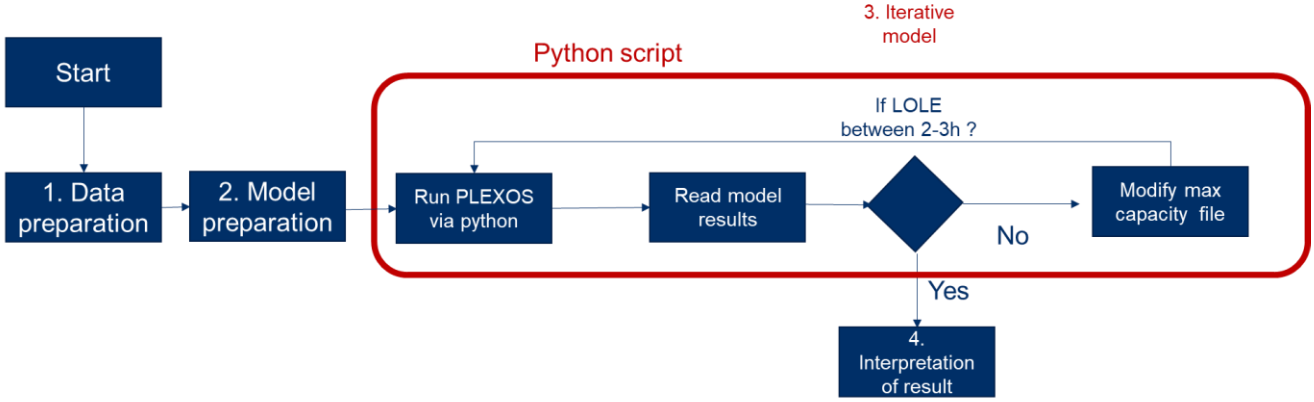


Figure 13: Algorithm steps

The modules indicated in the graph will be described in the following subsections.

Data preparation

For each hour and each node demand is decreased by RES generation. The values considered at this step are those from PECD (capacity factors and hydro profiles) and PEMMDB (installed capacities).

Staring point of the Loop is installed capacity from PEMMDB multiplied by capacity factor. The capacity factor is derived from National Grid ESO Capacity Market Auction Guidelines and ELIA PRODUCT SHEET CAPACITY REMUNERATION MECHANISM documents.

Capacity Factor used to prepare are shown in Table 4.

nuclear	lignite	hard coal	ccg	ocg	hydro	other	batteries	dsr
0.78	0.9	0.9	0.9435	0.9435	0.91	0.8852	0.4	0.4

Table 4: Capacity Factors for different technologies used.

Some nodes (e.g. offshore nodes) do not have demand, only generation. Due to this fact, negative demand was allowed, which will be interpreted by the model as sustainable RES generation. The dump energy appearing in the results will be an indicator informing about the available power in a given node.

This step is performed using the R software environment.

For each hour at each node:

Read RES timeseries from Plexos (same as PEMMDB/PECD):

"wndon", "wndoff", "solpv", "solthe", "othrs", "hydswl", "hydror", "hydres"

RES generation = wndon + wndoff + solpv + solthe + othrs + hydswl + hydror + hydres

Residual load = Demand_orginal – RES generation

*Max Capacity = 0.9 * max(residual load, 0)*

PLEXOS model preparation/simplification

For the purposes of this study the TYNDP 2024 CBA models for National Trends scenarios (2030 & 2040) and Distributed Energy (2040) were used. Models include existing electricity grid and electricity demand. Input data is in hourly granularity.

As assumed, during scarcity events economic dispatch is not important so all costs are deleted from the model. That gives the possibility to aggregate all generation units to one unit per node. Moreover, the H2 network is not included in the models so as not to distort the results.

Assumptions:

- TYNDYP 24 nodal model
- Node as bidding zone
- Electricity transmissions based on NTC (No H2)
- H2 network has no impact on the system during scarcity events.
- One aggregated generation per node
- Aggregated generation has only two parameters (max. capacity and load)
- iDSR is excluded from the study.

Model preparation instruction:

- *Delete all generators, storages, batteries, fuels, waterways, emissions*
- *Delete all H2 nodes*
- *Delete all H2 and electrolyzes lines*

Figure 14: Visualized representation of the updated model in Plexos environment

- *Create one SoS generator per node (set Units = 1) and set Max Capacity*

	Parent Object	Child Object	Property	Value	Data File	Units	Band	Date Fro
	System	AL00	Units	1		-	1	
	System	AL00	Max Capacity	15000	Max_Capacity_SoS	MW	1	

Figure 15: Graphical representation of the unit updates in Plexos environment

- *Set Max Capacity Data file as input for Max Capacity*
- *Change Demand to SoS_Demand*
- *Wheeling Charge change to 0*
- *Calculating model with Reserves*

Running iterative model / SoS loop

Simplified model used for the simulations with initial values of available capacity (installed capacity multiplied by capacity factor) in PLEXOS. In the next step LOLE is calculated for each country (sum of LOLE in nodes) and compared with the reliability standard of each country (Table 5). Further, depending on results max capacity parameter is changed in each market node simultaneously:

- if LOLE in country is higher than standard (Table 5), we increase capacity of the generation by 0.2% ,
- if it is lower (with tolerance of 1h), we decrease the Max Capacity in this node by the same value.

The loop is performed for all climate years available within the input datasets. The number of iteration steps is 500 to reach more or less convergence.

To obtain more realistic results, constraints were introduced into the model. Based on data from PEMMDB, a list of peaker units was prepared. Units with a cost higher than 115 €/ MWh are included (SRMC of new H_2 unit). Additionally, a restriction has been introduced that the reduction cannot exceed 10% of the available capacity in each market area.

Country	Standard
AL	3
AT	3
BA	3
BE	3
BG	3
CH	3
CY	3
CZ	15
DE	3
DK	3
DZ	3
EE	9
EG	3
ES	3
FI	2
FR	3
GE	3
GR	3
HR	3

HU	3
IE	8
IL	3
IT	3
LT	3
LU	3
LV	3
LY	3
MA	3
MD	3
ME	3
MK	3
MT	3
NL	4
NO	3
PL	3
PS	3
PT	5
RO	3
RS	3
SE	2
SI	3
SK	3
TN	3
TR	3
UA	3
UK	3

Table 5: Standard target LOLE of each country used in the studies.

This step is performed using the Python and PLEXOS environment.

For each CY:

For 500 steps:

Run PLEXOS

Read PLEXOS result LOLE

Sum LOLE for country

For each country:

If LOLE > Standard

*Max Capacity = Max Capacity + 0.002 * Max Capacity*

If LOLE < Standard -1

*Max Capacity = Max Capacity - 0.002 * Max Capacity*

Else

Max Capacity = Max Capacity

If Max Capacity < Max Capacity Boundaries

Max Capacity = Max Capacity Boundaries

Interpretation of result

The last stage is to interpret the results obtained. First the averaging of the results is done for the max capacity values obtained for all climatic years. This corresponds to the value expected due to climate variability and the definition of LOLE (which should be as described in LOLE standard or 3h/a as an average over all climate years). Finally, achieved values are compare with peaking units list mentioned above. Then if the numbers differ, peaking units are either removed or added to the given market area.

G.5. Application of the methodology

The methodology will be applied for

- All (34) climate years
- The target years (2030, 2040, 2050)
- The scenarios (national trends)

H. B6 Indicator detailed methodology and algorithm

H.1. Context and Background

The aim of this study was to develop a methodology that identifies the impact of project at energy unserved in the system.

Two main weaknesses of the old methodology:

- Long computation time: ~1 day per project
- Small number of samples: could lead to non-convergent and unreliable results. In CY with 3h of LOLE there are only 3 samples with unserved energy hours. The EENS estimate may be unreliable.

Main improvements to the new methodology:

- Calculation of the mean ΔEENS (difference with and without project) is done and compared with CONE
- Reasonable computational time, (less than 1 hour per project)
- Large number of samples – 10 0000 per climate year led to convergent estimation
- Reliable environment that allows for automation of the calculation process (R, Python,)

H.2. Methodology & General assumption

The calculation of mean ΔEENS (difference with and without project) and comparison with CONE are done under the following general assumptions:

- Focusing only on scarcity hours in the system
- Less focus on economic dispatch – the simplest model with fixed generation & demand (in emergency cases, the costs are not so relevant);
- Dumped Energy may represent available capacity that cannot be delivered;
- Simplification improves the modelling performance;
- Each hour is treated as independent sample.

H.3. Tools and optimization

In order to develop and verify the methodology, simulations were conducted using PLEXOS. The automation of the iterative approach is made using python and R with the use of PLEXOS Application

Programmable Interface. Other parts like data preparation (pre-processing) are prepared using R. This combination allows efficient performance of all tasks. Data preparation and visualization preparation are very quick. Calculation of single project-takes around 5-8 minutes. Hence, the loop for all projects takes about 16h. Full automation allows easy implementation for other climate years, target years and scenarios.

Data preparation

The first step is to perform simulation of reference scenarios in full granularity. The scenarios are calculated for all available weather scenarios datasets. The SoS update of the generation fleet is performed for the scenarios to ensure acceptable adequacy levels.

PLEXOS model preparation/simplification

The PLEXOS model preparation and simplification is similar to that of Security of Supply loop. The one difference is that the model is set to model 10000 hours treated as independent samples

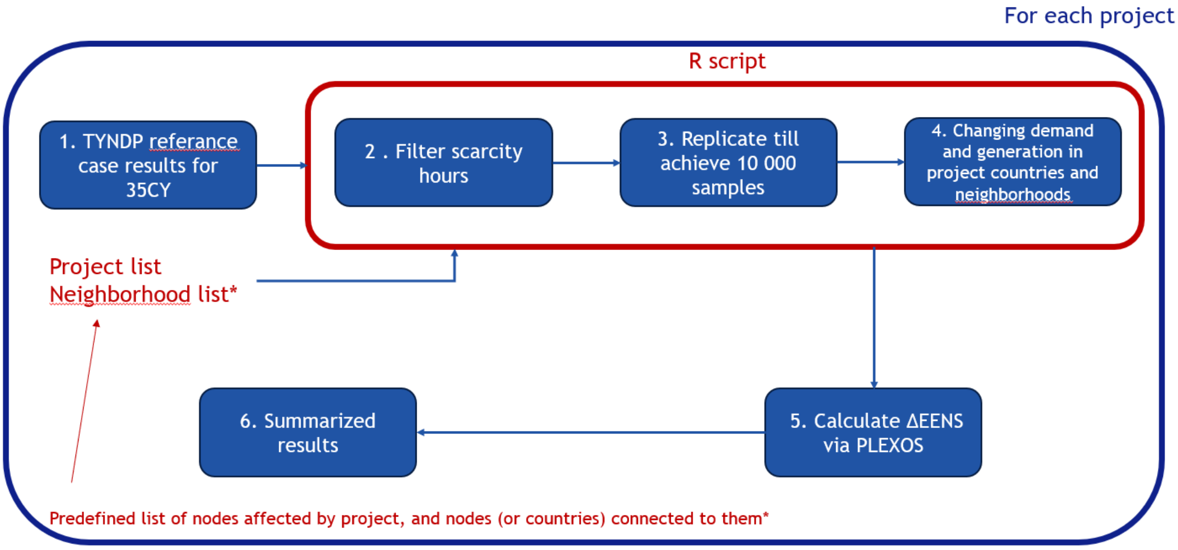
Project implementation:

- Transmission projects are implemented as connections.
- Generation and storage projects are implemented as fixed capacity multiplied by Capacity Factors. A Capacity Factor is a probabilistic measure of expected operating time. The same Capacity Factors as in SoS Loop were used in the analysis. Additionally, for PV connecting projects, only the possibility of working from 10 a.m. to 4 p.m. was introduced.

Capacity Factors used to prepare are shown those used also for the Security of Supply loop.

H.4. Algorithm

Using the Python, R and PLEXOS environments, an algorithm was created that allows quick and automatic calculation of the B6 indicator for all projects.



H.5. Data preparation

1. TYNDP result:
   From flat (.csv) file results we need:
   - Unserved Energy
   - Unserved Energy Hours
   - Native Load
   - Generation
2. Filtering EENS for project nodes, and indication of demand & generation for each node in those hours
3. Replicate samples till 10 000 of them are achieved
4. Draw 10 000 samples from normal distribution (μ=$value$, σ=$value$ ·0,01) for demand and generation
5. Preparing PV Factor files
6. Writing results – PLEXOS inputs

H.6. Running PLEXOS model with & without project

To calculate EENS we use PLEXOS environment. The simulation is run with and without the project.

H.7. Calculation of B6

Energy:

We calculate B6 as an absolute value of sum in all nodes (EENS with project - EENS without project)

Monetised value:

We calculate B6 as an absolute value of sum in all nodes VoLL * (EENS with project - EENS without project).

The VOLL value is specific to each country/node as provided in A.1.

Due to differences in the modeling of the TOOT and PINT projects, ABS function is included to ensure that results represent the value independent of the project configuration.

H.8. Sanity check

After calculation of the B6 indicator, simplified sanity check is performed. A sanity check is performed to cap the value computed by EENS savings.

A comparison is made between the added connections capacities with the project multiplied with the CONE and the actual monetized EENS savings cost obtained with the methodology described above.

The final result is taken as minimum value between both of them. CONE value depends also on the specific country/market node.

The equation can be summarized in the following way:

ΔNTC direct (MW) * CONE (from direct node) + ΔNTC indirect (MW) * CONE (from indirect node) + ΔRES capacity * CONE + Δ Storage * CONE

Final B6 value = min(EENS savings, Sanity check)