European Network of
Transmission System Operators
for Electricity

IMPLEMENTATION GUIDELINES FOR TYNDP 2024

BASED ON the 4th ENTSO-E GUIDELINE FOR COST BENEFIT ANALYSIS OF GRID DEVELOPMENT PROJECTS

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TABLE OF CONTENTS

1. Changes compared to TYNDP 2022 Implementation Guidelines

ENTSO-E is constantly working on improving the methodologies, data etc. for the assessment of projects within the TYDNP project assessment. Although this Implementation Guidelines is based on the 4th improved CBA Guideline and therefore to be seen as a mature document the following main changes compared to the TYNDP 2022 need to be highlighted:

- Inclusion of a new Security of Supply loop for the calibration of the scenarios.
- Generalisation of the SEW by formulation of the global SEW including a detailed example
- Clarification that when PiT are used, a detailed validation needs to be given
- Inclusion of a methodology on how to assess the commissioning years
- Deleted the section of the "Interlinkage between the electricity and the gas sectors" as this information was mainly included under the global SEW description
- Inclusion of a clear definition of the usage of Points-in-time
- Inclusion of a methodology to assess the B8.1 indicator
- Deleted the specific section on the B8.2 Black start service indicator making it more general in its application
- Actualisation of the list of simulation tools
- PEMMDB generators categories updated with inclusion of a new generator type being the CCGT Hydrogen
- Inclusion of the methodologies to assess the European Union targets as introduced in the 4th CBA Guideline

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

2. Introduction and scope

The TYNDP 2024 Implementation Guidelines provide complementary information to the 4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Project. They do not replace it. 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) 2024. Information not explicitly noted in the Implementation Guidelines has to be considered with respect to the 4th CBA guideline.

These guidelines for the TYNDP 2024 are drafted under the requirement of being made public, together with the TYNDP 2024 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 2024 these 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 pushed to the Implementation Guidelines while the CBA relies on the main concepts.

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

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

4th ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (Submitted to ACER 24.04.2023)

TYNDP 2024 Scenario Webpage

Key drivers of the methodology:

1. Complementing the guidance as given in the 4th CBA Guideline

2. Delivering the methodology for assessing projects with and without a major impact on 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

3. Modelling frameworks

The figure below outlines the project assessment process, including market and network simulations, and the link between the two.
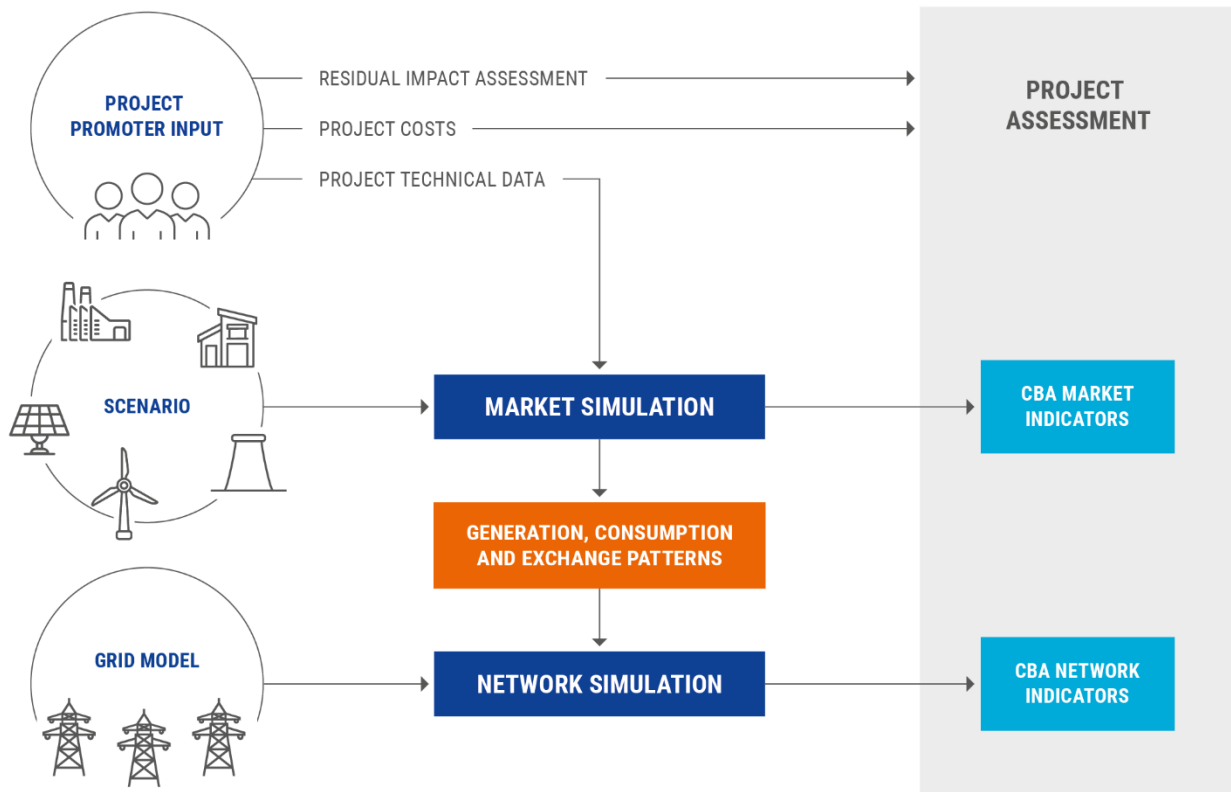
Figure 1 – Schematic project assessment process. Whereas 'CBA market indicators' and 'CBA network indicators' are the direct outcome of market and network studies, respectively, 'project costs' and 'residual impacts' are obtained without the use of simulations.

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 depending on specific factors detailed in the CBA 4 Guideline.

To capture and assess the cross-sectorial coupling impacts, the hydrogen and the electricity sectors are interlinked. 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 and can be used to compare projects across sectors.

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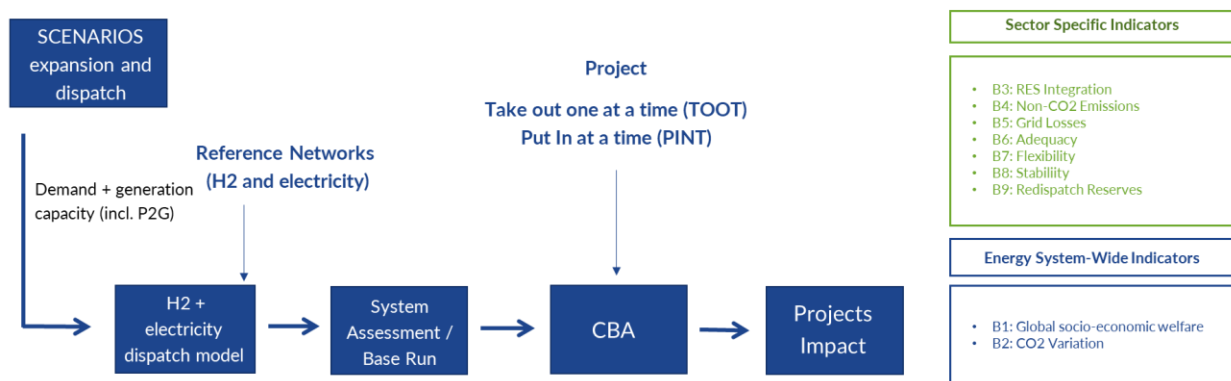
Figure 2 - Dual-(system) assessment of electricity projects in one overarching framework by interlinking the hydrogen and electricity sector.

3.1. Scenarios (2.1 in CBA 4)

An overview of the draft scenarios, their storylines, main data points and definitions as applied to the TYNDP 2024 can be found in the [LINK to Scenario 2024]

In the TYNDP 2024, the scenarios defined within the scenario building process are NT2030, NT2040, DE2040, GA2040 and DE2050, GA2050. Based on these scenarios, the focus for the CBA assessment in the TYNDP 2024 is on the 2030 and 2040 time horizons, while the NT scenario is given the highest priority as the scenarios following the national energy and climate policies derived from the European targets. Thus, in this context, it is important to note that the market CBA is calculated for the scenarios as shown in the table below, and the full CBA is only performed for the NT2030 scenario, meaning that this is the only scenario in which load flows and other network calculations are carried out.

Given the high uncertainties for very long-term scenarios and the focus on supporting the PCI process no simulations for the study year 2050 will be performed in the TNYDP 2024 project assessment. Thus the CBA assessment will be carried out for the 2030 and 2040 study horizon which also helps with the comparability of the CBA assessment results with the previous TYDNP.

Adequacy assessments are prioritised to NT2030, NT2040 and DE2040 scenarios.

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

The climate years have been selected based on their representativeness out of 30 climate years within the Pan-European Climate Database (PECD). The results from market simulations are then considered based on the weighted average from these three climate years. The weighting is as follows: 0.233 for 1995, 0.367 for 2008 and 0.4 for 2009.

The table below gives an overview of which scenario the CBA indicators and ΔNTC calculations are to be performed in.

Scenario	B1, B2, B3, B4	B5 – Losses	B6 – Adequacy	ΔNTC
NT2030 *Climate years*	Yes	Yes	Yes	Maybe
NT2040 *Climate years*	Yes	Yes*	Yes	
DE2040 *Climate years*	Yes	Yes*	Yes	
GA2040 *Climate years*	Yes	No	No	No
DE2050	No	No	No	No
GA2050	No	No	No	No

- The losses calculations for the NT2040 and DE2040 scenarios might be skipped in favour of the NT2030 simulations in case of running into issues concerning the project plan of the TYNDP 2024.

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

The methodology of the Security of Supply loop can be described in the following steps.

The reference case scenario must have a realistic LOLE level (maximum LOLE criteria with tolerance + 1h) for all countries without the project that is being assessed included in the system.

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

- Add peaking generation capacities or DSR where LOLE exceeds SoS standard (LOLE <3 h as default)
- Reduce installed capacities of peaking generation where LOLE <SoS standard

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

SoS quantification is based on standard methodology similar to one used within ERAA project conducted by ENTSO-E. The following assumptions are used:

- Several hundreds of Monte Carlo years are simulated for whole modelled perimeter
- Balancing reserves are added to the consumption or derated from the hydro generation or from the thermal generation
- For each country it is assumed that the LOLE should be below or equal 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).
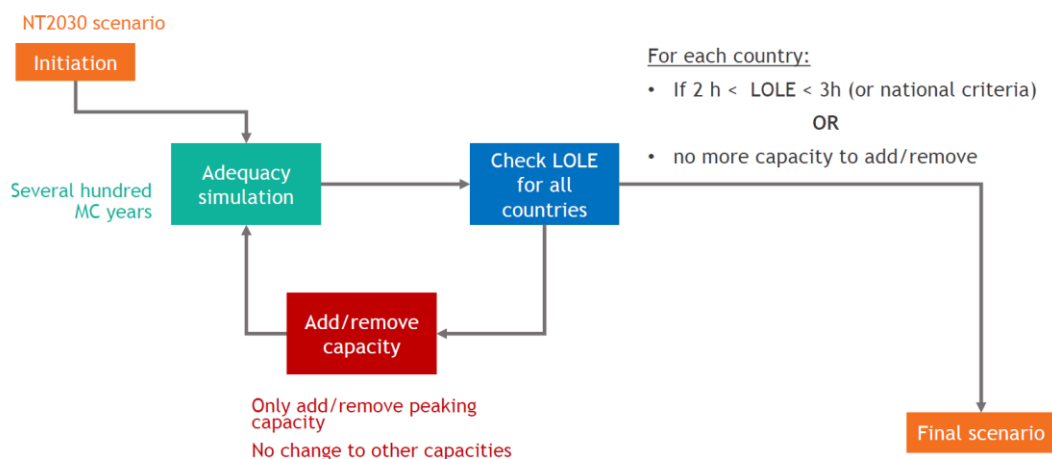
Figure 3 – SoS Loop Iterative Process Diagram in TYNDP 2022 process

For TOOT projects, 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 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 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 TOOT project is removed, LOLE in isolated market node is equal to 8760 h. If NTC increase value of new interconnection was to be added as peaking unit capacity in isolated country that has low average load no delta ENS would be calculated. To avoid this situation in isolated market node peaking unit capacity lower than NTC increase of TOOT project needs to be added. Added peaking unit capacity should be enough to meet the LOLE requirement in isolated market node (LOLE<3h) without TOOT project.

3.2. Market simulations (2.4 in CBA 4)

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
- Promed (internal tool)
- APG Tool (internal tool)

3.2.2. Generation cost and total surplus approach

Disclaimer: *the details of the global SEW and hydrogen modelling are currently under development within the TYNDP Study Team. The final information on how the global SEW is included and how hydrogen is modelled will be given in the final version of the Implementation Guidelines after public consultation. This section however already reflects the main principles as defined within the CBA 4.*

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 (i.e. fixed demand in each time step) demand only

- The **total surplus approach** compares the producer and consumer surpluses for the different bidding areas as well as the congestion rent between them, with and without the project. When sectors are coupled, the cross sectoral rent with and without the project are also compared. This approach is capable of dealing with both elastic and inelastic demand. 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.

Any component $c \in C$ of the energy system e.g. electrolyser or hydrogen gas turbine 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 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 or input power referenced to the hydrogen and electricity side, respectively. Note that these powers are different as they are coupled with the component's efficiency for the conversion from one energy carrier into another.

The producer rent for sector $j \in S$ is composed by the contributions from the generation $c \in G$ 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 the elasticity.

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

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

where $mcp_j^{from,t} - mcp_j^{to,t}$ is the price difference and $p_{ex}^{c,t}$ is the exchange power between the from and to directions of the interconnected market areas.

In the event of inelastic demand – which is the case for the modelling used in TYNDP 2024 – the two approaches give the exact same results. The SEW for third countries are calculated using the total surplus approach since considered solely, the exchanges between a third country and the ENTSO-E perimeter can change due to the adding of a transmission project.

The elasticity of the demand is modelled as demand side response (DSR) in the same manner as generators are modelled – this does not impact the validity of the generation cost approach.

3.2.3. Treatment of 'third countries'

The geographic perimeter for benefit and cost reporting in the TYNDP is defined as covering countries from ENTSO-E, as well as 3rd countries (Israel, Lybia, Ukraine, Moldova, Palestine, Tunisia, Georgia, UK, Egypt, Morocco, Algeria, Malta). Hence, this excludes countries as defined below.

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 assessment. The simulated costs and benefits may therefore need to be adjusted to account for the effects created in third countries (i.e. remove these effects when reporting a value).

Therefore, in the TYNDP assessment for projects that are connecting third countries (for example Tunisia, Libya, Egypt, Israel), the SEW is calculated with the use of the total surplus approach. As the total surplus approach gives the SEW components on the market node level, it is possible to get rid of benefits related to these third countries. The benefit is then reported separately for the ENTSO-E perimeter and for third countries. Similarly, the benefits are computed for the EU27 perimeter, covering 27 EU member state countries.

3.2.4. Geographical scope of the market

model

The geographic perimeter for the market model is defined as ENTSO-E countries (except for Iceland) and the following connecting third countries:

- Algeria, Georgia, Egypt, Israel, Libya, Morocco, Moldova, Malta, Palestine, Tunisia, Turkey, Ukraine and United Kingdom.

The TYNDP project assessment should report costs and benefits on a pan-European level. As described in Section 2.2 the costs and benefits need to be adjusted to account for the effects that are created in third countries. To remove the effects on third countries, projects connecting with them should use the total surplus approach. In contrast, but for the same reason, pan-Europe interactions between Russia are modelled as "fixed exchanges" in the market simulation.

3.2.5. Generation unit data

All assessments in the TYNDP 2024 use a common ENTSO-E database as defined within the Pan-European Market Modelling Database (PEMMDB) version 2.5. As the market simulations are carried out on the full pan-European perimeter plus third countries (see 3.2.4) a reduction in complexity has to be done to reduce the memory usage during the computations. Therefore, the modelling data based on the generator resolution (where detailed information per generator is given) is reduced to generation categories. This is done by merging each generator with comparable properties to one category (e.g. Nuclear, Lignite old 1, Lignite old 2 etc.). The full list of used categories is given in Annex C.

3.2.6. Modelling assumptions

The market simulation uses the following input data[1]:

- ENTSO-E's PEMMDB 2.5 package covering:

  o Hydro
  o Prices
  o Net generating capacities for all generating types
  o Pre-defined generation time series
  o Must-run values of thermal generation types

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[1] *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.*

  o Availabilities of thermal units
  o DSR capacities

- Demand profile time series for all market nodes, per climate year and scenario
- PECD covering solar irradiance, wind generation, ambient temperature and hydro inflow data per climate year and scenario
- Planned and forced outage time series
- Costs for generation:

  o Variable fuel costs
  o Internalised cost of CO2 emissions
  o Marginal cost of thermal generation
  o Variable operation and maintenance costs
  o Start-up and shut-down costs

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

3.2.7. 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.

3.2.8. Climate years

The climate years considered for TYNDP 2024 market simulations are 1995, 2008 and 2009. For each climate year, 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. This renewal infeed may be restricted by the export capacities or demand during the market simulation, which leads 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 climate year. In TYNDP 2024, part of Other RES and Other non-RES generation, also depends on the climate year.

3.2.9. Hurdle costs

A hurdle cost of 0.01 €/MWh is applied in TYNDP 2024, which is the same as in the previous TYNDPs 2022, 2020 and 2018.

Note: *A hurdle cost is a cost over the energy flowing through a line (like a small fee) and could be used to incentive 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 (2.4 in CBA 4)

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 2030 and NT 2040 scenario in ENTSO-E Common Grid Model
Exchange Specification (CGMES)[2] 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 TYNDP 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
Integral	Continental Europe	link
Powsybl	Continental Europe	link
PSS/E	Continental Europe, Baltics, Nordics	link
PowerFactory	Continental Europe, Great Britain	link
GridCal	Continental Europe	link

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

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. GridCal is an open source tool used in Spanish TSO. 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. 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[3] 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.

- **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 with an AC load-flow solution. However, due to the computational limitations of some of the tools, or other issues caused by unreliable forecasted data for reactive loads or the lack of harmonised voltage control strategies, DC load-flow approximation may also be used[4] for the following steps, i.e. losses and NTC calculations.

The load-flow simulations are all based on market simulation outputs, which are produced in an Excel file with a standardised structure and content.

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:

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[3] *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.*

[4] *As an AC load-flow for large power systems requires typically more iterations to converge towards a solution and higher computation times for calculating Jacobians in each iteration, an AC load-flow exhibits computational limitations. Moreover, the AC load-flow applied to large power systems could lead to convergence issues. A DC load flow approximation is convergent by definition and brings the complexity to a manageable level at a reasonable deviation in accuracy.*

- 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 identifying 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 done 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:

   o The target voltage level should be harmonised in the considered areas to ensure realistic voltage profile compliant with operational rules

   o 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.)

   o 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 3.3.1, 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 Baltic 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) and Turkey (TR00), Ukraine (UA00), Moldova (MD00), Georgia (GE00), 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[5] 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 2024, 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 climate year of the otherwise same market run.

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 was done centrally in the TYNDP 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 Europe (e.g. Nordics) were 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 of the climate years 1995, 2008 and 2009.

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

3.3.8. Load-Flow calculations for NTC calculations

For ΔNTC calculations, only one market output for a given climate year will be used.

A detailed description of the transfer capability calculations is given in section 4.2.

For the project submission, where project promoters are asked to submit the project specific dNTC values together with a respective documentation describing the specific modelling information on the dNTC calculations will be given in a separate documents submitted by the respective modellers of the dNTC calculations:

3.4.   Redispatch simulations (2.4.4 and 6.3 in CBA 4)

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, within the 2nd CBA guideline the use of redispatch simulations has been introduced. 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 of dealing with internal congestions.

Following its current application in reality, the redispatch simulations must be based on detailed market and subsequent load flow simulations. As it is not possible for the moment to calculate 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 2024, redispatch simulations will not be applied for interconnectors. 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 this implementation guideline, redispatch calculation can be performed. The project promoter has to submit a written acknowledgement in English language to ENTSO-E to prove compliance with the requirements of the CBA guideline.

Note with respect to the *guidelines on project level indicators*:

Within section 9 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 2024, these 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). These guidelines should thus provide everything needed at hand 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 2024 that have not participated within 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 climate years, 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, these 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.

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 2024, both options as given in the 4th CBA guideline (see also Figure 4) can be applied dependent 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

Project with focus on internal impact

- Redispatch calculation based on market simulation results

Benefit=ΔRD

MS$_1$: Market simulation with reference NTCs
RD$_1$: Redispatch calculated with reference network
RD$_2$: Redispatch calculated with the project taken out/in (TOOT/PINT)
ΔRD: Difference between RD$_1$ and RD$_2$

Project with CB impact

- Combination of Market and Redispatch simulations

Benefit=$\Delta MS + \Delta RD$

MS$_1$: Market simulation with reference network
RD$_1$: Redispatch calculated with reference network
MS$_2$: Market simulation with the project taken out/in (TOOT/PINT)
RD$_2$: Redispatch calculated with the project taken out/in (TOOT/PINT)
ΔMS: Difference between MS$_1$ and MS$_2$
ΔRD: Difference between RD$_1$ and RD$_2$

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 what method to be used is for the project promoter. However, in the end, within 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, also for 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[6]:

1. **Market Simulations (see also 3.4.7.1):** all subsequent simulations must be based on the centrally performed market simulations by ENTSO-E. The respective data must be obtained by the TYNDP Study Team.
2. **Load Flow Calculations (see also 3.4.7.2):** 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

**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.

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

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.

A Brief description of the model:

The sanity check model consists of six nodes (N=North, S=South, W=West & E=East). All nodes are connected by a 2-system 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 alsoFigure 5)

Illustration of the Sanity Check model.   )
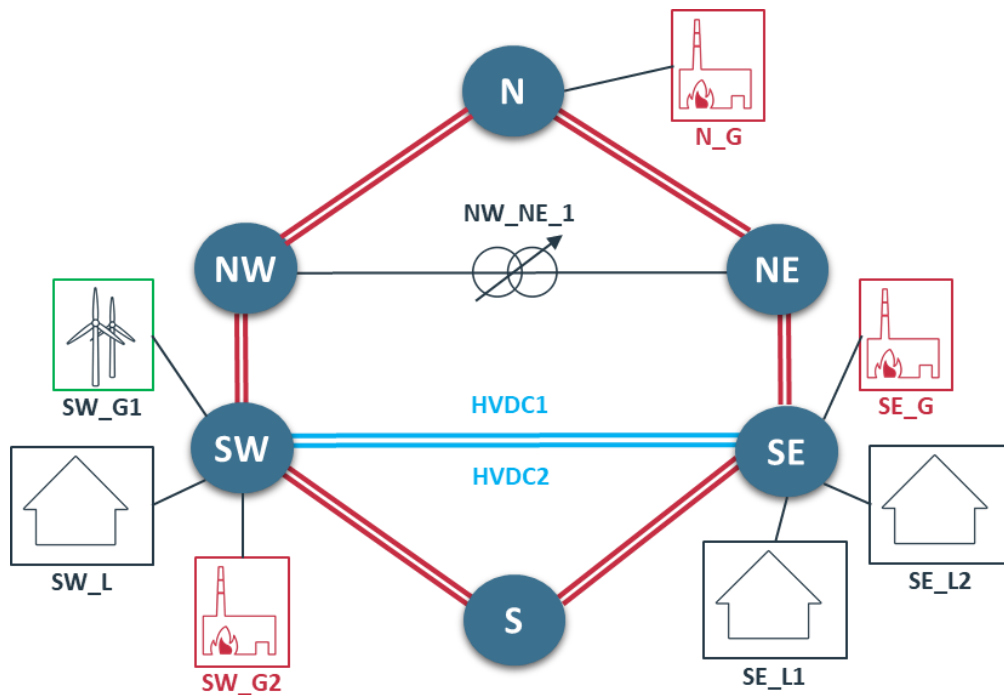
Figure 5 - Illustration of the Sanity Check model.

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 on:

- The compliance with the 4th CBA Guideline and the TYNDP 2024 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 2024 Input Data
- A description, which proposed options in the guidelines were chosen.
    o AC/DC

    o   Number of Scenarios and Climate Years

    o   Multiple TOOT/PINT

    o   Considered Branches Options (e.g.: 110 kV level)

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 yet available at the ENTSO-E level with the purpose of centrally coordinated computations. Within the framework of this guideline, 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).
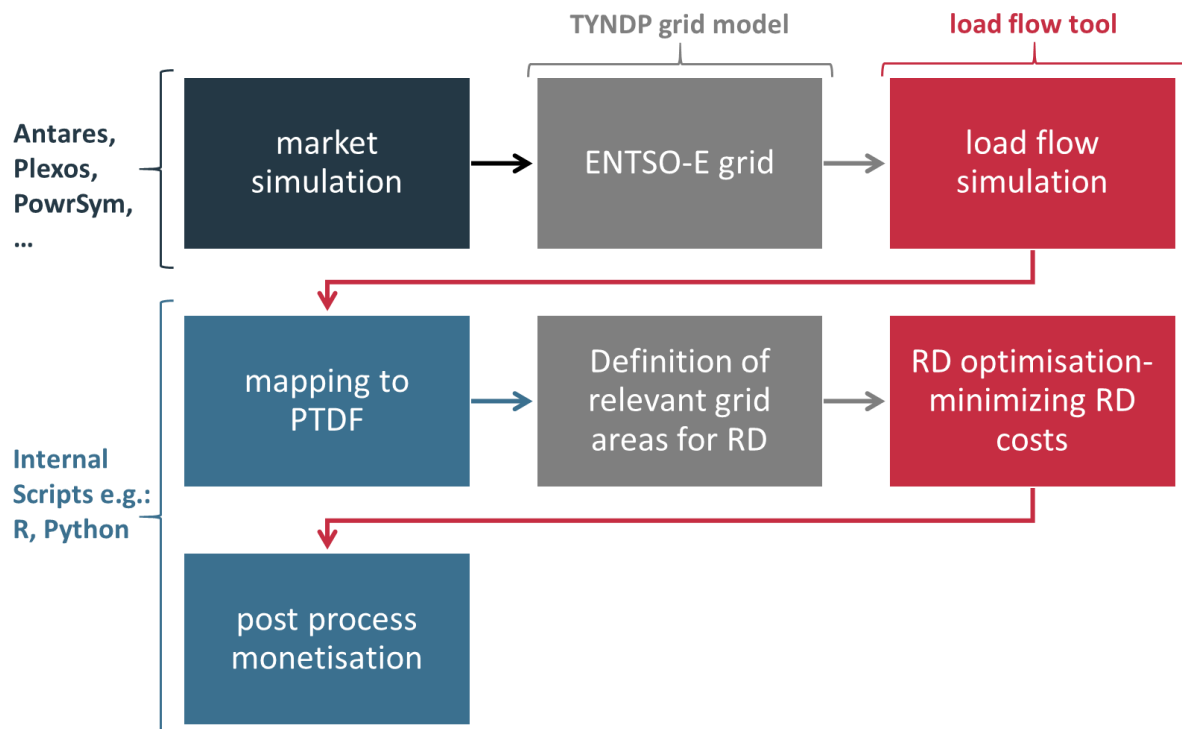
Figure 6 - General overview of the necessary steps to be performed to assess projects by use of redispatch calculations. The step of mapping to PTDF can be neglected in case where load-flow simulations are possible within the respective modelling tool.

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 2024. To meet this requirement, the market model input data (see 3.2.5 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 3.4.7):

- price assumptions (fuel prices, CO_2 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 with the standard market modelling output file provided by the TYNDP Study Team per scenario and climate year.

The methodology for mapping the market 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 proportional to the installed capacity of network element 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 parameter 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.

Network data

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 2024, 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).

Any new changes in the grid model after the official grid model collection process must be aligned with TYNDP Grid modelling guidelines and communicated with Working Group Data and Models and TYNDP Study Team.

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 missing comparability between different tools, the usage 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 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, addressed 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 guideline or to increase the level of detail of the methods. (e.g. more climate years 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.

Minimum number of TYNDP Scenarios and Time Horizons:

As a minimum requirement, the central policy scenario **National Trends** must be used for project evaluation.[7]

Minimum number of Climate Years:

The minimum requirement for project assessment is to use the most representative climate year of the three climate years represents the three climate groups (1995, 2008 & 2009). In the case of TYNDP 2024, the climate year **2009** is the most representative climate year.

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 TYNDP2024 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 these 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 part.

Internal projects (without significant CB impact)

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[7] 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.

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 are also valid in this case: it is recommended to also include at least the neighbours of the countries 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 or 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, such as renewable energy is 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.

In principle, the following sequence must be ensured – 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 of other branches in the system in each considered (n-1) case is 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 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:

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

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

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 (LINK: Price proposal_TYNDP2020).

$$\text{SEW } [€/yr] = \sum_{type} \Delta\ energy_{type}\ [MWh/yr] * marginal\ cost_{type}\ [€/MWh]$$

The marginal costs of RES are zero.

SEW_RES

Same application as described in section 5.1 of these Implementation Guidelines.

SEW_CO2

Same application as described in section 5.1 of these 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.

$$\Delta CO_2 \, [t/yr] = \sum_{type} \Delta \, energy_{type} \, [MWh/yr] * CO_2 \, emissions_{type} \, [t/MWh]$$

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 these Implementation Guidelines.

B4: Non-direct greenhouse emissions

Same application as described in section 5.4 of these Implementation

Guidelines. **B5: Losses**

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

B9 – Reduction of Redispatch Reserves:

Same application as described in section 5.9 of these Implementation Guidelines.

3.4.14. RD-Annex 1: Data for the quality

check for minimum modelling requirements

Table of technical parameters

Unit name	Unit	Feeder				Load		
		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

Unit name	Unit	Lines					
		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
U_r	kV	400	400
P_r	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

PIT	Feeder				Load		
	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								
13								
14								
15								
16								
17								

18							
19							
20							
21							
22							
23							
24							

3.5.   Reference grid (2.5 in CBA 4)

Based on the guidance given within the 4th CBA Guidelines, for the TYNDP 2024 two different reference grids are defined for the corresponding two horizons 2030 and 2040. The reference grid for the 2030 horizon, which corresponds to the mid-term horizon, is based on criteria a) and b) as defined within 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 the environmental impact assessment can be part of the 2030 reference grid. The reference grid for the long-term horizon (2040) on top of that includes projects fulfilling the criteria listed under c) within the 4th CBA Guideline.

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 scenarios are part of the reference grid. The cut-off has been set to 31 December 2030 for the mid-term horizon (2030) and 31 December 2035 for the long-term horizon (2040), 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 with an EU Member State, the respective projects need to be part of the national plan of the Member State connecting with the UK in order to meet the criterion for becoming part of the reference grid. In that 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. However, to deliver a realistic reference grid for the CBA assessment, fictive projects have been introduced to mimic the possible impact of future interconnectors to the UK. The specific treatment of the impacted projects can be seen in the very end of annex II.

A list of projects which are part of the respective reference grids is given in annex II.

3.6. Assessment of the commissioning dates (2.5 in CBA 4)

The 4th CBA Guideline addresses the need to assess the commissioning years. 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 31.12.2024.
- The period of time t for the duration until a project submitted to the TYNDP 2024 will be commissioned can be calculated as:

$$t = (t_x + t_{const}) \cdot f_1 \cdot f_2 \cdot f_3 \cdot f_4$$

Where:
- t_x equals
  - $t_{consideration}$ which is the assumed mean standard time of all projects to entering and completing the planning and permission period
  - $t_{pre-perm}$ which is the assumed mean standard time of all projects to entering and completing the permission period
  - t_{perm} which is the assumed mean standard time for projects already in the permitting phase to completing the permitting process
- t_{const} is the assumed mean standard time for the construction phase
- f_1 is a standard factor indicating the complexity of the project with respect to its technology (AC or DC)
- f_2 is a standard factor indicating the complexity of the project with respect to its setup whether it is an overhead line, cable, substation etc.
- f_3 is a standard factor indicating the complexity of the project with respect to whether it is an on- or offshore project
- f_4 is a standard factor indicating the complexity of the project with respect to whether it is a completely new project or an update
  f_5 is a standard factor indicating the complexity of the project with respect to environmental and social impacts of the project (see sections 5.13, 5.14 and 5.15 in CBA 4 Guideline)

Disclaimer: *All values used for the assessment of commissioning years are based on expert knowledge and might be changed in later editions of the TYNDP. It is therefore not foreseen to use this methodology to actually approve or disapprove any commissioning years. The outcome from this assessment will however be used as starting point for discussions where project promoters, in case of a mismatch between submitted and assessed commissioning years, will have to explain their submission.*

The standard duration times based on the project status t_x to be used for the assessment of commissioning years are defined as follows:

- $t_{consideration}$: 8 years
- $t_{pre-perm}$: 5 years
- t_{perm}: 2 years

The standard duration times for the construction period is expected to be strongly dependent on the length of the project. In order to simplify the assessment of commissioning years, the categories based on the length are defined. For each category distinct duration times are assumed:

- Short (0-200 km): 2 year
- Mid (200-500 km): 3 years
- Long (above 500 km): 4 years

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

The distinct values for the factors can be found in Annex General assumptions.

Example:

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

	Status	Length	Technology	Overhead/ cable	On-/ offshore	New or update
Input	planned, but not yet permitting	250 km	DC	Cable	offshore	upgrade
Times and factors	t = 5 years	mid: t = 3 years	$f_1 = 1.1$	$f_2 = 1.2$	$f_3 = 0.9$	$f_4 = 0.5$

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

$$t = 2024 + (5 + 3) \cdot 1.1 \cdot 1.2 \cdot 0.9 \cdot 0.5 = 2028$$

The commissioning year in this example would therefore be calculated as the year 2028.

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, more 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 (3.2.1 in CBA 4)

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 rules as described above must be applied.

4.2.   Transfer capability calculation (3.2.3 in CBA 4)

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 2024, such projects are to be assessed by redispatch simulations, which do not require the knowledge of the GTC impact of the project.

Any transfer capability calculations performed by project promoters and compliance checks by ENTSO-E have to be based on the methodology defined in this section.

4.2.1. Net transfer capacity

The dNTC is defined as the maximum admissible generation power shift (as defined in the CBA methodology) 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 2024, the ΔNTC calculations of all projects are based on the hourly market simulation results for the 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. 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 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.

The power shift method used for each project and border will be reported within a specific document to be published within the TYNDP 2024 package later in the process.

Other considerations

In the event the examined border includes PSTs, their phase shifts must be optimised in each hour before applying the power shift steps, in order to avoid sub-optimal outcomes because of possible N-1 problems.

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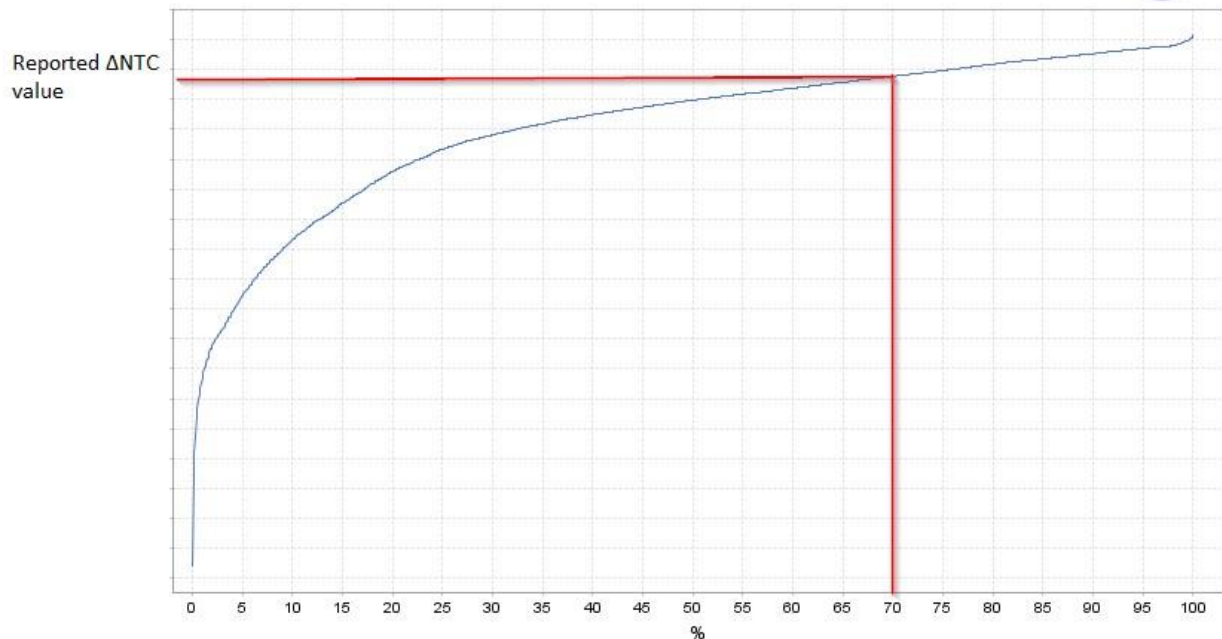
Figure 7 - Sample of a reported ΔNTC value as the difference in boundary exchange in a specific direction that can be supported for 30% of the year due to the project

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 branches
- 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

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 2024. 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 (5.1 in CBA 4)

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 2024. **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 must be calculated using the **redispatch methodology** by applying two 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 price zones, the assessment can be done using two market simulations:
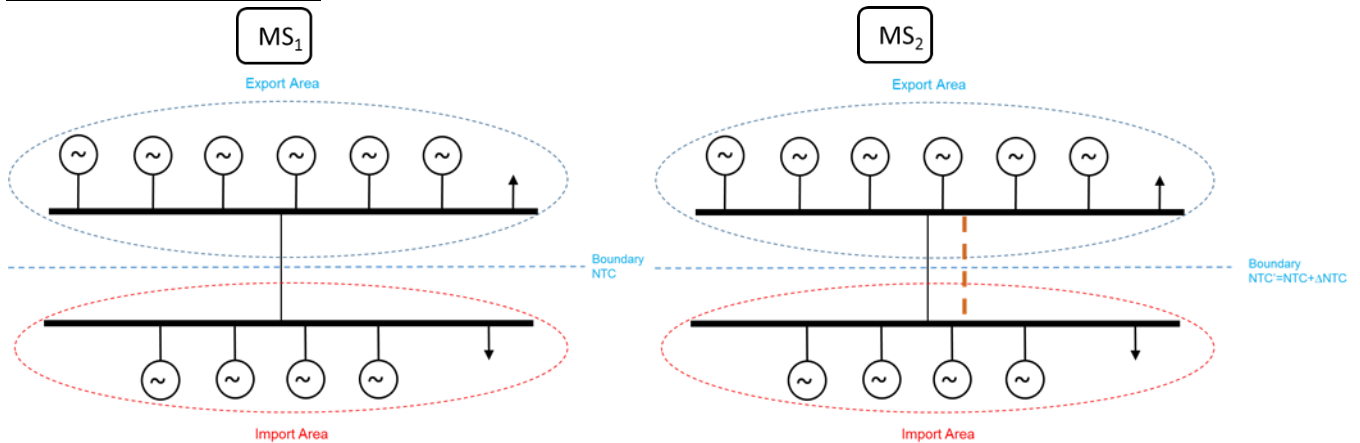
MS_1: Market simulation without the project

MS_2: Market simulation with the project

ΔMS: Difference between MS1 and MS2

Interconnection project

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 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' (=$NTC_{initial}$ + $\Delta NTC_{project}$) 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:
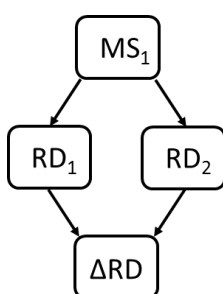
MS_1: Market simulation with reference NTCs

RD_1: Redispatch calculated without the internal project

RD_2: Redispatch calculated with the internal project

ΔRD: Difference between RD_1 and RD_2
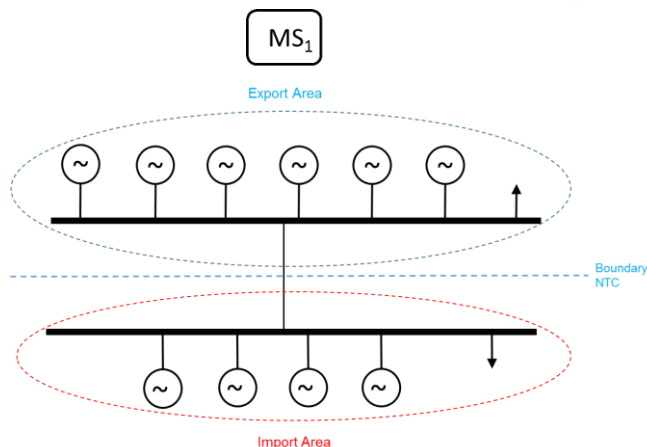
MS$_1$: Market simulation with reference NTC between bidding zones
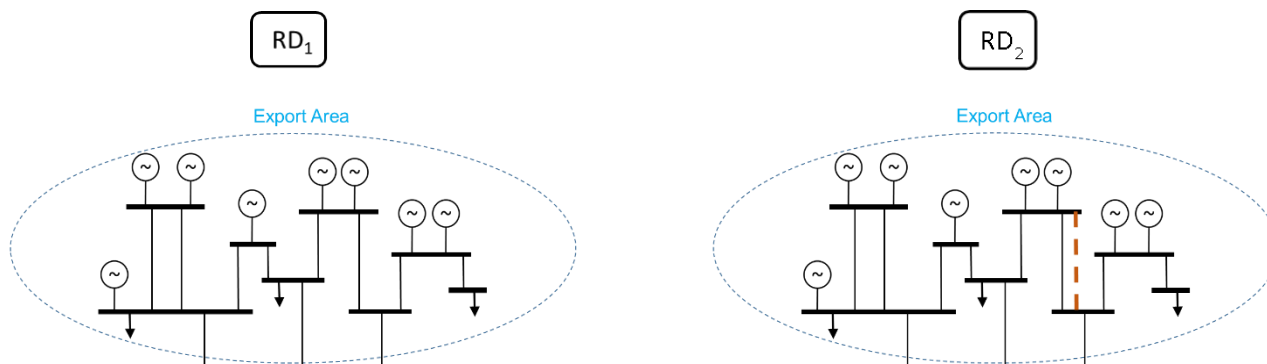
RD$_1$: Redispatch calculated without the internal project

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 chapter 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

<u>For internal projects with significant cross-border impact and with large internal benefits</u>, a combination of market and network studies can be performed:
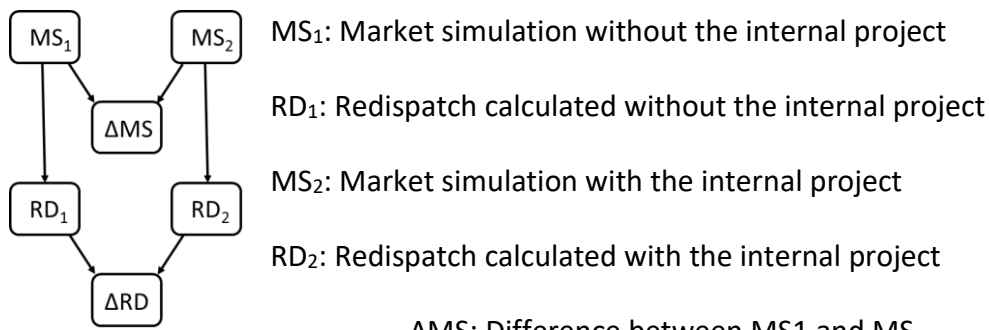
MS$_1$: Market simulation without the internal project

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$_2$
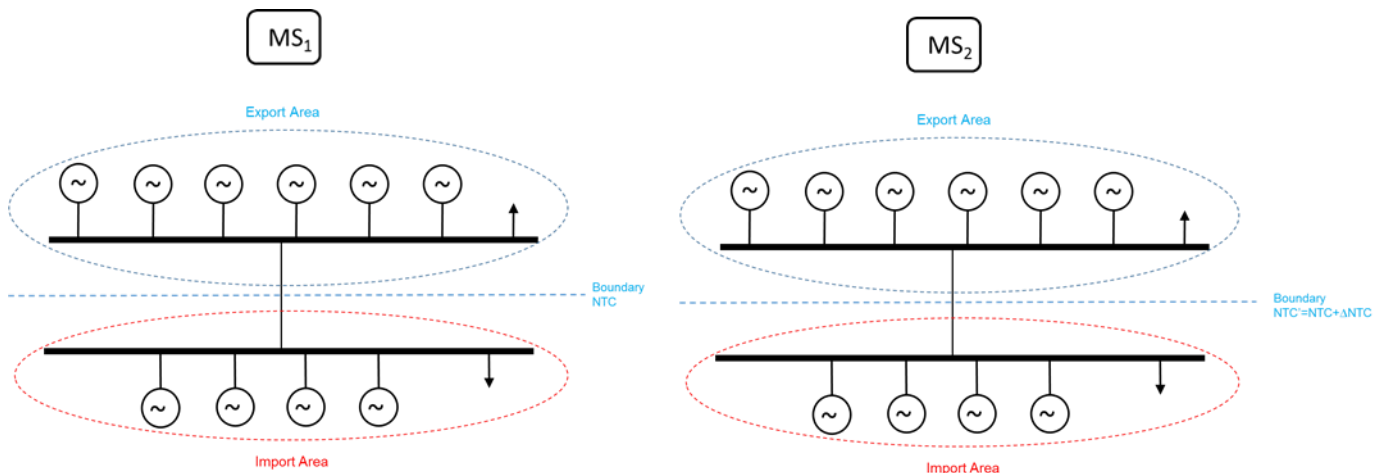
ΔRD: Difference between RD$_1$ and RD$_2$

MS$_1$: Market simulation with NTC (= NTC$_{initial}$) between bidding zones without the project
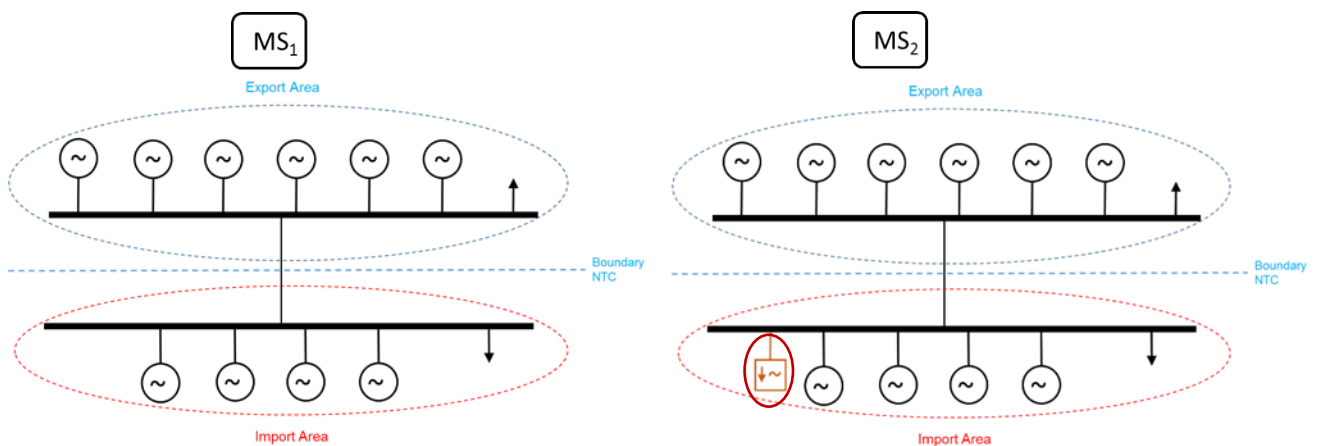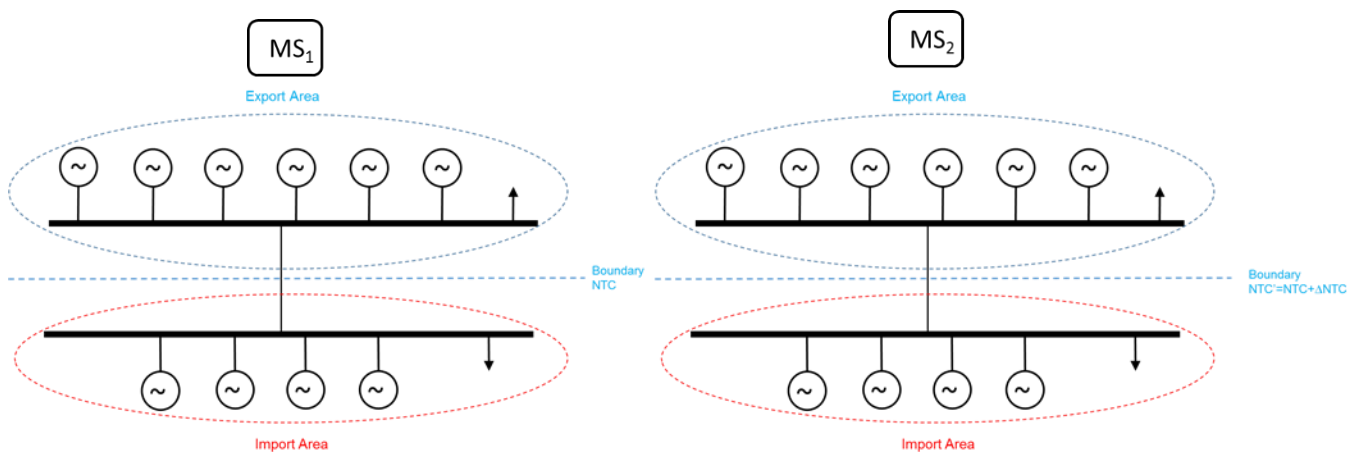
MS$_2$: Market simulation with NTC' (=NTC$_{initial}$ + ΔNTC$_{project}$) between bidding zones obtained with the internal project
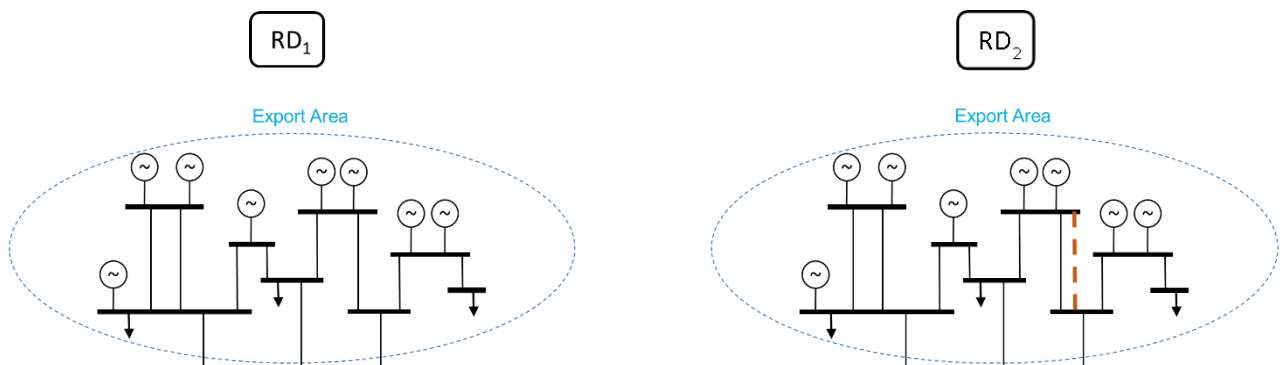
RD_1: Redispatch calculated without the internal project using the dispatch taken from MS_1

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.

$$SEW = ΔMS + ΔRD$$

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

$$SEW = ΔMS + ΔRD$$

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:

1. Calculate the demand weighted average marginal price (the hours of ENS [3000
   €/MWh] will be excluded of the computation) from market studies output
   (reference case – with/without project case) per area and per climate year.

2. Average over all areas to obtain a Pan-European value per climate year.

3. Multiply this average marginal price value [€/MWh] with the annual avoided RES
   curtailment [MWh] (B3. RES Integration benefit) per climate year.

4. The results are then weighted onto the base of the climate year'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 per climate year:

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

$MC_{q,n}$: Marginal cost at node q in hour n

$demand_q$: 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 avoided RES curtailment [MWh]

5.1.2. Avoided CO₂ emission costs (SEW CO₂)

The avoided CO_2 emission costs can easily be extracted from market simulations by
multiplying the difference in CO_2 emissions (in t) by the CO_2 costs used in the different
scenarios (in €/t). 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 (5.2 in CBA 4)

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) from

European Commission DG MOVE *Handbook on the external costs of transport[8]* are used. These avoidance costs are aligned with policies to reach the Paris agreement. To represent the uncertainty surrounding these costs within the TYNDP 2024, the societal value of CO_2 is calculated using the Low, Central and High value[9].

	Low value	Central value	High value
CO_2 cost (2030) €/t	60	100	189
CO_2 cost (2040) €/t	156	269	498

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.

Double counting

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.

Consequently, the formula for this indicator is the following:

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

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

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[8] *https://op.europa.eu/es/publication-detail/-/publication/9781f65f-8448-11ea-bf12-01aa75ed71a1/language-es*

[9] In some scenarios the ETS costs are higher than the low societal costs for 2030. In this case only the central and the high values are used for the monetisation of the B2 indicator.

5.2.1. Different parts of the CO₂ 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 accounting 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 accounting with B5)	European

5.3.   B3 – RES Integration (5.3 in CBA 4)

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/MWh figures.

Two indicators are used to quantify this impact:

a. For projects directly connecting RES such as offshore wind parks: **the power 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 connected power (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 (5.4 in CBA 4)

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 II) multiplied by the emission type specific emission factor as given in annex I.C. 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 (5.5 in CBA 4)

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 2024 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 3000 €/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 both all scenarios.

In TYNDP 2024, a network model was built only for the scenario National Trends 2030.
The values of indicators B5 *Variation in Grid Losses* and B2b *Societal costs of CO2
emissions from losses variation* for the scenario Distributed Energy 2030 are therefore
based on the losses (MWh) obtained from the NT 2030 network model, but monetised
with the price from DE2030.

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	€/year (market based)	European

5.6.   B6 – SoS – Adequacy (5.6 in CBA 4)

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:

- To properly model the loss of load probabilities, the hazards must be simulated in detail. This is achieved through a Monte Carlo 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 525 Monte Carlo years[10], resulting from the matching of the full set of the 35 PECD climate years and 15 outage patterns[11] time series. These times-series are randomly created through a Monte Carlo process based on the planned and forced outage rates and durations per power plant. See the ENTSO-E ERAA methodology for further details on adequacy assessment stochastics.
- The scenario is built to be realistic in terms of loss of load: for each country, Loss of Load Expectation (LOLE) should be within 1h of its reliability standard criteria[12], except for countries where there are too many base and semi base generations (in which case LOLE could be down to 0).

The following process is applied:

1. Step 1: Check scenarios (it is assumed that this step is not needed in the TNYDP 2024 based on the SoS-loop previously applied to the scenarios as describe in section 3.1.1)
   a. It is necessary to have a realistic LOLE (less than 1 hour above their national criteria) in the situation without the project. As the scenario is built accordingly based on the reference grid, all PINT projects abide by this principle.
   b. For a TOOT project, when removing the project, the LOLE goes beyond the acceptable range in some countries based on the NT2030 scenario; therefore, peaking generation units shall be added to comply with the reliability criteria (in all the countries of the global geographical area).

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[10] *From an internal study it turned out that convergence on the LoL by increasing the number of MC years can be achieved at around 500 years.*

[11] *An outage pattern time series gives the availability of the generation units on an hourly basis. They were created based on the availability rates of the fuel types as given in the PEMMDB. In alignment with the scenario building also for the B6 indicator assessment 15 outage patterns are to be considered.*

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

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 LOL in the situation without it, then the adequacy benefit of the project is 0.
   b. Assess the EENS without the project.

   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[13]
   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.

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

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 2024, 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.[14]

   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 2024, 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.[15]

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

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[14] *Studies show a wide variety of VoLL depending on methodology sector, country, time of day, time of year, duration and other parameters. A selection of reports on this topic is given in the 3rd CBA guideline. The selected value of 10 k€/MWh falls within the wide range of these studies.*

[15] *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 – SoS – Flexibility (5.7 in CBA 4)

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 2024 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 TYNDP 2022 results and public studies on market integration benefits:

- Definition of the ratio of the socio 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)
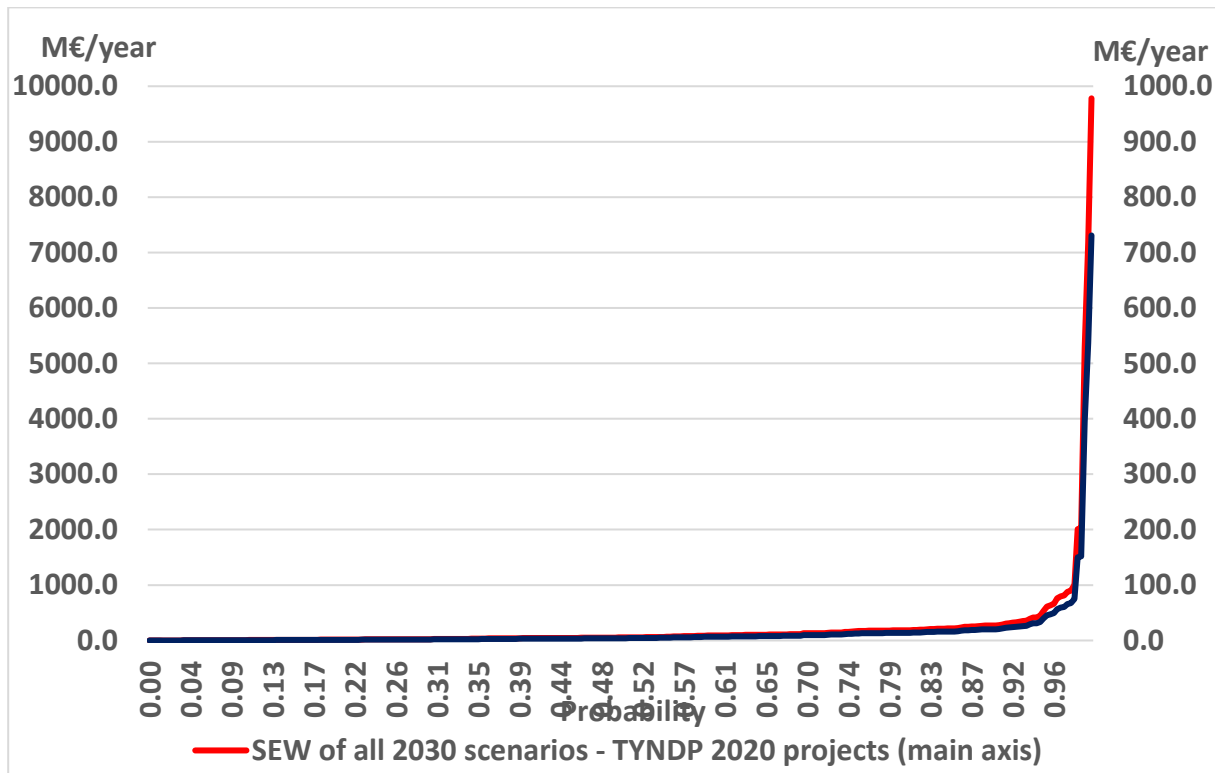
Figure 8 – Illustrative view on how TYNDP 2020 project SEW benefits can be mapped to contributions in balancing energy benefits to come to reasonable thresholds

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 the Annexes an example is included to further clarify the explanation of this indicator. The values included refer to the TYNDP 2022 Implementation Guidelines; 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 2024.

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

5.8. B8 – SoS – System stability (5.8 in CBA 4)

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:

Disclaimer: *for the final version of the Implementation Guidelines this section will be extended by adding more details and explanations to the application of this indicator.*

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 PLI 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 IN LONG-TERM SCENARIOS AND RELEVANT REQUIREMENTS"[16] 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 2024 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.

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

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 imbalance ($\Delta P_{imbalance}$), the system load (P_{Load}) and the inertia constant (H) at system frequency (f_0):[17]

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

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}):

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

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 2024 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. Further details are given in [add reference from TF PS]. 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/sec]: For all point in times the mean RoCoF is calculated for the reference case and the project case. A projects 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.

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[17] 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

This indicator is listed as one of the PLI and will be directly delivered by the respective project promoter. A detailed description of the used methodology has to be submitted, following the principles given within the 4th CBA Guideline.

The Black start services sub-indicator is contracted or imposed by TSOs to ensure that a minimum level of existing market flexible units are 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.

5.8.4. B8.4 – Voltage/reactive power services

This indicator is not assessed in the TYNDP 2024.

5.9. B9 – Reserves for redispatch power plants (5.9 in CBA 4)

Although not listed as one of the non-mature indicator within 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 2024 no centralized redispatch calculations are to be performed. A detailed description of the used methodology has to be submitted, following the principles given within the 4th CBA Guideline. 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 achieved
- 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 achieved.

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

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 (6.1 in CBA 4)

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 following formula should be used:

Sum of nominal transmission capacity of all interconnectors of country i /
peak load 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.

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

Sum of nominal transmission capacity al 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

To account for the energy efficiency the energy system boundaries in terms of geographical and sectorial scope need to be defined. The geographical perimeter is specified in Section 3.2.4 and the market model includes the electricity and hydrogen sector. Due to their coupling the involved energy carriers are treated endogenously. This means that those carriers introduce a simultaneously-combined market clearing.

The energy efficiency (EF) is

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

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

The indicator ET2 specifies any variation on energy system efficiency influenced by a project. It is given by

$$ET2 = EF_{wP} - EF_{woP} \ ,$$

where EF_{wP}, EF_{woP} are the energy efficiencies with and without the project. A positive value would indicate that a project improves the energy efficiency.

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

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

where E_{supply}^c is the yearly energy output of the generator $c \in G_{th}, G_{RES}, G_{H2}$ obtained from the market dispatch simulation. 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 set of all thermal generation units that are coupled with the electricity sector for exogeniously-treated primary energy carriers e.g. power plants fueled with methane, oil, coal or nuclear. 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 exogeniously-treated primary energy carriers. These units are hydrogen import terminals or steam methane reformers.

Components that couple endogeniously-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 or demand side response (DSR) appliances that solely shift energy on timescale, do not provide primary energy. Those units are excluded from the calculation.

The final energy consumption is calculated as

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

where E_{demand}^c denotes the energy demand for the components $c \in L_{el}, L_{H2}$. The set L_{el} specifies all electric conventional and 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 renewable penetration (ET_{res}) is calculated as the yearly energy gross consumption from renewable energy sources (E_{RES}) of energy divided by the gross final energy consumption (E_{final}):

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

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 final energy consumption is specified in the previous Section 6.2. Any variation in ET_{res} is reported as ET3 by taking the difference of ET_{res} with and without the project.

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) (5.10 in CBA 4)

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 I 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) (5.11 in CBA 4)

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

For non-mature investment C2 has to be taken as a yearly percentage of CAPEX assuming to be in the range of 0.7-2.2% of the C1.

In order to reflect more the reality, it is recommended to assume that this cost increase follows an S-shape curve being at a lower level at the beginning of exploitation time, as costs are limited to mainly forest cutting, clearance and general maintenance, while at a later stage higher C2 cost level is needed, in order to maintain the technical performance.
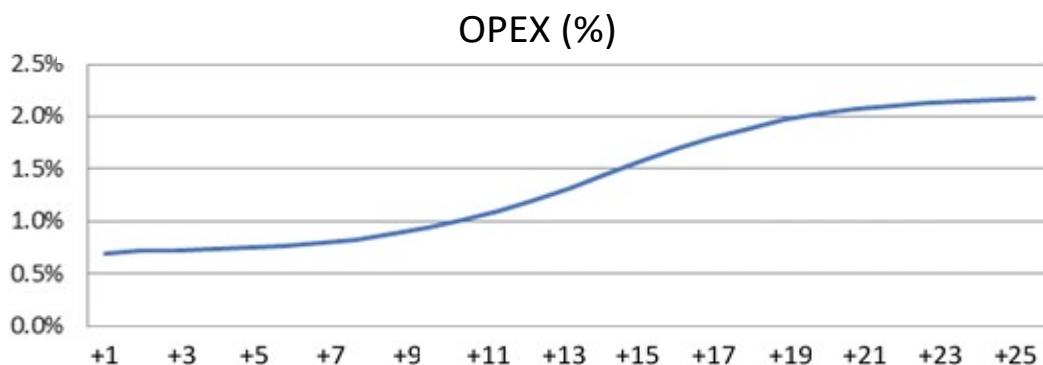
Figure 9 - example of the assumed OPEX time-dependency across the years (here for 25 years)

7.3.   Climate adaptation measures

A key driver for developing more sustainable transmission systems is to decrease the effects of climate change. Extreme weather has a significant impact on transmission system and is one of the main causes of wide-area electrical disturbances. In fact, weather-related power interruptions often tend to be of high impact and sustained duration, ranging from hours to days, because of the large damage on transmission system elements. Enhancing the grid resilience to such events is becoming of increasing importance.

In the TNYDP 2024 project promoters will be asked to provide information about adaptations to an investment in order to cope with possible extreme weather conditions caused by climate changes as a percentage of CAPEX in the following table:

Information about the part of the CAPEX used for investment climate adaptation measure:

Hazards	Explaination of adaptation	Climate adaptation cost (% of CAPEX)	Benefit
Ocean PH	foundation is protected against corrosion and structural failure		Corrosion resistance
Wild fire	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, operator 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 identify high-risk towers		prevent equipment damage
Ice jam	usage of materials and structures with low ice adhesion deicing properties		prevent equipment damage

8. Residual impacts (5.12-5.15 in CBA4)

In the TYNDP 2024, 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 2024.

9. 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 2024 need to give a detailed description of the methodology used.

The project level benefits identified within the TYNDP 2024 are as follows:

- B7.1: Balancing Energy Exchange

- B8.2: Black start services: Methodology for Synchronisation with Continental Europe

- 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 2024 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 2024 has to be followed in the same manner as for PLI together with the specific written compliance acknowledgement, as highlighted in section 2.4.5.

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 data-set 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.

10. Modelling of storage

Storage projects are modelled in the market simulation tools as hydro pump units connected to the corresponding node. This means that for every project, 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 climate year 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.

More detailed information on the modelling of storage will be given within the TYNDP 2024 package later in the process.

11. Assessment of hybrid projects (6.2 in CBA 4)

The CBA methodology application requires clarifications on several points for hybrid interconnection projects to ensure suitable implementation in the short term – for application as of TYNDP 2024 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 hybrid projects, other than being compliant with the principles of the 4th CBA guideline (e.g. clustering rules, no double counting of benefits etc.) 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 wind 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.

11.1. 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 2024 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.

The "best feasible solution" could be multiple things:

- a direct point-to-point interconnector,
- a direct radial connection,
- a hybrid (dual-/ multipurpose) interconnection setup

• meshing between existing radial connections or interconnectors

These key setups are highlighted below in Figure 10 – 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) |
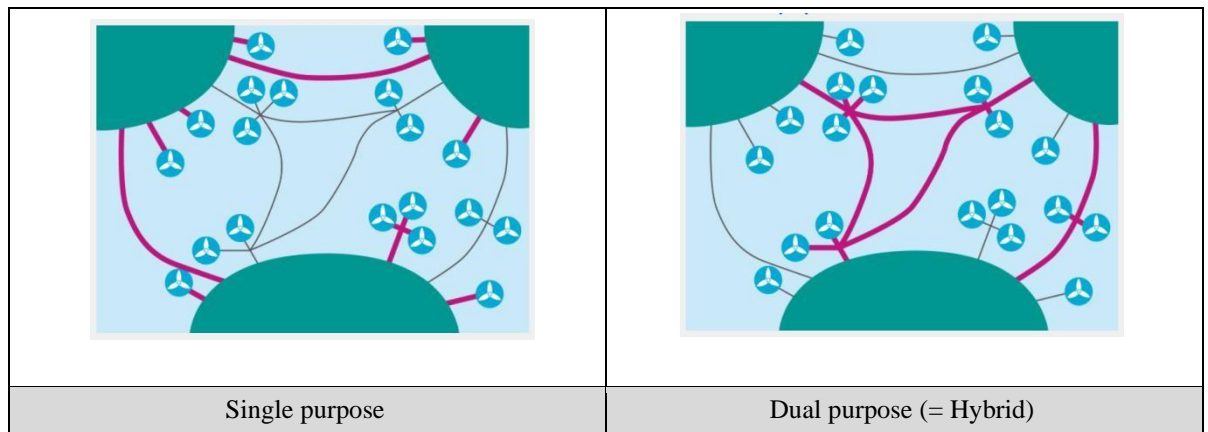
Figure 10 – figure taken from ENTSO-E Position on Offshore Development - Summary of Recommendations, July 2021

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

11.2.   Hybrid interconnector definition

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

As a reminder, a hybrid interconnection setup and dual purpose (seeFigure 10) can be defined **as a project which enables an interconnector function between bidding zones** (either onshore or offshore) **while simultaneously facilitating a client connection with a certain technology** (RES or non-RES; generation, load or storage; AC (e.g. Kriegers Flak) or DC (e.g. North Sea Wind Power Hub)).

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

- **CBA Case 1** expansion of an existing radial client connection through the inclusion of an XB interconnection (IC). The project is built on top of an already existing or planned radial connected RES by enabling <u>only</u> 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 a hybrid interconnector. The project enables both the RES-integration function (i.e. additional OWF capacity is integrated into the system through the project) and the additional interconnector function.
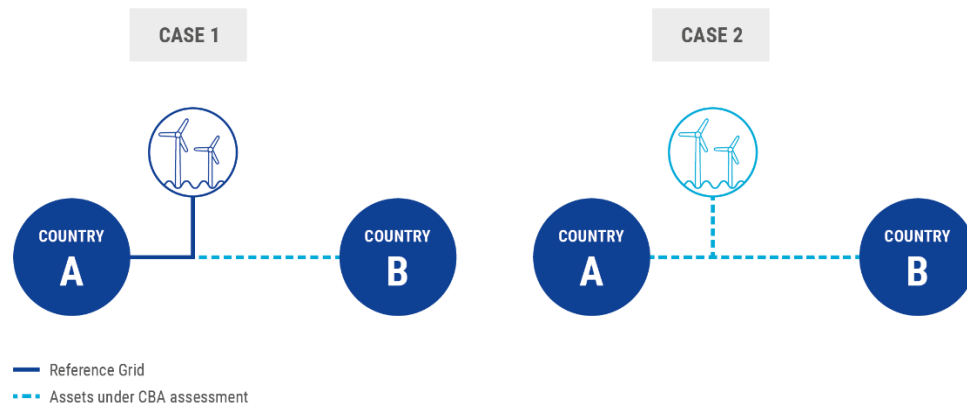
Figure 11 - schematic display of the two fundamental cases/setups of hybrid projects as applied to the CBA assessment

For illustration purposes, only the offshore wind technology setup will be given & discussed in the Implementation Guidelines. 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.

11.2.1.   CBA Case 1

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

The benefits of market integration (relevant B1, B2, B4, B6 indicators) are enabled by increasing the transfer capacity between country A and B, as shown in Figure 12, enabled either in a home market setup or offshore bidding zone setup. In the case of a home market setup, RES is strictly allocated to either country A or B, and the created single NTC would be lower compared to the case of a direct connection between A and B without RES, as the offshore RES energy will impact the options for remaining trade and congest the direct connection.

- In an HM setup, for implementation, the 'reduced NTC concept' needs to be defined, which is dependent on the expected RES infeed profile and which must be calculated as the 'normal NTC without RES' between county A and B minus the 'RES output' following the hourly dispatch results. The NTC calculation should respect general NTC calculation as specified in section4.2. If the wind output is unknown in case the targeted RES is an offshore wind farm, project promoters should indicate targeted offshore wind location and ENTSOE could calculate remaining NTC using default wind profiles.

- In an OBZ setup of the targeted RES in the hybrid system, 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 12 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

— Reference Grid
--- Project under CBA assessment
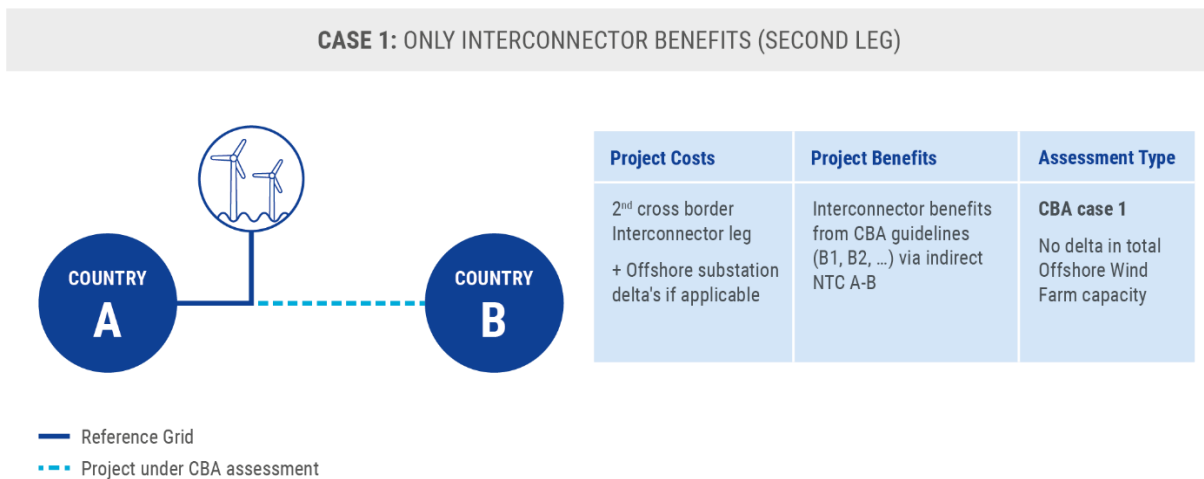
Figure 12 - Project cost & benefit scope under CBA Case 1 assessment

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

(3) 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 dependent on the chosen market
setup HM or OBZ). For the remainder of the text, only setup 1 is illustrated.

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

- Single NTC between A and B enabled in a home market setup (1 reduced NTC in total)
  and creation of direct RES integration.
- Double NTC (2 NTCs in total i.e. 1 between country A and RES, and 1 between country
  B and RES) enabled in an OBZ setup and the creation of direct RES integration itself.
- In TYNDP 2024 a sanity check will be applied in order to determine a reasonable cost
  approximation of the wind farm that needs to be deducted from the SEW (see
  section11.3).

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 13 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

—— Reference Grid
- - - Project under CBA assessment

Figure 13 - Project cost and benefit scope under CBA Case 2 assessment

11.2.3.   Radial projects:

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

The producer surplus of the targeted RES itself needs to be removed from the SEW, as a
proxy to warrant the required RES investment. As for hybrid projects, a sanity check will

be applied in order to determine a reasonable cost approximation
of the wind farm that needs to be deducted from the SEW (see section 11.3).

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

11.2.4. NTCs

NTCs should respect the guidance as given in section4.2, and hence can be different from the thermal capacity of the respective legs of the hybrid setup in general and clearly also when different leg sizing is applicable.

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

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).

11.3. Sanity check

This sanity check needs to be applied when Case 2 has been chosen for the project 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 costs for installing the RES generation. I.e. in order to not overestimate the benefit of the hybrid project assessed using Case 2, the costs for the installation of the additional RES generation should be considered in the final evaluation. However, as these costs may vary strongly dependent on the source the costs are taken from, a specific sanity check will be applied in order to get a reasonable approximation of the respective costs. This can be done by interpreting the producer surplus of the targeted RES as an approximation of the expected costs of the RES assets. This cost-approximation is then compared with either standard costs for the RES assets or, where available, with detailed projects costs delivered by the project promoter.

In general, for this sanity check two steps are to be performed:

• The cost-approximation, that in the first step is calculated as the producer surplus of the targeted RES itself, needs to be removed from the EU-SEW, as a proxy to warrant the required RES investment. The producer surplus can be calculated as the dispatched RES feed-in volume for all hours of the considered year, multiplied by the price the OWF gets, which is determined by the bidding zone in which it is

considered. This calculation can be done ex-post and, in the
event the RES is connected to 2 or more bidding zones onshore in a separate bidding
zone setup, then it will get the lowest price of all bidding zones to which it is linked.

- The following check implies the verification whether the cost-approximation is in the same range as the expected costs for the RES asset: the expected costs for the RES asset for this check are either given by the project promoter, based on which the range is set up to be +/- 20%; or ENTSO-E will apply standard costs used in the Scenario Building[18] for the corresponding TYNDP, which include a lower & higher value defining a range on those expected costs for the RES asset. In case the cost approximation would not fall within the range, an ex-post correction of it will be applied on the B1 indicator calculation.

Therefore, the following steps need to be performed when assessing hybrid project using Case 2:

1. Standard calculation of the B1 - SEW indicator
2. Calculation of the cost-approximation using the producer surplus as proxy for the costs of the RES investment
3. Definition of a cost range based on
    a. Minimum and maximum of given standard costs
    b. +/- 20% of investment costs delivered by the project promoter
4. Verification whether the cost-approximation based on the range defined under step 3.
    a. When the calculated cost-approximation falls within the range it is considered as a good approximation and no additional correction of the cost-approximation needs to be done.
    b. When the calculated cost-approximation lies above or below the range, it will be adjusted by
    $$cost_{prox,new} = (cost_{prox} + cost_{mean})/2$$
    Where
    o $cost_{prox,new}$ is the updated cost-approximation
    o $cost_{prox}$ is the initial cost-approximation as calculated under step 2.
    o $cost_{mean}$ is the mean value of the cost range as defined under step 3.
5. Subtracting the cost-approximation from the SEW as calculated under step 1[19].

Please note that the sanity check will only be applied for projects that are assessed following the PINT method, except in the case of the RES generation is included on the

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[18] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2023/07/20230704-Draft_Supply_Inputs_for_TYNDP_2024_Scenarios_2.xlsx (section 2.2)
- [19] The standard costs are taken from the TYNDP 2024 scenario report and have to include the annualised CAPEX and OPEX.
- Minimum value taken from GA2040
- Maximum value taken from DE2030

**NECPs (National Energy Climate Plan) and/or the RES project
is included in the NDP (National Development Plan).**

11.4.   Direct project promoter input

11.4.1.   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 could originate 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 2024 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 2030/2040. Project promoters should specify the targeted location & technology, if possible, in order to perform sanity checks where and if necessary.

11.4.2.   Data required for TYNDP 2024

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.
2. Indication of targeted market setup – either OBZ as default or HM (and which one) for the hybrid interconnection project under CBA assessment
3. Targeted RES location (minimally the target country/EEZ), installed capacity [MW], technology – with best accuracy possible
4. 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)

5. Sizing of power rating of different legs between onshore
bidding zones and OWF
    a. Needed to correctly reflect in NTC estimations
6. Voltage level and estimation of related no load & full load losses
    a. Needed for B5 – grid losses

7. 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.

11.5. Market setup – Offshore bidding zone versus home market

The market setup of the targeted client connection (e.g. offshore wind infeed) could in theory be either a "home-market" setup (meaning connected to a single BZ from the market clearing perspective) or a separate OBZ (meaning a different bidding zone compared to the bidding zones of the MS). Examples are included at the end of this chapter in Figure 14 and Figure 15 on how the market flows are impacted, dependent on the market prices that arise under perfect forecast (no imbalances) for an OBZ and HM setup between 2 countries.

Following an ENTSOE paper[20] on offshore development with a focus on market & regulatory issues from 2020–2021, there is a preference to only allow OBZs for future hybrid systems as this will be better for European society from a market welfare perspective and it ensures the continual respect of the Clean Energy Package rules regarding capacity calculation for interconnectors. Therefore, for modelling purpose, and to ensure a level playing field for a consistent implementation, by default only the use of OBZ for hybrid projects should be applied within the TYNDP project assessment. This implies that existing radial connections in a home market setup today, which would be transformed to hybrid interconnectors, are supposed to be transformed to OBZs setup always (CBA case 1) and similarly for a full hybrid system from the start (CBA case 2).

The concept of defining an OBZ remains to be further elaborated at the EU-level but, in general, the stipulations should respect the fact that no internal bottlenecks occur when defining the OBZ.

Illustration - impact on market modelling results

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[20] *https://www.entsoe.eu/news/2020/10/15/entso-e-releases-its-2d-position-paper-on-offshore-focusing-onmarket-regulatory-issues/*
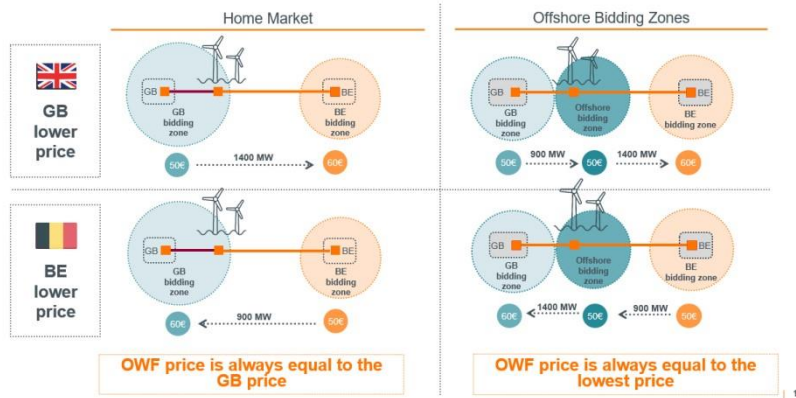
Figure 14 - Expected flows on different legs of an offshore hybrid interconnector, when market prices are positive, for both HM and OBZ setups
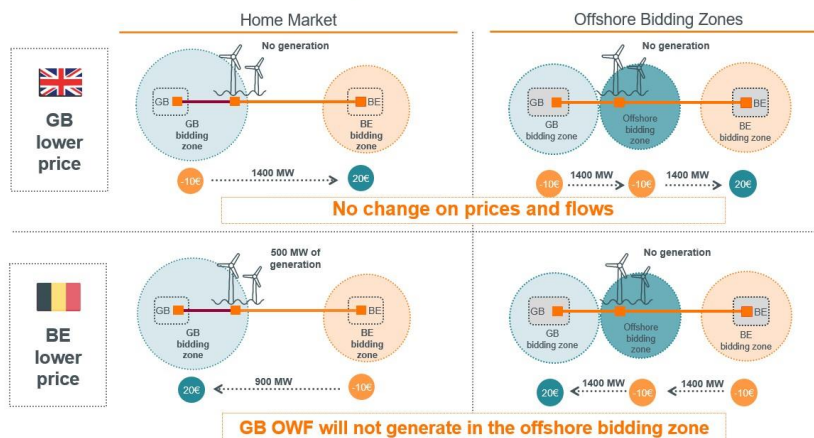
Figure 15 - Expected flows on different legs of an offshore hybrid interconnector, when 1 market price is negative, for both HM and OBZ setups

APPENDIX

A. QUANTITATIVE ASSUMPTIONS

A.I. General assumptions

Quantitative measure	Value
Hurdle costs	0.01 €/MWh
Cost for ENS in the market models	3000 €/MWh
Grouping of power plant types based on their marginal costs – only used for B2	2 €/MWh
Societal values of CO_2 emissions (2030) Societal values of CO_2 emissions (2040)	60 €/t, 100 €/t, 189 €/t 156 €/t, 269 €/t, 498 €/t
Cap of marginal costs for losses calculations	199.0 €/MWh (*NT2030*) 231.8 €/MWh (*NT2040*)
Value of Lost Load (general assumption)	10000 €/MWh for indicators B6 3000 €/MWh for all the other indicators
Cost of new entrant (general assumption)	42000 €/MW/yr

The Table below gives an overview of the VOLL and CONE used within the TYNDP 2024. The values are being collected by a survey addressed to the TSOs and their respective countries. In the event no values are submitted to ENTSO-E the standard values (see table above) are used. Note: the values will be delivered as an addendum to the Implementation Guidelines as soon as the survey is closed.

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
Czech Republic	4,016	59,200	59,200	15
Estonia	7,287	63,000	63,000	9
Finland	8,000	60,000	60,000	2
France	13,000	-	-	-

Country				
Germany	12,240	23,377	-	2
Greece	6,838	42,430	42,430	3
Lithuania	-	-	-	8
Luxemburg	12,240	23,377	-	2
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

Entry	factor
f1	
AC	1
DC	1,1
f2	
Overhead line	1
Substation	0,5
Transformer	0,5
Cable	1,2
Reactive compensation device	0,5
f3	
Onshore	1
Offshore	0,9
f4	
New	1
Upgrade	0,5
Mostly New	0,8
Mostly Upgrade	0,6

A.II. CO2 emission per type

Category #	Fuel	Type	Efficiency range in NCV terms	Standard efficiency in NCV terms	CO$_2$ emission factor	CO$_2$ emission factor	CO$_2$ emission factor
			%	%	kg / Net GJ	t / Net MWh	t / MWh
1	Nuclear	-	30% – 35%	33%	0	0.00	0.00
2	Hard coal	old 1	30% – 37%	35%	94	0.34	0.97
3	Hard coal	old 2	38% – 43%	40%	94	0.34	0.85
4	Hard coal	new	44% – 46%	46%	94	0.34	0.74
5	Hard coal	CCS	30% – 40%	38%	9.4	0.03	0.09
6	Lignite	old 1	30% – 37%	35%	101	0.36	1.04
7	Lignite	old 2	38% – 43%	40%	101	0.36	0.91
8	Lignite	new	44% - 46%	46%	101	0.36	0.79
9	Lignite	CCS	30% - 40%	38%	10.1	0.04	0.10
10	Gas	conventional old 1	25% – 38%	36%	57	0.21	0.57
11	Gas	conventional old 2	39% – 42%	41%	57	0.21	0.50
12	Gas	CCGT old 1	33% – 44%	40%	57	0.21	0.51
13	Gas	CCGT old 2	45% – 52%	48%	57	0.21	0.43
14	Gas	CCGT present 1	53% – 60%	56%	57	0.21	0.37
15	Gas	CCGT present 2	53% – 60%	58%	57	0.21	0.35
16	Gas	CCGT new	53% – 60%	60%	57	0.21	0.34
17	Gas	CCGT CCS	43% – 52%	51%	5.70	0.02	0.04
18	Gas	OCGT old	35% – 38%	35%	57	0.21	0.59
19	Gas	OCGT new	39% – 44%	42%	57	0.21	0.49
20	Light oil	-	32% – 38%	35%	78	0.28	0.80
21	Heavy oil	old 1	25% – 37%	35%	78	0.28	0.80
22	Heavy oil	old 2	38% – 43%	40%	78	0.28	0.70

| 23 | Oil shale | old | 28% – 33% | 29% | 100 | 0.36 | 1.24 |
| 24 | Oil shale | new | 34% – 39% | 39% | 100 | 0.36 | 0.92 |

A.III.   Non-CO2 emission factors

Fuel	Type	Standard efficiency in NCV terms	NOx emission factor [21]	NH3 emission factor	SO2 emission factor [20]	PM2.5 and smaller emission factor[22]	PM10 emission factor [20]	NMVOC emission factor [23]
		%	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

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

[22] 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

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

Oil shale	old	29%	0,24	0	0,16	0,0062	0,0086	0,0023
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

A.IV.   Project standard costs

Below is a table with standard costs for the different technologies of transmission lines. As these values are mainly outdated – an update of the costs is still in progress – the values need to be treated with care and, most probably, higher values can be expected.

AC onshore overhead lines

Investment type	Standard cost[24]	Unit
AC 380-400 kV OHL 2 circuits	1.0	M€/km
AC 380-400 kV OHL 1 circuit	0.6	M€/km
AC 220-225 kV OHL 2 circuits	0.4	M€/km
AC 220-225 kV OHL 1 circuit	0.3	M€/km

AC onshore cable

Investment type	Standard cost	Unit
AC 380-400 kV cable 2 circuits	4.9	M€/km
AC 220-225 kV cable 2 circuits	3.3	M€/km
AC 220-225 kV cable 1 circuit	2.2	M€/km
AC 150 kV cable 2 circuits	1.5	M€/km
AC 150 kV cable 1 circuit	0.6	M€/km

[24] *Taken from the ACER report; only the rounded mean value is reported here.*
http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/UIC Report - Electricity infrastructure.pdf

Subsea cables

Investment type	Standard cost	Unit
AC 150-220 kV cables	1.1	M€/km
DC 250-500 kV cables	0.8	M€/km

AC substations (gas and air isolated i.e. GIS and AIS)

Investment type	Standard cost	Unit
GIS substations	42.6	k€/kV
AIS with 9+ bays	44.0	k€/kV
AIS with 5-8 bays	35.6	k€/kV
AIS with 1-4 bays	33.2	k€/kV

Transformer

Investment type	Standard cost	Unit
Per MVA rating	9.9	k€/MVA

HVDC converter

Investment type	Standard cost	Unit
1-4 converter transformers	87.2	k€/MVA
6-8 converter transformers	155.7	k€/MVA

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.

ID	Project name	Border	A-B	B-A	In ref. grid 2030?	In ref. grid 2040?	Commissioning year	Project Status ID	CBA maturity criteria
1	RES in north of Portugal	internalPT00	1400	1400	yes	yes	2023	4	
4	Interconnection Portugal-Spain	ES00-PT00	1500	800	yes	yes	2024	3	
16	Biscay Gulf	ES00-FR00	2200	2200	yes	yes	2027	3	
26	Reschenpass Interconnector Project	AT00-ITN1	300	300	yes	yes	2023	4	
28	Italy-Montenegro	ITCS-ME00	600	600	no	yes	2026	4	
29	Italy-Tunisia	ITSI-TN00	600	600	yes	yes	2028	3	
33	Central Northern Italy	ITCN-ITN1	400	400	yes	yes	2023	4	
33	Central Northern Italy	ITCN-ITCS	150	150	yes	yes	2023	4	
35	CZ Southwest-east corridor	CZ00-DE00	500	500	yes	yes	2028	3	
47	Westtirol - Vöhringen	AT00-DE00	600	600	yes	yes	2030	2	
81	North South Interconnector	IE00-UKNI	950	900	yes	yes	2026	3	
85	Integration of RES in Alentejo	internalPT00	1000	1000	yes	yes	2022	3	
94	GerPol Improvements	DE00-PLI0	500	1500	yes	yes	2025	4	
94	GerPol Improvements	PLI0-PL00	500	1500	yes	yes	2025	4	
103	Reinforcements Ring NL phase I	DE00-NL00	600	600	yes	yes	2026	4	
107	Celtic Interconnector	FR00-IE00	700	700	yes	yes	2026	3	
111	3rd AC Finland-Sweden north	FI00-SE01	900	800	yes	yes	2025	3	
120	MOG II: connection of up to 2 GW additional offshore wind Belgium	internalBE00	2100/ 1400	2100/ 1400	yes	yes	2028	2	

121	Nautilus: 2nd interconnector Belgium - UK	BE00-UK00	1400	1400	yes	yes	2029	2	
124	NordBalt phase 2	LT00-SE04	0	0	yes	yes	2027	3	
127	Central Southern Italy	ITCS-ITS1	500	500	yes	yes	2028	3	
130	HVDC Wolmirstedt to area Isar	internalDE00	2000	2000	yes	yes	2027	3	
132	HVDC Line A-North	internalDE00	2400	2400	yes	yes	2027	3	
138	Black Sea Corridor	BG00-RO00	600	600	yes	yes	2024	4	
142	CSE4	BG00-GR00	930	600	yes	yes	2023	4	
144	Mid Continental East corridor	RO00-RS00	844	600	yes	yes	2029	3	
144	Mid Continental East corridor	HU00-RO00	617	335	yes	yes	2029	3	
150	Italy-Slovenia	ITN1-SI00	400	400	yes	yes	2040	1	
153	France-Alderney-Britain	FR00-UK00	1250	1250	no	yes	2031	3	
170	Baltics synchro with CE	LT00-PL00	700	700	yes	yes	2028	4	
174	Greenconnector	CH00-ITN1	1000	1000	yes	yes	2026	3	
176	Hansa PowerBridge I	DE00-SE04	700	700	yes	yes	2027	3	
183	"DKW-DE, Westcoast"	DE00-DKW1	1000	1000	yes	yes	2024	3	
186	east of Austria	internalAT00	2000	2000	yes	yes	2022	4	
187	St. Peter (AT) - Pleinting (DE)	AT00-DE00	1500	1500	yes	yes	2030	3	
200	CZ Northwest-South corridor	CZ00-DE00	500	500	yes	yes	2024	3	
210	Wurmlach (AT) - Somplago (IT) interconnection	AT00-ITN1	150	150	yes	yes	2026	3	
219	EuroAsia Interconnector	CY00-GR03	1000	1000	yes	yes	2026	3	
219	EuroAsia Interconnector	CY00-IL00	1000	1000	yes	yes	2026	3	

227	Transbalkan Corridor	BA00-RS00	1200	1200	yes	yes	2027	3	
227	Transbalkan Corridor	ME00-RS00	240	840	yes	yes	2027	3	
228	Muhlbach - Eichstetten	DE00-FR00	300	300	yes	yes	2027	2	
230	GerPol Power Bridge I	DE00-PLI0	1500	500	yes	yes	2024	4	
230	GerPol Power Bridge I	PLI0-PL00	1500	500	yes	yes	2024	4	
231	Concept project Germany-Switzerland	CH00-DE00	100	600	no	yes	2035	2	
235	HVDC Brunsbüttel/Wilster to Großgartach/Grafenrheinfeld	internalDE00	4000	4000	yes	yes	2028	3	
244	Vigy - Uchtelfangen area	DE00-FR00	1500	1500	yes	yes	2029	2	
247	AQUIND Interconnector	FR00-UK00	2075	2075	yes	yes	2026	3	
250	"Merchant line ""Castasegna (CH) - Mese (IT)"""	CH00-ITN1	200	200	yes	yes	2027	3	
254	Ultranet	internalDE00	2000	2000	yes	yes	2026	3	
259	HU-RO	HU00-RO00	1410	740	no	yes	2030	2	
260	New Great Britain - Netherlands interconnection	UK00-NL00	2000	2000	yes	yes	2030	1	
267	Hansa PowerBridge II	DE00-SE04	700	700	no	yes	2035	1	
270	FR-ES project -Aragón-Atlantic Pyrenees	ES00-FR00	1500	1500	no	yes	2030	2	
280	FR-BE III: study Lonny-Achene-Gramme	BE00-FR00	1000	1000	no	yes	2030	1	
285	GridLink	FR00-UK00	1400	1400	yes	yes	2029	3	
286	Greenlink	UK00-IE00	500	500	yes	yes	2024	4	
293	Southern Aegean Interconnector	internalGR00	582	582	no	yes	2025	1	
297	BRABO II + III	BE00-NL00	1000	1000	yes	yes	2026	4	
299	SACOI3	FR15 - ITCO	100	100	yes	yes	2026	3	
299	SACOI3	ITCN-ITCO	400	400	yes	yes	2026	3	
309	NeuConnect	DE00-UK00	1400	1400	yes	yes	2028	4	

312	St. Peter - Tauern (AT internal)	AT00-DE00	2000	2000	yes	yes	2025	4	
313	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	AT00-DE00	2000	2000	yes	yes	2026	3	
323	Dekani (SI) - Zaule (IT) interconnection	ITN1-SI00	Up to 60	Up to 10	yes	yes	2025	3	
324	Redipuglia (IT) - Vrtojba (SI) interconnection	ITN1-SI00	Up to 70	Up to 100	yes	yes	2025	3	
325	Obersielach (AT) - Podlog (SI)	AT00-SI00	500	500	no	yes	2034	1	
328	Interconnector DE-LUX	DE00-LUG1	1000	1000	yes	yes	2027	2	
329	Stevin-Izegem/Avelgem (Kustlus): new corridor	internalBE00	6000	6000	yes	yes	2028	2	
330	4th 400kV CZ-SK interconnector	CZ00-SK00	500	500	no	yes	2035	1	
338	Adriatic HVDC link	ITN1-ITCN	600	1000	yes	yes	2028	3	
338	Adriatic HVDC link	ITCN-ITCS	1000	1000	yes	yes	2028	3	
339	Italian HVDC Tyrrhenian link	ITCS-ITSIvirt	1000	1000	yes	yes	2027	2	
339	Italian HVDC Tyrrhenian link	ITSA-ITSIvirt	1000	1000	yes	yes	2027	2	
339	Italian HVDC Tyrrhenian link	ITSI-ITSIvirt	1500	1500	yes	yes	2027	2	
340	Avelgem-Center: new corridor	internalBE00	6000	6000	yes	yes	2029	2	
341	North CSE Corridor	RO00-RS00	680	720	yes	yes	2029	2	
342	Central Balkan Corridor	BG00-RS00	490	270	no	yes	2034	2	
343	CSE1 New	BA00-HR00	644	298	no	yes	2035	2	
346	ZuidWest380 NL	BE00-NL00	1000	0	no	yes	2032	3	
349	MARES Organic Power Interconnector (OPIC)	IE00-UK00	750	750	yes	yes	2030	2	
350	South Balkan Corridor	AL00-MK00	500	500	yes	yes	2024	4	
375	Lienz (AT) - Veneto region (IT) 220 kV	AT00-ITN1	500	500	no	yes	2035	2	
377	Upgrade BE-NL interconnector VanEyck-Maasbracht	BE00-NL00	1000	1000	no	yes	2034	1	

378	Transformer Gatica	internalES00	-	-	yes	yes	2027	2	
379	Uprate Gatica lines	internalES00	-	-	yes	yes	2026	2	
1034	HVCD corridor from Northern Germany to Western Germany	internalDE00	4000	4000	no	yes	2031	2	
1040	LirIC	UKNI-UK00	700	700	no	yes	2030	1	
1041	GREGY Interconnector	GR00-EG00	3000	3000	yes	yes	2028	1	
1042	Offshore wind integration	internalLT00	700	700	no	yes	2028	2	
1046	Finnish North-South reinforcement	internalFI00	3000	3000	no	yes	2030	2	
1050	Tarchon Energy Ltd	DE00-UK00	1400	1400	no	yes	2030	1	
1051	Aminth Energy Ltd	DKW1-UK00	1400	1400	no	yes	2031	1	
1052	Lienz (AT) – Obersielach (AT)	AT00-SI00	500	500	no	yes	2032	2	
1054	Westtirol (AT) - Zell/Ziller (AT)	AT00-DE00	600	600	yes	yes	2029	2	
1055	Interconnection of Crete to the Mainland System of Greece	GR00-GR03	800	800	yes	yes	2024	4	
1059	Southern Italy	ITCS-ITS1	200	200	yes	yes	2028	3	
1059	Southern Italy	ITS1-ITCA	900	900	yes	yes	2028	3	
1068	LaSGo Link	LV00-SE03	500	500	no	yes	2036	1	
1074	Pannonian Corridor	HU00-RS00	500	500	no	yes	2030	2	
1085	Malta-Italy Cable Link No.2	MT00-ITSI	225	225	no	yes	2035	1	
1086	Estonia internal grid reinforcement to increase RES connection capability (RRF project)	EE00internal	700	700	yes	yes	2026	4	
1092	Offshore Hybrid HVDC Interconnector BEDK	BE00-DKOBZ	2000	2000	no	yes	2031	1	
1092	Offshore Hybrid HVDC Interconnector BEDK	DKW1-DKOBZ	1400	1400	no	yes	2031	1	
1094	Estlink 3	EE00-FI00	700	700	no	yes	2033	1	
1095	Aurora line 2 (4th AC Finland-Sweden north)	FI00-SE01	800	800	no	yes	2035	1	
1096	Beznau - Mettlen	CH00-DE00	0	700	yes	yes	2028	3	

1098	Offshore Wind LT 2	LTOffshore	700	700	no	yes	2030	2	
1100	Reinforcement of the existing CZ-DE interconnector (Hradec - Röhrsdorf) on the CZ side	CZ00-DE00	0	500	yes	yes	2028	3	
1102	Mettlen - Ulrichen	CH00-DE00	200	0	no	yes	2034	3	
1103	Bickigen - Chippis	CH00-DE00	0	500	yes	yes	2027	3	
1104	Niederstedem - Roost	DE00-LUG1	400	400	yes	yes	2027	2	
1106	Bornholm Energy Island (BEI)	DE00-BolEnergy	2000	2000	yes	yes	2030	1	
1106	Bornholm Energy Island (BEI)	BolEnergy-DKE1	1200	1200	yes	yes	2030	1	
1109	Basilicata - Campania reinforcements	ITCS-ITS1	500	500	no	yes	2035	2	
1110	Sicily - Calabria	ITCA-ITSI	500	500	yes	yes	2026	2	
1112	GRITA 2	ITS1-GR00	1000	1000	no	yes	2031	1	
1121	Hessenberg (AT) - Weißenbach (AT)	ATInternal	600	600	yes	yes	2029	2	
1122	Offshore Wind connection Centre Manche 1	FROffshore	1250	1250	no	yes	2031	2	
1123	Offshore Wind Connection Centre Manche 2	FROffshore	1250	1250	no	yes	2031	2	
1124	Offshore Wind Connection South Britanny	FROffshore	750	750	yes	yes	2029	2	
1125	Offshore Wind Connection Occitanie	FROffshore	750	750	yes	yes	2030	2	
1126	Offshore Wind Connection PACA	FROffshore	750	750	yes	yes	2030	2	
1127	Offshore Wind Connection South Atlantic	FROffshore	1250	1250	no	yes	2032	2	
1129	New RES at Minho region	internalPT00	400	400	yes	yes	2029	2	

1168	HG Ionian-Tyrrhenian Corridor	ITSI-ITCA	2000	2000	no	yes	2035	2	
1168	HG Ionian-Tyrrhenian Corridor	ITS1-ITCA	2000	2000	no	yes	2035	2	
1168	HG Ionian-Tyrrhenian Corridor	ITCS-ITS1	2000	2000	no	yes	2035	2	
1167	HG Central link	ITCS-ITCN	600	600	yes	yes	2030	2	
1165	Offshore Wind Connection Vendée 1	FROffshore			no	yes	2034	1	
1164	Offshore Wind Connection Fos	FROffshore			no	yes	2035	1	
1163	Offshore Wind Connection Le Havre 2	FROffshore			no	yes	2034	1	
1162	Offshore Wind Connection Le Havre 1	FROffshore			no	yes	2033	1	
1161	Offshore Wind Connection South Atlantic Oléron 2	FROffshore			no	yes	2034	0	
1160	PST Riddes	CH00			yes	yes	2026	3	
1159	Bisamberg (AT) – Wien Südost (AT)	ATInternal			no	yes	2034	2	
1158	Bisamberg (AT) – Gaweinstal (AT) – Zaya (AT)	ATInternal			no	yes	2033	0	
1157	HG North Tyrrhenian Corridor	ITCS-ITN1	2000	2000	yes	yes	2030	2	
1157	HG North Tyrrhenian Corridor	ITCS-ITCN	800	0	yes	yes	2030	2	
1156	Hessenberg (AT) – Trumau (AT) – Wien Südost (AT)	ATInternal			no	yes	2032	2	

1155	Wien Südost (AT) - Trumau (AT) - Parndorf (AT)	ATInternal			no	yes	2030	2	
1154	Bisamberg (AT) - Dürnrohr (AT)	ATInternal			no	yes	2035	0	
1153	PST romands	CH00-FR00	800	800	yes	yes	2030	0	
1148	Transformer Lachmatt	CH00-DE00	0	0	yes	yes	2026	3	
1147	Istrian peninsula 400 kV project	HR00-SI00	100	75	no	yes	2034	2	
1145	Obersielach (AT) - Hessenberg (AT)	ATInternal			no	yes	2033	2	
1140	St. Peter (AT) - Dürnrohr (AT)	ATInternal			no	yes	2035	2	
1139	380-kV Westtirol (AT) – Zell/Ziller (AT)	ATInternal			no	yes	2033	0	
1138	New 400 kV OHL Suceava (RO) - Balti (MD)	MD00-RO00	350	350	yes	yes	2030	2	
1137	Cesana (IT) - Briançon / L'Argentiere (FR)	FR00-ITN1	0	0	yes	yes	2026	3	
1134	Façade Atlantique	ES00-FR00	0	0	no	yes	2034	0	
1135	EHV S/S Thesprotias and its connection to the 400 kV System	GR00Internal	1200	1200	yes	yes	2030	2	
1136	New interconnection line 400 kV Greece - Albania	AL00-GR00	200	200	yes	yes	2030	2	

Figure 16 - Overview of the specific treatment of the EU–UK border

Border	Combined NTC of projects in TYNDP 2024 portfolio (TOOT+PINT)	Needs identified in IoSN2020 (additional to 2025)	Ref. grid definition for CBA 2030	Ref. grid definition for CBA 2040
UK-FR	4725 MW (1400MW from P285, 2075 MW from P247, 1250 MW from P153)	1400 MW in 2030, 2800 MW in 2040	Fictive 1600 MW	4725 MW (1400MW from P285, 2075 MW from P247, 1250 MW from P153)
UK-BE	2800 MW (1400 MW from P121, 1400 MW from P1049)	0 in both time horizons	-	1400 MW from P121
UK-NL	2000 MW (from P260)	0 MW in 2030, 2000 MW in 2040	-	2000 MW from P260
UK-DE	2800 MW (1400 MW from P309 and 1400 MW from P1050)	0 MW in both time horizons	1400 MW from P309	1400 MW from P309
UK-DK	1400 MW (from P1051)	0 MW in both time horizons	-	-
UK-NO	1400 MW (from P190)	0 MW in both time horizons	1400 MW from P190	1400 MW from P190

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
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 2024.

E. EXAMPLES OF PROJECT LEVEL INDICATORS CALCULATIONS

E.I. 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					
Date	Hour	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)	
				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:

		Balancing Need direction A-->B B-->A	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				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 A-->B B-->A	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					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.

F. 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 2.4. 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):

   $P_{RD\,(with)} = 16000\,M$, which appears in hour 3465

   $P_{R(without)} = 18000\,MW$, which appears in hour 5687

3. Build the delta:

   $\Delta P_{RD} = P_{RD(without)} - P_{RD(with)} = 18000\,MW - 16000\,MW = 2000\,MW$

4. Monetise the benefit with 20k€/MW of allocated redispatch power plant:

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

G. 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 2024 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 table 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.

Total Surplus Approach	
$R_{CSR}^{elec \leftrightarrow h2} = (80 * 2.5 - 15 * 5) + (80 * 4 - 40 * 8) = 125$	$R_{CSR}^{elec \leftrightarrow h2} = (80 * 2.5 - 15 * 5) + (80 * 5 - 15 * 10) = 375$
$R_{cons}^{elec} = (100 - 15) * 5 + (100 - 40) * 20 = 1625$	$R_{cons}^{elec} = (100 - 15) * 5 + (100 - 15) * 20 = 2125$
$R_{cons}^{h2} = (100 - 80) * 2.5 + (100 - 80) * 5 = 150$	$R_{cons}^{h2} = (100 - 80) * 2.5 + (100 - 80) * 5 = 150$
$R_{prod}^{elec} = (15 - 15) * 13 + (40 - 1) * 25 = 975$	$R_{prod}^{elec} = (15 - 15) * 15 + (15 - 1) * 25 = 350$
$R_{prod}^{h2} = (80 - 80) * 1 = 0$	$R_{prod}^{h2} = (80 - 80) * 0 = 0$
$R_{cong}^{elec} = (40 - 15) * 3 = 75$	$R_{cong}^{elec} = (15 - 15) * 8 = 0$
$R_{cong}^{h2} = (80 - 80) * 0 = 0$	$R_{cong}^{h2} = (80 - 80) * 0 = 0$
$SEW = \sum R = 2950$	$SEW = \sum R = 3000$

<div align="center">

Delta SEW = 3000-2950 = 50

</div>

Generation Cost Approach	
$Generation\ Cost = 13 * 15 + 25 * 1 + 1 * 80 = 300$	$Generation\ Cost = 15 * 15 + 25 * 1 + 0 * 80 = 250$

<div align="center">

Delta SEW = 300-250 = 50

</div>