IMPLEMENTATION GUIDELINES FOR TYNDP 2020 BASED ON 3RD ENTSO-E GUIDELINE FOR COST BENEFIT ANALYSIS OF GRID DEVELOPMENT PROJECTS

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1.INTRODUCTION AND SCOPE

The Implementation Guideline provides complementary information to the 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (–"3rd CBA guideline") as published on 28 January 2020. It does not replace it. For a full understanding of this Implementation Guideline it is strongly recommended for the reader to familiarise with the 3rd CBA guideline. Only together, both documents combined deliver the needed information to practically perform a project CBA in the ENTSO-E Ten-Year Network Development Plan (TYNDP) 2020. Information that is not explicitly noted in the Implementation Guideline has to be considered with respect to the 3rd CBA guideline.

This guideline differs from the previous TYNDP implementation guidelines where earlier CBA guidelines were in place. The version for TYNDP 2020 is drafted under the requirement of being made public together with the TYNDP 2020 package as demanded by the 3rd CBA Guideline. The new structure of the 3rd CBA guideline is more general and modular. It explicitly refers to and relies on this Implementation Guideline:

a. It is modular as each individual indicator or aspect within the 3rd CBA guideline is presented as individual module. This approach would allow 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 guideline needs to fulfil different requirements that are described below.

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

2nd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (FINAL EC Approved 27.09.2018)

3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (Draft Version 28.01.2020)

TYNDP 2020 Scenario Report

Identification of System Need

TYNDP 2020 Redispatch Implementation Guideline

Implementation guideline on Project-Level Benefits

Project information: NTC calculation

Project information: Market simulations

2.MODELLING FRAMEWORKS

The figure below outlines the project assessment process, including market and network simulations, and the link between the two.
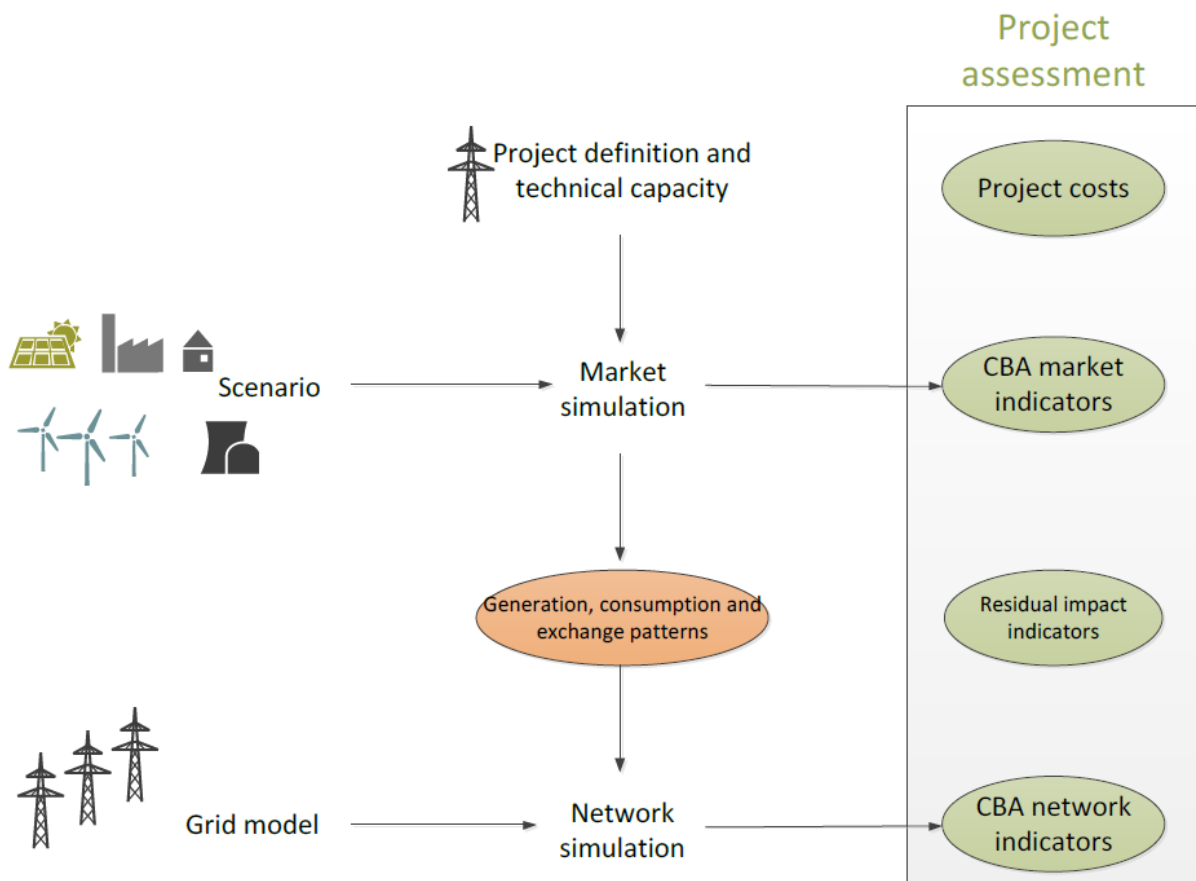
Figure 1 - Role of market and network simulations with respect to the CBA indicators of a TYNDP project assessment

The market simulation uses following input data[1]:

- ENTSO-E's Pan-European Market Modelling Database (PEMMDB) package covering all scenarios, including prices, generation data such as installed capacities by PEMMDB

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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.*

category, pre-defined generation time series for certain types, must-run data, Net Transfer Capacities (NTCs) and Demand Side Response parameters (DSR);

- Demand profile time series for all market nodes, per climate year and scenario;
- Pan-European Climate Database (PECD) covering solar irridation, wind generation, ambient temperature and hydro inflow data per climate year and scenario; and
- Planned and forced outage time series

The following results of a market simulation are mapped to the grid model for each time step of the network simulation:

- Generation for each PEMMDB category, for every market node;
- Balance (including demand) for every market node; and
- Exchange patterns, mapped directly to connections towards non-modelled countries and HVDC-only borders.

2.1.SCENARIOS (2.1 in CBA 3)

An overview of the scenarios, their storylines, main data points and definitions as applied to the TYNDP 2020 can be found in the TYNDP 2020 Scenario Report.

In addition, ENTSO-E developed the Current Trends (CT) 2030 scenario. In this scenario, an attempt is made to capture slow progress of economy as the main storyline behind the scenario. An overview of the CT 2030 scenario can be found in the TYNDP 2020 report.

In the TYNDP 2020, the scenarios in which cost-benefit analysis are calculated using market tools (to be specified in the next section) are NT2025, NT2030, DE2030, GA2030 and CT2030. In this context, it is important to note that the market CBA is calculated for all the scenarios mentioned before, but full CBA is only performed for the NT2025 and NT2030 scenarios, meaning that these are the only scenarios in which load flows and other network calculations are carried out.

The ΔNTC is verified by network studies in those two scenarios for the average climatic year and applied in market studies for the other scenarios and climate years at the same time horizon.

Adequacy assessments are only prioritized to the NT2030 scenario.

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

The climate years have been selected based on its representativeness out of all 34 climate years within the PECD Database. The results from market simulations are then considered base on the weighted average from these three climate years. The weighting is as follows: 0.235 for 1982, 0.265 1984, 0.5 for 2007.

Scenario	B1, B2, B3, B4	B6 – Adequacy	B5 – Losses	ΔNTC
NT2025 **Climate years**	Yes 1982, 1984, 2007	No	Yes 1982, 1984, 2007	Yes 2007
NT2030 **Climate years**	Yes 1982, 1984, 2007	Yes[2] Synthetic MC years	Yes 1982, 1984, 2007	No
DE2030 **Climate years**	Yes 1982, 1984, 2007	No	No	No
GA2030 **Climate years**	Yes 1982, 1984, 2007	No	No	No
CT2030 **Climate years**	Yes 1982, 1984, 2007	No	No	No

2.2.MARKET SIMULATIONS (2.4 in CBA 3)

Tools used for market simulations

The TYNDP project assessment should report costs and benefits on a pan-European level thanks to market and network simulations. The tools that are used for market simulations are (see also the table "Modelling info: Tools":

- Antares
- PowrSym
- Plexos
- Promed
- Pymas
- APG Tool
- BID3

Further information on these tools can be found in the TYNDP 2020 Insight Report

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[2] *In order to ensure "realistic LOLE levels" for TOOT projects the NT2030 scenario has been adjusted following the principles as layed down within the 3rd CBA Guideline – this adjustment has just been applied for the SoS calculations.*

Generation cost and total surplus approach

Market simulations for assessing indicators B1-B2-B3-B4 can rely on two possible approaches to calculate the variation in the socio-economic welfare (SEW): the generation cost approach or the total surplus approach. Both are elaborated in the 3rd CBA Guideline in Annexes I and II.

- The **generation cost approach**, which compares the generation costs with and without the project for the different bidding areas. This approach can be used both for inelastic (i.e., fixed demand in each time step) and elastic (i.e., demand served in each time step is variable and subject to its value according to the demand curve) demand only;
- the **total surplus approach**, which compares the producer and consumer surpluses for both bidding areas, as well as the congestion rent between them, with and without the project. This approach is capable of dealing with elastic demand.

Depending on the used market tool, the SEW for the projects that are connecting Countries included within the ENTSO-E perimeter is calculated using the generation cost approach. In case of inelastic demand – which is the case for the modelling used in TYNDP2020 – the two approaches give the exact same results. 3rd countries are calculated using the total surplus approach (see below).

The inelasticity of the demand is modelled as demand side response (DSR) the same way as generators are modelled – this does not impact the validity of the total surplus approach.

Treatment of 'third countries'

That geographic perimeter for benefit and cost reporting in the TYNDP is defined as covering countries from ENTSO-E, as well as observer member Turkey. Hence, this excludes countries as defined below.

This ENTSO-E perimeter is connected to non-member countries – so called third countries -, in costs and benefits may arise. It is therefore necessary to properly take into account 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 that are 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 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 that are related to these third countries. The benefit is then reported separately for the ENTSO-E perimeter and for third countries.

Geographical scope of the market model

The geographic perimeter for the market model is defined as ENTSO-E countries and the following connecting third-countries Tunisia, Israel, and Ukraine. The countries Cyprus, Iceland, Israel, and Tunisia are part of the reference case market model and are only modelled when associated PINT

projects are assessed. 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 third countries should use the total surplus approach. In contrast but for the same reason, pan-Europe interactions between Russia and Morocco are modelled as "fixed exchanges" in the market simulation.

Generation unit data

All assessments in the TYNDP 2020 use a common ENTSO-E PEMMDB. As the market simulations are carried out on the full pan-European perimeter a reduction in complexity has to be done in order 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 II.

Time-resolution

The market simulations are performed for 8736 hourly steps (starting with Monday based on 2007 as the reference year) to have exactly 52 weeks. This is useful as most tools apply weekly optimizations.

Climate years

The climate years considered for TYNDP 2020 market simulations are 1982, 1984 and 2007 as in the previous TYNDP 2018. 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 case of hydro power plants with natural inflow, hourly inflow data is used, which also depends on the climate year.

Hurdle costs

A hurdle cost of 0.01 €/MWh is applied in TYNDP 2020, which is the same as in the previous TYNDP 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 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).

2.3.NETWORK SIMULATIONS (2.4 in CBA 3)

Merging of the Grid Models

All load-flow simulations for merging the grid models are performed on models collected from TSOs for the NT 2025 and NT 2030 scenarios in ENTSO-E CGMES[3] format, for reference hours selected from a base case 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 exchanges in Europe being minimized, in order to help the convergence of the merged models. These merged models can then be sued 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 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 were built by TSOs for their own simulation tools that participate in the CBA calculations in the TYNDP Study Team. The load-flow results were compared and necessary fixes were done in each tool in case of discrepancies before starting the simulations. The following tools ar eused:

Tool	Merged Model
Convergence	Continental Europe
Integral	Continental Europe
PSS/E	Continental Europe, Baltics, Nordics
PowerFactory	Continental Europe, Great Britain

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

Mapping the market simulation results to the network models

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

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 information needed 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 way:

- **Mapping of generation for each modelled market node**: The market simulation results contain the total generation for each PEMMDB category (e.g. CCGT Present 1, Lignite Old 1, Wind Onshore etc. see section 2.2) per market node. Hence, it is not possible to directly allocate the generation pattern to each single generator – while 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 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.
- **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 AC or HVDCs, the mapping to each boundary node per border is done in proportion of the capacity of each line.
- **HVDC setpoints**: HVDCs can be modelled in different ways in the TYNDP grid models. In case of HVDCs within a country (market node), AC emulation (defined as a K [MW/°] factor provided by the TSO) is used. In case of borders that consist of both AC lines and HVDCs, either a formula is defined to calculate the HVDC setpoints in function of the exchange value from the market simulation, or AC emulation is used here as well (it is up to the relevant TSOs). 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. This way, the total load plus the losses remains equal to the demand value from the market simulation. Loads represented by the NonConformLoad[4] 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.

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 computational limitations of

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

some of the tools, or other issues caused by unreliable forecasted data for reactive loads or the lack of harmonized voltage control strategies, DC load-flow approximation may also be used[5] for the following steps, i.e. losses and NTC calculations.

From the tools used for load-flow simulations within the TNYDP2020 only Integral is able to perform full AC computations.

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

Improving DC calculations using results from AC calculations

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

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

Geographical scope of the grid models

As described in Section 2.3.1 the market simulation results are mapped to separate merged grid models representing different synchronous areas. The grid models do not contain following countries/areas: Cyprus (CY00), Corsica (FR15), Iceland (IL00), Israel (IS00), Malta (MT00), Tunisia (TN00), Turkey (TR00), Ukraine West – Burshtyn Island (UA01).

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[6] for the base case merged model. Additionally, to ensure that all modelling rules for year-round calculations are implemented the same way, 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 case AC load-flow is used (only for Integral), the loads in each modelled market area have to be scaled in order 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

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[5] *Since an AC load-flow for large power systems require 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.*

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

demand values cannot be used directly). The AC solution should be obtained by respecting the reactive limits of the generators.

In TYNDP 2020, AC load-flow can only be utilized for CBA calculations by Integral users (German TSOs and APG). In order 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.

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. While 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.

Load-Flow calculations for the CBA-phase

All losses calculations are based on year-round simulations utilizing the market simulation results for all 8736 hours of the climate years 1982, 1984 and 2007.

Load-Flow calculations for NTC calculations

For ΔNTC calculations, only the Antares market output for climate year 2007 was used.

The detailed description of the transfer capability calculations is given in section 3.2.

Table "Modelling information: NTC calculations" gives an overview (per project) of:

- the used Tool

- whether load shift or generation shift has been used

- whether year round simulations or points in time have been used

2.4. REDISPATCH SIMULATIONS (2.4 and 6.21 in CBA 3)

A detailed description of the methodology for redispatch calculations within the TYNDP 2020 is given in the specific "Implementation Guideline For Redispatch Assessment".

2.5. REFERENCE GRID (2.5 in CBA 3)

As the reference grid is one of the core elements of the studies within the framework of the TYNDP 2020, it is not only fundamental for the project assessment as carried out by applying the CBA Guideline, but also by the earlier published Identification of System Needs study. Therefore a more detailed description of the definition of the reference grid together with a list of projects that are part of the reference grid is given within the respective documentation on the Identification of System Needs.

The reference grid for the Identification of System Needs can be seen as the starting point for this exercise. It is therefore reasonable to use the most probable reference grid available for both, the starting point of the IoSN and the CBA assessment.

3.GENERAL CONCEPTS AND ASSUMPTIONS

3.1.CLUSTERING OF INVESTMENTS (3.2.1 in CBA 3)

Following the 3rd 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 needed that the full potential of the main investment can only be achieved after realisation of the supporting investment(s).

Re-clustering for projects from former TYNDP:

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

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

The interpretation of "significant delay" and the decision whether it is still allowed to cluster the investments may be case specific, but nevertheless must be directly linked to the needed justification as for any clustering. In this respect it might happen that the clustering of one project is allowed while for the other one, e.g. where the investment with the earlier commissioning date is strictly needed 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 have to be applied.

3.2. TRANSFER CAPABILITY CALCULATION (3.2.3 in CBA 3)

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, while 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 has to be reported. For an internal project without cross-border impact ΔGTC can be reported, however in TYNDP 2020, such projects are to be assessed by redispatch simulations, which do not require the knowledge of the GTC impact of the project.

3.2.1. NET TRANSFER CAPACITY (NTC)

NTC 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.

In order to get the delta in NTC in a given hour and direction, two different calculations have to be done (one with the project included and one without the project):

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

The NTC values have to 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 has to 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 needed for the calculations

For TYNDP 2020, the ΔNTC calculation of all projects are based on the hourly market simulation results for the NT2025 scenario from Antares, climate year 2007. The selection of the climate year was based on 2007 having the highest representativeness of the three used in TYNDP 2020. 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 2.3**Error! Reference source not found.**. Other than the market simulation output, no other databases are needed to be used directly.

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 optimization algorithms used in the market simulators. In 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%. This filtering may not be accurate enough for all borders and projects: in such cases, manual addition or removal of network elements from the CB/CO lists needs to be consulted with the relevant TSOs.

In terms of line ratings, the grid model needs to include both winter and summer values, at least for the critical branches to take into account 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. While 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 not enough dispatchable generation in the examined areas).

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

- in proportion of their maximum active power,

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

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 case 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 2.3) are to be shifted.

The power shift method used for each project and border is reported within table "Modelling information: NTC calculations" enclosed to this guideline.

Other considerations

In case the examined border includes PSTs, their phase shifts need to be optimized 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 on the following diagram.
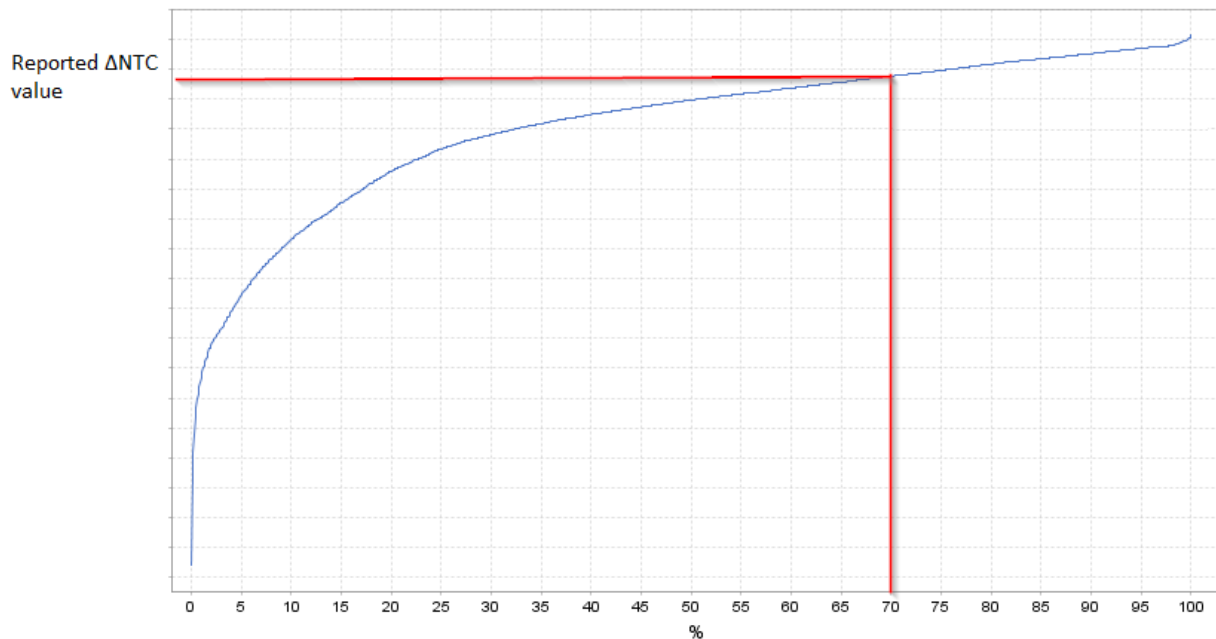
Figure 2 – Sample of a reported ΔNTC value as the difference in boundary exchange in a specific direction that can be supported for 30% of the year due to the project

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 case 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 summarized 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 optimization: depending on the assessed border(s), optimization 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 weight of the PiT are needed
    - 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

3.2.2. GRID TRANSFER CAPACITY (GTC)

In general, the generation or load power shift method can also be applied for calculating the change in GTC. The only difference would be the interpretation of the results: while for the NTC calculation as described in chapter 3.2.1the change in the power shift is directly taken to get the ΔNTC, for the GTC calculation the change in the physical flow across a certain boundary (for which the ΔGTC is calculated) has to be monitored (with respect to the safety criteria in the whole grid).

Calculation of ΔGTC

The main steps of the calculation are thus generally the same as for a ΔNTC calculation. The differences are:

- Instead of monitoring and setting up duration curves of the market exchange shift across a boundary, the physical flow across that boundary is monitored

- Two market simulation outputs (both for the case with and without the project) may be used to achieve higher accuracy of the physical border flows. Note that for the ΔNTC calculation

the same market model output is taken as starting point for the power shift in the case with and without project.

3.3. ASSESSMENT OF STORAGE (4 and 6.20 in CBA 3)

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 taken into account. These are: Natural inflow, Maximum/Minimum Generated energy, Maximum/Minimum Pumped energy, Maximum/Minimum Generation, Maximum/Minimum Pumping, Reservoir level at beginning of each week and Maximum/Minimum Reservoir levels at 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 in order to calculate the market CBA indicators and at the same time to 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 have to 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 turbining). Then, the losses are calculated the same way as for the standard project assessment.

3.4. PROJECT LEVEL INDICATORS

Project level indicators are indicators given within the 3rd CBA Guideline where 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 lack of tools available at ENTSO-E level or common input data specifically needed for the respective indicator or where the methodology is not yet mature enough to get a full assessment on ENTSO-E level.
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. In order to allow Project Promoter to deliver their own calculations for the TYNDP2020, the specific document on PLI has been released earlier in the process.

It is not foreseen to define within this Guideline a more detailed picture of the PLI on top of the main principles as defined within the 3rd CBA Guideline. However, project promoters applying for PLI within the TYNDP2020 need to give a detailed description of the methodology used.

The project level benefits identified within the TYNDP 2020 are as follows:

- B7.1: Balancing Energy Exchange

- B8.1: Frequency Stability

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

- B9: Avoidance of the renewal/replacement costs of infrastructure

- B10: Reduction of necessary reserve for re-dispatch power plants

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

All indicators calculated based on redispatch simulations within the TYNDP 2020 are to be seen as project promoter based. As the indicators determined by redistpacht are the same as from market simulations (except of the B10 indicator) where the detailed methodology is defined within the 3rd CBA guideline, they are not called project level indiactors. However their inclusion in the TNYDP 2020 has to be followed comparable as for PLI.

The detailed assessment requirements for the indicators are described in the TYNDP project sheets and are addressed in the corresponding support sections that are dedicated to each indicator.

Implementation details for the assessment of these benefits are also described within the PLI guidelines.

In order 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 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 supporting section that is 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. Clear explanation of how the methodology illustrated in this guideline has been implemented and applied to perform the study; and

   e. 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 promoter (PLIs ans supporting documentation) with respect to compliance to the 3rd 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.

4. BENEFIT INDICATORS (B1 – B10)

This section delivers additional information in order to complement the 3rd CBA Guideline with insight into the benefit assessment within the TYNDP2020. All sections are directly linked to the respective sections within the 3rd CBA Guideline. Even in case no additional information is needed to be delivered in this document, the respective indicator is displayed nonetheless for reasons of completeness.

4.1. B1 – SEW (6.3 in CBA 3)

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 3rd CBA Guideline for the general methodology, and Section 2.2 for the specific approach in TYNDP2020.

Internal projects can have significant cross-border impact as interconnection projects or can solve internal bottlenecks leading to obtain large internal benefits by reducing the redispatch cost generation. Their SEW has to 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, storage and internal projects which affect the NTC between price zones, the assessment can be done using two market simulations:
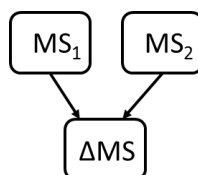
MS_1: Market simulation without the project

MS_2: Market simulation with the project

ΔMS: Difference between MS1 and MS2

Interconnection project
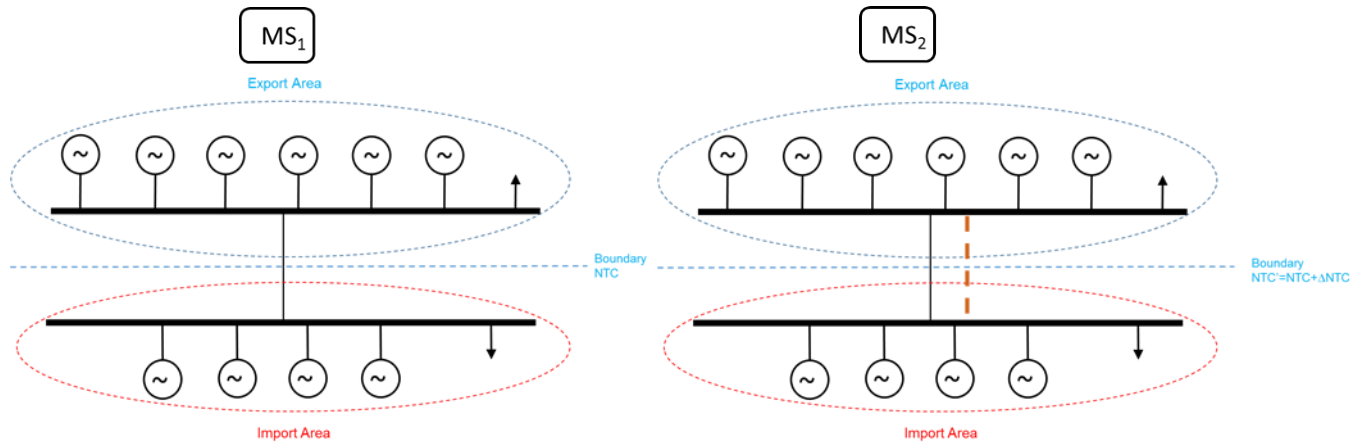
MS$_1$: Market simulation with NTC (= NTC $_{initial}$) between bidding zones without the project

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.
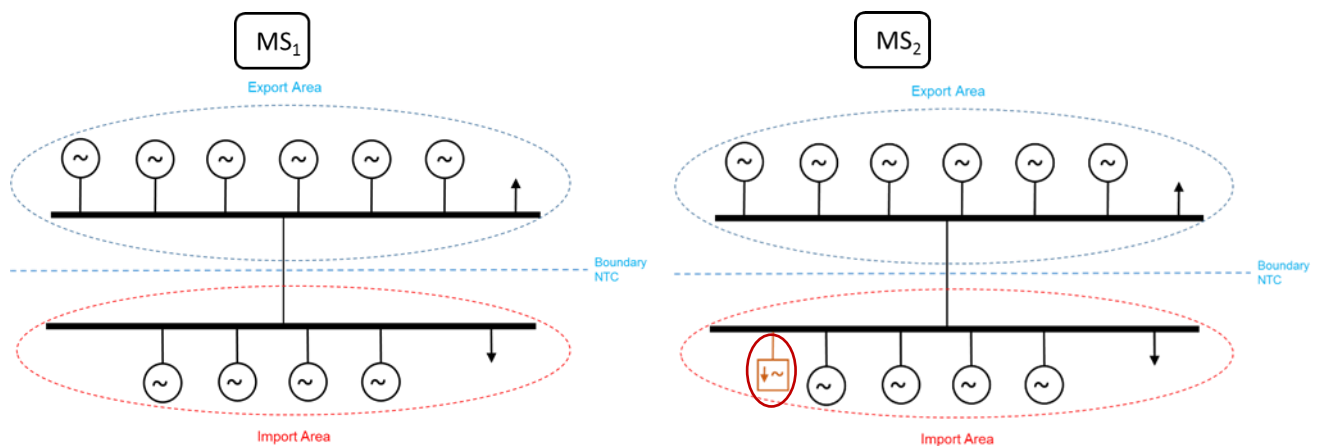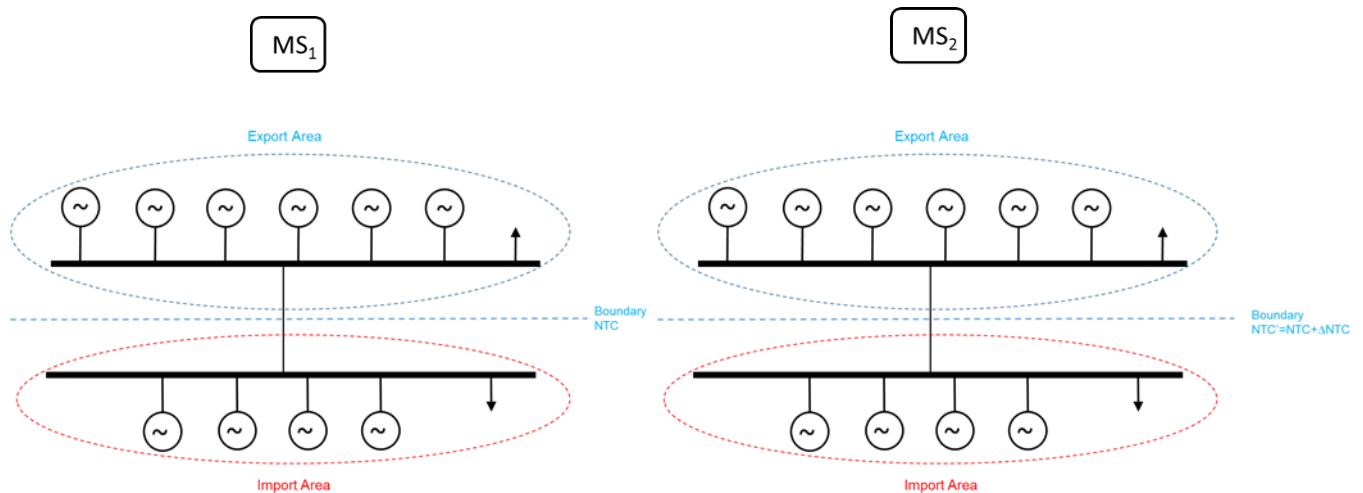

MS_1: Market simulation with NTC (= NTC $_{initial}$) between bidding zones without the project

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 summarizing 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 <u>internal projects without significant cross-border impact but with large internal benefits</u>, a combination of market and network studies can be performed:
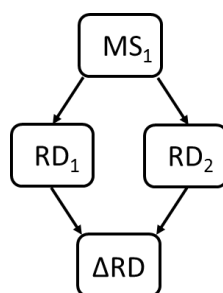
MS_1: Market simulation with reference NTCs

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 under the following constraints to mitigate the congestions:

- The balance of the system has to be kept
- The network must be free of congestions after the redispatch
- The redispatch has to be done in a cost optimal way meeting the actual legal obligations for redispatch by taking into account:
    1. HVDC and PST optimisation
    2. Conventional plants
    3. RES curtailment
    4. Cross border redispatch

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 cases (*Points in Time*; or *PiTs*) may be used.

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

The total benefit (SEW) is calculated by summarizing the difference in total generation costs (ΔRD) obtained from redispatch for all the 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:
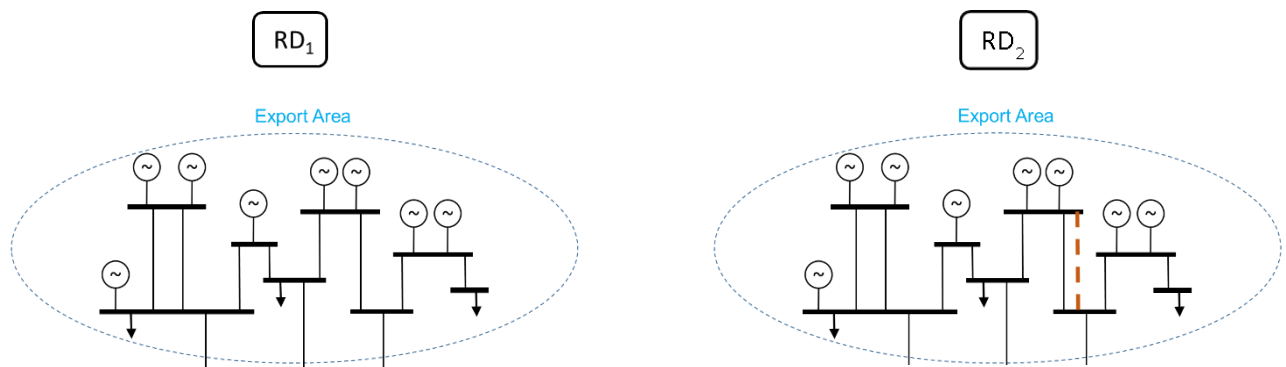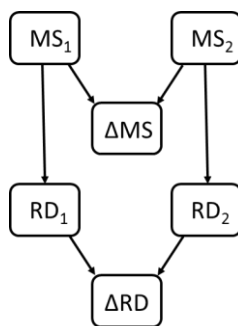

MS_1: Market simulation without the internal project

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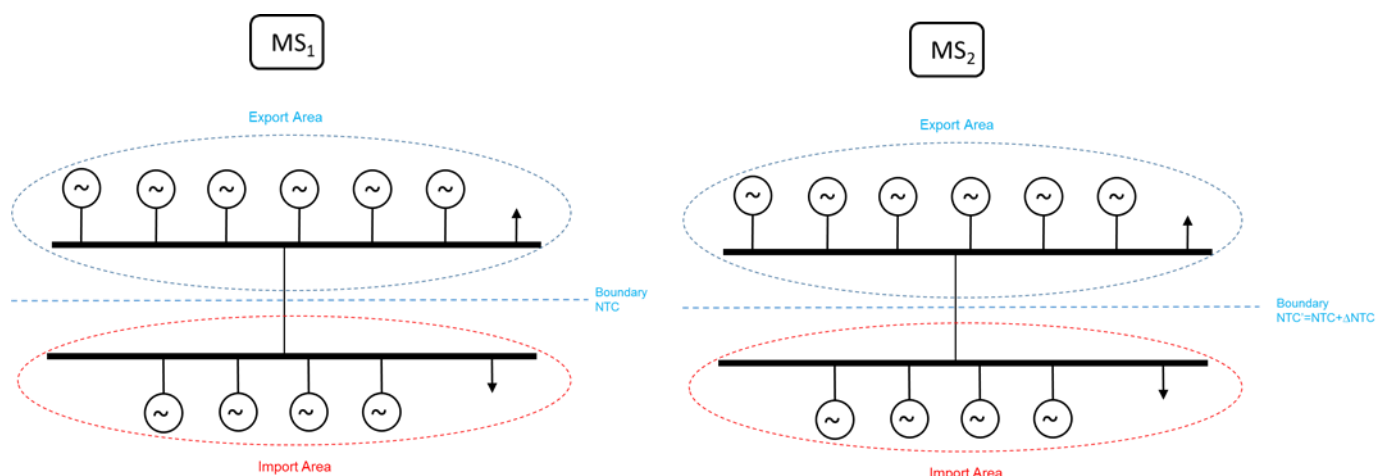
MS_1: Market simulation with NTC (= $NTC_{initial}$) between bidding zones without the project

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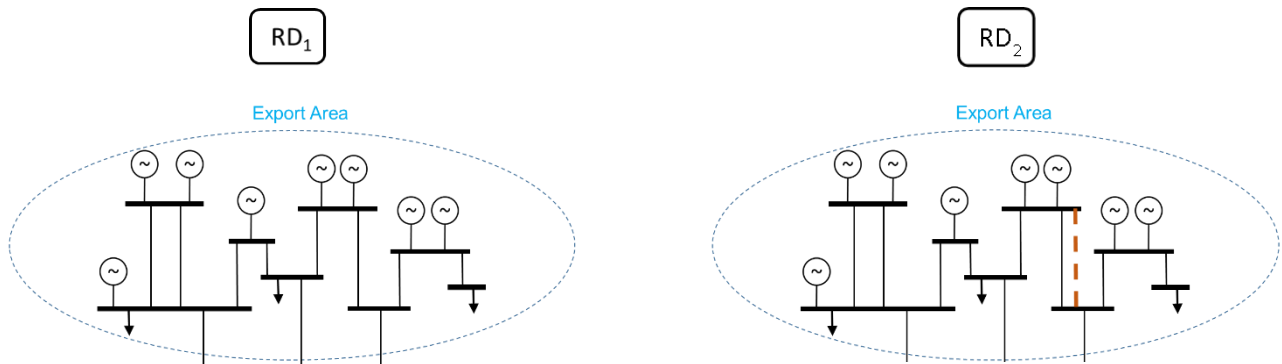
RD$_1$: Redispatch calculated without the internal project using the dispatch taken from MS$_1$
RD$_2$: Redispatch calculated with the internal project using the dispatch taken from MS$_2$

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

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

The market simulations give the benefit related to a change in market capacity between market nodes and the redispatch simulations give the benefit related to a change in line loadings. The change in dispatch from the market studies will influence the line loadings, but this is not taken into account 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 sums 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:

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

which is the same as

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

4.1.1. 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 3rd CBA Guideline it is explicitly monetized 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 monetize the effect of integrating RES within the system, its monetization must be performed as a post process. The RES integration is monetized by multiplying the annual avoided curtailed RES (in MWh) by the average marginal price (€/MWh) as described:

1. Calculate the demand weighted average marginal price (the hours of ENS [10000 €/MWh] will be excluded of the computation) from market studies output (reference case – with/without project case) per area 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 on the base of 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 monetization 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 in [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]

4.1.2. 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 has to be noted that on top of 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 needs to be drawn on the risk of double accounting with these societal costs of CO_2 emissions. This will also be described within the following chapter.

As with the fuel savings due to RES integration, also this monetized 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.

4.2. B2 – ADDITIONAL SOCIETAL BENEFIT DUE TO CO2 EMISSIONS (6.4 in CBA 3)

Variation of CO2 emission

The variation of CO_2 emissions comes from two effects
- The change of generation plans: $\Delta CO2_{generation\ plan}$
- The change of the losses volumes: $\Delta CO2_{losse}$

CO₂ 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.

CO₂ emissions variation from the change of losses volumes
In the market simulations, losses are taken into account via a fixed loaddemand time series. The addition (or the withdrawal) of a new project can have an impact on the hourly losses volumes and in consequence on the hourly total energy generation and finally on the CO_2 emissions. The

change of the hourly generation is not taken into account 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 not to double count 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 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 a lot. Hence, in order to avoid some edge effects, plant types that have close marginal cost (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.

Monetization

The variation of CO_2 emission is monetized 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:

- 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
- The shadow price (or avoidance cost) that is determined by the climate goal under consideration. It can be interpreted as the willingness to pay for imposing the goal as a political constraint.

In general, avoidance cost approach is preferred to guide investments. Literature reports numerous studies of both social cost and avoidance cost. It 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*[7] are used, more specifically the short-and-medium-run costs up to 2030. These avoidance costs are aligned with policies to reach the Paris

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[7] *https://ec.europa.eu/transport/sites/transport/files/studies/internalisation-handbook-isbn-978-92-79-96917-1.pdf*

agreement.. In order to represent the uncertainty surrounding these costs within the TNYDP 2020 the societal value of CO2 is calculated using the Low, Central and High value.

	Low value	Central value	High value
CO_2 cost (2025 and 2030) €/t	60	100	189

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 projectsions. The EC DG Move Handbook provides for avoidance costs in the long run (2040-2060) to become much higher in the range of 156 to 498 €/t. Care is needed in interpreting these societal costs and comparing them with other monetized costs. Also note that these societal costs are not factored in the market study runs where dispatch is still optimized based on other/lower carbon costs which reflect an effective monetary flow.

Double counting

Part of the CO_2 emission variation benefit is already computed within the SEW and the losses cost. Hence, the B2 indicator should only report the additional part of CO_2 benefit that is not already captured. As a result, the formula for this indicator is the following:

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

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

4.2.1. DIFFERENT PARTS OF THE CO2 EMISSIONS CALCULATION

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	Market or redispatch studies	€/yr	Societal costs decreased by ETS	European

from market substitution	(substitution effect)		costs as used in the scenario (to avoid double accounting with B1)	
Societal costs of CO_2 emissions from losses variation	Network studies (losses computation)	€/yr	Societal costs decreased by ETS costs as used in the scenario (to avoid double accounting with B5)	European

4.3.B3 – RES INTEGRATION (6.5 in CBA 3)

The integration of RES is facilitated in two ways:

1. Infrastructure that allows the connection of new RES generation to the main power system.
2. Increasing the capacity between areas with excess of RES generation and other areas which facilitates integration of both existing and new planned RES.

Depending on the type of project, either one or the other option is used.

The monetized value is already fully included in the B1 indicator (SEW). This indicator B3 provides the benefit of RES integration in quantitative MW/MWh figures.

4.3.1. Directly connected RES

If a project connects only RES to the main power system (e.g. a connection of offshore wind parks), the power of the integrated RES is reported (in MW). However, this connected RES might not always be available due to RES curtailment caused by congestions somewhere in the grid. In that case it would be necessary to show the RES integration as described below.

For projects directly connecting RES such as offshore wind parks the RES integration can also be given as energy per year instead of the connected power. Especially when the market simulations display dump energy just giving the connected power is not an appropriate way due to the linked curtailments.

4.3.2. RES Integration

Background

The RES integration benefit is the difference in total RES production (i.e., without counting the curtailed production) with and without the project, based on the changes that can be made to the generation dispatch in order to maximize RES integration while being compliant with the planning standards. The RES integration for each project will be computed as energy given in GWh for the period of one year.

Guidelines for calculation

Calculations should be performed as year round simulations. As alternative a numerous representative points in times with the assigned duration (number of hours) can be used. A project with an NTC increase can have a positive impact on the integration of RES if it reduces curtailment that would occur without the project. Hence, using market simulations the RES integration indicator can be calculated by the difference in dump energy caused as the raised NTC when comparing two market simulation runs with and without the project.

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.

The RES integration in this case shall be given as

$$RES = E_{project} - \left(E_{dump}^{with} - E_{dump}^{without} \right),$$

with

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

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	MWh/yr	included in generation cost savings (B1)	European

4.4.B4 – NON-DIRECT GREENHOUSE EMISSIONS

(6.6 in CBA 3)

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 emission 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 **Error! Reference source not found.**. It has to 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

4.5.B5 – VARIATION IN LOSSES (6.7 in CBA 3)

The losses calculations are generally performed by comparing the network simulation results using two market simulation outputs: with and without the project to take into account the change of flows due to the differences in generation dispatch caused by the NTC increase of the project in the market assessment. While the general rules of the load-flow simulations were described in section 2.3, 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. In order 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 statistical screening of the branch flows of AC load flow si,mulations.

Monetization

The demand curves used in the market simulations for TYNDP 2020 are constructed to cover estimated losses. Therefore, to avoid partial double counting with the B1 benefit (SEW), one of the two possible assumptions that are described in the 3rd CBA Guideline has to be taken. For 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 monetization 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 monetized results, the marginal costs need to be capped to the highest generation cost of the given scenario. This avoids occasional/exceptional marginal costs of 10000 €/MWh in case of ENS which would strongly distort the results. Following values are applied:

Scenario	Cap price [€/MWh]
2025NT	212.9
2030NT	234.5

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

Losses on HVDCs are to be calculated using a linearized model (Idle Loss+K*Setpoint), for which the parameters are provided by the TSOs and the relevant project promoters. In case 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

4.6.B6 – SoS – ADEQUACY (6.8 in CBA 3)

Only for NT2030 the B6 indicator has been calculated.

The adequacy benefit is estimated through the assessment of the EENS saved by the addition of the project. This value is monetized via the 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:

- In order to properly model the loss of load probabilities, the hazards must be simulated in detail. As a result, for the TYNDP, adequacy simulations must be performed with 510 Monte Carlo years, resulting of the matching of the full set of the 34 PECD climate years and 15 outage patterns[8] time series. See the ENTSO-E MAF methodology for further details on adequacy assessment stochastics.
- The scenario is built in order to be realistic in terms of loss of load: for each country LOLE should be within 1h of its reliability standard criteria[9], 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:

- Step 1 : Check scenarios
  - o 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.
  - o For 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 has been added to comply to the reliability criteria (in all the countries of the global geographical area)..

- Step 2 : Assess avoided EENS
  - o Preliminary

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[8] 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.
[9] By default 3h/year (if no official value)

- 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.
- 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.
  - o Assess the EENS without the project.
  - o 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.
  - o Compute the difference of EENS between both situations. Report this value
  - o Monetize this difference using the VoLL of each country.

- Step 3 : Sanity check[10]
  - o Transmission project
    - 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
    - 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.
  - o For storage
    - The sanity check is equal to the generation capacity of the project if the addition of the project decreases LOLE in the country and is not needed when there is no LOLE decrease due to the project.
  - o For RES project
    - 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 needed when there is no LOLE decrease due to the project.
  - o Particular projects
    - For project with several contributions (in transmission, storage or RES generation), the sanity check is the sum of the sanity checks of each contribution
    - For 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.
  - o Report the sanity check capacity.
  - o Monetize the sanity check with the Cost of New Entry (CONE) value for each country.
- Monetization
  - o **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 2020, the result of this study is not available yet. Therefore, the VoLL is based on expert judgement at 10 k€/MWh for each country for the monetization of B6

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

indicator, in line with common values found in the literature.[11] his is without prejudice to the outcome of the VoLL study ENTSO-E is doing.

- o **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 2020, the result of this study is not yet available. Therefore, the CONE is based on expert judgement set at 40 k€/MW/yr for each country for the monetization of B6 indicator, in line with common values found in the literature.[12]
- Final value
  - o The adequacy benefit is the minimum between the monetization of the EENS avoided by the project and monetization 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

4.7.B7 – SoS – FLEXIBILITY (6.9 in CBA 3)

4.7.1.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 3rd CBA Guideline.

It has to be noted that there is a challenge when it comes to choosing the right balance between 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 3rd CBA

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[11] *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.*

[12] *This value relates to that of a CCGT overnight installation cost spread over 20 years, in line with costs of generation as given in the TYNDP2020 Scenario Report*

Guideline predicts monetary results, the value submitted by the promoter will not be published in the TYNDP 2020 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 published in the Project Sheet
< 1 M€	0
[1 M€; 15 M€[	+
≥15 M€	++

To ensure the indicator is statistically meaningful, the range thresholds are set based on earlier TYNDP 2018 results and public studies on market integration benefits:

- Definition of the ratio of the socio welfares from:

$$\frac{balancing\ market\ integration}{Long\ Term + Day\ Ahead\ "cross-border"}$$

- Relationship between the socio-economic benefits (SEW) of TYNDP 2018 projects for all 2030 scenarios and the expected ratio between Long Term + Day Ahead cross-border trade social welfare (associated to SEW) and 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 2018 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);
- Afterwards, 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 1 M€ is 35% and below 15M€ is 87.5% (see Figure below)
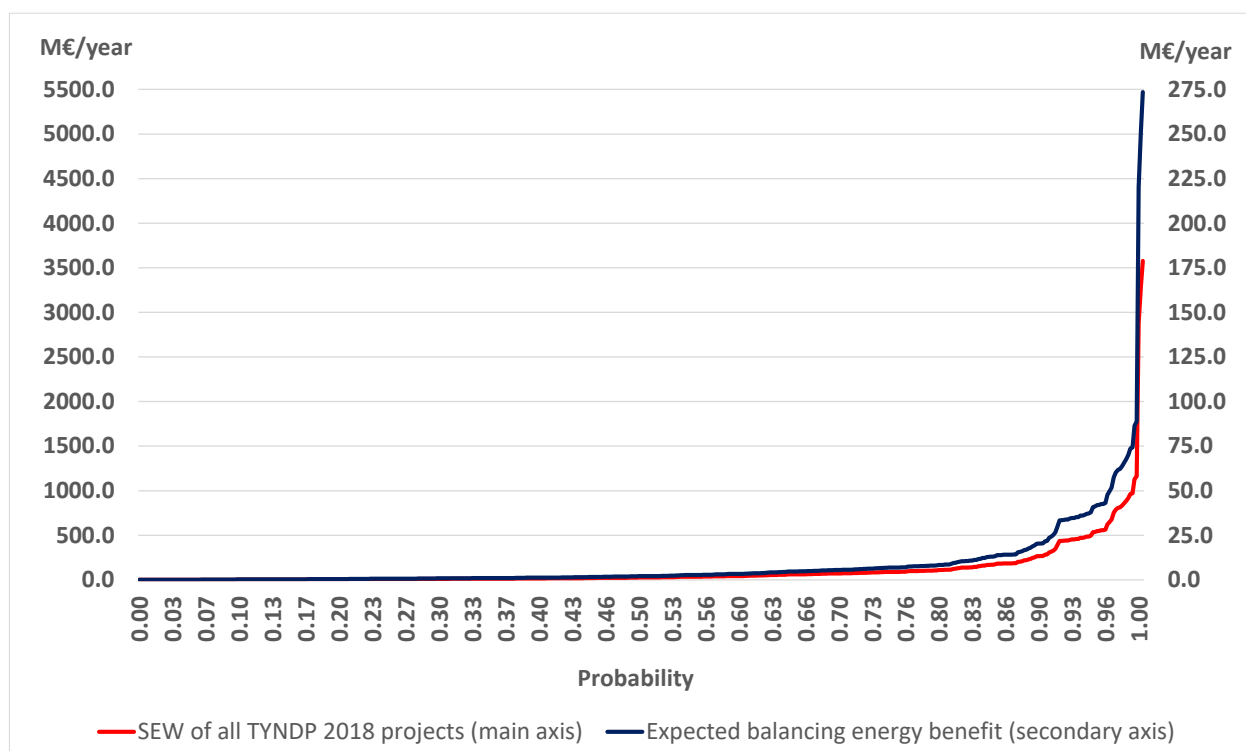
Figure 3 - Illustrative view on how TYNDP2018 project SEW benefits can be mapped to contributions in balancing energy benefits to come to reasonable thresholds

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

4.8.B7.2 - Balancing capacity exchange/sharing

As this indicator has been introduced to the 3rd 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 TYNDP2020.

4.9.B8 – SoS - SYSTEM STABILITY (6.10 in CBA 3)

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 3rd CBA guideline's 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.

B8.0 Qualitative stability indicator:

This indicator has to be implemented following the guidance given within the 3rd CBA Guideline.

B8.1 Frequency stability:

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 3rd CBA Guideline.

B8.2 Blackstart 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 3rd CBA Guideline.

The Blackstart 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.

Small systems (such as Baltic States (Latvia, Estonia, Lithuania)) or poorly connected systems has operating costs.In line with the long-term plans of the EU (climate policy goals and targets for 2030 or 2050 year), these systems will face RES integration challenges, nonsynchronous generation, decrease of inertia, short circuit power and dynamic voltage stability. These reasons could lead to cascade events or blackout. Such small systems could operate in island mode or with IPS/UPS. However, in the future these systems will meet with expensiveness of operating system control. To avoid or to reduce this, such systems should synchronize. Therefore, such systems must satisfy the requirements of the ENTSO-E to ensure stable work/operation. For this reason, TSOs are doing research and studies. It may be mentioned that the EC with the assistance of the Joint Research Centre (JRC) and in cooperation with ENTSO-E and the Baltic TSOs launched a study on the "Integration of the Baltic States into the EU electricity system" (the end of 2015). As a further step towards synchronisation of the power systems of Baltic countries into the CEN – three Baltic TSOs in cooperation with Tractebel have performed the multi-disciplinary study of isolated operation of the Baltic power system[13] (2017). In 2017-2018 Baltic TSOs and PSE together with Institute of Power

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[13] https://www.litgrid.eu/uploads/files/dir393/dir19/6_0.php

Engineering in Gdansk have performed "Dynamic Study of Extension of the Synchronous Area Continental Europe for the Baltic States Transmission Systems". After that Baltic TSOs together with ENTSO-E and PSE Operator have performed the Study assessing the frequency stability of synchronously interconnected Baltic States and Continental European electricity network. There are also numerous other studies covering the similar topics. It is important to mention that this sub-indicator evaluates extended blackout risks and the consequences of such an event. The calculation of this benefits is carried out by calculating the total costs incurred in case of total regional blackout event. Its application is mainly given by Project Promoters.

B8.3 – Voltage/reactive power

This indicator is not assessed in the TYNDP2020.

4.10.B9 – AVOIDANCE OF RENEWAL/REPLACEMENT COST OF INFRASTRUCTURE (6.11 in CBA 3)

This indicator was introduced to 3rd CBA Guideline after being included to the "missing benefits" from TYNDP 2018. The methodology is described in 3rd CBA Guideline and its application mainly relies on Project Promoter information.

Parameter	Source of Calculation	Basic Unit of Measure	Monetary measure	Level of Coherence
Benefit from avoidance of renewal/ replacement of infrastructure	Information delivered by project promoter	€	per definition monetary	Regional/PP level

4.11.B10 – RESERVES FOR REDISPATCH POWER PLANTS (6.12 in CBA 3)

This indicator is listed as one of the PLI and can be provided by the respective project promoter. A detailed description of the used methodology has to be submitted, following the principles given within the 3rd CBA Guideline.

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

5. PROJECT COSTS

The costs are presented with two main indicators C1 (CAPEX, C1a and C1b) and C2 (OPEX) for every investment in the price base year as defined within the 3rd CBA Guideline.
C1a, C1b and C2 need to be reported separately.

5.1. CAPEX (C1a, C1b) (6.13 in CBA 3)

All costs have to be delivered by the Project Promoter based on the guidance given within the 3rd CBA Guideline.

For non-mature projects the standard costs have to be taken from the table in Annex I.

5.2. OPEX (6.14 in CBA 3)

All expected maintenance and operation costs have to be delivered by the Project Promoter based on the guidance given in the 3rd CBA Guideline.

6. RESIDUAL IMPACTS (6.16, 6.17 AND 6.18 IN CBA 3)

In the TYNDP 2020 the Project Promoter will directly deliver the Residual Impacts S1, S2 and S3 following the guidance given in the 3rd CBA Guideline.

The values for the residual impacts have to be determined in line with the line-routing of the projects as given in the TNYDP 2020.

ANNEXES

I. QUANTITATIVE ASSUMPTIONS

A. GENERAL ASSUMPTIONS

Quantitative measure	Value
Hurdle costs	0.01 €/MWh
Cost for ENS in the market models	10000 €/MWh
Grouping of power plants types based on their marginal costs – only used for B2	2 €/MWh
Societal values of CO_2 emissions	60 €/t, 100 €/t, 189 €/t
Cap of marginal costs for losses calculations	212.9 €/MWh (NT2025); 234.5 €/MWh (NT2030)
Value of Lost Load	10000 €/MWh
Cost for new entrant	40000 €/MW/yr

B. NON-CO_2 EMISSION FACTORS

Fuel	Type	Standard efficiency in NCV terms	NOx emission factor	NH3 emission factor	SO2 emission factor	PM5 and smaller emission factor	PM10 emission factor	NMVOC emission factor
		%	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ	kg / Net GJ
Nuclear	-	33%	0	0	0		0	
Hard coal	old 1	35%	0,19960	0,00170	0,31983	0,00598	0,00394	0,00100
Hard coal	old 2	40%	0,19960	0,00170	0,31983	0,00598	0,00394	0,00100
Hard coal	new	46%	0,19960	0,00170	0,31983	0,00598	0,00394	0,00100
Hard coal	CCS	38%	0,01996	0,00017	0,03198	0,00060	0,00039	NA
Lignite	old 1	35%	0,20308	0,00100	0,22250	0,01688	0,01128	NA
Lignite	old 2	40%	0,20308	0,00100	0,22250	0,01688	0,01128	NA
Lignite	new	46%	0,20308	0,00100	0,22250	0,01688	0,01128	NA
Lignite	CCS	38%	0,02031	0,00010	0,02225	0,00169	0,00113	NA

Gas	conventional old 1	36%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	conventional old 2	41%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT old 1	40%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT old 2	48%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT present 1	56%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT present 2	58%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT new	60%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	CCGT CCS	51%	0,00913	0,00106	0,00025	0,00073	0,00046	NA
Gas	OCGT old	35%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Gas	OCGT new	42%	0,05150	0,00600	0,00142	0,00413	0,00262	0,00180
Light oil	-	35%	0,13800	NA	0,31900	0,00250	0,02000	0,00080
Heavy oil	old 1	35%	0,13800	NA	0,31900	0,00250	0,02000	0,00080
Heavy oil	old 2	40%	0,13800	NA	0,31900	0,00250	0,02000	0,00080
Oil shale	old	29%	0,05000	NA	0,56050	0,00500	0,02000	NA
Oil shale	new	39%	0,05000	NA	0,56050	0,00500	0,02000	NA
Other non-RES	-	-	0,19845	0,01191	0,25290	0,01136	0,01611	0,00393

C. PROJECT STANDARD COSTS

AC onshore overhead lines

Investment type	Standard cost[14]	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

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[14] *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

Invesmtent 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

Subsea cables

Invesmtent 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)

Invesmtent 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

II. 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
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)
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

III. POINTS IN TIMES FOR LOAD-FLOW CALCULATIONS

In case points in time are used instead of year-round calculations, the selection of representative hours has to 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 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 need to be given within the documentation of the TYNDP2020.

Acknowledgements