European Network of
Transmission System Operators
for Electricity

ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects

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25 April – 31 May

Disclaimer

This document reflects the work done by ENTSO-E in compliance with Regulation (EC) 347/2013.

This document is a draft version and reflects the suggestions given by our stakeholders until now and the TSOs experience based on the TYNDP 2014 and partially 2016.

The final version approved by the EC is expected spring 2017.

Contents

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General definitions

Grid Transfer Capability (GTC)

Grid Transfer Capability is defined as the maximum power flow allowed on the grid to transfer energy across a boundary without the occurrence of grid congestions whilst taking into account the N-1 system security criterion. The boundary can be identified as an internal border as well as borders between countries and/or market/bidding areas.

The GTC reflects the ability of the grid to transport electricity across a boundary, such as from one bidding area (area within a country or a TSO) to another, or at any other relevant cross-section of a transmission corridor (within one country or across multiple countries) having the effect of increasing the capability of the grid to accommodate a (larger) power flow.

The concept of delta GTC is applicable regardless of the market coupling mechanism applied i.e. NTC-based or low-based.

a. In case of flow-based: there is a direct relationship between the increased power flow reflected by the delta GTC and the potential for additional market exchanges, irrespectively of cross-border or internal projects
b. In case of NTC-based: an indirect relationship is to be established between the 'delta power shift' behind the 'delta GTC calculation' on a boundary and the NTC-increase on that boundary. Given that NTC values are only set on cross-border level, a specific guideline is introduced to deal with internal projects

Boundary

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

c. Be the border between two bidding zones or countries.
d. Span multiple borders between multiple bidding zones or countries.
e. Be located inside a market-area or country dividing the area into two or multiple subareas.

Generation power-shift

Generation power shift is used to calculate the additional power flow across a specified boundary. A generation power-shift can be seen as the deviation from the cost-optimal power plant dispatch (determined by market simulations) with the purpose to influence the grid utilisation[1]. For example, one

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

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can imagine the loading of a line across the boundary which separates System A from System B (with energy transported from A to B). Starting from this situation, generation can be incrementally decreased in area A and increased in area B. This process is carried out up to the point, where the line loading security criteria in System A or System B are reached.

Competing projects

Two or more transmission projects are regarded as competing if they fulfil the following criteria:

a. They increase GTC on the same boundary, and
b. There is no need to realise both (multiple) projects, i.e. only one (a subset) of the projects is economically viable.

Project

A project is defined as the smallest set of assets that effectively add capacity to the transmission infrastructure that can be used to transmit electric power, such as a transformer + overhead line + transformer.

Cluster

A cluster is defined as a set of (a) a main project that is built to increase GTC across a certain boundary by a certain amount, and (b) one or more supporting projects that must be realised together with the main project in order to make it possible for the main project to realize its intended GTC increase.

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1 INTRODUCTION AND SCOPE

1.1 TRANSMISSION SYSTEM PLANNING

The move to a more diverse power generation portfolio due to the rapid development of renewable energy sources (RES) and the liberalisation of the European electricity market has resulted in more and more interdependent power flows across Europe, with large and correlated variations. Therefore, transmission system design must look beyond traditional (often national) TSO boundaries, and progress towards regional and European solutions. Close cooperation of ENTSO-E member companies responsible for the future development of the European transmission system is required to achieve coherent and coordinated planning that is necessary for such solutions to materialise.

The main objective of transmission system planning is to ensure the development of an adequate pan-European transmission system which, with respect to the scenario framework:

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

In this process certain key rules have to be kept in mind, in particular:

- Requirements and general regulations of the liberalised European power and electricity market set by relevant EU legislation;
- EU policies and targets;
- National legislation and regulatory framework;
- Security of people and infrastructure;
- Environmental policies and constraints;
- Transparency in procedures applied;
- Economic efficiency.

The planning criteria to which transmission systems are designed are generally specified in transmission planning documents. Such criteria have been developed for application by individual TSOs taking into account the above mentioned factors, as well as specific conditions of the network to which they relate. Within the framework of the pan-European Ten Year Network Development Plan (TYNDP), ENTSO-E has developed common Guidelines for Grid Development (e.g. Annex 3 of TYNDP 2012). Thus, suitable methodologies have been adopted for future development projects and common assessments have been developed.

Furthermore, Regulation (EU) 347/2013 requests ENTSO-E to establish a “methodology, including on network and market modelling, for a harmonised energy system-wide cost-benefit analysis at Union-wide level for projects of common interest” (Article 11).

This document constitutes an update of ENTSO-E's Guidelines for Grid Development, aiming at compliance with the requirements of the EU Regulation, and ensuring a common framework for multi-criteria cost-benefit analysis (CBA) for TYNDP projects, which are the sole base for candidate projects of common interest (PCI). In this regard all projects (including storage and transmission projects) and promoters (either TSO or third party) are treated and assessed in the same way.

1.2 Scope of the document

This document describes the common principles and procedures, including network and market modelling methodologies (see Section 2.1.2), to be used when performing combined multi-criteria and cost-benefit analysis in view of elaborating Regional Investment Plans and the Union-wide TYNDP, as ratified by EU Regulation 714/2009 of the 3rd Legislative Package. Following the EU Regulation on guidelines for trans-European energy infrastructure (347/2013), it will also serve as a basis for a harmonised assessment at Union Level for PCIs.

When planning the future power system, new transmission assets are one of a number of possible system solutions. Other possible solutions include storage, generation, and demand-side management. The scope of this methodology is planning the future transmission system. However, the Regulation also requires ENTSO-E to consider storage in its CBA methodology. The principles of assessing storage projects using this methodology are therefore described in C**Error! Reference source not found.**. Storage projects re, in principle, assessed in a similar way as transmission projects. This is further explained in the respective chapter.

This CBA guideline sets out the ENTSO-E criteria for the assessment of costs and benefits of a transmission (or storage) project, all of which stem from European policies on market integration, security of supply and sustainability In order to ensure a full assessment of all transmission benefits, some of the indicators are monetised (inner ring of Figure 1), while others are quantified in their typical physical units, such as tons or kWh (outer ring of Figure 1).

This set of common European-wide indicators will form a complete and solid basis, both for project assessment within the TYNDP, and coherent project portfolio development for the PCI selection process[2].

[2] It should be noted that he TYNDP will not contain any ranking of projects. Indeed, as stated by the EU Regulation 347/2013 (art4.2.4), « each Group shall determine its assessment method on the basis of the aggregated contribution to the criteria […] this assessment shall lead to a ranking of projects for internal use of the Group. Neither the regional list nor the Union list shall contain any ranking, nor shall the ranking be used for any subsequent purpose »

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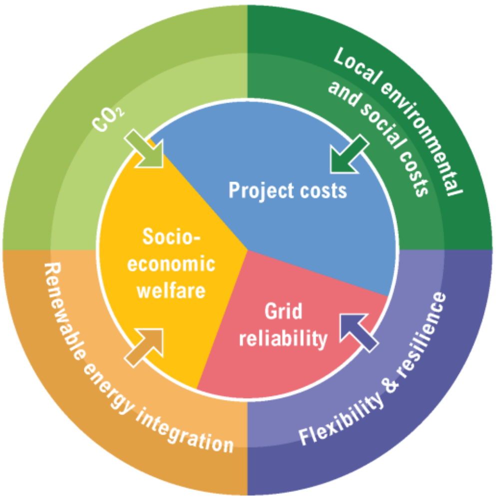

Figure 1: Scope of cost benefit analysis (source: THINK project)

1.3 Content of the Document

The CBA methodology is developed to evaluate the benefits and costs of TYNDP projects from a pan-European perspective, providing important input for the selection process of PCIs. The main objective of this CBA methodology is to provide a common and uniform basis for the assessment of projects with regard to their value for European society.

Transmission system development focuses on the long-term preparation and scheduling of reinforcements and extensions to the existing transmission grid. This document describes the assessment of projects, which are identified in the TYNDP based on the current guidelines for grid development, further defined in the TYNDP process.

The cost-benefit impact assessment criteria adopted in this document reflect each project's added value for society. Hence, economic and social viability are displayed in terms of increased capacity for trading of energy and balancing services between bidding areas (market integration), sustainability (RES integration, CO_2 variation) and security of supply (secure system operation). The indicators also reflect the effects of the project in terms of costs and environmental viability. They are calculated through an iteration of market and network studies. It should be noted that some benefits are partly or fully internalised within other benefits, such as avoided CO_2 and RES integration via socio-economic welfare, while others remain completely non-monetised.

This is a continuously evolving process, so this document will be reviewed periodically, in line with prudent planning practice and further editions of the TYNDP or upon request (as foreseen by Article 11 of the EU Regulation 347/2013).

2 SCENARIO- AND GRID DEVELOPMENT

Scenarios are defined to represent potential future developments of the energy system. The essence of scenario analysis is to come up with plausible pictures of the future. Scenarios are means to approach uncertainties and the interaction between these uncertainties. The scenarios are a representation of how the generation-transmission system could look like in the future. Scenarios shall at least represent the Union's electricity system level and be adapted in more detail at a regional level. They shall reflect European Union and national legislations in force at the date of analysis. Scenarios are the basis for the further calculation of the grid development needs.

2.1 CONTENT OF SCENARIOS

Scenarios represent the European electricity system level and can be adapted in more detail at a regional level. They reflect European and national legislations in force at the time of the analysis. Scenarios are a description of plausible futures characterised by a **generation portfolio, demand forecast** and **exchange patterns** with the systems outside the study region. The objective is to construct contrasting future developments that differ enough from each other to capture a realistic range of possible futures that result in different challenges for the grid.

Multi-criteria cost benefit analysis of candidate projects of European interest is based on the scenarios developed in ENTSO-E's TYNDP. These scenarios aim to provide stakeholders in the European electricity market with an overview of generation, demand and their adequacy in different scenarios for the future ENTSO-E power system, with a focus on the power balance, margins, energy indicators and the generation mix. The scenarios are elaborated after formally consulting Member States and the organisations representing all relevant stakeholders.

2.1.1 TIME HORIZONS.

The scenarios will be representative of at least two time horizons based on the following:

- Mid-term horizon (typically 5 to 10 years). Mid-term analyses should be based on a forecast for this time horizon. ENTSO-E's Regional Groups and project promoters will have to consider whether a new analysis has to be made or analysis from last TYNDP (i.e. former long term analysis) can be re-used. Long-term horizon (typically 10 to 20 years). Long-term analyses will be systematically assessed and should be based on common ENTSO-E scenarios.

- Very long-term horizon (typically 30 to 40 years). Analysis or qualitative considerations could be based on the ENTSO-E 2050-reports.

- Horizons which are not covered by separate data sets will be described through interpolation techniques.

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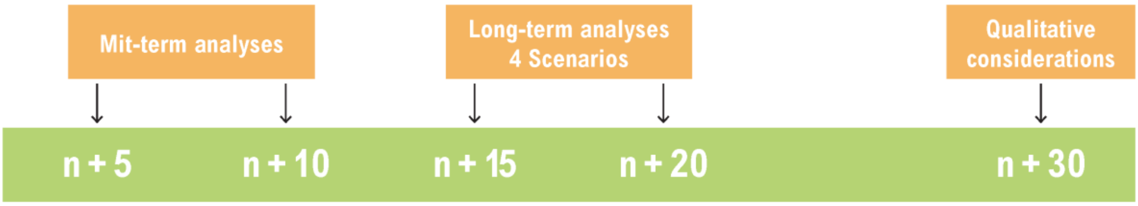

Figure 2: Time Horizons

As shown in Figure 2, the scenarios developed in a long-term perspective may be used as a bridge between mid-term horizon and very long term horizons (+30 or 40). The aim of the n+20 perspective should be that the pathway realised in the future falls within the range described by the scenarios with a high level of certainty.

2.1.2 MARKET AND NETWORK STUDIES

Market studies are used to calculate the dispatch of generation units, load per bidding area, market exchanges between bidding areas and corresponding prices on an hourly basis, using a simplified model of the physical grid. They represent bidding areas through a network of interconnected nodes using a single branch to represent the physical interconnections that exist between each pair of bidding areas. Thus the market studies analyses the cost-optimal generation pattern for every hour taking into account today's market design.

Market studies are used to determine the benefits of making available additional transport capacity and enabling a more efficient usage of generation units available in different locations. They take into account several constraints such as flexibility and availability of thermal units, hydro conditions, wind and solar profiles, load profile and uncertainties. They also allow to measure the economy in generation costs allowed by investments in the grid (and/or in storage).

Network studies, on the other hand, are based on network models representing the transmission network in a high level of detail and are used to calculate the actual load flows that take place in the network under given generation/load/market exchange conditions (see Annex 1). Network studies allow to identify bottlenecks in the grid corresponding to the bulk power flows resulting from the market exchanges, and are in particular necessary to compute the GTCs used in NTC-based market studies (see Annex 3).

Both types of studies thus provide different information and –as they complement one another– are often used in an iterative manner.

For internal projects which are defined as projects that do not show a significant impact on cross-border capacities (in terms of international borders) a combination of both network and NTC-based market studies can be applied to combine network contingencies within a defined market area with the economy of the generation dispatch (see Annex 2).

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2.2 MULTI-CASE ANALYSIS

System planning studies are carried out with market simulations producing hourly results. The network studies then perform load flow calculations using these hourly results.

The network studies are to be performed treating either each individual hourly output as a separate planning case (thus 8760 cases) either working with a limited but still adequate set of planning cases. In the latter case, adequate means that the planning cases selected out of the available 8760 cases need to be representative for the year-round effect of the generation dispatch, load dispatch and market exchanges within the area under study.

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3 PROJECT ASSESSMENT: COMBINED COST BENEFIT AND MULTI-CRITERIA ANALYSIS

The goal of project assessment is to characterise the impact of transmission projects, both in terms of added value for society (increase of capacity for trading of energy and balancing services between bidding areas, RES integration, increased security of supply) as well as in terms of costs.

ENTSO-E has the role to define a robust and consistent methodology. Thus ENTSO-E has defined this multi-criteria CBA Guideline, which compares the contribution of a project to the different indicators on a consistent basis. A robust assessment of transmission projects, especially in a meshed system, is a complex matter. Additional transmission infrastructure provides more transmission capacity and hence allows for an optimization of the generation portfolio, which leads to an increase of Social-Economic Welfare[3] throughout Europe. Further benefits such as Security of Supply (SOS) or improvements of the flexibility also have to be taken into due account.

The multi-criteria approach highlights the characteristics of a project and gives sufficient information to the decision makers.

A fully monetized approach would require all socio economic costs and benefits to be converted to their monetary value. This is not sufficient in this context as many benefits are financially unquantified, for example benefits to market design, competitiveness, ability to attract multi-nationals, system safety, environmental impact, etc.

Multi-criteria analysis however can account for each of these including cost benefit analysis of those elements that can be monetized so provides the flexibility consistently and transparently represent these as the project progresses and greater detail is known. A single monetary value would not identify either the cost of benefit that is the catalyst when a change occurs.

This chapter establishes a methodology for the identification of projects and (if applicable) project clusters, and consequently project or cluster assessment.

3.1 CLUSTERING OF PROJECTS

In situations where multiple projects depend on each other to perform a single function (i.e. one project cannot perform its intended function without the realisation of another project) they can be clustered and assessed as a single project.

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In the context of the TYNDP, clustering is defined as the grouping of projects that must be realised jointly in order to achieve a specific function, e.g. a GTC increase across a defined boundary. Clustering should only be applied in cases where multiple projects strongly depend on each other; i.e. where one project cannot fully accomplish a particular goal, without one or more supporting projects. Note that competitive projects cannot be clustered together.

When clustering several projects together, the project promoter(s) must ensure that all projects contribute to the total GTC increase in a significant manner but in addition, they must explain (in writing) how the reinforcements complement each other and the disadvantage of not developing one of them. Hence, projects should only be clustered with other projects when this is necessary to reach the full potential of the main project. It must be clearly stated and understandable for a third party why a set of projects have to be clustered.

In order to avoid that projects are clustered, but do contribute the same goal in practice because they are commissioned too far apart in time (which would also introduce a risk that one or more projects in the cluster are never realized eventually), a limiting criterion is introduced that prohibits clustering of projects with very different project statuses. ENTSO-E distinguishes four project statuses that represent the maturity of a project that is listed in the TYNDP (under consideration – planned – design & permitting – under construction). Projects can only be clustered if they are at maximum one stage of maturity apart from the main project. This limiting criterion is introduced in order to avoid excessive clustering of projects that do not contribute to realizing the same function because they are commissioned too far ahead in time.

under construction	**design & permitting**	**planned**	**under consideration**

Figure 3: Clustering

3.2 Assessment Framework

The assessment framework is a combined cost-benefit and multi-criteria assessment[4], complying with Article 11 and Annexes IV and V of the EU Regulation 347/2013. The criteria set out in this document have been selected on the following basis:

- They enable an appreciation of project benefits in terms of EU network objectives to:
    - Ensure the development of a single European grid to permit the EU climate policy and sustainability objectives (RES, energy efficiency, CO^2);

[4] More details on multi-criteria assessment and cost-benefit analysis are provided in Annex 5.

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- Guarantee security of supply;
- Complete the internal energy market, especially through a contribution to increased socio-economic welfare ;
- Ensure system stability.

- They provide a measurement of project costs and feasibility (especially environmental and social viability).
- The indicators used are as simple and robust as possible. This leads to simplified methodologies for some indicators.

Figure 3 shows the main categories of indicators used to assess the impact of projects on the transmission grid.

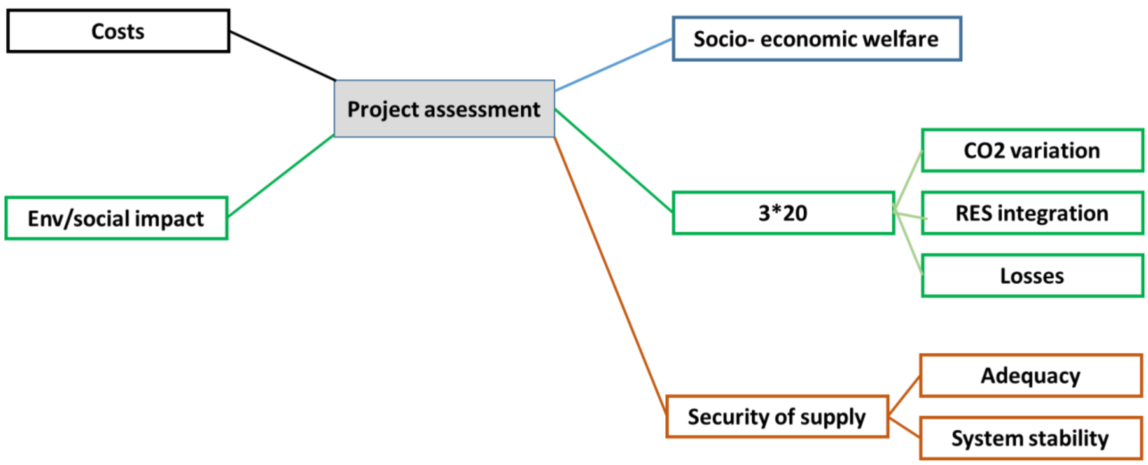

Figure 3: Main categories of the project assessment methodology

Some projects will provide all the benefit categories, whereas other projects will only contribute significantly to one or two of them. Other benefits, such as benefits for competition[5], also exist. These are more difficult to model, and will not be explicitly taken into account.

The **benefit categories** are defined as follows:

B1. Security of supply: Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand, hereby taking into account the variability of climatic effects on demand and renewable energy sources production..

[5] Some definitions of a market benefit include an aspect of facilitating competition in the generation of electricity. These Guidelines are unable to well-define any metric solely relating to facilitation of competition. If transmission reinforcement has minimised congestion, that has facilitated competition in generation to the greatest extent possible. For further developments, see Annex 4.

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B2. Security of supply: System stability is the ability of a power system to provide a secure supply of electricity as per the technical criteria defined in Annex 1.

B4. Socio-economic welfare (SEW)[6] or market integration is characterised by the ability of a power system to reduce congestion and thus provide an adequate GTC so that electricity markets can trade power in an economically efficient manner[7].

B3. RES integration: Support to **RES integration** is defined as the ability of the system to allow the connection of new RES plants and unlock existing and future "green" generation, while minimising curtailments[8].

B5. Variation in losses in the transmission grid is the characterisation of the evolution of thermal losses in the power system. It is an indicator of energy efficiency[9] .

B6. Variation in CO_2 emissions is the characterisation of the evolution of CO_2 emissions in the power system. It is a consequence of B3 and B4 (the unlocking of generation with lower carbon content)[10].

The **project costs** are defined as follows:

C1. Total project expenditures are based on prices used by each TSO and rough estimates on project consistency (e.g. km of lines).

The **project impact on society** is defined as follows:

S.1. Environmental impact characterises the project impact as assessed through preliminary studies, and aims at giving a measure of the environmental sensitivity associated with the project.

S.2. Social impact characterises the project impact on the (local) population that is affected by the project as assessed through preliminary studies, and aims at giving a measure of the social sensitivity associated with the project.

These two indicators refer to the remaining impacts, after potential mitigation measures defined when the project definition becomes more precise.

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

[7] This category contributes to the criteria 'market integration" set out in Article 4, 2a and to criteria 6b of Annex V, namely "evolution of future generation costs".

[8] This category corresponds to the criterion 2a of Article 4, namely "sustainability", and covers criteria 2b of Annex IV.

[9] This category contributes to the criterion 6b of Annex V, namely "transmission losses over the technical lifecycle of the project".

[10] This category contributes to the criterion « sustainability » set out in Article 4, 2b and to criteria 6b of Annex V, namely " greenhouse gas emissions"

ASSESSMENT SUMMARY TABLE

	CBA results non specific scenario				CBA results for each scenario					CBA results non specific scenario			
	GTC increase direction 1 [MW]	GTC increase direction 2 [MW]	TYNDP scenarios	Contribution to Intercon-nection rate [%]	B1 - SoS – adequacy [MWh/y]	B4 - SEW [M€/y]	B3 - RES [MWh/y or MW/y]	B5 - Losses [MWh]	B6 - CO2 [kT/y]	B2 –SOS - System Stability	S1 - protected areas [km]	S2 - urban areas [km]	C1 - Estimated cost [M€]
Assessment results CLUSTER													

Figure 4: Example of assessment summary table

Figure 4 shows how the project assessment can be displayed in tabular format, including the seven categories of benefits mentioned above, as well as the two impact indicators (environmental and social impacts) and cost of a cluster. In addition, a "neutral" characterisation of a cluster, is provided through an assessment of the GTC directional increase and the impact on the level of electricity interconnection relative to the installed production capacity in the Member State[11]. For those countries that have not reached the minimum interconnection ratio as defined by the European Commission, each cluster must report the contribution to reach this minimum threshold.

3.3 GRID TRANSFER CAPABILITY CALCULATION

The **Grid Transfer Capability (GTC)** reflects the ability of the grid to transport electricity across a boundary. A boundary represents a bottleneck in the power system where the transfer capability is insufficient to accommodate the likely power flows (resulting from the scenarios) that will need to cross them. A boundary may be fixed (e.g. a border between countries or bidding areas), or vary from one horizon or scenario to another.

The repartition of power flows across a boundary – and by consequence also the GTC – depends on the considered state of consumption, generation and exchange, as well as the topology and availability of the grid, and accounts for safety rules described in Annex 1. Therefore the delta GTC contribution of a project on a boundary is dependent on the scenario which is being evaluated.

When it concerns market integration, the (delta) GTC is oriented, which means that values might be different per direction.

[11] The COM (2001) 775 establishes that "all Member States should achieve a level of electricity interconnection equivalent to at least 10% of their installed generation capacity". This goal was confirmed at the European Council of March 2002 in Barcelona and chosen as an indicator the EU Regulation 347/2013 (Annex Annex IV 2.a) The interconnection ratio is obtained as the sum of importing GTCs/total installed generation capacity

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The delta GTC figure applies to the year-round situation (8760 hours) of how the power flow behaves across the boundary under analysis. This year-round situation should be reflected in the load flow analysis either via a simulation of each individual hour, either via a simulation of a set of points in time which are representative for the year-round situation.

The calculation of the GTC increase is based upon a reference network model in line with the considered scenario. Two options are possible with respect to how the project under evaluation is positioned with respect to the reference network model in a specific scenario:

- The project is part of the reference network model: the GTC variation is obtained by applying a TOOT approach which means calculating the difference in GTC between the reference network model (project in) and the reference network model from which the project is excluded (project out)
- The project is not part of the reference network model: GTC variation is obtained by applying a PINT approach which means calculating the difference in GTC between the reference network model onto which the project is added first (project in) and the reference network model (project out).[12]

[12] For an example of GTC calculation see Annex 3.

3.4 COST AND ENVIRONMENTAL LIABILITY ASSESSMENT

C.1. Total project expenditure

For each project, costs[13] and corresponding uncertainty ranges have to be estimated. The following items should be taken into account:

- Expected cost for materials and assembly costs (such as towers, foundations, conductors, substations, protection and control systems);
- Expected costs for temporary solutions which are necessary to realise a project (e.g. a new overhead line has to be built in an existing route, and a temporary circuit has to be installed during the construction period);
- Expected environmental and consenting costs (such as environmental costs avoided, mitigated or compensated under existing legal provisions[14], cost of planning procedures, and dismantling costs at the end of the life time);
- Expected costs for devices that have to be replaced within the given period (consideration of project life-cycle);
- Dismantling costs at the end of the equipment life-cycle.
- Maintenance and operation costs

Costs for losses are not part of the total project expenditure, as the losses are reported separately by the indicator B5.
The level of information about expected project costs depends on the status of the project. Therefore reporting of costs shall be done in two different ways:

1. For projects under construction or in the design and permitting phase, the costs should be reported based on the current data of project promoters.
2. For projects in the planning phase or under consideration, the cost estimation is to be performed using the best information available, whilst ensuring consistency of assumptions and thus comparable cost figures.

Costs shall be estimated as follows:

a. Identify the default investment costs to define the default project costs
b. Project promoters define a project-specific complexity factor that lies in a range between 0.5 and 5.0. This complexity factor enables one to take into account the characteristics of a project or its components that may cause its cost to deviate from the set of default investment costs.
c. Each project promoter should explain why a certain factor was chosen for the project (e.g. heavy routing etc.).

[13] Project costs must be reported as pre-tax values.
[14] These costs vary from one TSO to another because of different legal provisions. They may include mitigation costs for avian collisions of overhead lines, landscape integration of power stations or impact on water and soils for cables, compensation costs for land use or visual impact etc…

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As far as environmental costs are concerned, only the costs of measures taken to mitigate the impacts are considered here. Some impacts may remain after these measures, which are then included in the indicators S1 and S2. This split ensures that all measurable costs are taken into account, and that there is no double-accounting between these indicators.

S.1. Environmental impact

Environmental impact characterises the local impact of the project on nature and biodiversity as assessed through preliminary studies. It is expressed in terms of the number of kilometres an overhead line or underground/submarine cable that may run through environmentally 'sensitive' areas as defined in Annex 9: Environmental and social impact. This indicator only takes into account the residual impact or a project, i.e. the portion of impact that is not fully accounted for under C.1. The assessment method is described in Annex 9. For storage projects, these indicators are less well defined. They have to be examined on a project by project basis.

S.2 Social impact

Social impact characterises the project impact on the local population, as assessed through preliminary studies. It is expressed in terms of the number of kilometres an overhead line or underground/submarine cable that may run through socially sensitive areas, as defined in Annex 7. This indicator only takes into account the residual impact of a project, i.e. the portion of impact that is not fully accounted for under C.1. The assessment method is described in Annex 9. As for the environmental impact, these indicators are less well defined for storage projects, and have to be examined on a project by project basis.

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3.5 BOUNDARY CONDITIONS AND MAIN PARAMETERS OF BENEFIT ASSESSMENT

3.5.1 GEOGRAPHICAL SCOPE

The main principle of system modelling is to use detailed information within the studied area, and a decreasing level of detail when deviating from the studied area. The geographical scope of the analysis is an ENTSO-E Region at minimum, including its closest neighbours. In any case, the study area shall cover all Member States and third countries on whose territory the project shall be built, all directly neighbouring Member States and all other Member States significantly impacted by the project[15]. Finally, in order to take into account the interaction of the pan-European modelled system, exchange conditions will be fixed using hourly steps, based on a global market simulation[16].

Project appraisal is based hence on analyses of the global (European) increase of welfare[17]. This means that the goal is to bring up the projects which are the best for the European power system.

3.5.2 DISCOUNT RATE

The purpose of using a single discount rate all over Europe is to convert future monetary benefits and costs into their present value, so that they can be meaningfully used for comparison and evaluation purposes.

Discounting is a technique which allows the assessor to bring costs and monetised benefits of a particular project to a common price base, so that they can be compared consistently and obtain the project's net present value (NPV). In particular, calculating the difference between the present value of costs and present value of benefits provides the NPV of a project.

Common Discounting Method

A prudent approach to discounting requires defining key parameters, such as discount rate, assessment period and residual value, as identified by ACER in their assessment of ENSTO-E's previous version of the CBA Methodology.

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[15] Annex V, §10 Regulation (EU) 347/2013

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

[17] Some benefits (socio-economic welfare, CO_2…) may also be disaggregated on a smaller geographical scale, like a member state or a TSO area. This is mainly useful in the perspective of cost allocation, and should be calculated on a case by case basis, taking into account the larger variability of results across scenarios when calculating benefits related to smaller areas. In any cost allocation, due regard should be paid to compensation moneys paid under ITC (which is article 13 of Regulation 714 (see also Annex 1 for caveats on Market Power and cost allocation).

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The assessment period is typically driven by the expected economic asset life-cycle of the proposed project without considerable replacement cost. Empirical evidence suggests that a typical transmission project has an asset life-cycle of approximately 40 years. Such an assumption can be readily adopted across Europe or further afield.

However, in practice discount rates are quite different throughout Europe. Even within a specific Regional Group discount rates could be different for each component country, as they could be driven by their national regulatory authority. Furthermore, depreciation assumptions which are used to estimate residual values of an asset could be different within a single country.

Within this context, a common pan-European discounting approach is proposed by the Commission and ACER in their relevant Opinions to this CBA Methodology[18] and accepted by ENTSO-E to be used for PCI and TYNDP projects assessments. In fact, in the electricity sector, one single discount rate shall be used for all of Europe to compute the socio-economic benefits of a project. This shall be a real discount rate of 4 % for a 25 year life-cycle, and a residual value of zero.

The results of cost benefit analysis are derived from a pre-defined scenario framework. The period of analysis starts with the commissioning date of the project and extends to a time frame covering the lifecycle of the assets. It is generally recommended to study at least two horizons, one midterm and one long term (see chapter 2). To evaluate projects on a common basis, benefits should be aggregated across years as follows:

- For years from year of commission (start of benefits) to midterm (if any), extend midterm benefits backwards.
- For years between midterm long term and very long term (if any), linearly interpolate benefits between the time horizons.
- For years beyond the most future time horizon, maintain benefits of this most future time horizon

All costs and benefits are discounted to the present, and expressed in the price base of that year.

3.5.3 Benefit analysis

Project benefits are calculated as the difference between a simulation which does not include the project and a simulation which does include the project. The two proposed methods for project assessment are as follows:

- **Take Out One at the Time (TOOT)** method, where the reference case reflects a future grid situation in which additional network capacity is presumed to be realised (compared to the present-day

[18] ACER Opinion on ENTSO-E CBA Methodology - Jan 2014

situation) and projects under assessment are removed from the forecasted network structure to evaluate the changes to the load flow and other indicators. The difference in results between the situations with and without the examined project reflects the benefits of the project that is being assessed.

- **Put IN one at the Time (PINT)** method, where the reference case reflects a state of the network without the projects under assessment, and projects under assessment are added to this reference case to evaluate the network load flow and changes in other indicators with and without the project.

The TOOT method provides an estimation of benefits for each project, as if it was the last to be commissioned. In fact, the TOOT method evaluates each new development project into the whole forecasted network. The advantage of this analysis is that it immediately appreciates every benefit brought by each project, without considering the order of projects. All benefits are considered in a conservative manner, in fact each evaluated project is considered into an already developed environment, in which all programmed development projects are present. Hence, this method allows analyses and assessments at TYNDP level, considering the whole future system environment and every future network evolution.

In general, application of the TOOT approach underestimates the benefits of projects, because all project benefits are calculated under the assumption that the project is the last (marginal) project to be realised and project benefits are generally negatively affected by the presence of other projects (i.e. if one project gets built, a second will have lower benefits). This effect is generally the strongest when two (or more) projects are constructed to achieve a common goal across the same boundary, but may also be present when projects are constructed along different boundaries.

A set of two or more projects is defined as competitive in the event that this effect is so strong that only a subset of the set, rather than all of the projects from the set, can be reasonably expected to be realised (i.e., there is no business case to realise all projects).

Project promoters may wish to reflect properly the benefits of a project. Instead of the strict application of TOOT, the project assessment results presented in the TYNDP may be calculated by the project promoter to show the benefits of a project in relation to the realisation of other projects on the same boundary (multiple TOOT). Consequently, the assessment results can be based on the strict application of TOOT or on the application of multiple TOOT and therefore form the basis for comparison of projects.

However, it should be noted that strictly competitive project assessments, i.e. projects delivering the same service to the grid, may need several steps:

- TOOT method: if the benefit is significant, then all the projects are useful.
- Poor benefits in this first TOOT assessment do not necessarily mean that none of the projects should be undertaken. Indeed one should take the reference network without ALL competing projects (but keeping all projects elsewhere in Europe), and adding them one by one. This will allow to determine the right level of development to reach in this part of the grid.

This conclusion will apply to any of the competitive projects. The assessment will not conclude which one should be preferred, but how much of this kind of project is useful.

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3.6 METHODOLOGY FOR EACH BENEFIT INDICATOR

According to Regulation (EU) 347/2013, the present CBA Guideline establishes a methodology for project identification and for characterisation of the impact of projects. This methodology includes all the elements described in Article 11 and Annexes IV and V of the above-mentioned Regulation.

3.6.1 B1. SECURITY OF SUPPLY: ADEQUACY TO MEET DEMAND

Adequacy to meet demand is the ability of a power system to provide an adequate supply of electricity to meet the demand, hereby taking into account the variability of climatic effects on demand and renewable energy sources production. It concerns the physical delivery of electricity with the objective to minimize the volume of load that must be shed. This requires that sufficient generation capacity is available and that (sufficient) transmission capacity is in place so that all consumer load at a given moment can be met. In achieving this objective, generation and transmission capacity are complementary elements: generation capacity requires a transmission grid for power to flow from generation source to load. This is particularly relevant in the context of geo-temporal fluctuations in intermittent renewable energy sources, which may require certain areas to depend on generation that is only available in other areas at a certain moment.

Transmission capacity makes it possible to meet demand in one area with generation capacity that is located in another area. If there is sufficient generation capacity in a given area to meet demand at all times, constructing additional transmission capacity will not lead to a reduction of lost load. Notwithstanding, the availability of transmission capacity increases security of supply in that region, because it provides access to generation sources elsewhere which may be needed during extreme situations (e.g. power plant outages resulting in an inability to meet demand at some moment). Furthermore, if the generation and load profiles of multiple areas are different (e.g. different RES availability), spare generation capacity may be shared across regions allowing for a more efficient use of installed generation capacity. Hence, to some extent generation and transmission capacity are substitutes. Transmission capacity allows for the use of (surplus) generation capacity in a different location, which could avoid the need for construction of an additional generation unit in a given area.

Generation adequacy is expressed using two sub-indicators, with the aim to capture security of supply issues as well as the contribution of transmission capacity to the efficiency of spare generation capacity:

- Expected Energy Not Served (EENS) [MWh]: to capture the benefit of the project in case there is an actual security of supply issue detected;

If Project Promoters of a specific cluster agree, it is possible to give the monetised figure for SoS as and additional information. In this case, the Project promoters have to explain which VoLL they choose and display this in the assessment table.

- Avoided investment in spare capacity [MW]: to capture the benefit of the project if EENS equals 0 MWh.

Avoided generation investment is measured in MWs of spare capacity that does not need to be installed as a result of expanding transmission capacity. It can be conservatively monetised on the basis of investment costs of peaking units.

3.6.2 B2. Security of supply: System stability

System stability is the ability of a power system to provide a secure supply of electricity under extraordinary conditions[19] and to withstand and recover from extreme system conditions (exceptional contingencies)[20].

The provision of an adequate and secure supply of electricity can be hampered by a number of factors. These factors can pose a problem to system stability in various combinations, and be present for different periods of time, and generally difficult to recover from. In the context of increasing penetration of intermittent RES, conventional generation is required to be more flexible to deal with more frequent and acute ramping. Beyond adequacy (which is assessed under indicator B1 of this methodology), the ability of the system to face more dynamic issues must be ensured and the contribution of additional grid elements to securing it is important to consider as well.

The assessment is performed on the basis of pre-defined extreme cases (e.g. extreme weather, n-x secure, …). Each Regional Group is required to define these cases prior to the project assessment phase in the TYNDP process.

The assessment must be performed for a geographically delineated area with an annual electricity demand of at least 3 TWh[21]. The boundary of the area may consist of the nodes of a quasi-radial sub-system or semi-isolated area (e.g. with a single 400 kV injection). An example is provided below, with the project indicated in orange[22].

[19] This category covers criteria 2b of Annex IV of the EU Regulation 347/2013, namely "secure system operation and interoperability".
[20] This category contributes to the criterion "interoperability and secure system operation" set out in Article 4, 2b and to criteria 2d of Annex IV, as well as to criteria 6b of Annex V, namely "system resilience" (EU Regulation 347/2013).
[21] This value is seen as a significant threshold for electricity consumption for smart grids in the EU Regulation 347/2013 (Annex IV, 1e)
[22] One should notice that although the definition of a 'delimited geographical area' that is made subject to Security of Supply calculation may be considered an arbitrary exercise, the indicator score (see below) is determined proportionally to the size of the area (i.e. its annual electricity demand). In order to be scored the same, a larger geographic area thus requires a larger absolute improvement in Security of Supply compared to a smaller area.

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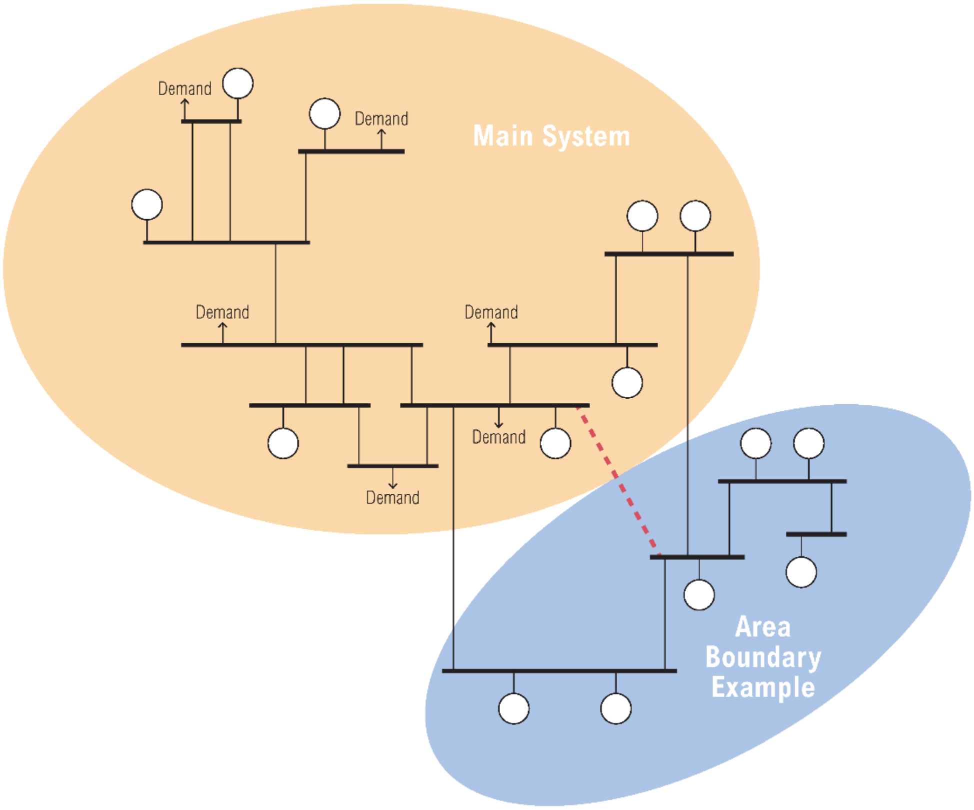

Figure 5: Illustration of delimited area for security of supply calculations

3.6.3 B4. Socio-economic welfare

The most common economic indicator for measuring benefits of transmission investments is the reductions in total generation cost. This metric values transmission investment in terms of saving total generation costs, since a project that increases GTC between two bidding areas allows generators in the lower priced area to export power to the higher priced area, as shown below in Figure 5. The new transmission capacity reduces the fuel and other variable operating costs and hence increases socio-economic welfare. These generation cost savings are only one part of the overall economic benefit provided by transmission investments and do not capture other transmission-related benefits, including the capacity value of transmission investments. This capacity value occurs because transmission capacity allows for the use of (surplus) generation capacity in a different location, which could avoid or postpone the need for construction of an additional generation unit in a given area.

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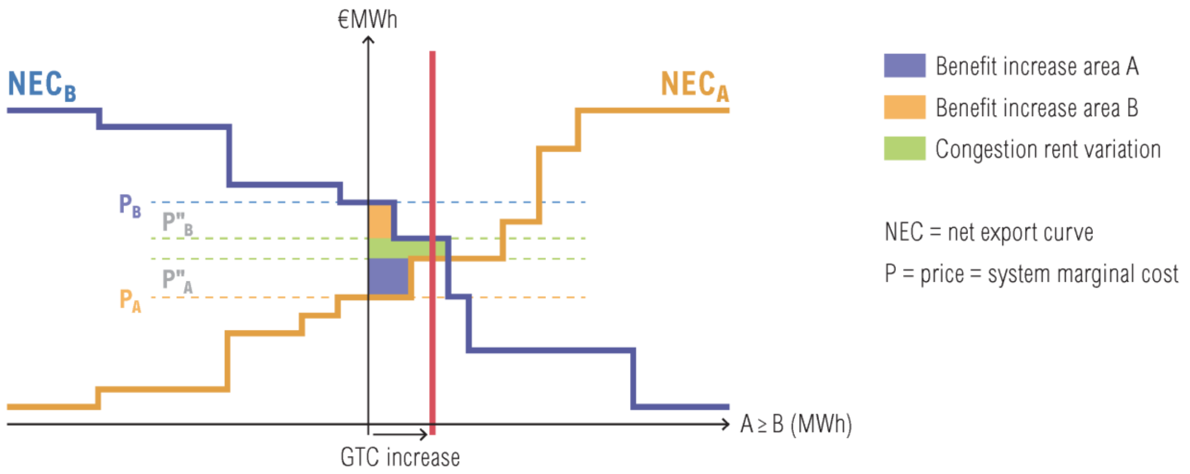

Figure 6: Illustration of benefits due to GTC increase between two bidding areas

In order to calculate the savings in total generation costs a perfect market is assumed with the following assumptions:

- Equal access to information by market participants,
- No barriers to enter or exit,
- No market power.

In general, two different approaches can be used for calculating the increased benefit from socio-economic welfare in terms of savings in total generation costs:

- The generation cost approach, which compares the generation costs with and without the project for the different bidding areas.
- 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[23].

If demand is considered inelastic to price, both methods will yield the same result. If demand is considered as elastic, modelling becomes more complex. The choice of assumptions on demand elasticity and methodology of calculation of benefit from socio-economic welfare is left to ENTSO-E's Regional Groups. Most European countries are presently considered to have price inelastic demand. However, there are various developments that appear to cause a more elastic demand-side. The development of

[23] More details about how to calculate surplus are provided in Annex 6

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smart grids and smart metering, as well as a growing flexibility need from the changing production technologies (more renewables, less thermal and nuclear) are drivers towards a more price-elastic demand. There are two ways of taking into account greater flexibility of demand when assessing socio-economic welfare, the choice of the method being decided within ENSTO-E's Regional Groups:

1) The demand that will have to be supplied by generation is estimated through various scenarios, reshaping the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles etc. The demand response will not be elastic at each hour, but a movement of energy consumption from hours of potentially high prices to hours of potentially low prices. The generation costs to supply a known demand are minimised through the generation cost approach. This assumption simplifies the complexity of the model and therefore the demand can be treated as a time series of loads that has to be met, while at the same time considering different scenarios of demand-side management.

2) Introduce hypotheses on level of price elasticity of demand. Two methods are possible:

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

Generation cost approach

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

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

b. A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation. In the case of connection of renewables, this is directly expressed by benefit B3, RES Integration. In other cases, the direct connection figures will be available in the background scenarios.

c. A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers. The methods do not consider market power (see Annex 4), and as a result the expression of socio-economic welfare is the reduction in generation costs.

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

Benefit (for each hour) = Generation costs without the project – Generation costs with the project

The socio-economic welfare in terms of savings in total generation costs can be calculated for internal constraints by considering virtual smaller bidding areas (with different market prices) separated by the congested internal boundary inside an official bidding area (see Annex 2).

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

Total surplus approach

The economic benefit is calculated by adding the producer surplus, the consumer surplus and the congestion rents for all price areas as shown in Figure 7. The total surplus approach consists of the following three items:

a. By reducing network bottlenecks, the total generation cost will be economically optimised. This is reflected in the sum of the producer surpluses.

b. By reducing network bottlenecks that restrict the access of import from low-price areas, the total consumption cost will be decreased. This is reflected in the sum of the consumer surpluses.

c. Finally, reducing network bottlenecks will lead to a change in total congestion rent for the TSOs.

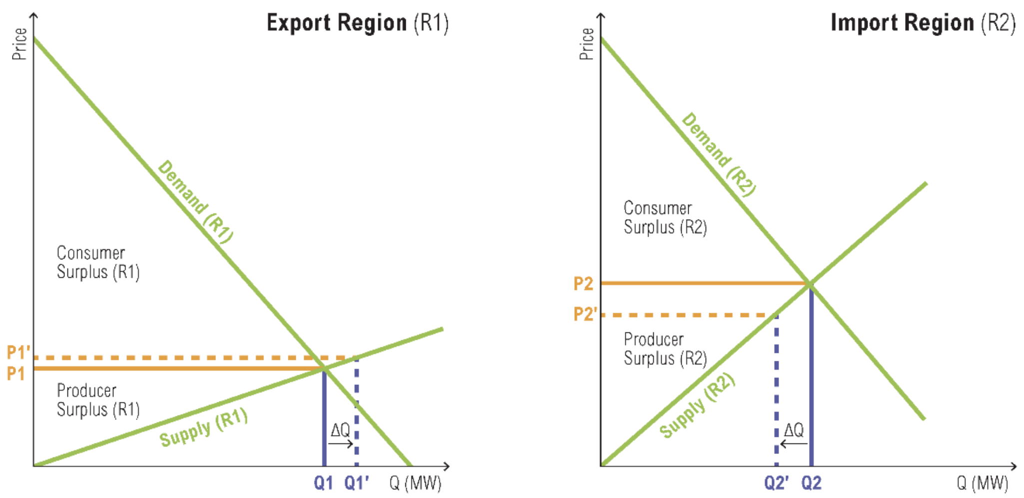

Figure 7: Example of a new project increasing GTC between an export and an import region.

An economic optimisation is undertaken to determine the total sum of the producer surplus, the consumer surplus and the change of congestion rent, with and without the project. The benefit for each case is calculated by:

Benefit (for each hour) = Total surplus with the project – Total surplus without the project

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

New transmission investments can avoid or postpone generation investments needs in resource-constrained areas by increasing the GTC from neighbouring countries with surplus generation capacity. Increasing the imports of capacity from countries with surplus generating defers the need for building additional generation in countries with deficit of capacity.

Parameter	Source of calculation[24]	Basic unit of measure		Monetary measure (externality or market-based?)
Reduced generation costs/ additional overall welfare	Market studies (optimisation of generation portfolios across boundaries)	€	idem	
Re-dispatch costs	Network and market studies (optimisation of generation dispatch within a boundary considering grid constraints)	€	idem	

TABLE 1 REPORTING SHEET OF THIS INDICATOR IN THE TYNDP

[24] Cf Annex IV, 2a.

3.6.4 B3. RES INTEGRATION[25]

Introduction

The integration of both existing and planned RES is facilitated by:

1. The connection of RES generation to the main power system.
2. Increasing the GTC between one area with excess RES generation to other areas, in order to facilitate an overall higher level of RES penetration.

This indicator provides a standalone value associated with additional RES available for the system. It measures the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the project. An explicit distinction is thus made between RES integration projects related to (1) the direct connection of RES to the main system and (2) projects that increase GTC in the main system itself.

Methodology

Although both types of projects can lead to the same indicator scores, they are calculated on the basis of different measurement units. Direct connection (1) is expressed in $MW_{RES\text{-}connected}$ (without regard to actual avoided spillage), whereas the GTC-based indicator (2) is expressed as the avoided curtailment (in MWh) due to (a reduction of) congestion in the main system. Avoided spillage is extracted from the studies for indicator B4. Connected RES is only applied for the direct connection of RES integration projects. Both kinds of indicators may be used for the project assessment, provided that the method used is reported (see table below). In both cases, the basis of calculation is the amount of RES foreseen in the scenario or planning case.

Monetisation

Any monetisation of this indicator will be reported implicitly by B3. The benefits of RES in terms of CO_2 reduction will be reported by B6.

Parameter	Source of calculation	Basic unit of measure	Monetary measure (externality or market-based?)	Level of coherence of monetary measure
Connected RES	project specification	MW		European

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

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Avoided RES spillage	Market or network studies	MWh	Included in generation cost savings (B4)	European

TABLE 2 REPORTING SHEET OF THIS INDICATOR IN THE TYNDP

3.6.5 B5. VARIATION IN LOSSES (ENERGY EFFICIENCY)

Introduction

The energy efficiency benefit of a project is measured through the reduction of thermal losses in the system. At constant power flow levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load flow pattern when they decrease the distance between production and consumption. Increasing the voltage level and the use of more efficient conductors also reduce losses. It must be noted, however, that the main driver for transmission projects is currently the need for transmission over long distances, which increases losses.

Methodology

In order to calculate the difference in losses (in MWh) attributable to each project, and the related monetisation, the losses have to be computed in two different simulations, one with and one without the project. A sufficient quality of the amount of calculated losses is obtained, if at least the following requirements are met:

1. Losses are representative for the relevant geographical area;
2. Losses are representative for the relevant period of time;
3. Market results (generation dispatch pattern) used for each simulation are in accordance with the grid model, especially regarding cross-border capacities.

1. <u>Relevant geographical area/grid model</u>

The calculated losses should be representative for Europe as a whole. However, they may be approximated by a regional losses modelling approach for the time being. Thus the minimum requirement should be to use a **regional network model**. A regional model should include at least the relevant countries/bidding areas for the assessed project, typically the hosting countries, their neighbours, and the countries on which the project has a significant impact in terms of cross-border capacity or generation pattern (as given by the market simulation). An AC calculation should be used where possible or a DC calculation if convergence in the load flow tools is not reached.

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

The losses affecting the project itself are deemed not relevant for the evaluation of a difference in losses with and without the project. This is true, since the project would modify the flow pattern on other lines due to the change in impedances, and due to a new generation pattern (also in other countries than the hosting countries), in case of a RES connection project.

2. Relevant period of time

An hourly calculation over the complete year should be aimed for all regions. The chosen methodology must be representative for the considered period of time (in the current TYNDP visions this means one complete calendar year), so in case of the use of point in times, they should be numerous enough to ensure this representativeness, and weighted in a correct manner.

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

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

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

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

4. Monetisation of losses

Once the calculation of an amount of losses in MWh is performed, monetisation should follow. In a general sense, this should be assessed with the perspective of the cost borne by society to cover losses.

The proposal is to base the approach on market prices given from the marginal cost as given by the market simulation. More precisely, for a given project we consider for each hour of the year, h, and each market zone , i:

- p’h,i (with project) and ph,i (without project) the amount of losses in MWh (after eventual measures for securing the grid situation);
- $s'_{h,i}$ (with project) and $s_{h,i}$ (without project) the hourly spot price in €/MWh.

The delta cost of losses should be calculated as the sum of *h* and *i* of the term $(p'_{h,i} * s'_{h,i}) - (p_{h,i} * s_{h,i})$. In this case, eventual redispatch costs are not taken into account.

The prerequisites for the calculation are the computation of the marginal cost and amount of losses for each market zone, with and without the assessed project. In order to simplify the monetisation, an acceptable compromise should be used as an average yearly price per market zone. The variation of losses in MWh can be monetised considering the average yearly price of electricity in the relevant country(ies) where the project has an impact. The formula for losses monetisation is as follows:

$$Yearly\ cost\ C = \sum_i \sum_h s_{h,i} p_{h,i} \approx \sum_i s_i \sum_h p_{h,i} = \sum_i s_i P_i$$

With:

$s_i = \frac{1}{8760} \sum_h s_{h,i}$
(the yearly average spot price for the price area, i)

$P_i = \sum_h p_{h,i}$
(the yearly sum of losses for the price area , i)

- The variation in losses in energy is $\sum_i P'_i - \sum_i P_i$ (total system losses with the project minus total system losses without the project)
- The monetisation of the variation of losses is therefore $\sum_i s'_i P'_i - \sum_i s_i P_i$ (total losses cost with the project minus total losses cost without the project)

Parameter	Source of calculation[26]	Basic unit of measure	Monetary measure (externality or market-based?)	Level of coherence of monetary measure
Losses	Network studies	MWh	€/year (market-based)	European

TABLE 3 REPORTING SHEET OF THIS INDICATOR IN THE TYNDP

3.6.6 B6. VARIATION IN CO_2 EMISSIONS

Introduction

By relieving network congestion, reinforcements may enable low-carbon generation to generate more electricity, thus replacing conventional plants with higher carbon emissions. Considering the specific emissions of CO_2 for each power plant and the annual production of each plant, the annual emissions at power plant level and perimeter level can be calculated and the standard emission rate established.

[26] Cf Annex IV, 2c.

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Methodology

Generation dispatch and unit commitment used for calculation of socio-economic welfare benefit with and without the project is used to calculate the CO_2 impact, taking into account standard emission rates.

Monetisation

The monetisation of CO_2 is based on forecasted CO_2 prices for electricity in the studied horizon. The price is derived from official sources such as the IEA for the studied perimeter. As the cost of CO_2 is already included (internalised) in generation costs (B4), the indicator only displays the benefit in tons in order to avoid double accounting.

However, it is possible that the prices of CO_2 included in the generation costs (B4) understate the full long-term societal value of CO_2. Accordingly, a sensitivity analysis could be performed for this indicator B6, under which CO_2 is valued at a long-term societal price. To perform this sensitivity without double-counting against B3:

- Derive the delta volume of CO_2, as above;
- Consider the CO_2 price internalised in B4;
- Adopt a long-term societal price of CO_2;
- Multiply the volume of (a) by the difference in prices (c) minus (b). This represents the monetisation of this sensitivity of an increased value of CO_2[27].

Parameter	Source of calculation	Basic unit of measure	Monetary measure	Level of coherence
CO_2	Market studies (substitution effect)	tons	CO_2 price derived from generation costs (internalised in B4)	European

TABLE 4 REPORTING SHEET OF THIS INDICATOR IN THE TYNDP

3.7 OVERALL ASSESSMENT AND SENSITIVITY ANALYSIS

3.7.1 OVERALL ASSESSMENT

The overall assessment is displayed as a multi-criteria matrix in the TYNDP, as shown in Section 3.2. All indicators are quantified. Costs, socio-economic welfare and the variation of transmission losses are displayed in Euros. The other indicators are displayed through the most relevant units ensuring both a

[27] Note: for this sensitivity to B6, one does not adjust the merit order and the dispatch for B4 for the higher Carbon price. If one were to perform that exercise, that would represent a full re-run of indicator B4, against the different data assumption of a higher forecast carbon price included in the generation background and merit order.

coherent measure all over Europe and an opposable value, while avoiding the double accounting in Euros. Indeed, some benefits like avoided CO_2 and RES integration are already internalised in socio-economic welfare.

Furthermore, each indicator is qualified on a multiple level colour scale, expressing negative, neutral, minor positive, medium positive or high positive impact. This scale allows displaying the results in various formats, such as the table in Figure 4 or radar formats as shown below in Figure 8.

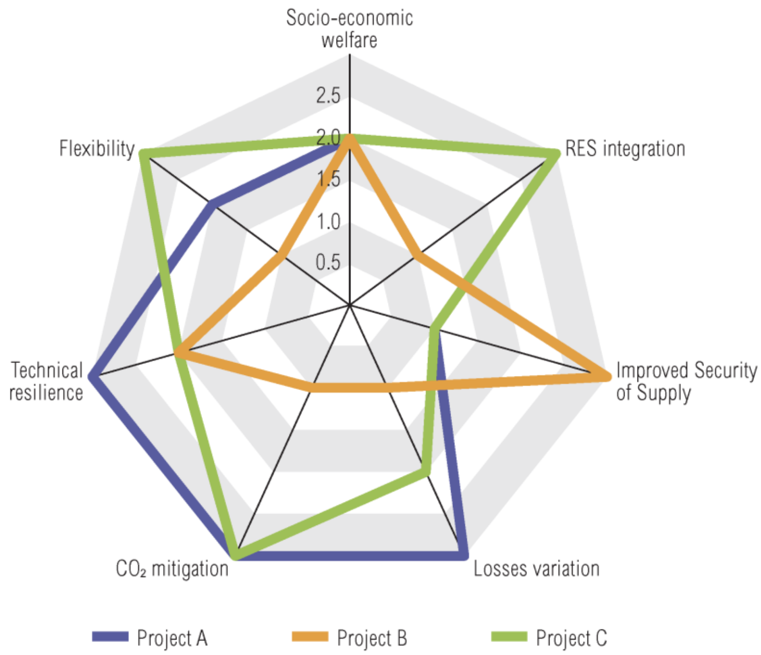

Figure 8: Radar illustration of overall assessment

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4 ASSESSMENT OF STORAGE

The principles and procedures described in this document, for combined Multi-criteria and Cost Benefit Analysis, may be used for the evaluation of centralised[28] storage devices on transmission system. These Multi-criteria and Cost Benefit Analysis are applicable both to storage systems planned by TSOs and both by private promoters, even if a distinction on different roles and operation uses between these two types must be done. In fact the possibility to install storage plants on the transmission grid by TSOs is strictly connected to the objective of improving and preserving system security and guaranteeing cheapness of network operation without affecting internal market mechanisms and influence any market behaviour.

The location of storage plants is decisive to the service storage will provide. Therefore, before carrying out the CBA, an assessment of the maximum power of the storage device at different points in time (for the injection and withdrawal of electricity to/from the grid) taking into account local grid capacity, should be undertaken, in the same way as the GTC is calculated for transmission.

Storage plants can be very easily introduced in market studies, since the existing facilities of this type are already modelled. Hence it can take into account some functioning constraints, and the losses between stored and retrieved energies.

Business models for storage are often categorised by the nature of the main target service, distinguishing between a deregulated-driven business model (income from activities in electricity markets), and a regulated-driven business model (income from regulated services). The CBA will not account for these differences[29]. As for transmission, it will yield monetised benefits of storage using a perfect market assumption (including perfect foresight), and account for non-monetised benefits using the most relevant physical indicators.

The characterisation of the impact of storage projects can be evaluated in terms of added value for society as improvement of security of supply, increase of capacity for trading of energy and balancing services between bidding areas, RES integration, variation of losses and CO_2 emission, resilience and flexibility. The remainder of this Chapter will describe the assessment of storage in the same way the CBA indicators were applied in the main document

B1./B2. Security of supply: The security of supply indicator for storage follows the same principles as for the transmission projects, covering the benefit to system adequacy (B1) combined with the increase in system flexibility (B2).

Energy storage may improve security of supply by smoothening the load pattern ("peak shaving"): increasing off-peak load (storing the energy during periods of low energy demand) and lowering peak

[28] At least 225 MW and 250 GWh/yeryear as defined by the published EC RegulationRegulation (EU) No 347/2013

[29] It should be noted the following the regulatory systems, the owners of storage will not be likely to capture the full value of storage. Hence, in some countries, a TSO owner will not be able to capture any arbitrage value, whereas a private owner will not be able to capture any system service value.

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load (dropping it during highest demand periods).Market studies will account for the value provided at the level of a European Region (specific cases of very large storage devices).

With regard to the benefits on the system flexibility of a storage project it is recommended to use a qualitative approach based on the table below. This assessment is to be based on the expert view considering the existing studies and technology information.

Response time – FCR	0 = more than 30 s += less than 30 s ++= less than 1 s	30 s : ramp time of FCR 1 s : typical inertia time scale
Response time – including delay time of IT and control systems	0 = more than 200 s += less than 200 s ++= less than 30 s	200 s: FRR ramp time 30 s: FCR ramp time
Duration at rated power – total time during which available power can be sustained	0 = less than 1 min += less than 15 min ++= 15 min or more	1 min : double the response time of FCR 15 min : PTU size
Available power – power that is continuously available within the activation time	0 = below 20 MW += 20 - 225 MW ++= 225 MW or higher	20 MW : 1-2% of a typical power plant is reserved for FCR and reachable from a project perspective 225 MW : PCI size
Ability to facilitate sharing of balancing services on wider geographical areas, including between synchronous areas		Suggestion to remove as this is too specific and difficult to quantify

B4. Socio-economic welfare: The impact of storage on socio-economic welfare is the main claimed benefit of large-scale storage. In fact the use of storage systems on the network can generate opportunities in terms of generation portfolio optimisation (arbitrage) and congestion solutions that imply cost savings on users of whole transmission system. Market studies will be able to assess this value based on an hourly resolution, which is consistent with current market models. Indeed, storage can take advantage of the differences in hourly peak and off-peak electricity prices by storing electricity at times when prices are low, and then offering it back to the system when the price of energy is greater, hence increasing socio-economic welfare.

B3. RES integration: Storage devices provide resources for the electricity system in order to manage RES generation and in particular to deal with intermittent generation sources. As for transmission, this service will be measured by avoided spillage, using market studies or network studies, and its economic value is internalised in socio-economic welfare.

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B5. Variation in losses: Depending on the location, the technology and the services provided by storage may increase or decrease losses in the system. This effect is measured by network studies.

B6. Variation in CO_2 emissions: As for transmission, the CO_2 indicator is directly derived from the ability of the storage device to impact generation portfolio optimisation. Its economic value is internalised in socio-economic welfare.

Storage also has costs and environmental impact. The same indicators as in the main document will be used.

C.1. Total project expenditure of storage includes investment costs, costs of operation and maintenance during the project lifecycle as well as environmental costs (compensations, dismantling costs etc.).

S.1.Environmental impact: The environmental impact of a storage project is different from transmission, and highly dependent on technology. The assessment must take into account national legal provisions regarding environmental impact assessment and mitigation measures.

S.2. Social impact: The social impact of a storage project is different from transmission, and highly dependent on technology. The assessment must take into account national legal provisions regarding social impact assessment and mitigation measures. The CBA of storage will use the same boundary conditions, parameters, overall assessment and sensitivity analysis techniques as the CBA for transmission. In particular, the TOOT methodology implies that the assessment will be carried out including all storage projects outlined in the TYNDP, taking out one storage project at the time in order to assess it benefits.

The methodology performed shall be used for storage project appraisals carried out for the TYNDP and for individual storage project appraisals undertaken by TSOs or project promoters.

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5 ANNEXES

5.1 ANNEX 1: TECHNICAL CRITERIA FOR PLANNING

Technical criteria and methods are required when assessing the planning scenarios, in order to identify future problems and determine the required development of the transmission grid. These assessments take into account the outcomes from the scenarios analysis. Currently deterministic criteria are used in the planning of the grid.

5.1.1 DEFINITIONS[30]

D.1. **Base Case for grid analysis.** Data used for analysis are mainly determined by the planning cases. For any relevant point in time, the expected state of the whole system, “with all network equipment available”, forms the basis for the analysis (“Base case analysis”).

D.2. **Contingencies**. A contingency is the loss of one or several elements of the transmission grid. A differentiation is made between ordinary, exceptional and out-of-range contingencies. The wide range of climatic conditions and the size and strength of different networks within ENTSO-E mean that the frequency and consequences of contingencies vary among TSOs. As a result, the definitions of ordinary and exceptional contingencies can differ between TSOs. The standard allows for some variation in the categorisation of contingencies, based on their likelihood and impact within a specific TSO network.

- An ordinary contingency is the (not unusual) loss of one of the following elements:
  - Generator.
  - Transmission circuit (overhead, underground or mixed).
  - A single transmission transformer or two transformers connected to the same bay.
  - Shunt device (i.e. capacitors, reactors, etc.).
  - Single DC circuit.
  - Network equipment for load flow control (phase shifter, FACTS …).
  - A line with two or more circuits on the same towers if a TSO considers this appropriate and includes this contingency in its normal system planning

- An exceptional contingency is the (unusual) loss of one of the following elements:
  - A line with two or more circuits on the same towers if a TSO considers this appropriate and does not include this contingency in its normal system planning
  - A single bus-bar.
  - A common mode failure with the loss of more than one generating unit or plant.

[30] For all definitions, see also ENTSO-E’s draft Operational Security Network Code (https://www.entsoe.eu/resources/network-codes/operational-security/)

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- A common mode failure with the loss of more than one DC link.

- An out-of-range contingency includes the (very unusual) loss of one of the following:
  - Two lines independently and simultaneously.
  - A total substation with more than one bus-bar.
  - Loss of more than one generation unit independently.

D.3. **N-1 criterion for grid planning.** The N-1 security criterion is satisfied if the grid is within acceptable limits for expected supply and demand situations as defined by the planning cases, following a temporary (or permanent) outage of one of the elements of the ordinary contingency list (see D2 and chapter 4.2.2).

5.1.2 COMMON CRITERIA

5.1.2.1 STUDIES TO BE PERFORMED

C.1. **Load flow analysis**

- **Examination of ordinary contingencies.** N-1 criterion is systematically assessed taking into account each single ordinary contingency of one of the elements mentioned above.

- **Examination of exceptional contingencies.** Exceptional contingencies are assessed in order to prevent serious interruption of supply within a wide-spread area. This kind of assessment is done for specific cases based on the probability of occurrence and/or based on the severity of the consequences.

- **Examination of out-of-range contingencies.** Out-of-range contingencies are very rarely assessed at the planning stage. Their consequences are minimised through Defence Plans.

C.2. **Short circuit** analysis. Maximum and minimum symmetrical and single-phase short-circuit currents are evaluated according to the IEC 60 909, in every bus of the transmission grid

C.3. **Voltage collapse.** Analysis of cases with a further demand increase by a certain percentage above the peak demand value is undertaken. The resulting voltage profile, reactive power reserves, and transformer tap positions are calculated.

C.4. **Stability analysis.** Transient simulations and other detailed analysis oriented to identifying possible instability shall be performed only in cases where problems with stability can be expected, based on TSO knowledge.

5.1.2.2 CRITERIA FOR ASSESSING CONSEQUENCES

C.5. **Steady state criteria**

- **Cascade tripping.** A single contingency must not result in any cascade tripping that may lead to a serious interruption of supply within a wide-spread area (e.g. further tripping due to system protection schemes after the tripping of the primarily failed element).

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- **Maximum permissible thermal load.** The base case and the case of failure must not result in an excess of the permitted rating of the network equipment. Taking into account duration, short term overload capability can be considered, but only assuming that the overloads can be eliminated by operational countermeasures within the defined time interval, and do not cause a threat to safe operation.

- **Maximum and minimum voltage levels.** The base case and the case of failure shall not result in a voltage collapse, nor in a permanent shortfall of the minimum voltage level of the transmission grid, which are needed to ensure acceptable voltage levels in the sub-transmission grid. The base case and the case of failure shall not result in an excess of the maximum admissible voltage level of the transmission grids defined by equipment ratings and national regulation, taking into account duration.

C.6. **Maximum loss of load or generation** should not exceed the active power frequency response available for each synchronous area.

C.7. **Short circuit criteria.** The rating of equipment shall not be exceeded to be able to withstand both the initial symmetrical and single-phase short-circuit current (e.g. the make rating) when energising on to a fault and the short circuit current at the point of arc extinction (e.g. the break rating). Minimum short-circuit currents must be assessed in particular in bus-bars where a HVDC installation is connected in order to check that it works properly.

C.8. **Voltage collapse criteria.** The reactive power output of generators and compensation equipment in the area should not exceed their continuous rating, taking into account transformer tap ranges. In addition the generator terminal voltage shall not exceed its admissible range.

C.9. **Stability criteria.** Taking into account the definitions and classifications of stability phenomena[31], the objective of stability analysis is the rotor angle stability, frequency stability and voltage stability in case of ordinary contingencies (see section 3.1), i.e. incidents which are specifically foreseen in the planning and operation of the system..

- **Transient stability.** Any 3-phase short circuits successfully cleared shall not result in the loss of the rotor angle and the disconnection of the generation unit (unless the protection scheme requires the disconnection of a generation unit from the grid).

- **Small Disturbance Angle Stability**. Possible phase swinging and power oscillations (e.g. triggered by switching operation) in the transmission grid shall not result in poorly damped or even un-damped power oscillations.
- **Voltage security**. Ordinary contingencies (including loss of reactive power in-feed) must

[31] Definition and Classification of Power System Stability, IEEE/CIGRE Joint Task Force, June 2003

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not lead to violation of the admissible voltage range that is specified by the respective TSO (generally 0.95 p.u. – 1.05 p.u.

5.1.2.3 BEST PRACTICE

R1. **Load flow analysis. Failures combined with maintenance.** Certain combinations of possible failures and non-availabilities of transmission elements may be considered in some occasions. Maintenance related non-availability of one element combined with a failure of another one may be assessed. Such investigations are done by the TSO based on the probability of occurrence and/or based on the severity of the consequences, and are of particular relevance for network equipment that may be unavailable for a considerable period of time due to a failure, maintenance, overhaul (for instance cables or transformers) or during major constructions.

R2. **Steady state analysis.** Acceptable consequences depend on the type of event that is assessed. In the case of exceptional contingencies, acceptable consequences can be defined regarding the scale of the incident, and include loss of demand. Angular differences should be assessed to ensure that circuit breakers can re-close without imposing unacceptable step changes on local generators.

R3. **Voltage Collapse analysis:** The aim of voltage collapse analysis is to give some confidence that there is sufficient margin to the point of system collapse in the analysed case to allow for some uncertainty in future levels of demand and generation.

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5.2 ANNEX 2: ASSESSMENT OF INTERNAL PROJECTS

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 due to the fact that most projects also show significant positive benefits that cannot be covered by only increasing the capacities of a certain border. This effect is strongest but not limited to internal projects.

Internal projects do not necessarily have a significant impact on cross border capacities which make it difficult to assess them by market simulations considering one node per country, if not using a flow based model.

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

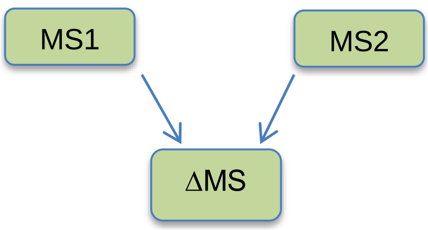
For different types of projects different methods should be used as there is not yet a unified method available that could handle the special aspects of all these projects in a satisfying way. Therefore four options will be given below: options one and four uses market simulations to calculate the benefits; options two and three integrate both market and network modelling.

5.2.1.1 BORDER-GTC-VARIATION

For internal projects where the cross-border impact is the main driver and internal aspects can be neglected the assessment can be done using two market simulations

Guideline:

- reduction of the cross-border GTC and calculation identical to cross-border project
- the GTC reduction has to be calculated similarly to those as for cross-border lines (see 3.3)



MS1: market simulation with reference GTCs
MS2: market simulation with the project being assessed taken out/in (TOOT/PINT with variation of ΔGTC)
ΔMS: difference between MS1 and MS2 unit commitment (different generation costs, different CO_2 output etc.)

5.2.1.2 Redispatch

For internal projects without significant cross-border impact (for which the option in 5.2.1.1 is not capable) but with large internal benefits redispatch calculations (which can be seen as a combination of market- and network studies) can be performed.

In this context the redispatch calculation starts from the dispatch taken from a market simulation. With this dispatch the load flow within a certain country (region) has to be calculated. If congestions were detected the redispatch has to be done under the following constraints to mitigate the congestions:

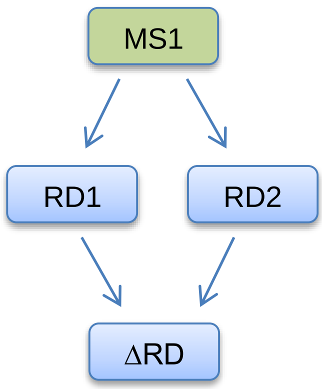
- the balance of the system has to be kept (the rise in generation must be covered by the same amount of reduced generation)
- the network must be free of congestions after the redispatch
- the redispatch has to be done in a cost optimal way

To be considered:

- the order of redispatch: e.g. first conventional power plants; second RES; third cross border redispatch
- as result two different and comparable power plant dispatches must be given
- the benefits in term of SEW, CO2, RES, SOS can be calculated like for cross-border projects by comparing two dispatches

Guideline:

- calculate the redispatch with and without the internal project for each hour of the year (in cases this is not possible representative cases may be used instead) based on the dispatch taken from a market simulation



MS1: market simulation reference GTCs
RD1: redispatch run with reference network
RD2: redispatch run with the project being assessed taken out/in (TOOT/PINT)
ΔRD: difference between RD1 and RD2 unit commitment (different generation costs, different CO2 output etc.)

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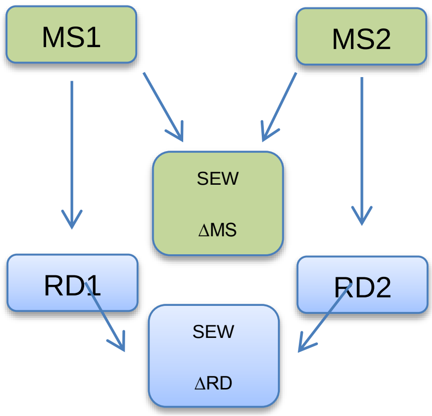
5.2.1.3 COMBINATION: BORDER-NTC-DECREASE AND REDISPATCH

The benefits of some projects are mainly depending on internal bottlenecks, but also can have significant cross-border impact. In this case a two-step approach can be used by combining the options 5.2.1.1 and 5.2.1.2 while the final result is the sum of both options.

Guideline:

- reduction of the cross-border GTC as done in 5.2.1.1
- calculate redispatch with the project based on the market simulation with reference GTC
- calculate redispatch without the project based on the market simulation without the project (reduced by ΔGTC)
- The benefit of the project is the sum of the benefits of the two steps.



MS1: market simulation with reference network
MS2: market simulation with the project being assessed taken out/in (TOOT/PINT)
ΔMS: difference between MS1 and MS2 unit commitment
RD1: redispatch run with reference network
RD2: redispatch run with the project being assessed taken out/in (TOOT/PINT)
ΔRD: difference between RD1 and RD2 unit commitment
ΔTOTAL = ΔRD + ΔMS

5.2.1.4 FICTIVE MARKET-AREAS FOR MODELLING PURPOSE

- divide one country into two or several (fictive) modelling market areas (ideally in such way that the project being assessed crosses this new border)
- the project can then be assessed by varying the GTC across the new border by the ΔGTC the projects cases across that border
- in cases, where projects also have significant impact on the GTC between two countries, this GTC should also be taken into account for the assessment calculations
- it should be noted that the use of fictive model market areas is just related to modelling purpose and must not be mistaken by proposals for possible future market divisions

5.3 ANNEX 3: EXAMPLE OF GTC CALCULATION

Methodology for calculating delta GTC explained on TOOT approach (PINT approach is similar, only the position of the project towards the reference network model changes)

1. Perform load flow analysis on the reference network model in line with the security criteria described in chapter 4 thus taking into account the N-1 criteria
2. Identify the amount of power flow ‘PF1’ which corresponds with at least one line loaded at exactly 100% under N-1-condition (100%-situation), and with no other congestion. Two situations can occur
    a. if the initial N-1 load flow analysis delivers load-flows above 100%, then no additional step is needed to find the corresponding power flow value across the boundary
    b. if the initial N-1 load flow analysis does not hit the 100% mark, then a power shift relative to the initial dispatch across the boundary is to be applied in order to reach the 100% and find the corresponding power value.
3. Repeat steps 1 and 2 on the reference network model from which the project has been removed (TOOT of the project for which the ΔGTC shall be determined). This will give the value ‘PF2’
4. Calculate the ΔGTC as the difference between the power flow values that correspond with the 100%-situation: ΔGTC = PF1 - PF2
5. Apply this process to both directions of power flow across the boundary under analysis

Simplified example of GTC increase from direction X to Y across a boundary

	Step 1	Step 2	Step 3	Step 4	Step 5
Incident	Line B in	Line B in	TOOT line B	TOOT line B	Δ GTC X > Y [MW]
Situation	initial situation	100% situation	>100% situation	mitigated situation thus back to 100%	
Generation power-shift [MW]	0	+500	0	200	/
Power flow across boundary		PF1: 1000		PF 2: 400	600
Load [%] Line A	80	100	150	100	
Load [%] Line B	50	80	-	-	

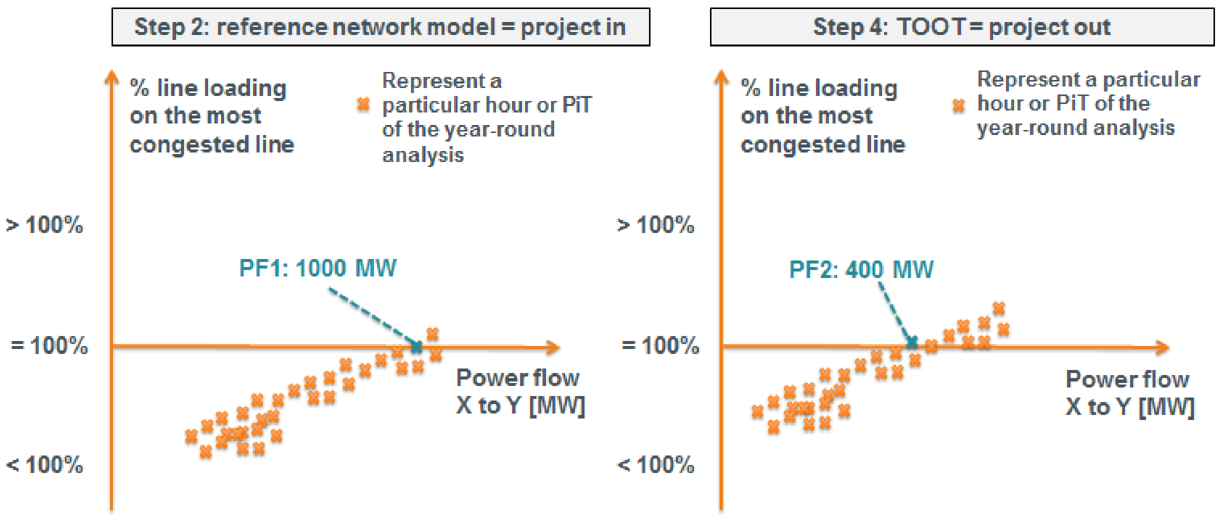
Table 1: Example of how to calculate the ΔGTC: Step 1 denotes the initial situation where all projects are put in (including line B marked in green). No overloads show up illustrated by the loadings marked in green. In Step 2 the system generation power-shift has been done until on line is loaded at exact 100% (here line A) under N-1 conditions. The power-shift-volume needed was 500 MW. The corresponding maximum power flow PF1 that can

be sustained across the boundary from a year-round perspective in the direction X > Y with the project is1000 MW.

In Step 3 line B is taken out as per TOOT approach. The dispatch is fixed as it was after Step 2 with 500 MW. The loading of line A became 150% (N-1) marked in red. In Step 4 the generation power-shift is done in the opposite direction compared to Step 2 to reduce the load on line A to 100% (N-1). The remaining power-shift is 200 MW. The corresponding maximum power flow PF2 that can be sustained across the boundary from a year-round perspective in the direction X>Y without the project is 400 MW.

Step 5 illustrates the corresponding Δorrein the direction X>Y across the boundary as the gain in maximum power flow that is achieved by the project

- In the reference network model (project in) the load flow analysis carried out on the year-round dataset indicates that the maximum power flow that can be transported across the boundary equals 1000 MW = PF1
- When the project is subtracted from the reference network model, the load flow analysis carried out on the year-round dataset indicates that the maximum power flow that can be transported across the boundary equals 400 MW = PF2
- The corresponding ΔGTC thus equals 1000 MW – 400 MW = 600 MW



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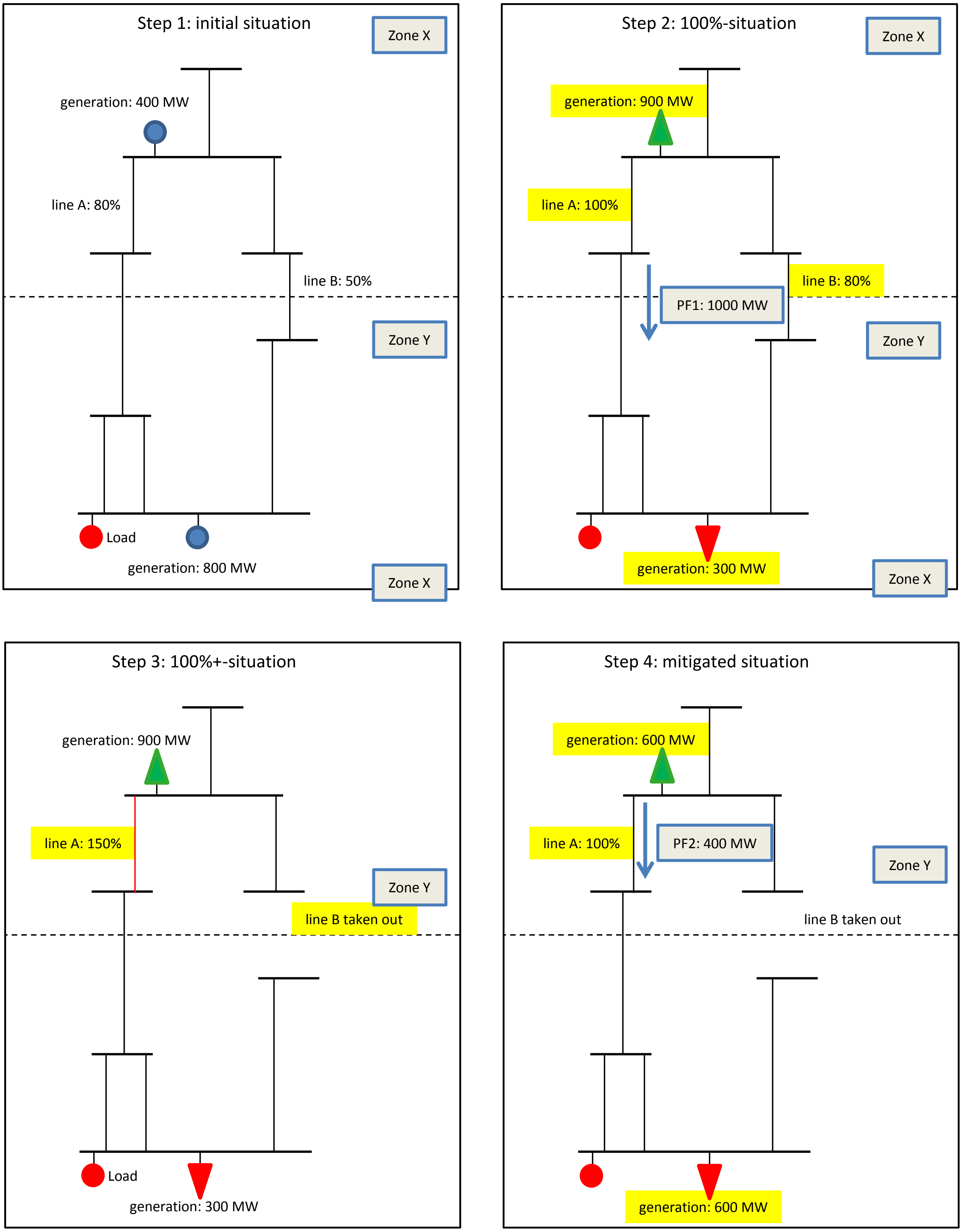

Step 1: initial situation
Zone X
generation: 400 MW
line A: 80%
line B: 50%
Zone Y
Load
generation: 800 MW
Zone X
Step 2: 100%-situation
Zone X
generation: 900 MW
line A: 100%
line B: 80%
PF1: 1000 MW
Zone Y
generation: 300 MW
Zone X
Step 3: 100%+-situation
generation: 900 MW
line A: 150%
Zone Y
line B taken out
Load
generation: 300 MW
Step 4: mitigated situation
generation: 600 MW
line A: 100%
PF2: 400 MW
Zone Y
line B taken out
generation: 600 MW

5.4 ANNEX 4: IMPACT ON MARKET POWER

Context

The Regulation (EU) n.347/2013 project requires that this CBA methodology takes into account the impact of transmission infrastructures on market power in Member States. This paper analyses this indicator and its limits, as well as the necessary methodology to construct it.

Basics on methodology

Market power is the ability to alter prices away from competitive levels. It is important to point out that this ability is a reflection of potential. A market player can have market power without using it. Only when it is actually used, market power has negative consequences on socio-economic welfare, by reducing the overall economic surplus to the benefit of a single market player. Taking into account market power in a CBA therefore requires three steps:

- To define carefully which asset(s)/ will be assessed. The calculation of the index will be made with and without this object, and the difference on this two calculations will be the outcome of the CBA.
- To define the market on which the index will be applied: geographic extension, how to take into account interconnections and market coupling, treatment of regulated market segments, market products to consider.
- To define a market power index, which require the choosing of an index among existing possibilities such as Residual Supply Index (RSI) or Herfindahl-Hirschman Index (HHI). Each of these has its advantages and disadvantages.

All of these choices affect the results of a market power analysis, i.e. the perceived market power is highly dependent on how it is defined.

Limits of market power indicators

First, it must be highlighted that the calculation of all these indexes requires confidential data as input. Thus, a balance has to be found between the necessary confidentiality of these data and the need for transparency that is required for CBA, as this is a necessary condition to obtain EU permitting and financial assistance.

Furthermore, monetisation of this market power index requires that the impact of a change in the market power index on socio-economic welfare is estimated. This requires that one is able to model the functioning of a future market under the hypothesis of imperfect competition, despite the fact that the validity of such a model is virtually impossible to prove. The inevitable model assumptions can radically change the results. The results of a CBA in terms of market power can therefore only be qualitative, and its use as a reference for cost allocation would raise many objections.

A CBA study is typically performed by evaluating the impact of a project during its whole life cycle. This requires to make a complete set of hypothesis on the future, for example the evolution of the level of consumption. Unfortunately, market power evolution cannot be modelled, as it is dependent on individual and regulatory decisions. Market structure could change dramatically in the future, for instance as the result of a merger. A solution to this issue could be to assess the impact of the infrastructure on the observed situation only. However, it should be noted that evaluating market power in a different hypothesis framework from the other aspects of the CBA would imply that the results are not consistent, and should not be compared.

Building projects may have a positive impact on market power issues, but it is not the only solution. One should note that a project takes more time to complete is more costly than a decision affecting regulation/competition. In case a market power issue is identified in a Member State, the national regulator should undertake relevant actions to force market players to respect the rules, rather than trying to solve the problem by expanding the infrastructure. Indeed, regulatory solutions are much more adapted to such an issue.

The instability of market power compared to the other aspects of a CBA has a crucial impact on its relevance as part of a decision making process. Dealing with generator ownership structures 10 or 20 years from now adds a highly uncertain dimension to the evaluation of European benefits of a given asset. Taking the impact of infrastructure capacity on market power into account in a CBA can heavily affect the identification of priority projects. Moreover, a change in the market structure can completely change the decision of building a particular project. This is all the more important considering that there are other, faster ways to solve market power issues, through regulation for example. By the time a project is completed, it is very likely that the market power issue has already been tackled by the regulator, and the project will not bring any benefit on this aspect. Taking market power into account in a CBA can thus lead to sub-optimal decisions.

Conclusion

The impact of future assets on current market power (which is generally positive) is an important indication, but this short-term aspect cannot be used in the assessment of an investment decision which is, by definition, a long-term commitment. National markets have already begun to merge, through market coupling, and a reporting of benefits on market power by Member States is already outdated.

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5.5 Annex 5: Multi-criteria analysis and cost benefit analysis

Goals of any project assessment method

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

The limits of a fully monetised cost benefit analysis

A fully monetised CBA cannot cover all criteria specified in Annexes IV and V of the Regulation (EU) No 347/2013, since some of these are difficult to monetise.

- This is the case for High Impact Low Probability events such as « disaster and climate resilience » (multiplying low probabilities and very high consequences have little meaning);
- Other benefits, such as, operational flexibility, have no opposable monetary value today (they qualify robustness and flexibility rather than a quantifiable economic value);
- Some benefits have opposable values at a national level, but no common value exists in Europe. This is the case with, for instance, the Value of Lost Load (VOLL), which depends on the structure of consumption in each country (tertiary sector versus industry, importance of electricity in the economy etc.);
- Some benefits (e.g. CO_2) are already internalised (e.g. in socio-economic welfare). Displaying a value in tons provides additional information and prevents double accounting.

As stated in the EC Guide to Cost Benefit Analysis (2008): “In contrast to CBA, which focuses on a unique criterion (the maximisation of socio-economic welfare), multi -criteria analysis is a tool for dealing with a set of different objectives that cannot be aggregated through shadow prices and welfare weights, as in standard CBA. Multi-criteria analysis, i.e. multi-objective analysis, can be helpful when some objectives are intractable in other ways and should be seen as a complement to CBA".

This is why ENTSO-E favours a combined multi-criteria and cost benefit analysis that is well adapted to the proposed governance and allows an evaluation based on the most robust indicators, including monetary values if an opposable and coherent unit value exists on a European-wide level. This approach allows for a homogenous assessment of projects on all criteria.

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5.6 Annex 6: Total surplus analysis

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

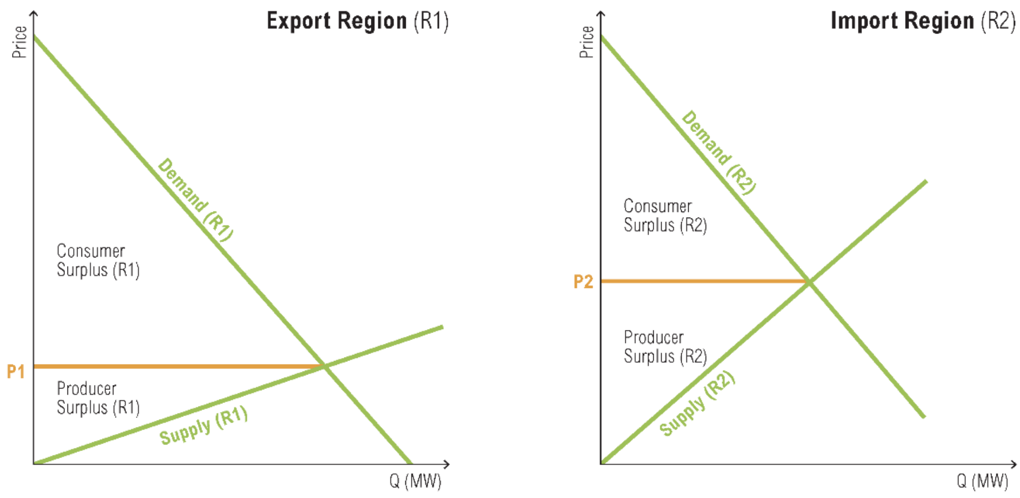

Figure 3.1: Example of an export region (left) and an import region (right) with no (or congested) interconnection capacity (elastic demand)

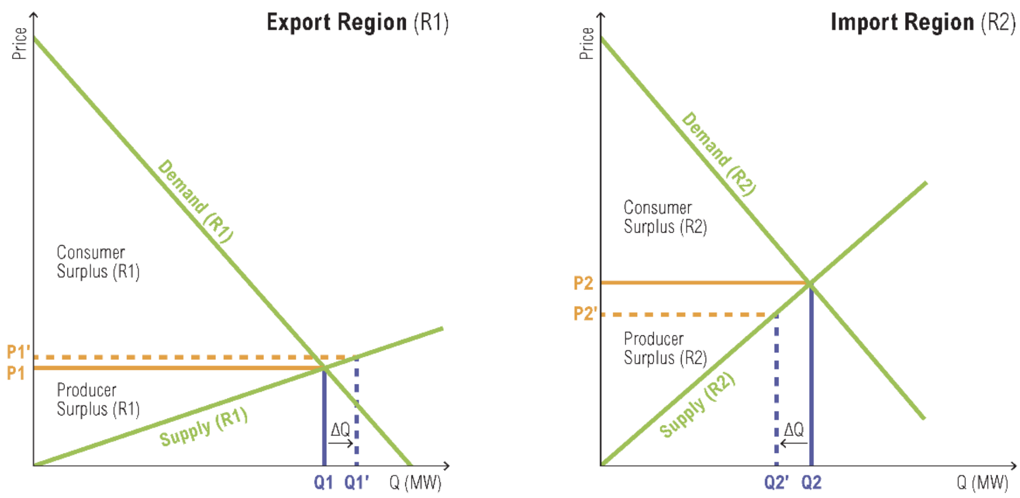

Figure 3.2: Example of an export region and an import region, with a new project increasing the GTC between the two regions (elastic demand)

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

Change in welfare = change in consumer surplus + change in producer surplus + change in total congestion rents

The total benefit for the horizon is calculated by summing the benefit for all hours of the year.

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Inelasticity of demand

In the case of the electricity market, short-term demand can be considered as inelastic, since customers do not respond directly to real-time market prices (no willingness-to-pay-value is available). The change in consumer surplus[32] can be calculated as follows:

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

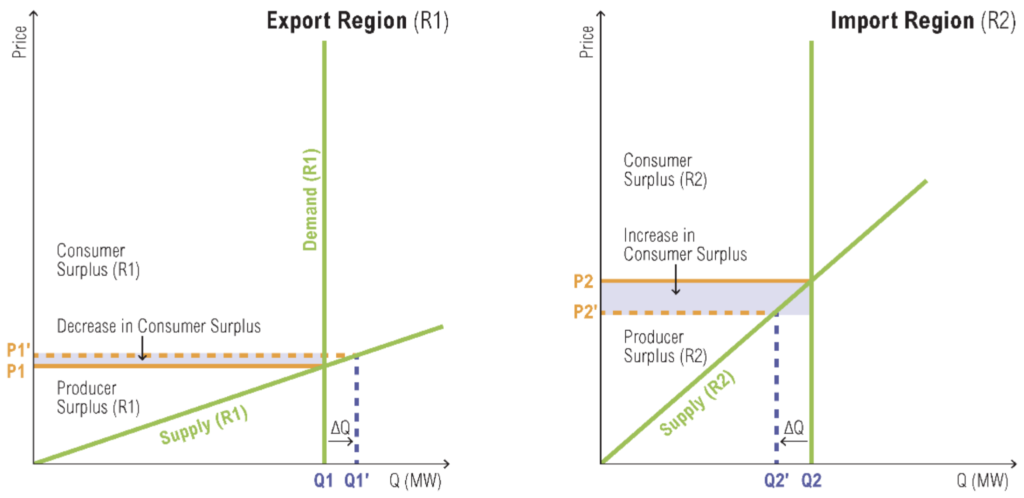

Figure 3.3: Change in consumer surplus

The change in producer surplus can be calculated as follows:

Change in producer surplus = generation revenues[33] – generation costs

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

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

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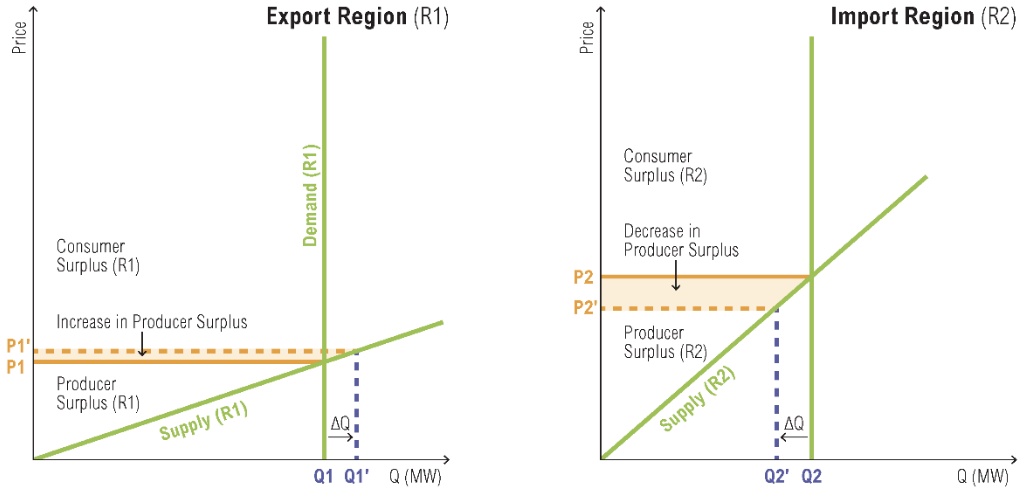

Figure 3.4: Change in producer surplus

The congestion rents with the project can be calculated by the price difference between the importing and the exporting area, multiplied by the additional power traded by the new link[34].

The change in total congestion rent can be calculated as follows:

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

[34] In a practical way, it's calculated as the absolute value of (Marginal cost of Export Area – Marginal cost of Import Area) x flows on the interconnector

5.7 ANNEX 7: VALUE OF LOST LOAD

The Value of Lost Load (VOLL) is a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It is generally measured in €/kWh. It reflects the mean value of an outage per kWh (long interruptions) or kW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or nation considered. It is an externality, since there is no market for security of supply.

The accurate calculation of a single value of VOLL cannot be performed uniformly on a European-wide basis. Experience has demonstrated that VOLL can vary significantly from one country to another, within countries or from one economic region to another. Large variations can occur due to differences in the nature of load composition, the type of affected consumers, and the level of dependency on electricity in the geographical area impacted, differences in reliability standards and the time of year and the duration of the impact.

The level of VOLL should reflect the real cost of outages for system users, hence providing an accurate basis for investment decisions. In this respect, too high a level of VOLL would lead to over-investment. Conversely, if the value were too low, it would lead to inadequate security of supply. There is an optimal level, expressing the consumer's willingness to pay for security of supply, therefore VOLL should allow for striking the right balance between transmission reinforcements (which have a cost, reflected in tariffs) and outage costs. Transmission reinforcements contribute to the improvement of security and quality of electricity supply, reducing the probability and severity of outages, and thus the costs for consumers.

The energy figure expressed in MWh, which ENTSO-E provides as the security of supply indicator in the CBA evaluation of each project, allows all interested parties to monetise by using the preferred VOLL available. Using a general uniform estimation for VOLL would lead to less transparency and inconsistency, and greatly increase uncertainties compared to presenting the physical units. ENTSO-E does not intend to reduce the accuracy or level of information provided by its assessment results through the application of an estimated VOLL.

The CEER has set out European guidelines[35] for nationwide studies on estimation of costs due to electricity interruptions and voltage disturbances, recommending that "*National Regulatory Authorities should perform nationwide cost-estimation studies regarding electricity interruptions and voltage disturbances*". Applying these guidelines throughout Europe would help establishing correct levels of VOLL, enabling comparable and

[35] Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010. Other reports have also established such guidelines, such as CIGRE (2001) and EPRI

References:
1) CIGRE Task Force 38.06.01: "Methods to consider customer interruption costs in power system analysis". Technical Brochure, August 2001
2) Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances, CEER, December 2010

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consistent project assessments all over Europe. However, this is not yet the case, and an investigation program would be a pre-condition for adopting VOLL for consistent TYNDP or PCI assessments.

5.8 ANNEX 8: ASSESSMENT OF ANCILLARY SERVICES

Exchange and sharing of ancillary services, in particular balancing resources, is crucial both to increase RES integration and to enhance the efficient use of available generation capacities. However, today, there is a great diversity of arrangements for ancillary services throughout Europe[36]. Common rules for cross-border exchanges of such services are foreseen within the future Network Code on Electricity Balancing. In the absence of such a code, any homogenous assessment of the value of transmission for exchange of ancillary services remains difficult. Some principles established by ACER's Framework Guidelines on Balancing Services provide a possible scope for cost benefit analysis of ancillary services:

- Frequency containment reserves[37] are shared and commonly activated in synchronous areas through the reliability margin foreseen for that purpose. These margins may be included in SEW calculations, and could lead to double-counting.
- The Network Code on Electricity Balancing shall set all necessary features to facilitate the development of cross-border exchanges of balancing energy and stipulate that these are made possible on every border, in the limits defined by Network Code on Load Frequency Control and Reserves concerning the procurement of Ancillary Services such as frequency restoration reserves (FRR) and replacement reserves (RR). However, the reservation of cross-border capacity for the purpose of balancing energy, from FRR and RR, is generally forbidden, except for cases where TSOs can demonstrate that such reservation would result in increased overall social welfare.

In general, the increase of cross-border capacities between bidding zones through grid development would therefore only lead to additional value in terms of balancing energy from frequency restoration reserves and replacement reserves during non-congested hours. Moreover, the value could only be monetised in certain conditions, as described below.

Many transmission projects, especially new interconnectors between or within coordinated markets, can provide the benefit of good reserve, provided only that the sending market has spare reserve capacity being held. The technical capability of an interconnector to deliver reserve, at various timescales should be carefully evaluated, considering both the technical characteristics of the interconnector and the technical definitions of reserve products in the markets. If at least one of the interconnected markets has a market-based approach in balancing services, such that a price of balancing services can be sensibly projected over a forecast horizon,

[36] See for instance ENTSO-E's survey on *Ancillary Services Procurement and Electricity Balancing Market Design* https://www.entsoe.eu/resources/network-codes/electricity-balancing/.

[37] *Frequency containment reserves* are operating *reserves* necessary for constant containment of frequency deviations (in order to constantly maintain the power balance in the whole synchronously interconnected system. This category typically includes operating *reserves* with the activation time up to 30 seconds. Operating *reserves* of this category are usually activated automatically.

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then a question of monetisation of a balancing services benefit arises. If these conditions are fulfilled, the following guidance could be given:

- If the transmission project lies entirely within one control area, which has a market-based approach in balancing services, then the benefit of that project, in terms of permitting greater access to market of reserve services should be assessed using forecast prices of reserve within the control area. Note that such prices are normally low – it is unusual to have reserve sources significantly limited by transmission, such that differential prices of reserve is released by extra transmission.
- If the transmission project interconnects two control areas, both of which have a market-based approach in balancing services and similar reserve products, then the reserve benefits of that project should be assessed using forecast prices of reserve within each bidding zone. Note the benefits are two-way. For example, if the interconnector is floating at one hour, then it can let reserve from control area A contribute to the requirement to control area B and simultaneously let reserve from control area B contribute to control area A. But of course, if the interconnector is flowing fully from A to B at that hour, then no reserve benefit in control area B can be also claimed. In general, the reserve benefit will be lower than the trading benefit evaluated under SEW (benefit B4).
- If the transmission project interconnects one control area A, which has a market-based approach in balancing services, with a second control area B which does not, or reserve products are very different, then great care should be exercised in attempting to quantify any reserve benefit. Obviously, zero benefit can be claimed for delivery of reserves from control area A into control area B if control area B does not have a marked based approach in balancing services. A Reserve benefit can only be claimed, if it is thought likely to be able to establish the holding of a Reserve service in control area B able to meet the technical requirements of Reserve in control area A. Further, a prudent forecast should be made of the price of holding the reserve in control area B, and this forecast deducted from the forecasted reserve price in control area A. If in doubt, it should be assumed that the price of holding in control area B exceeds the value in control area A, such that zero reserve benefit is claimed.
- Finally, if the transmission project interconnects two control areas which have no market-based approach in balancing services, then obviously, zero benefit can be claimed for delivery of reserves into either market.

5.9 ANNEX 9: ENVIRONMENTAL AND SOCIAL IMPACT

As stated in chapter 1, the main objective of transmission system planning is to ensure the development of an adequate transmission system which:

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

The TYNDP highlights the way transmission projects of European Significance contribute to the EU's overall sustainability goals, such as CO_2 reduction or integration of renewable energy sources (RES). On a local level, these projects may also impact other EU sustainability objectives, such as the EU Biodiversity Strategy (COM 2011 244) and landscape protection policies (European Landscape Convention). Moreover, new infrastructure needs to be carefully implemented though appropriate public participation at different stages of the project, taking into account the goals of the Aarhus Convention (1998) and the measures foreseen by the Regulation on Guidelines for trans-European energy infrastructure (EU n° 347-2013).

As a rule, the first measure to deal with the potential negative social and environmental effects of a project is to avoid causing the impact (e.g. through routing decisions) wherever possible. Steps are also taken to minimise impacts through mitigation measures, and in some instances compensatory measures, such as wildlife habitat creation, may be a legal requirement. When project planning is in a sufficiently advanced stage, the cost of such measures can be estimated accurately, and they are incorporated in the total project costs (listed under indicator C.1).

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

- indicate where potential impacts have not yet been internalized i.e. where additional expenditures may be necessary to avoid, mitigate and/or compensate for impacts, but where these cannot yet be estimated with enough accuracy for the costs to be included in indicator C.1.
- indicate the *residual* social and environmental effects of projects, i.e. effects which may not be fully mitigated in final project design, and cannot be objectively monetised;

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

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

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

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

When first identifying the need for additional transmission capacity between two areas, one may have a general idea about the areas that will be connected, while more detailed information on, for instance, the exact route of such an expansion is still lacking, since routing decisions are not taken until a later stage. In the early stages of a project it is often thus difficult to say anything concrete about the social and environmental consequences of a project, let alone determine the cost of mitigation measures to counter such effects. The quantification on these indicators will thus be presented in the form of a range, of which the 'bandwidth' tends to decrease as information increases as the project progresses in time. In the very early stages of development, it is possible that the indicators are left blank in the TYNDP and are only scored in a successive version of the TYNDP when some preliminary studies have been done and there is at least some information available to base such scoring upon. A strength of this type of measure is that it can be applied at rather early stages of a project, when the environmental and social impact of projects is generally not very clear and mitigation measures cannot yet be defined. In subsequent iterations of the TYNDP, as route planning advances and specification of mitigation measures becomes clearer, the costs will be internalised in 'project costs' (C.1), or indicated as 'residual' impacts.

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

Considering that translating the project score to a colour code would make the indicator appear to be simpler and more objective than it actually is, and would undermine its main intention, which is to provide full information to decision makers and the public, scoring is carried out in the following manner:

Assessment system for residual environmental impact

- Stage: Indicate the stage of project development. This is an important indication for the extent to which environmental impact can be measured at a particular moment.
- Basic notion: amount of km that might have to run "in" sensitive areas. An area can be sensitive to (nearby) infrastructure because of the potential effects this infrastructure will have on nature and biodiversity[38]
- Type of sensitivity: Define why this area is considered sensitive.

Example:

Project	Stage	Impact Potentially crosses environmentally sensitive area (nb of km)	Typology of sensitivity	Link to further information
A	Planned	Yes (a. 50 to 75 km; b. 30 to 40 km)	a. Birds Directive; b. Habitats Directive	e.g. Big Hill SPA www.…
B	Design & permitting	No		www.…
C	Planned	Yes (20 km)	Habitats Directive	www.…
D	Under consideration	N.A	N.A	www.…

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

Assessment system for residual social impact

- Stage: Indicate the stage of project development. This is an important indication for the extent to which social impact can be measured at a particular moment.
- Basic notion: # of km "in" sensitive area. An area can be sensitive to (nearby) infrastructure if it is densely populated or protected for its landscape value.
- Type of sensitivity: Define why this area is considered sensitive.

Example:

Project	Stage	Impact Crosses dense area (nb of km)	Sensitivity Typology of sensitivity	Link to further information
A	Design & permitting	Yes (20 to 40km)	Dense area	www….
A	Planned	Yes (100 km)	European Landscape Convention:	www…
B	Planned	No	Submarine cable	www….
C	Under construction	Yes (50 km)	Dense area, OHL	www….

Definitions:

This section provides an overview of impacts that may qualify an area as environmentally or socially 'sensitive'.

Environmental impact

- Sensitivity regarding biodiversity:
  - Land protected under the following Directives or International Laws:
    - Habitats Directive (92/43)
    - Birds Directive (2009/147)
    - RAMSAR site
    - IUCN key biodiversity areas
    - Other areas protected by national law
  - Land within national parks and areas of outstanding natural beauty
  - Land with cultural significance

Social impact

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

End note.

System development tools are continuingly evolving, and it is the intention that this document will be reviewed periodically pursuant to Regulation (EU) n.347/2013, Art.11 §6, and in line with prudent planning practice and further editions of the TYNDP document of ENTSO-E.

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