MEDITERRANEAN TRANSMISSION SYSTEM OPERATORS

Deliverable 2.2.3
Proposal of a CBA Methodology for transmission projects assessment

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“Mediterranean Project”

Task 2 “Planning and development of the Euro-Mediterranean Electricity Reference Grid ”

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Description of Cost Benefit Analysis (CBA) methodology for transmission project assessment

Presentation of the Report

This document describes the common principles and procedures for performing combined multi-criteria and cost-benefit analysis, using network, market and interlinked modeling methodologies, following the current ENTSOE proposal submitted to ACER on July 2016 and based on Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure. Its objective is to serve as a basis for a harmonized assessment of the new interconnection Projects analyzed and assessed in the Mediterranean region under the umbrella of MEDTSO studies.

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 (DSM) or a suitable cost-effective combination of all previous solutions. Therefore, the primary scope of this methodology is to assess and to plan the future transmission system in the Mediterranean Region.

This CBA Methodology sets out the MEDTSO criteria for the assessment of costs and benefits of a new transmission project, all of which stem from ENTSOE practice based on 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 monetized, while others are quantified in their typical physical units (such as tons or GWh). A general overview of the indicators is given in Chapters 2 and 3 below while a more detailed representation of the indicators is given in Chapter 4.

This set of common indicators forms a complete and solid basis for project assessment across the Mediterranean area within the scope of the Mediterranean Project.

1 Purpose of CBA Methodology

The CBA methodology is developed to evaluate the benefits and costs of new interconnection projects from a Mediterranean perspective, providing important input for the assessment of the interconnection projects considered in the Mediterranean Region. The main objective of this CBA methodology is to provide a common and uniform basis for the assessment of these projects.

Transmission system development focuses on the long-term planning and scheduling of reinforcements and extensions to the existing transmission grid. This document describes the assessment of projects, which are identified in the Mediterranean Region.

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 exchange of energy and balancing services between market 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 internalized within other benefits, such as avoided CO_2 and RES integration via socio-economic welfare, while others remain completely non-monetized.

2 Scenario Building and Grid Development

Scenarios are defined to represent potential future developments of the power 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 Mediterranean electricity system level and be adapted in more detail at a regional level. They shall also 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 Characteristics of Scenarios

Scenarios represent the whole Mediterranean electricity system level and can be adapted in more detail at a regional level (corridor). 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 Mediterranean interest is based on the scenarios developed by MEDTSO in the Mediterranean Project. These visions provide the frame within which the future is likely to occur but do not have probability of occurrence attached to them. MEDTSO scenarios were built following different approaches: thus some have a stronger national focus than others, some are ‘top-down’, others ‘bottom-up’ etc.

There is no right and wrong or likely/unlikely options: all visions have to be treated equally and due to the uncertainties of the future energy sector no scenario can be defined as a ‘leading scenario’. These scenarios aim to provide stakeholders with an overview of generation, demand and their adequacy in different scenarios for the future Mediterranean power system, with a focus on the power balance, margins, energy indicators and the generation mix.

The scenarios will be representative of Long-term horizon (typically 10 to 20 years), being 2030 the best option chosen for the Mediterranean Project.

2.2 Modelling framework

NTC-based market simulations

To meet the hourly load of each market area, market studies are used to calculate the cost optimal dispatch of generation units, market exchanges between market areas and corresponding marginal costs on an hourly basis, using a simplified model of the physical grid. The market areas are represented as a network of interconnected nodes connected by a Net Transfer Capacity (NTC) to represent the physical interconnections that exist between each pair of market areas. Thus the market studies analyses the cost-optimal generation pattern for every hour taking into account energy-based market mechanisms.

In general the market flow is different from the corresponding physical flow since for getting the trading capacities e.g. loop flows (across multiple interconnections between the same areas characterized by a meshed grid) are not needed to be considered. The important information is the net trading capacity between two market areas.

Market studies are used to determine the benefits of providing additional transport capacity and enabling a more efficient usage of generation units available in different locations across market areas. They take into account several constraints such as flexibility and availability of thermal units, hydro conditions, wind and solar profiles, load profile and outages. They also allow measuring the savings in generation investment costs allowed by investments in the grid.

Network simulations

Network studies, on the other hand, are based on network models representing the transmission network in adequate level of detail and are used to calculate, by means of load flow analysis, the physical flows that take place in the network under given generation/load/market exchange conditions. Network studies allow identifying bottlenecks in the grid corresponding to the bulk power flows resulting from the market exchanges, and are in particular necessary to compute the delta GTCs necessary to determine the NTC used in NTC-based market studies.

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

2.3 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) or working with a limited but still adequate set of planning cases (Points in Time – PiT). In the latter case, adequate means that the planning cases selected out of the available 8760 cases need to be highly representative situations (hours) for the power grid operation, characterized by significant stress conditions for the power grid within the area under study. Specifically, situations in which relevant power lines (such as interconnection or the project under investigation) are likely to be overloaded or close to their limit of transmission capacity, situations in which a certain generation and load pattern is likely to determine undesired voltages levels (displacement from nominal conditions) within a certain portion of the power grid or other relevant system operation conditions.

The PiT selection shall include all scenarios described in paragraph 2.2 on a joint regional basis, taking into account the experience of involved TSOs and with the aim to represent above mentioned demanding situations.

2.4 Sensitivities

Sensitivity analysis is performed with the intention to observe how minor changes of the scenario (e.g., by changing only one separate parameter or a set of interlinked parameters) affect model results, in order to achieve a deeper understanding of the system's behavior related to these parameters. In principle, each individual model parameter can be used for a sensitivity analysis, but not all might be equally useful to achieve the desired information. Furthermore different parameters can have different impact on the results, also depending on the scenario and it is therefore strongly recommended to perform detailed scenario-specific studies to determine the most impacting parameters.

3 Project Assessment: Combined Cost Benefit and Multi-criteria Analysis

The goal of project assessment is to characterize the impact of transmission projects, both in terms of added value for society (increase of capacity for exchanges of energy and balancing services between market areas, RES integration, increased security of supply) as well as in terms of costs. It is the task of Med-TSO to define a robust and consistent methodology to assess the contribution of projects across Mediterranean area on a consistent basis. Med-TSO proposes this CBA methodology to achieve a uniform assessment process for projects across the whole Mediterranean area.

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 Socio-Economic Welfare (SEW) 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 feasible in this context as many benefits cannot be quantified financially in an objective manner, such as 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 only when project progresses and greater detail is known. A single monetary value would not fully identify the value expressed by these kind of costs and benefits.

3.1 Clustering of transmission 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 realization of another project) they can be clustered and assessed as a single transmission project.

In the context of Med-TSO, clustering is defined as the grouping of investments that must be realized jointly in order to achieve a specific function, e.g. a Grid Transfer Capability (GTC) increase across a defined boundary. Clustering should only be applied in cases where multiple investments strongly depend on each other; i.e. where one investment cannot fully accomplish its expected goal, without one or more supporting projects. Typically this regards reinforcements in the existing grids in proximity of the terminal nodes of a new line.

Note that investment competing each other (i.e alternative among them) cannot be clustered together.

When clustering several investments together, the project promoter(s) must ensure that all investments contribute to the total GTC increase in a significant manner. Hence, investments should only be clustered with other investments 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 investments have to be clustered. A proper project description must explain how the reinforcements complement each other and what the negative consequences of not developing one of them would be.

3.2 Assessment Framework

The assessment framework is a combined cost-benefit and multi-criteria assessment. The criteria set out in this document have been selected on the following basis:

- They enable an appreciation of project benefits in terms of network objectives to:
  - Ensure the development of an interconnected Euro-Mediterranean grid to substantiate climate policy and sustainability objectives (RES, energy efficiency, CO_2);
  - Guarantee security of supply;
  - Complete the integration of energy markets, thus contributing to increased socio-economic welfare ;
  - Ensure system stability, increase stability and resilience.
- 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 1 shows the main categories of indicators used to assess the impact of projects on the transmission grid. The indicators that report on EU 20-20-20 targets are marked in green.

In the first version of the CBA methodology adopted in Europe (referred to as CBA 1.0), the challenges of SoS were reported using three different indicators (B1 – Security of supply, B6 – Technical resilience/ system safety, and B7 – Flexibility); In the second (current) version of the methodology (referred to as CBA 2.0), the SoS indicator reports these elements using two indicators: adequacy to meet demand (B5a) and system stability (B5b). Some projects will provide all the benefit categories, whereas other projects will only contribute significantly to one or two of them.

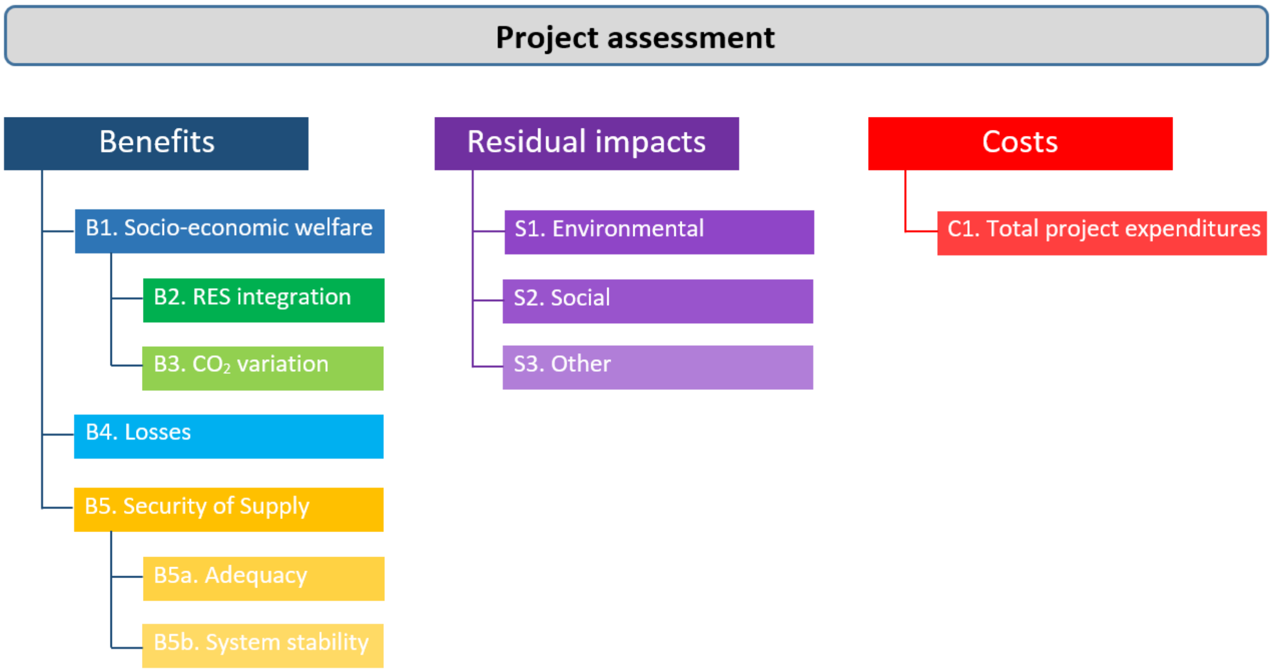

Figure 1: Main categories of the project assessment methodology

Benefit categories are defined as follows:

- **B1. Socio-economic welfare (SEW)** or market integration is characterized by the ability of a project to reduce congestion and thus provide an adequate GTC that ensures increasing NTC so that electricity markets can trade power in an economically efficient manner.

  In chapter 4, the methodology to obtain this indicator is presented.

- **B2. 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 minimizing curtailments. Although this indicator is economically accounted for in the calculation of SEW (a variation of the RES integration will result in a variation of the energy from conventional sources and thus affect the system costs.), the RES integration is one key target in the Mediterranean region and is therefore displayed separately.

In chapter 5, the methodology to obtain this indicator is presented.

- **B3. Variation in CO_2 emissions** is the characterization of the evolution of CO_2 emissions in the power system due to the new project. It is a consequence of B1 and B2 (the unlocking of generation with lower carbon content). Although this indicator is economically accounted for in the calculation of SEW (a variation of the CO_2 emission and the resulting change in emission costs will affect the system costs), the CO_2 indicator is one key targets in the Mediterranean region and is therefore displayed separately.

  In chapter 6, the methodology to obtain this indicator is presented.

- **B4. Variation in losses** in the transmission grid is the characterization of the evolution of energy losses in the power system due to the new project. It is an indicator of energy efficiency.

  In chapter 7, the methodology to obtain this indicator is presented.

- **B5a & B5b. Security of supply**
  Adequacy to meet demand characterizes the new project's impact on the ability of a power system to provide an adequate supply of electricity to meet the demand, taking into account the variability of climatic effects on demand and on forecasts of renewable energy sources production.

  System stability characterizes the new project's impact on the ability of a power system to keep a stable and reliable supply of electricity taking into account the possible occurrences of system disturbances and faults.

  In chapter 8, the methodology to obtain this indicator is presented.

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, undersea cables, HVDC substations, maintenance and operational costs…).

  For each mature project, the cost (and corresponding uncertainty range) has to be reported, including items such as:

  - Expected cost for materials and execution costs (such as towers, foundations, conductors, substations, protection and control systems);
  - Expected costs for temporary solutions which are necessary to realize 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 permitting costs (such as environmental costs avoided, mitigated or compensated under existing legal provisions, cost of permitting procedures);

- 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 B4.

The level of information about expected project costs depends on the status of the project. Therefore reporting of costs shall be done using the best information available, whilst ensuring consistency of assumptions and thus comparable cost figures.

Costs shall be estimated as follows:

a. Identify the standard investment costs to define the standard project costs.

b. Project costs may be higher or lower than the standard investment costs. In this case, the project promoters define a project-specific complexity factor (if project costs equal the standard investment costs, the complexity factor is equal to 1) to account for the deviation from standard investment costs.

Residual impact is defined as follows:

As far as environmental and social mitigation costs are concerned, the costs of measures taken to mitigate the impacts of a project should be included in the project cost (indicator C1). Some impacts may remain after these mitigation measures are implemented. These residual impacts are accounted for by and included in indicators S1, S2, and S3. This split ensures that all measurable costs are taken into account, and that there is no double-accounting between these indicators.

- **S1. Environmental impact** characterizes the project impact as assessed through preliminary studies, and aims at giving a measure of the environmental sensitivity associated with the project. It can be expressed in terms of the number of kilometers an overhead line or underground/submarine cable that run through environmentally 'sensitive' areas. This indicator only takes into account the residual impact of a new project, i.e. the portion of impact that is not fully accounted for under C1.

- **S2. Social impact** characterizes 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. It can be expressed in terms of the number of kilometers an overhead line or underground/submarine cable that may run through socially sensitive areas. This indicator only takes into account the residual impact of a new project, i.e. the portion of impact that is not fully accounted for under C1.

- **S3. Other impacts**; this indicator lists the impact(s) of a project that are not covered by indicators S1 and S2, after potential mitigation measures defined when the project definition becomes more precise. These impacts may be positive or negative and will be included as a list in the assessment results. Impacts that are accounted for by indicators S1 or S2 shall not be included.

Assessment Summary Table (example)

Assessment results for cluster/project MA-PT						
non scenario specific	GTC increase direction 1 (MW)		1000			
	GTC increase direction 2 (MW)		1000			
scenario specific			Med-TSO scenario			
			1	**2**	**3**	**4**
Increase the interconnection rate (%)						
Benefit Indicators	B1-SEW	(M€/y)				
	B2-RES	(MWh/y or MW/y)				
	B3-CO2	(kT/y)				
	B4 - Losses	(M€/y)				
	B5a-SoS Adequacy	(MWh/y)				
	B5b-SoS System Stability					
External Impact Indicators	S1- Environmental Impact					
	S2-Social Impact					
	S3-Other Impact					
Costs	C1-Estimated Costs	(M€)				

Assessment	Scale	Color code
negative	0	
neutral	1	
positive	2	
Not Available	NA	
monetized		

Figure 2: Example of an assessment summary table

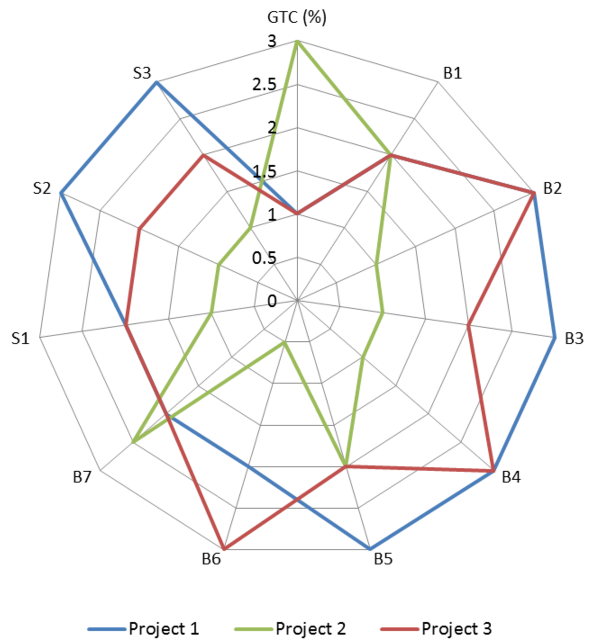

Figure 3: Example of an assessment spider diagram

Figure 2 and 3 shows how the project assessment can be displayed in tabular and graphical format respectively, including the six categories of benefits mentioned above, as well as the three residual impact indicators (environmental, social and other impacts) and the cost of each cluster. An additional characterization of the cluster is provided through an assessment of the GTC directional increase.

The GTC contribution, the benefit, cost and residual impact indicators will be provided for the project as a whole. The contribution to GTC is time and even rarely scenario dependent, but a single value should be reported for clarity reasons.

4 Methodology for Socio-Economic Welfare (SEW) – Indicator B1

In the context of the Euro-Mediterranean region, socio-economic welfare is defined as the economic surpluses of electricity consumers, producers, and transmission owners (congestion rent). The most common economic indicator for measuring benefits of transmission investments in planning scenarios is the reduction in total variable generation costs.

This metric values transmission investment in terms of saving total generation costs, since a project that increases the commercial exchange capability between two market areas allows generators in the lower priced area to export power to the higher priced area, as shown below in Figure 4.

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.

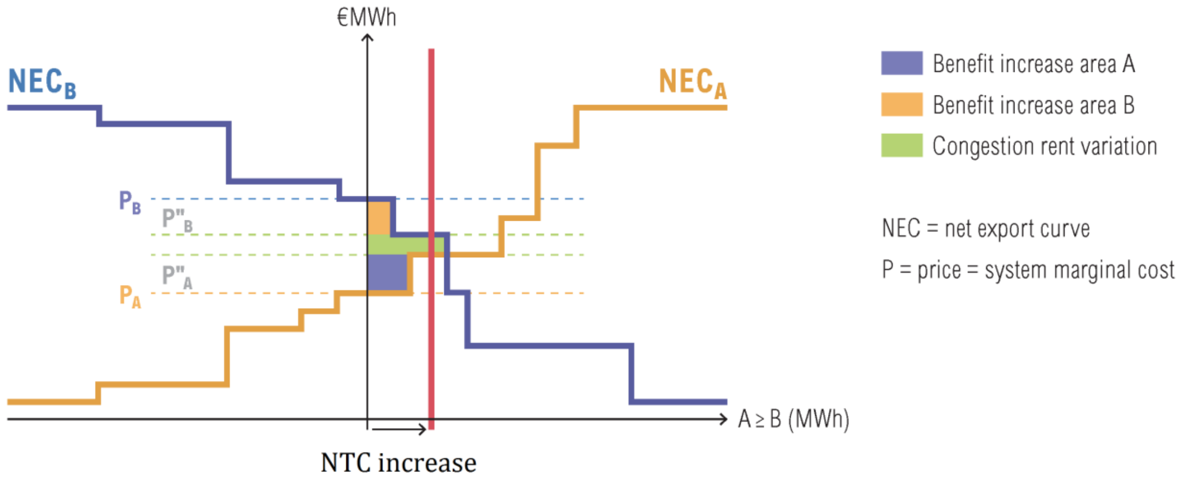

Figure 4: Illustration of benefit due to NTC increase between two market areas

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.

Total generation costs are equal to the sum of thermal generation costs, Energy Not Served (ENS) costs, Other Non-Res costs and Demand Side Response (DSR) costs. The different cost terms generally used in market simulations are shown in the table below:

Cost terms in Market Simulation	Description
Fuel costs	Costs for fuel of thermal power plants (e.g. lignite, hard coal, natural gas etc.)
CO_2-Costs	Costs for CO_2-emissions caused by thermal fired power plants. Depends on the power generation of thermal power plants and CO_2-Price.
Start-up-costs / Shut-down costs	These terms reflects the quasi-fixed costs for starting up a thermal power plant to at least a minimum power level.
Operation and maintenance costs	Costs for operation and maintenance of power plants.
ENS-Costs	Costs for Energy not served (ENS). ENS is the expected amount of energy not being served to consumers.
DSR-Costs	Costs for Demand Side Response (DSR). DSR is load demand that can be actively changed by a certain trigger.

Table 1: Cost terms used in Market Simulations

Demand is estimated through scenarios, which results in a reshaping of the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles, etc. In this case, demand response is not elastic at each time step, but constitutes a shift of energy consumption from time steps with potentially high prices to time steps with potentially low prices (e.g., on the basis of hourly RES availability factors).

The generation costs to supply a known demand are minimised through the generation cost approach. This assumption simplifies the complexity of the model and therefore the demand can be treated as a time series of loads that has to be met, while at the same time considering different scenarios of demand-side management.

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

- By reducing network bottlenecks that restrict the access of generation to the integrated Euro-Mediterranean market, a project can reduce costs of generation restrictions, both within and between market areas.
- A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation. In the case of connection of renewables, this is also expressed by benefit B2, RES Integration.
- A project can also facilitate increased competition between generators, reducing the price of electricity to final consumers. The methods do not consider market power and 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 time step) = Generation costs without the project (sum over all time steps) – Generation costs with the project (sum over all time steps)

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

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

Results

Changes in SEW must be reported in €/yr for each new project (for a given scenario and study year). In addition to the overall socio-economic welfare changes, the SEW changes that are the result of integrating RES and that are the result of variation in CO_2 emissions must be reported separately:

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

5 Methodology for RES Integration – Indicator B2

The volume of integrated RES (in MW or MWh) must be reported in any case. The integration of both existing and planned RES is facilitated by:

- The connection of RES generation to the main power system.
- Increasing the capacity 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 the capacity in the main system itself.

Although both types of projects can lead to the same indicators, 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 capacity-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 B1 or 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

Increasing the penetration of RES in the electricity system has effects that are partly captured by other indicators (B1, with regard to changes in the variable cost of electricity supply; B3 a reduction of CO_2 emissions). The mere variation in the installed (connected) RES capacity may also have value to a certain stakeholder, but this effect in itself cannot be monetized in an objective manner beyond the economic effects that are already internalized in generation cost savings (indicator B1) and the variation of CO_2 emissions (indicator B3). A methodology to perform a CBA assessment using a monetized value could be to monetize the integration of RES by multiplying the MW or MWh value with the value of monetary benefit it attains to having additional RES integrated in the system, in addition to the variation in generation costs (B1) and/or reduction of CO_2 emissions (B3) that are reported in separate indicators.

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		Euro-Mediterranean
Avoided RES spillage	Market or network studies	MWh/yr	Partly included in generation cost savings (B1) and variation in CO_2 emissions (B3)	Euro-Mediterranean

Table 2: Reporting Sheet of RES integration Indicator

Double-counting

Indicator B2 reports the increased penetration of RES generation in the system. As this also affects the input parameters of the simulation runs, the economic effects in terms of variable generation costs and CO_2 emissions are already captured in other indicators (B1 and B3, respectively). When considering the indicator B2 – RES integration one should therefore only consider the benefits that stem from the mere fact of having more RES generation in the system (e.g., impact on meeting RES targets, international agreements, increased societal well-being from knowledge that more RES is installed, etc.), without considering the benefits that are already captured by other indicators.

6 Methodology for Variation in C02 Emission – Indicator B3

By relieving network congestion, reinforcements enable cheaper generation to generate more electricity, thus replacing more expensive conventional plants (with higher or lower carbon emissions). Depending on the assumptions on the CO_2 price, it may lead to higher or lower CO_2 emissions expressed in tonnes. 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.

Monetisation

The monetary value attached to CO_2 emissions in a CBA assessment should reflect the (avoided) cost of mitigating the harmful effects that CO_2 emissions pose for society (e.g., the consequences of global warming). This societal cost of CO_2 should be viewed separately from the cost that is imposed on carbon-based electricity production, which may take the form of carbon taxes and/or the obligation to purchase CO_2 emission rights under the Emissions Trading the EU Scheme (ETS) or equivalent schemes which could be set up in the Mediterranean area . The cost of the latter is internalized in production costs and has an effect on SEW, hence, it is captured by indicator B1. But it is as direct benefits, which doesn't reflect the total effect. The Variation in CO_2 emissions indicator (B3) can be used for further analysis of the societal effects of CO_2 emissions, if these deviate from the CO_2 emission costs as assumed in indicator B1. These cannot presently be monetized in an objective manner: while CO_2 emissions are generally considered to have a negative effect on society, the magnitude of this effect is the topic of an ongoing and controversial political debate. Therefore, the CBA Methodology requires that CO_2 emissions are reported separately (in tons).

Parameter	**Source of calculation**	**Basic unit of measure**	**Monetary measure (externality or market-based?)**	**Level of coherence of monetary measure**
CO_2	Market Studies (substitution effect)	Tons	Societal cost of CO2 (partly or fully internalised in B1, depending on stakeholder perspective with regard to assumed CO2 emission costs affecting variable generation costs)	Euro-Méditerranean

Table 3: Reporting Sheet of CO2 Emission Indicator

Double-counting

Indicator B1 reports the SEW of a project, taking into account inter alia the generation costs of electricity, which includes a cost for CO2 emissions (e.g., the result of a carbon tax or purchase of

ETS rights). A carbon tax or ETS rights costs affect the variable production costs of a generation unit, even if they do not reflect the true underlying societal cost of CO_2, and as a result affects power plant dispatch (and thereby market exchanges, line loadings, etc.). When monetizing the societal cost of CO_2 emissions, one may need to correct for the part of CO_2 costs that was already internalized in B1, because higher production costs were assumed.

Example: if one values the societal cost of CO_2 emissions at €100/ton and a carbon tax of €20/ton is applied in the market simulations, the monetized, societal cost of CO_2 emissions that is not yet accounted for is (100–20) [€/tonne] * <tonnes avoided CO_2 emissions> [tonne CO_2].

Note that this indicator is fully monetized under SEW (B1) in the event that the input value for CO_2 emission costs fully reflects the societal cost of CO_2 as perceived by the stakeholder.

Example: if one values the societal cost of CO_2 emissions at €40/ton and an emissions right cost of €40/ton is applied in the market simulations, the monetized, societal cost of CO_2 emissions that is not yet accounted for is (40–40) [€/ton] * <tonnes avoided CO_2 emissions> [ton CO_2] = 0 [€/ton].

Sensitivity analysis

Monetisation of CO_2 for the purpose of reflecting variable generation costs is based on forecasted CO_2 prices for electricity in the studied horizon. The price is derived from official sources such as the International Energy Agency (IEA) for the studied perimeter and form a part of scenario input. Because the prices of CO_2 included in the generation costs (B1) may understate (or: overstate) the full long-term societal value of CO_2, a sensitivity analysis could be performed for this indicator, under which CO_2 is valued at a long-term societal price. To perform this sensitivity without double-counting against B1:

- Derive the delta volume of CO_2, as above;
- Consider the CO_2 price internalised in B1;
- 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.

7 Methodology for Variation in Losses – Indicator B4

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.

However, since most of the projects are dedicated to improve international exchanges over long distances, those transmission projects may increase the thermal losses.

7.1 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, **a)** one with and **b)** one without the project and relevant internal reinforcements (clustering). A sufficient quality of the amount of calculated losses is obtained, if at least the following requirements are met:

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

7.2 Relevant geographical area/grid model

The calculated losses should be representative for Europe and Mediterranean area 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 (or corridor approach). 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 total diferential losses is the sum of two terms: **a)** the variation of the internal losses in each power system and also **b)** the losses in the new interconnection line. 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.

7.3 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 (typically 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.

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

Since a transmission 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.

7.5 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 the power system to generate such 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 relevant internal reinforcements) 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 relevant internal reinforcements) and sh,i (without project) the hourly marginal cost 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) – (ph,i * sh,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.

8 Methodology for Security of Supply – Indicators B5a & B5b

8.1 Adequacy to meet demand (B5a)

Network studies are conducted to evaluate the contribution of a new project to reducing the Loss of Load probability (LoL) in N and N-1 conditions. For the selected PiT contingency analysis is performed based on a predefined list of disturbances (N-1) to detect cases of loss of load. The results from this analysis are combined with statistical data on the annual occurrence and duration of specific disturbances. In this way it is possible to calculate the Loss of Load (in MW) and the Expected Energy Not Supplied (EENS) according to the following relations:

$$Loss\ of\ Load = \sum_{i \varepsilon S} m_i f_i \quad \text{(MW)}$$

$$EENS = \sum_{i \varepsilon S} m_i f_i d_i \quad \text{(MWh)}$$

Where:

S: the set of contingencies leading to loss of load
m_i: the loss of load for the contingency i
f_i: the annual frequency of occurrence the contingency i
d_i: the duration of the contingency i in hours

Monetisation

The monetisation of indicator B5a – SoS Adequacy - is performed through the Value of Lost Load (VOLL in €/MWh), which can be a function of many factors, including the type of load (industrial, domestic, etc.), the level of dependence on electricity in the geographical area of interest, and the reliability of the supply. An approximation can be given by the country's gross domestic product ratio to annual energy consumption. Anyway the use of common criteria for calculating the VOLLs in the whole Mediterranean region is strongly recommended.

EENS can be monetized multiplying the lost load in a year with the VOLL. Final result in €/year will be reported together with the value of MWh.

Anyway, in many cases resulting EENS is almost always equal to zero by principle since each country supply is balanced in the Reference case, so before adding the new interconnection lines. For this aim, some tentative to monetize this indicator is to include it in the SEW indicator by adding annuity of avoided Generation investment as a consequence of improving import capacity.

8.2 System stability (B5b)

Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. Examples of physical disturbances could be electrical faults, load changes, generator outages, line outages, voltage collapse or some combination of these. The objective of including a system stability indicator is to provide an indication of the change in system stability as a result of a reinforcement project, such as a new interconnection.

The assessment of system stability typically requires significant additional modelling and simulations to be undertaken for which the supporting models would be required. The studies are by their nature complex and time consuming and challenging to include within the Euro-Mediterranean region at this stage. Future revision of this methodology should include a proposal on how to calculate and monetize this indicator.

Anyway, at this stage, it could be practical to include a qualitative assessment based on the technology being employed in different factors: transient stability, voltage stability, frequency stability and sharing of reserves.

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