e-HIGHWAY 2050

Modular Development Plan of the Pan-European Transmission System 2050

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PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
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CO	Confidential, only for members of the consortium (including the Commission Services)	

Document information

General purpose

This deliverable describes the methodological approach elaborated by the WP6 of the project e-Highway2050 to score investment alternatives for the European transmission grid at the time horizon 2050. With respect to the traditional approaches, the present one significantly enlarges the scope of the analysis to include a full range of technical-economic aspects, thanks to several original research contributions. However, an eye is always maintained to keep the computational burden and the formulas complexity within a level that can be easily implemented by an MS-ACCESS application including VBA macros. Such an application environment, named “toolbox” will be the subject of the subsequent deliverable D6.2.

In a further phase, the approach here explained will be applied in assessing the five scenarios set up by the WP2 with the aim of scoring the investment alternatives proposed by the WP2, thus allowing to elaborate the pan-European 2050 Modular Plan, that is the ultimate goal of the project e-Highway2050. In that framework, the simplifications applied by the WP2 simulations along with the fact that the WP6 cost-benefit assessment is carried out in sequence to the WP2 simulations has imposed the necessity to adapt the WP6 methodology here described in order to make it feasible within the assessment chain carried out by the project. Wherever possible, these limitations are highlighted already in this deliverable together with indications on how the assessment could be improved in case these limitations are removed.

Change status

Revision	Date	Changes description	Authors
V1.0	08.11.2013	First deliverable draft	G. Migliavacca, S. Rossi, F. Careri (RSE)
V2.0	14.05.2014	Revision by adding a few theoretical improvements and by taking into account stakeholders’ comments	G. Migliavacca, S. Rossi, F. Careri (RSE)
V3.0	16.07.2014	Revision after deliverable consultation comments	G. Migliavacca, S. Rossi, F. Careri (RSE)
V4.0	16.09.2014	Final check and revision following a few comments from the Project Coordinator	G. Migliavacca (RSE)

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EXECUTIVE SUMMARY

The report aims at providing the details of the methodology set-up within the WP6 of the eHIGHWAY2050 project for the prioritization of alternative investments on a transmission network. This approach will be applied within the project for the assessment of the long-term investment needs (at 2050) on the pan-European system, generating the so-called Modular Plan.

With respect to the traditional approaches, the present one significantly enlarges the scope of the analysis including a full range of technical-economic aspects, thanks to several original research contributions. However, particular care is taken in order to limit the computational burden and the formulation complexity, allowing an easy application in actual cases using widespread computation tools.

The benefits and costs assessment (BCA) methodology is based on a reduction of all the cost and benefit elements the system is subject to as a consequence of the deployment of new transmission infrastructures. The different elements are all expressed in quantitative economical terms that can be algebraically added up in order to provide a clear scoring parameter to be used for analyzing alternative investments resulting from the e-Highway2050 scenarios.

The selected approach has some peculiarities and limitations due to the application of the analysis ex post[1] to the clusterized simulation carried out by the WP2[2] and the consequent formulation of alternative investment strategies to be compared. The entire BCA methodology was conceived as exclusively fed by the output of these simulations, avoiding the necessity to resort itself to specific simulation tools. This could favor the possible take-up of the methodology, also in conjunction with the toolbox to be specifically developed and delivered by the WP6 in a second phase (D6.2).

The number of aspects considered in the WP6 BCA is very high, for sure much higher than what considered in any current documented methodology. This work was done for completeness and also in order to locate all possible BCA ingredients. In a second step, these elements were critically considered and only the most promising one were included as “core” parameters, whereas most others were only considered for carrying out sensitivity analyses and a few were discarded.

All the components investigated in the analysis can be grouped in four topics, as shown by Fig. 1: **economic profitability**, **socio-environmental and technological aspects**, **system resilience and security of supply** and **financial and regulatory aspects**. Great effort has been spent to express all the cost-benefit components in monetary terms, in order to sum all together and get a final value representing the profitability scoring of a specific network architecture.

1 Putting in sequence scenario simulation and BCA is necessary in order to provide to the BCA the correct information for carrying out the assessment.

2 We note that it was a precise choice of the e-Highway2050 project not to perform a detailed pan-European network study but only a clusterized assessment at the target year based on a grouping into clusters of the European system. If this approach is justified on the basis of the scarce information available on a so long timeframe, this creates a challenge for the subsequent application of the BCA, as BCAs, like all network planning activities, are usually based on a thorough assessment on the full nodal system.

Due to the very long-term horizon addressed by the project, all assessments are affected by significant uncertainties. Therefore, sensitivity analyses will be performed in order to check the robustness of the results. Specific attention has been paid to distinguish between criteria that are in the "core" of the analysis and those that are part of a sensitivity analysis.

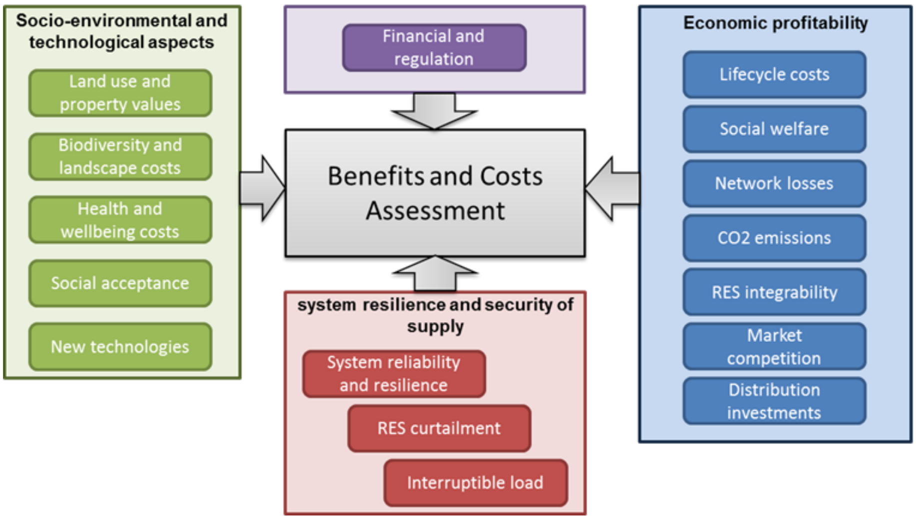


Fig. 1 - Relevant components included in the BCA methodology

In the following, a short description of all considered aspects (costs and benefits) is provided. For details, please refer to the specific chapters of the deliverable.

Economic profitability

This topic includes all the main aspects that have a direct economic impact on the system, following a network improvement. Such components include lifecycle costs, benefits on the social welfare, costs of network losses, benefits of RES integration and CO_2 emission reduction, as well as innovative contributions related to the impact of market power and synergies with the distribution network investments.

Life cycle costs

The life phases of a transmission asset can be divided in: *authorization*, *building/refurbishment*, *investment life*, *decommissioning phase*, *disposal phase*. The methodology proposed to account for life cycle costs in the BCA of a transmission expansion planning is based on highlighting different cost components occurring during the life phases, taking into account the temporal dimension by means of the NPV calculation[3]. The general cost breakdown proposed allows to take into account several transmission technologies and different environmental conditions:

- *authorization expenses (if applicable) AUTEX*
- *installation/refurbishment expenses INSTEX*
- *asset capital expenses ASSEX*
- *operation and maintenance expenses OPEX*
- *decommissioning expenses DECOMMEX*
- *disposal net expenses DISPEX*

Here, the commonly utilized tag CAPEX ("capital expenditure") is meant to result from the sum of ASSEX and INSTEX.

Regarding the variation of these costs in time, it was supposed that all cost components do not vary in time according to technological evolution, with the exception of *ASSEX*, for which learning experience curves can be considered for technologies that are not fully mature. The whole life cycle cost is then assembled by the NPV calculation:

$$
\begin{aligned}
& LCC(\hat{t}) = \\
& = AUTEX \cdot DF_{AUTEX}(\hat{t}) + \\
& + (ASSEX + INSTEX) \cdot DF_{ASSEX}(\hat{t}) + \\
& + OPEX \cdot DF(\hat{t}) + \\
& + (DECOMMEX + DISPEX) \cdot DF_{DECOMMEX}(\hat{t})
\end{aligned}
$$

For each cost component a different discount factor can be considered.

The LCC methodology accounts for the whole set of costs that a product/service experiences during its whole life cycle. If the BCA is carried out on a given target year at the end of which the asset still retains a value, a *residual value* of the investment in this time instant should be taken into account as well. The simplest way to estimate the residual value of a transmission asset is to consider it equal to the economic value of the asset that has not been amortized yet. Even if this approach does not allow considering the capability of a transmission asset to generate a benefit after the amortization phase, it has the advantage to be simple to adopt, not requiring to perform additional simulations.

Social welfare

The change in social welfare (SW) value calculated on the basis of the market simulations reflects the whole benefit introduced by a transmission improvement in the system. This value is the one

[3] In the first assessment, that will be carried out at the target year 2050, no further temporal points will be available. So, the benefits calculated at 2050 will be supposed constant for the following asset life. In the subsequent evaluations at 2040 and 2030, the different time assessment will be correctly included considering the usual NPV approach.

adopted in the mainstream of the cost-benefit calculation. However the total value of social welfare is the sum of surpluses of different subjects participating in the market, that is consumers, producers and possible transmission owners. Moreover, in a multiregional context, the system social welfare is the sum of values deriving from national/regional markets. In such conditions, the impact of a transmission expansion may have both positive and negative effects on the benefits of the subjects participating in the market, even if the global index of the social welfare is increased, due to local transfers of surplus. Hence, “winners” and “losers” do exist, even if their perspective is not taken into account by the whole benefit indicator of the system social welfare.
We can point out these aspects in the framework of a sensitivity analysis. The change of the total social welfare value (before and after the transmission improvement) is split for each regional market *i* in its main component:

$$SW_i = \text{consumers surplus } (CS_i) + \text{producer surplus } (PS_i) + \text{merchandise surplus } (MS_i)$$

Such values are indicated in a detailed table, to show clearly the impact of the new transmission investment on each single component:

	ΔCS	ΔPS	ΔMS
Zone 1	-	+	-
Zone 2	+	-	-
Zone *i*-th	-	+	+

Network losses

Concerning losses evaluation in the e-Highway2050 project, the adopted simulation approach estimates the electricity market outcomes on the basis of a macro-zonal model where zonal clusters are interconnected by equivalent corridors. Thus simulations do not take into account explicitly the full network layout. Moreover, the equivalent network connecting macro-zones, is evaluated by a DC model, neglecting the power losses that occur in the transmission grid. The evaluation and monetization of network losses should be done in a post-processing, starting from the active power flows on the network given as an output of the optimization. Taking into account the clustering adopted in the e-Highway2050 project, the losses estimation can be split in the sum of two contributions*: inter-zonal losses* and *intra-zonal losses*.

- *Inter-zonal losses* - Variable transmission losses on a branch are characterized by a quadratic relationship with the power flowing through the conductor. Therefore, knowing these flows from simulations, as well as the transmission technology adopted to deliver them, an ex-post evaluation of inter-zonal transmission losses can be done. The final monetization of the transmission losses value can be done by means of the system marginal price emerging form market simulations.

- *Intra-zonal losses* – The estimation of losses in an equivalent clusterized network is a tough task. Two ways can be followed. The first entails the estimation of losses starting from the load flow results of a known network (or a forecast model) in the peak load and in the minimum load conditions. The losses can be profiled on the basis of hourly load over the target year. The second strategies entails to perform ad hoc simulations by means of optimal power flow procedure on a full network model. In any case, considering details on intra-cluster losses is not compatible with the modeling choices adopted in the e-Highhway2050 project. Additionally, we can suppose that the majority of the losses located in distribution are not influenced by the studied corridor expansions and so their contribute is elided when performing the differences between "with" and "without" cases. So, it was decided not to include intra-cluster losses in the e-Highway2050 BCA methodology.

CO_2 emissions costs

The cost for emission rights are implicitly accounted into the market simulations, monetized at reference emission trade price forecasts at the target year. Thus, their contribution has just to be isolated from the overall social welfare parameter (not to be added again, in order to avoid double counting).

In order to extrapolate the benefit of CO_2 emission reduction effect from the overall social welfare calculation, the total amount of emissions in the case with and without can be separately calculated. This is done by multiplying the total energy produced by each generation technology times the specific emission rate of corresponding technologies. The difference between the two cases monetized with the CO_2 price, provides the benefit of carbon emission reduction due to the new transmission project.

An interesting further sensitivity analysis is the calculation of the range of variation for the CO_2 emission price that does not imply a change in generation merit order. The change of the CO_2 price inevitably affects the cost of generation in different ways, according to the generation technology. This will be reflected in the marginal cost of generation. By means of a sensitivity, the break-even point of the CO_2 price that causes a switch between the marginal costs of two generation technologies can be detected. This limit defines the range of variation of the CO_2 price that preserves the solution calculated by the performed system simulations, since the generation scheduling is not affected (only the overall costs).
Such an additional sensitivity will allow to understand what limits of CO_2 variation won't affect the merit order, i.e. the solution of the dispatch. Outside these limits, the assessment done is not valid any longer.

RES integrability benefits

The improvement of transmission network leads to a more efficient exploitation of the generation capacity present in the system, thanks to the removal of grid congestions. For example an expansion project can make fully available the cheap energy produced by a set of RES generators from a zone that was poorly connected to the load center of the system. This kind of benefit is implicitly accounted for in the increase of social welfare.

The benefits here considered are the potential extra economic benefits that could be extracted from a further deployment of RES generation made possible by the transmission upgrade. A certain amount of further RES generation is gradually added in each cluster; the additional RES generation is compensated reducing the thermal generation, according to a linear approximation of the dispatch low. In an iterative approach, this increase in RES generation stops when network violations occur.

Market competition analysis

Within the transmission planning studies, benefits and costs assessments (BCA) in general rely upon marginal cost pricing simulations to evaluate the economic benefit of potential transmission investment projects. Neglecting the negative effect of market power on the system social welfare can lead to a distorted forecast of scenarios and inaccurate estimation of the benefits. The methodology developed here for including the effect of the price-cost markup on top of the market outcomes carried out in the hypothesis perfect competition, is based on a linear estimation and on certain market conditions assumed as drivers. It entails the estimation of the relationships between certain market variables (such as demand levels and residual supply margins) and price-cost markups, similar to the methods used by CAISO for market monitoring purposes. The most common index for measuring the price-cost markup is given by the Lerner Index, that is a factor accounting for how much the market price lies above the estimated competitive level:

$$LI = \frac{\text{Price} - \text{Marginal Costs}}{\text{Price}}$$

The residual supply index (RSI) of the largest supplier in each regional market and load demand value are used as indicators of when suppliers could raise price above a competitive level. Thus a linear regression model is estimated:

$$LI = a + b * RSI + c * Load + \varepsilon$$

The model estimation is carried out with an empirical approach, based on historical market data. This provides the mark-up level that each market incumbent applies above its marginal costs, that would inevitably affect the merit order curve and the resulting social welfare. Calculation of new equilibrium prices and dispatch under strategic bidding in a meshed network is very complex and requires a generation dispatch model including strategic bid-up curves. Hence, for this indicator, additional system simulations will be carried out as part of the BCA assessment, in order to appreciate the effect of the market power both with and without network reinforcements. Considering the potential effect of market power in transmission expansion assessment could result in an additional benefit for the system, deriving from the reduction of market inefficiencies due to the new infrastructure.

Distribution network investments

The challenge of this indicator is to estimate investment needs in the distribution grid[4] while simulations consider the transmission corridors between macro-zones only. That said, no distinction will be made in the input data between demand and generation on transmission and distribution side. The approach proposed is that of comparing the net power exchange of each cluster resulting before and after the transmission expansion planning. The net power exchange of each cluster is defined as the absolute value of the difference between generation and load of the cluster:

$$P_{diff}(k,t) \ = |P_G(k,t) - P_L(k,t)|$$

Assuming that the internal network of the cluster is correctly sized for the case "without" or that it has already been subject to reinforcements that are not in the perimeter of our study, if the ratio between the peak of power exchange profile before and after the transmission expansion is greater than one (i.e. the new transmission improvement brings additional power exchange), we assume that the distribution network needs additional investments, estimated proportionally to the power exchange ratio:

$$\Delta P_{diff}(k)\big|_{architecture\ j} = \frac{P_{diff,max}(k)\big|_{after}}{P_{diff,max}(k)\big|_{before}}$$

And the cost of investment are estimated as:

$$Cost_{grid}(k)\big|_{architecture\ j} = \left(\Delta P_{diff}(k)\big|_{after} - 1\right) \cdot \left(\sum_{V} L(k,V) \cdot Cost_{line}(k,V)\right)$$

where $L(k,V)$ is the size of the distribution network (in km), that can be extrapolated from the methodology adopted for defining the equivalent macro-areas, and $Cost_{line}(k,V)$ is the unitary cost of improvement for distribution network in the specific cluster.

Before comparing the power exchange profiles, the effect of DSM and distributed storage is also considered, for smoothing the power exchange profile, in order to reduce the ratio between peaks and thus the investment needs in the distribution network.

Socio-environmental and technological issues

Power transmission projects show a variety of socio-environmental impacts, in particular on (i) land use and other property values, (ii) biodiversity and landscape, (iii) health and well-being, and (iv) public attitudes and actions. In general, the costs (and benefits) of the three first-mentioned impacts can be assessed based on the following steps:

[4] For this assessment, it is considered that the term "distribution" also includes all the levels of transmission voltage that are not considered in the e-Highway2050 project.

- Identifying the type of (sensitive) areas through which a proposed new transmission infrastructure will be located.
- Estimating the size, i.e. either the length (in km) or the surface (in ha or km^2) of the areas through which a transmission highway will be located and for which "rights of way" will be paid.
- Multiplying the average cost and benefits per type of area by the size (i.e. length or surface) of the portion crossed by the transmission infrastructure under scrutiny.
- Projecting/extrapolating present data on costs and benefits to future periods (up to 2050).

Even if the general approach outlined above seems simple and straightforward, its detailed analysis highlights that there are a lot of critical points. Indeed, developing and applying a cost-benefit approach to analyze the main social and environmental impacts of new trans-European transmission infrastructures up to 2050 faces some major challenges and difficulties, in particular:

- The costs and benefits related to these impacts depend not only on the routing of the transmission highways, i.e. the type and size of (sensitive) areas crossed, but also on (i) the type of the transmission technology used, and (ii) the (additional) measures to avoid, mitigate or compensate these impacts. As a result, developing and applying a benefit and cost assessment during the initial phases of the transmission planning process is very hard (as little relevant details on the project are known), while it becomes rather complex and site-specific during later phases of the planning process (when more details become known);
- Moreover, the costs and benefits of some social and environmental aspects are not only very site-specific but also vary significantly across sites, occasionally by a factor of 100 or more. This implies that using average figures per area – or even a range of figures – has limited meaning;
- The costs and benefits of some social and environmental aspects are hard to quantify in an objective, widely accepted way;
- Data on the costs and benefits of some social and environmental impacts – e.g. on compensation costs of income or property value losses – are often scarce and confidential and, therefore, hardly publicly available.

Below, we will further illustrate the general approach for two specific categories of socio-environmental impacts of transmission projects, i.e. on land use and on biodiversity and landscape.

Impact on land use

Transmission grids have an impact on land use values. For instance, to achieve so-called 'rights-of-way' (ROW) on agricultural land – in order to be able to construct, operate, maintain and repair transmission facilities – grid operators pay a certain amount of compensation to the owner of the land. These compensation costs depend not only on the width of the ROW strip of land – and, hence, on the type of grid facilities – but also on the type and quality of the land and, therefore, on the routing of the grid. Since both the type of transmission facilities and the type/quality of the land are largely unknown during the initial stages of the transmission grid development process, we propose the following approach to quantify the ROW compensation costs:

- In the early stages of the grid development process, the ROW compensation costs can be roughly estimated by multiplying (i) either the length or the surface of the ROW track, and (ii) the average (or range of) ROW costs per km or ha. For instance, if the length of the transmission line is 500 km and the average ROW cost are 10,000 €/km (0.2% of CAPEX), the total ROW costs amount to € 5 million.
- In later stages of the planning process – when more specific details are known on the type of transmission facilities and the routing of the power line and, hence, on the type and quality of the land crossed – a more precise estimate of the ROW costs can be made by multiplying (i) the length or surface of specific ROW tracks, and (ii) the specific ROW costs of each respective track.
- In order to extrapolate costs up to 2050, we simply assume that (i) all costs are expressed in real terms for a given base or reference year (for instance, 2010 or 2013), and (ii) all costs remain the same in real terms up to 2050, unless there are well-motivated considerations that costs will behave differently, i.e. either increase or decrease in real terms by a certain percentage up to 2050.

Impact on biodiversity and landscape

For the impacts of transmission systems on biodiversity and landscape in sensitive (protected) areas, the proposed approach seeks to quantify and monetize the costs of mitigating these impacts. More specifically, the proposed method includes the following steps:

1) Identify assumed route: the assumed route is defined as the shortest pathway between two nodes
2) Identify length of assumed route that crosses sensitive areas: the definition of sensitive areas is assumed to be the same as identified
3) Identify costs of mitigation options:
    a. Re-routing to avoid sensitive areas or to follow existing infrastructure corridors: additional costs from increase in route length
    b. Undergrounding cables through sensitive areas, whenever less impacting from the environmental point of view: cost difference between OHLs and underground cable for length of route through protected area
    c. Compensation through provision of alternative habitats and payments to affected residents

4) Apply the cost of the cheapest mitigation measure to the overall cost of the line

Public attitudes and actions

Public attitudes and actions can have a large impact on the implementation time of a new transmission infrastructure, depending whether it is accepted or opposed by both national and local communities. The approach to assess the costs of this factor differs from the general BCA framework for assessing socio-economic impacts outlined above in the sense that the impact of public attitudes and actions are usually translated into extra time required by the approval procedures and, hence, into a time delay before the entering into service of the new transmission infrastructure. This time delay may affect costs/benefits in two ways:

- The services from the new infrastructure are actually not achieved over a certain time period. If the new infrastructure is highly needed, this will mean extra a range of non-extracted benefits for a certain amount of years;
- The benefits will be extracted later, implying that the (discounted) net present values of these benefits will be lower. Alternatively, if the project is to be in operation for a given year, the construction has to be anticipated and the relevant costs will be anticipated as well. However, this anticipation is subject to a lot of scenario uncertainties and is not always possible.

Impacts of innovative transmission technologies

Besides the costs and benefits of conventional grid facilities, the deployment of innovative transmission technologies – such as FACTS, HVDC, DLR/RTTR, PST or PMU/WAMS – may have specific, additional impacts. These impacts refer to the following grid technology aspects:

- Controllability. This aspect refers to the capability of the power (transmission) system to flexibly react to rapid and large imbalances, such as unpredictable fluctuations in demand or in variable generation. The costs related to this aspect include the investment and operational costs of innovative devices such as FACTS or HVDC. The benefits refer to improvements in system security and reliability resulting in a reduction of grid congestion and use of balancing markets through a more efficient management of power repartition over parallel paths. These effects are ultimately translated into an increase of the Social Welfare (SW) index.
- Adaptability/relocatability. Adaptability refers to the ability of a grid reinforcement plan to adapt to different possible future development patterns (scenarios), while relocatability relates to the possibility of facilities to be moved and relocated. The costs and benefits of these technological aspects can be assessed by means of the so-called ‘real option approach, i.e. a risk management method that allows to properly handling uncertainties which are unresolved at the time of making investment decisions.
- Enhanced observability. This aspect refers to the ability to better monitor the system. The costs related to this aspect include investment and operation costs of innovative facilities such

as WAMS or PMU. Benefits from WAMS can be assessed by taking into account, if available, statistics of EENS variation with respect to the amount of PMU.

These benefits are relevant mainly from the intra-zonal point of view. Because of this reason and because of lack of in-depth information (as well as of a clear business case for relocatability) it was decided not to include these benefits in the e-Highway2050 BCA.

System resilience and security of supply

In any power system, there are three different types of costs associated with the security of the system: (i) reliability costs, or costs of service interruptions under normal conditions; (ii) resilience costs, or costs of service interruptions under extreme events; and (iii) demand side management (DSM) costs, or costs of mobilizing demand to react to system conditions to preserve system security. The following sections provided details on these three costs categories.

System reliability

Usually, reliability costs are estimated, from the results of network-constrained market simulations performed for a typical year, as the cost of service interruptions, meant as the amount of load interrupted times the unit value of non-served energy, VoLL (Value of Lost Load). The methodology adopted for the calculation of the VoLL is illustrated in detail in the relevant chapter of this report.

However, the VoLL depends on the use that would have been made of non-served energy. The use to be made of that energy can be estimated according to the value adopted by several factors, namely:

a) the composition of load existing in each node of the network, since least valuable energy uses should be the ones curtailed in the future (assuming that selecting which load to curtail is possible),

b) the amount of interrupted load in this node

c) the duration of the interruption affecting this node, since, with the passing of time after an interruption starts, more valuable energy uses, which had initially been preserved from the disruption of service, may end up being affected by them.

The VoLL can be calculated for each time horizon, type of economic activity and starting time of an interruption. Different levels of VoLL can be estimated for the first hour, for the next eleven hours and longer interruption periods, with decreasing value. The time differentiation is divided according to that generally provided in the literature. The total amount of load interrupted in each node and hour is divided in different types of economic activities proportionally to the amount of load corresponding to each type of activity.

The value of Non Served Energy is calculated as a function of hour, node and typology of activity and the split figures are then multiplied by the relevant VoLL value and added up in order to calculate the total interruption cost.

System resilience cost

System resilience is defined as the ability of the electric system to cope with extremely adverse conditions associated with climate and a combination of system contingencies whose probability of occurrence is above a certain threshold level. With respect to the common concept of adequacy (that has to be guaranteed in “normal” situations of system operation), resilience is meant as targeting the capability of the system to cope with those extreme but disruptive events. The Scenario Outlook and System Adequacy Forecast (SOAF) studies classify reductions in available generation capacity caused by these events into “Non-usable capacity of generation”, which is associated with climate effects, including the non-availability of primary energy resources; “Maintenance and overhauls and outages”, associated with forced and scheduled outages of units; and “System Service Reserve”, which represents the capacity required to maintain the security of supply according to the operating rules of each TSO in the presence of large changes in load or the outage of lines.

We shall determine the threshold capacity margin required for node *n* to endure an extreme event as that corresponding to the aggregate reduction of generation capacity in *n* caused by all types of events previously mentioned. Reference values for this threshold margin estimated for certain load and generation conditions may be deemed also valid for other conditions (scenario, time horizon) if expressed in relative terms with respect to (RES and conventional) generation capacity.

The existing capacity margin in market analyses for each node *n* and hour *h* of the year has to be computed as the amount of locally installed generation less the amount of demand in the node *n* in this hour.

Besides local generation, neighboring nodes may also provide support to that affected by an extreme event. The total amount of power that a node is able to import from third nodes, can be computed as the minimum between the available interconnection capacity with neighboring nodes and the amount of power available in these nodes to be exported.

The amount of available power from neighboring nodes takes into account their own threshold capacity margin, the load and the import capacity available to them.

The amount of non-served power in each node *n* and hour *h* if an extreme event occurs amounts to the maximum between zero and the difference between the threshold capacity margin for this node and the sum of its actual capacity margin and available imports into it. Non-served energy under normal conditions, which has already been considered under reliability costs, is deducted from total non-served energy here computed in order to avoid double counting.

The cost of the lack of resilience of the system is computed as the sum, over all nodes, of the extra NSE due to extreme events in each node *n* and hour *h*, valued at the VoLL in this node associated to extreme events $VoLL_n^*$ times the probability of occurrence of extreme events in this node and hour.

Demand side management

The cost of DSM measures applied to avoid service interruptions shall be deemed equal to that of interruptible contracts, or equivalent reliability driven measures like regulating energy markets, since most other DSM actions are not aimed at preserving the security of the system but at increasing the economic efficiency of system operation.

The cost of interruptible contracts comprises two different types of costs: 1) the cost of procuring a load available to be interrupted if necessary, which is a cost incurred per MW of interruptible load at any hour and 2) that cost corresponding to the use of this available service, that is the cost of actually calling this load to be interrupted.

$$\mathrm{ILMCO} = \mathrm{ILFCO} + \mathrm{ILVCO}$$

where ILFCO is the total cost related to the reservation (through either contracts or any reliability market scheme) of a given amount of load (MW) to be available to be interrupted whenever necessary; and ILVCO represents the total cost related to the use (through either contracts or any reliability market scheme) of the amount of energy (MWh) that has been interrupted for reliability purposes.

Financial and Regulatory Aspects

This task focuses on assessing the impact of financial and regulatory conditions onto the costs and benefits of transmission system investments of the future European power system. To this purpose we took the investor's perspective directly impacted by financing and regulatory conditions.

Ownership and system operation structures as well as regulatory and financing frameworks directly determining revenues and cost allocation for large infrastructure projects are considered. Also the potential capital costs due to the risks and uncertainties associated with these projects are accounted for.

This approach is not traditional to Benefits-Costs Assessments. We, thus, not only propose a methodology for application to the e-Highway2050 grid architectures but also offer a basis and structure for a future reflection on these issues.

Financial considerations are complex by nature; their application in the context of EU-wide investments to 2050 thus calls for certain approximations. The following analysis for instance demonstrates that the various aspects considered, from ownership, pricing regulations, availability of financing, all principally impact a finite set of factors. These factors, such as the cost of capital, financeability ratios and delivery times, can thus be used as proxy to assess the impact on total project costs.

The proposed methodology weighs the different aspects and integrates them into a single factor, the discount rate. Furthermore, adjustments to the BCA are proposed to correctly represent the different ownership structures that may be used.

We believe this to be a necessary addition to traditional approaches for it takes into account the reality of developing large scale, capital-intensive and long-term infrastructure projects in an uncertain policy, technological and financing environment. As a result of the work presented here, the different architectures that are presented within the e-Highway2050 project might be ranked differently depending on the regulatory and financing framework that is considered. A sensitivity analysis will also be presented wrt to an evaluation carried out at a uniform standard rate.

When scanning financing and regulation, a wide range of components that influence the BCA were first identified and organized into four categories as follows:

1 Ownership
   a System operator collaboration: multiple national SO/regional SO/ single European SO
   b Investment type: public/private investment
   c System owner/operator framework: TSO, ISO/TO
   d Asset ownership structure: regulated investment/merchant investment
2 Pricing regulation
   a Cost based regulation
   b Incentive based regulation
3 Financing indicators
   a Cost of capital
   b Financeability ratio
4 Risks
   a Financial risks
   b Scenario risks

After identification of the different components that influence cost and benefits, they were prioritized by literature review and a questionnaire which was answered by the TSOs in the e-Highway 2050 consortium. Focusing on the components that were selected as the most relevant, a more detailed study was performed to determine an index which is quantifiable. For this two aspects are investigated.

The first analysis is how (which aspect) of the BCA is affected. Not all components influence the BCA in a similar manner (e.g. some aspects are related to the discount rate, while others are related to a specific part of the costs or benefits). A part of the analysis also consists of analyzing whether the component is quantifiable. The financing and regulation evaluation can be split in those that require an adjustment of the BCA methodology such as the life cycle cost and alternative social welfare calculation and those that influence the different parts of the BCA such as cost of capital. In the second step of the analysis, the actual value of the influence needs to be determined. A risk band and cost of capital approach is proposed to integrate all relevant aspects into a single index.

The single cost of capital index which integrates important investment aspects is developed by following steps:

1. Analyze regulation framework based on stylized governance model;
2. Analyze the systematic risk borne by investor and assign risk weight;

Identify the asset beta with overall systematic risk weight.

Core elements and sensitivity factors

With reference to the specific application in the e-Highway2050 project and considering all the constraints to the methodology deriving from it, a selection has been done, so as to retain only those indicators that:

- are **adequately supported by data** in the WP2 simulations. Some extra input parameters may be employed, e.g. split of the VoLL per macro-zone and load typology, only if they can be reliably acquired on the basis of existing sources. Also there, agreement has to be sought with the WP2 scenario hypotheses.
- have a **clear regulatory, technological or economical foundation**. Factors whose importance at 2050 is either not clear or depending on uncertain factors (like un-foreseeable technological evolution or strong regulatory changes that are not evident from the scenario narratives) should not be implemented.
- entail **calculations that are feasible in the toolbox** (ex-post assessment starting from the results provided by WP2-WP4, no additional simulations in WP6). The toolbox should be a simple tool making straightforward evaluations. It should be implementable on an Excel/Access platform including VBA macros.

On the basis of what considered above, it is possible to outline what should be the main indicators (automatically included into the BCA scoring), what should be considered as additional sensitivity factors and what indicators should not be implemented.

Tab. 1 shows the list and a brief description of the **main indicators that constitute the set of benefits and costs included in the ranking assessment** of different network architectures.

On the other hand, Tab. 2 shows the set of parameter selected for possible further sensitivity analyses for completing the assessment of the architectures. **Being sensitivity factors, they do not automatically concur in defining the final ranking of the architectures**, but they provide additional information to the study as a function of the varying parameters.

Finally it can be noted that the indicators related to the “Intra-zonal losses” and the “Effect of new technologies” are not included at all. Nonetheless, the discussion relevant to these factors is reported in the present report in order to show the reasons why they have been discarded.

Tab. 1 – Set of main indicators selected for the assessment of the e-Highway2050 scenarios

MAIN INDICATORS	
INDICATOR	**DESCRIPTION**
Lifecycle costs	Costs incurred during the lifecycle of the new infrastructures, divided by category and temporal phase
System social welfare	Market benefits provided to the system by a new infrastructure
Network losses	Economic impact of inter-cluster losses
CO_2 emissions	Costs for CO_2 allowances sustained by thermal generation (implicitly accounted in simulations)
Distribution investments	Estimation of the economic value of the investment needs within the single market clusters as a consequence of the inter-cluster transmission development
Market competition	Quantification of the impact on market results of the exercise of market power by incumbent thermal producers
Socio-environmental costs	Costs related to land use, property values, biodiversity and landscape, health and wellbeing
Social acceptance	Assessment of extra deployment delays due to public opposition
System reliability	Costs of system interruption due to unexpected events accounted for by the market simulation scenarios
System resilience	Capacity of the system to face unexpected (extra scenario) events
DSM costs	System costs tied with interruptable loads management
Financing and regulation	Evaluation of the WACC parameter to be used for the actualization of incurred costs and benefits, depending on an analysis of financing risks

Tab. 2 – Set of sensitivity factors selected for further analysis of the e-Highway2050 scenarios

SENSITIVITY FACTORS	
INIDCATOR	**DESCRIPTION**
Social welfare split	Split of social welfare by stakeholders (generators, consumers) and areas to show different viewpoints (losers/winners)
RES integrability	Potential extra economic benefits that could be extracted from a further deployment of RES generation made possible by the transmission upgrade
CO_2 price	Evaluation of price interval that does not imply a change in the generation merit order resulting from simulations
RES curtailment costs	Economic appraisal of possible refunds provided to the RES generation in case of curtailment
Risk driven vs "standard" rates	Comparison of the NPV calculated with risk driven WACC and standard uniform rates
Scenario flexibility	Evaluation of the flexibility of each architecture against the change of the different scenarios
Pillars weighing sensitivity	Sensitivity of the final score of an architecture grouping the main indicators as: economical profitability, socio-environmental factors, security of supply (the three pillars of the EC energy policy)

Flexiblity and Sensitivity

Once all the ingredients of the BCA are clarified, they are put together by means of an algebraic sum in order to calculate the scoring parameter. However, two additional aspects have to be considered in order to give robustness to the whole approach:

- Scenario flexibility (see section 7.1), accounting for the uncertainty of the scenario under which the scoring results are obtained. By means of an ex-post sensitivity analysis including a supposed probability of occurrence of each scenario, it is possible to give an extra evaluation to those infrastructural variants that are common to several scenarios
- Final sensitivity analysis (see section 7.2), accounting for possible modifications in the scoring due to a different reciprocal importance given to the costs and benefits classified under the three pillars of the EU policy (security of supply, economical profitability and sustainability).

TABLE OF CONTENT

INTRODUCTION

The e-Highway2050 project aims at defining methods and tools to support the planning of an Electricity Highways System. It develops options for a Pan-European grid architecture, under different power system scenarios, taking into account benefits, costs and risks for each of them.
The new developed top-down methodology, which should address the transition planning between now and 2050, is built in a process including the following five main steps:

1. The development and application of an approach to design different long-term scenarios in terms of energy generation mix, exchanges and consumption scenarios;
2. The power location, using the assumptions about generation mix, energy exchanges, and consumption for each scenario, at country level;
3. The system simulations, taking into account the different generation and demand profiles, in order to identify the possible weak points of the transmission grid in case of no reinforcement;
4. The identification of optimized grid architecture in 2050, while taking into account storage, demand-side management, and transmission technologies available by 2050;
5. The development of implementation routes, from now up to 2050, of the pan-European transmission system, covering each of the studied scenarios, and optimized by taking into account social welfare, environmental constraints, as well as grid operation issues.

In the step 3, a clustering method has been introduced in order simplify the grid simulations, as the real European transmission grid, with almost 10000 electrical nodes is too complex.
Finally, Europe is split in 105 clusters, meaning 105 electrical nodes.

The system simulations aim at pointing out the needs for solutions, highlighting the weak points or congestions of the transmission grid, in case of no pro-active action.
The solutions are studied by using technology options e.g transmission technology options.

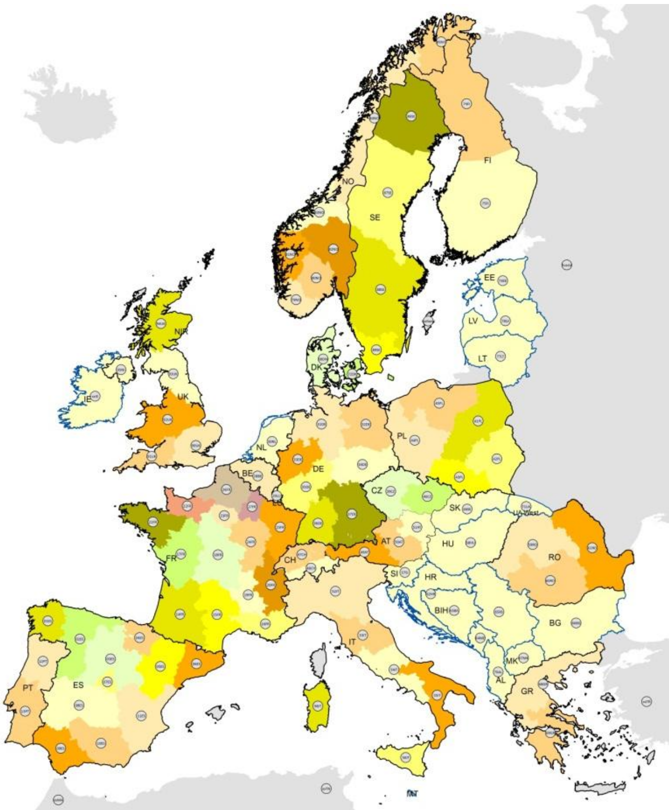


Fig.2 - clusters of Europe – e-Highway2050

The transmission technology solutions explore mainly two options for the grid topology:

- Reinforcement of present corridors between adjacent clusters,
- Overlay structure connecting non adjacent clusters, using long distance links.

After defining different alternative grid architectures for 2050, the objective is to rank them according to their cost efficiency. In this respect, economic analysis, including benefit and costs assessments, are needed, and developed in the steps 4 and 5.

It must be highlighted that e-Highway2050 shall provide grid architectures, and not a list of individual and precise grid links, as it is yet performed by national transmission developers (e.g. Ten Year Development Plan, provided by ENTSO-E). The granularity of the cluster model chosen doesn't allow the description in details of the grid reinforcement.

The WP6 of e-Highway2050 project is dedicated to the socio-economic evaluation of the proposed grid architectures. Starting from the criteria classically used to assess single grid infrastructure reinforcement, the WP6 has proposed a comprehensive cost-benefit approach for analyzing the pan-European transmission highways deployment. This methodology will be tested and used at a later stage in the project on one hand for ranking the 2050 grid architectures, and on the other hand for the development of the global modular plan over 2020-2050.

This deliverable describes the methodological approach elaborated by the WP6 of the project e-Highway2050 for scoring investment alternatives for the European transmission grid at the time horizon 2050. With respect to the traditional approaches, the present one significantly enlarges the scope of the analysis to including a full range of technical-economic aspects, thanks to several original research contributions. However, an eye is always maintained to keep the computational burden and the formulas complexity within a level that can be easily implemented by a MS-ACCESS application including a few VBA macros. Such an application environment, named "toolbox" will be the subject of the subsequent deliverable D6.2.

In a further phase, the approach here explained will be applied in assessing the five scenarios set up by the step1 with the aim of scoring the investment alternatives proposed by the step4 , and the pan-European 2050 Modular Plan proposed by step5. In that framework, the simplifications applied by the step3-4 simulations has imposed the necessity to adapt the WP6 methodology here described in order to make it feasible within the assessment chain carried out by the project. Wherever possible, these limitations are highlighted already in this deliverable together with indications on how the assessment could be improved in case these limitations are removed.

Due to the very long-term horizon addressed by the project, all assessments are affected by significant uncertainties. Therefore, sensitivity analyses will be performed in order to check the robustness of the results. Specific attention has been paid to distinguish between criteria that are in the "core" of the analysis and those that are part of a sensitivity analysis.

The following chapters are organized as follows:

- Chapter 1 presents a brief history of the approaches to cost-benefit analysis in support to grid-planning, showing some interesting past and present approaches that provide a background for the methodology proposed in the present report;
- Chapter 2 provides an overview of the proposed approach, showing the important new elements with respect to the past and highlighting its limitations in consideration to the specificities of the project e-Highway2050;
- Chapters 3 to 6 provide details on the different categories of costs and benefits considered in the proposed methodology;
- Chapter 7 shows as the overall cost-benefit approach is created by integrating all the elements illustrated in the previous chapters;
- Chapter 8 provides some conclusive remarks.

1. A brief history of the approaches to cost-benefit analysis in support to grid-planning

1.1. The cost-benefit analysis in the transmission planning approach

As already explained in the Introduction, the unbundling of the European TSOs has also modified the scope of grid planning. If in the procedures of a vertically integrated system operator generation transmission expansion are planned together with the aim to reduce the overall operative costs, in an unbundled situation, the generation set-up can only be hypothesized as a scenario and/or sensitivity parameter to be analysed but not modified. This adds complexity and uncertainty to the whole planning process.

Another factor adding complexity and uncertainty is the non-deterministic production pattern of RES generation.

In a recent report of the CIGRE WG C1.24 [8], the space of the theoretic approaches to transmission planning is classified along three axes (Fig. 3):

- **regulation of the power system** – old regulated approaches, where vertically integrated TSOs are optimizing together generation and transmission are to be replaced by deregulated ones, where generation is a system parameter and no longer an optimization variable;
- **characterization of system uncertainty, in particular RES generation** – the increasing penetration of RES generation is pushing more and more the modelling choice towards probabilistic approaches (typically Monte Carlo simulation). This significantly increases the computational complexity and sometimes forces towards some additional modelling simplification in order to maintain reasonable computation times. Additionally to RES variability, other potentially stochastic parameter are generation and transmission lines failure probabilities;
- **time horizon** – TSO plans tend to look more and more towards the long term. Consequently, a static optimization taking into account the needs at a given target year can result insufficient because system conditions are steadily changing along a long time horizon and the optimization should then not be carried out for a target year but along the whole expansion

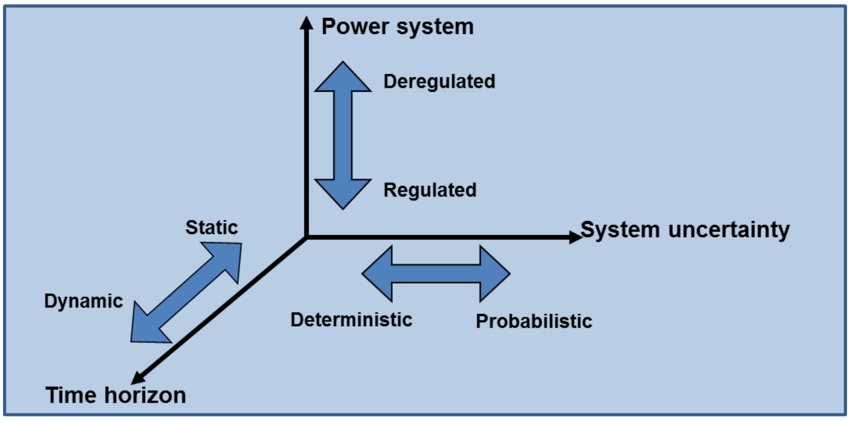


Fig. 3 – Vertical and horizontal highways concept (source [8])

path to get to this target year. Dynamic approaches go in this direction, trying to set up a unique simulation target for a long term period instead of suboptimal optimizations for each sub-period. However, these approaches are still very heavy from the computational point of view and very rarely their application domain lies outside universities and research centres.

The deliverable D3.3.1 of REALISEGRID [9] has performed an extensive check of the typical approaches. We recommend it for getting deeper on this topic. Another reference is [10].

Another important distinction is between cost-benefit analysis and other methodological tools that are applied in other phases of the planning process. For clarity sake, it can be opportune to operate a rough distinction of the planning process into three typical macro-phases (Fig. 4):

- **scenario development** – A first phase consists in projecting the system knowledge to the target year by setting up one or several scenarios. Analysing these scenarios doesn't represent a way to capture the system future, but just a manner to perform "what-if" experiments and detect what could be the system criticalities if the scenario underlying hypotheses are verified.
- **security analysis** – Once scenarios are defined, system security is checked for the target year. The result of these analyses represents a what-if check on the system finalized to assessing bottlenecks and detect system criticalities that could bring to potentially dangerous situations. At this stage, acquiring a thorough technical-economic perspective of the investment is not the aim of the investigation. After detecting system criticalities, alternative solutions are formulated on the basis of the experience of the TSO planning department that could overcome the signalled bottlenecks/criticalities. An alternative has to be meant as a series of interventions (line expansions, placing of reactive banks, etc.) each one of which is able to solve a given problem. In this way, a single line reinforcement could not constitute an alternative because it is not able to solve singularly a given bottleneck, but the alternative could be constituted by a series of reinforcements along a given transmission corridor able to increase the NTC between two points.
- **cost-benefit analysis** – Once a series of alternatives has been formulated, the final stage is to put in place a methodology to score them from the technical/economic point of view so as to be able to locate the best investment solution(s). This is the domain of cost-benefit analysis.

Cost-benefit analysis has been introduced as last in the chain described above and in most of the practical applications it consists in a sheer evaluation of achievable reduction of dispatching costs against the entity of the investments. This aspect (social welfare assessment) is of course an

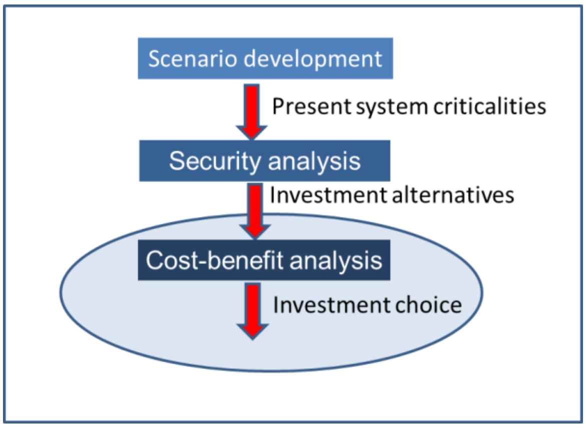


Fig. 4 – Macro phases of the planning process

important part of the cost-benefit analysis. However, this is not the only aspect. For instance, traditionally the environmental analyses (viability of a solution on the basis of the territory the new infrastructures have to cross, potential delays deriving from authorization procedures and public acceptance) are traditionally carried out separately, but actually turn out to be an important part of the investment analysis. So, the basic question is what aspects can reasonably be included into an overall technic-economic assessment in order to perform a more effective optimization and rightly find the most beneficial expansion plan for the system rather than a sub-optimal one while retaining an approach that is both feasible and can reasonably be fed with the needed data.

As shown in Fig. 5, replying to this question is not simple because the goals of a cost-benefit analysis are potentially conflicting with each other. On one side completeness is a target, but on the other simplicity is also important: a real methodology should be able to bring to a documentable decision process, that can be explained to policy-makers and to the public opinion and fed with data that can be motivated (realism). It has to be objective and system targeted, not discarding any important decisional ingredient to be included in the trade-off, while being able to check that none of the factors is even partially double-counted (non-overlapping).
Ultimately, the evaluation of different investment alternatives (variants) needs to define:

- a set of criteria (metrics);
- a set of weights that establish the reciprocal importance of the criteria.

If defining the criteria is critical for the reasons listed above, defining the set of weights may be even more critical and controversial because it underlies a whole conception of values of the society (what we could call, with a terminology lent from the German romanticism, its "Weltanschauung").

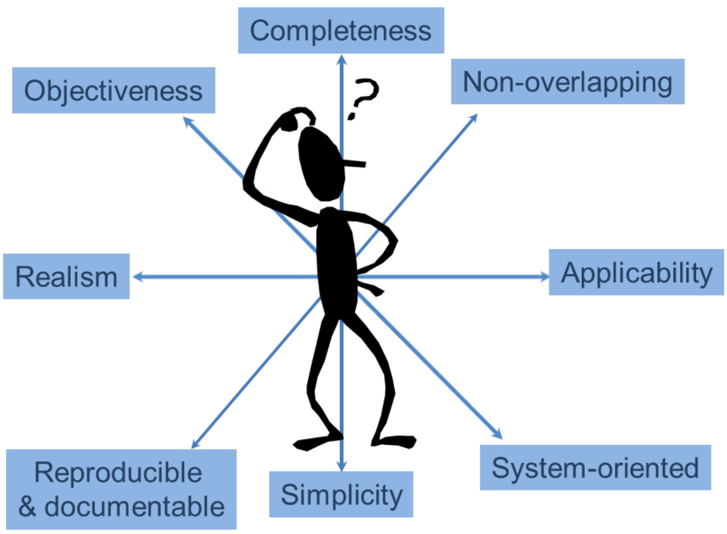


Fig. 5 – Potentially conflicting goals of a cost-benefit analysis

A possible approach to reduce the problem complexity consists of converting all indicators into monetary unit. In this case, one speaks of Benefits Costs Assessment (BCA). This approach helps finding an objective way to:

- transform all indicators into one unit;
- find a way to establish a weight for the different indicators.

However, some parameters might not be easily transformed into monetary units (e.g. some environmental or social parameters). In this case, some authors propose the so-called multi-criteria approach (MCA).

Typically, this consists, in synthesis in the following steps:

1) a set of criteria is defined that could be used to classify alternative investment variants. It can be methodologically opportune to organize these criteria into a decision tree (Fig.6). In defining the decision tree it is important that potentially overlapping criteria are avoided.

2) then quantitative indicators are provided in order to quantify the selected criteria. These indicators can be represented either by absolute measurements (indicators) or through a differential measurement with respect to a base case (impact factors). In this way, an evaluation matrix (Fig. 7), matching criteria with alternatives can be filled in.

3) thereafter, all the criteria indicators need to be converted into one only, possibly a-dimensional, utility value, expressing the level of satisfaction or approval that a single value of the indicator has towards the society as a whole. Typically, a utility value equal to zero expresses no satisfaction, whereas a figure equal to one expresses maximum satisfaction. The function performing this conversion is in general called a utility function (Fig. 8).

4) once all the indicators have been converted into one only utility parameter, all the indicators values relevant to a single alternative may be linearly combined so as to calculate one only ranking parameter attached to this alternative. In general, a weighed linear combination is calculated, making use of a weights vector. This vector incorporates the reciprocal importance (for the public opinion, for the political and/or technical decision-makers, etc.) of one criterion with respect to the others.

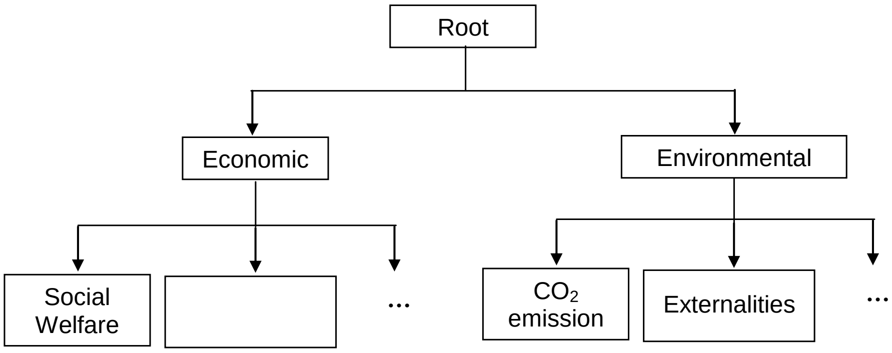


Fig. 6 – Sample decision tree

	Alternative 1	Alternative 2	…
Criterion 1			
Criterion 2			
…			

Fig. 7 – Sample evaluation matrix

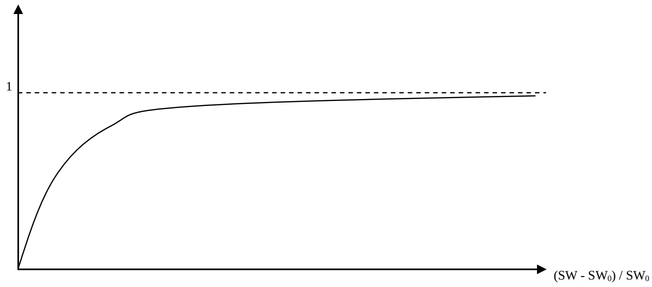


Fig. 8 – Sample utility function

From the description above, a few criticalities emerge associated with the MCA:

- The decision tree set-up is not easy and it is not clear how it can be assured that all the main factors are included while avoiding overlapping.
- The quantification through non-homogeneous indicators doesn't allow to establish a common metrics on the basis of which to compare the reciprocal importance of the different criteria, that is an important outcome of the analysis.
- The set-up of utility functions is a potential interesting degree of freedom but in the practice it seems very complicated and, to some extent, questionable, to establish clear and documented criteria to establish the level of public satisfaction in relationship with the indicators values. Sometimes, this difficulty is overcome by ad hoc questionnaires, but in our opinion this doesn't solve the problem (How to check the significance and the completeness of the statistic respondents' sample? How to move the respondents to reflect into their replies their real opinion and not the easiest way out?)

- The establishment of a set of weights measuring the reciprocal importance of the different criteria is a subject for infinite debates, that risk to be never conclusive in case interests are at stake.

For the reasons above, we deem that the CBA is, wherever feasible, the most documentable one and just for the few aspects for which an economical quantification can be subject to a very high arbitrariness, a mixed approach can be suggested. Actually, in the establishment of the WP6 methodology we realized that a quantification can be given to all relevant factors and so a CBA approach was formulated.

1.2. The approach adopted by the project REALISEGRID

The FP7 project REALISEGRID made a first attempt to provide an answer to the necessity to identify a simple, documentable approach to the technical-economic assessment of alternative investment options in a pan-European perspective.

This project, carried out by a consortium of 20 partners over a period of three years (2008-2011) on behalf of the European Commission (DG-ENERGY), was also expressly requested by DG-ENERGY to deliver an extra report answering to technical questions deemed useful in sight of the finalization of the Infrastructure Package.

The BCA methodology approach by REALISEGRID [9] is based on the identification of a simple set of costs and benefits, all translated into economic terms:

- **social welfare** - Congestion means lower market efficiency. So, by calculating the total dispatching cost for the whole system over one year of simulation it is possible to model the so-called substitution effect, consisting in the reduction of dispatching cost as an effect of the possibility to replace expensive local generation with cheaper one imported from other system zones/nodes (in a least cost dispatch, more efficient generators replace less efficient ones);
- **reduction of losses** – Losses are translated into money by valorising them at market price (opportunity cost). Actually, new corridors available after transmission expansion are very likely to increase overall transits and, as a consequence, losses might grow instead of decreasing (thus being this effect accounted as costs, not benefits);
- **reduction of wind curtailment** – This effect is translated into money by multiplying it by a hypothesized remuneration factor to wind owners (equal to market price).
- **reduction of load shedding** - translated into money by multiplying the value of the Expected Energy Non Supplied (EENS calculated by the REMARK tool, based on a non-sequential Monte Carlo methodology) by the Value of Lost-Load (VoLL). Even if the VoLL quantification could, in principle, result problematic, the highly meshed European system is characterized by a very high security of supply and, so, the quantification of load shedding costs stays very low, never being decisive for the results of the BCA assessment.
- **reduction of CO_2 emissions** – Emissions were translated into money by assuming an average 2010 Emission Trading price and projecting it to the target years (2015, 2020 and 2030) by means of literature information (World Energy Outlook [12]). A lesson learnt was that new corridors allow cheaper but not necessarily “greener” generation to be dispatched (e.g. German coal typically replaces Italian gas-fired CCGT). In this sense, the benefit may be negative, turning out to be actually a cost.

To the previous five benefits, a further sensitivity factor was added : **reduction of cost for extra-EU fuel supply** – Increasing the reliability of supply, as an effect of transmission investments, has a positive effect on the European trading balance and reduces the potential for exercise of market power by incumbent fuel monopolists.

All the factors were reduced into an only scoring parameter by applying the Net Present Value (NPV) algorithm. The NPV is calculated by taking into account the typical investment phases, as represented in Fig. 9:

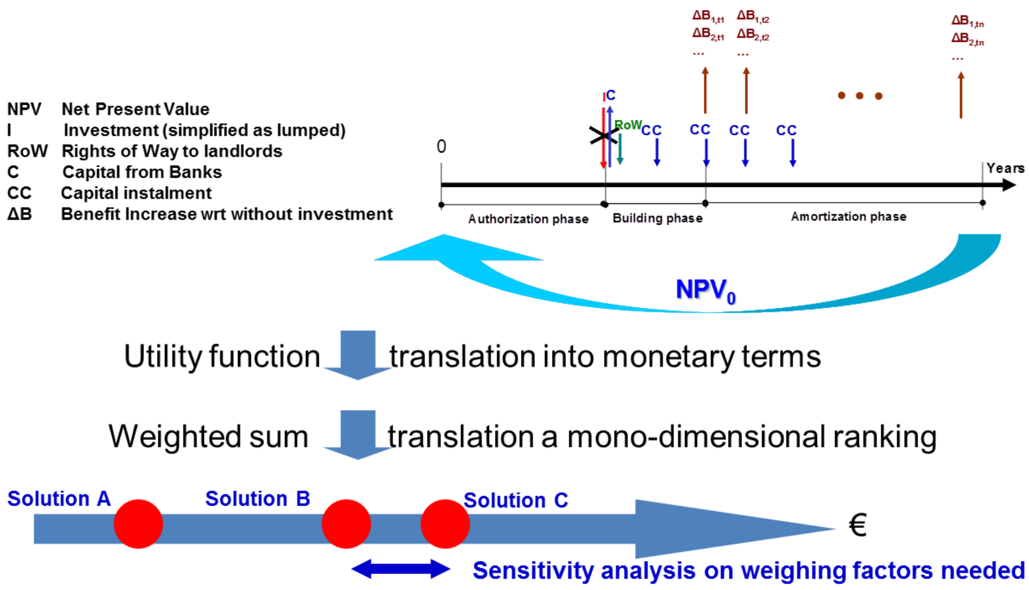


Fig. 9 – Phases of the authorization procedure and CBA methodology of REALISEGRID

- **Authorization phase** – this phase is substantially characterized by a delay due to the authorization procedures. Here, investments are negligible and normally limited to the preliminary studies carried out by the TSOs.
- **Building phase** –infrastructure investments (I) can, for simplicity sake, be thought as concentrated at the starting point of this phase. At the same instant, capital (C) is lent from the bank system. The two amounts C and I reciprocally cancel themselves. Then the capital is given back to the bank system in a certain number of rates (CC), thus incorporating a cost of capital rate.
- **Amortization phase** – when the new infrastructure is put in service, the increase in the benefits for the system begins to be apparent with respect to the situation without this infrastructure. Every year t and for each benefit i, a quantity $\Delta B_{i,t}$ will be collected.

The use of NPV and the application of the above described CBA methodology for transmission expansion cost-benefit analysis can be also an effective instrument in order to evaluate the cost of inaction due to a delay in one or more stages of the transmission planning process. Then, in case of lengthy or prolonged authorization paths, the change (loss) in the ΔNPV ("with" case versus "without" case), calculated for an equal interval of years, can be a measure for the extra cost that a postponement of the realization of a transmission option has caused to the society, as it is shown in Fig. 10.

The REALISEGRID CBA was applied in order to develop a cost/benefits classification of the most important projects belonging to Trans European Network priority axis "*EL.2. Borders of Italy with France, Austria, Slovenia and Switzerland: increasing electricity interconnection capacities*". This region is one of the most interesting ones to assess the impact and the benefits of future cross-border transmission projects. A wide nodal model encompassing most of central Europe (Italy, Austria, Germany, France, Slovenia and part of the Balkan region) was developed for this assessment. The list of the represented candidate expansion lines is represented in Fig. 11. These lines were grouped in three alternative corridors (Brenner tunnel, corridor Italy-Austria/Kärnten

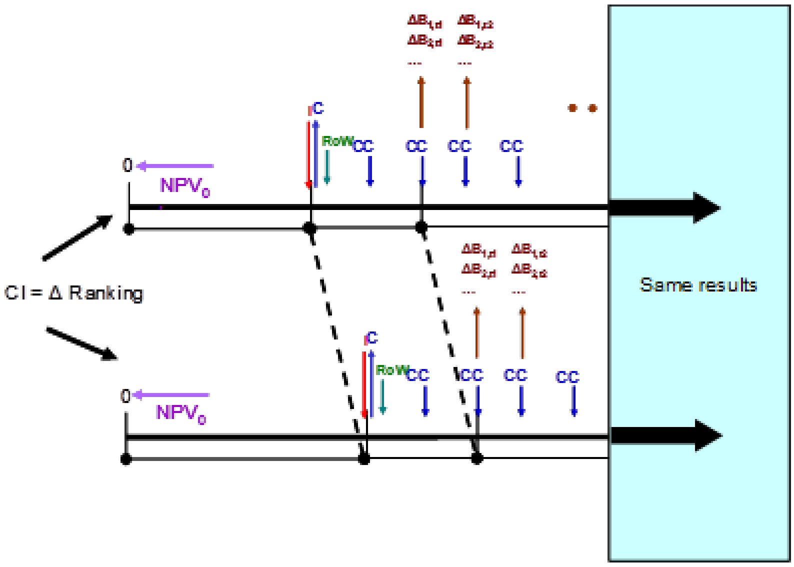


Fig. 10 – Cost of Inaction represented in the methodology by REALISEGRID

- Lienz (AT) - Cordignano (IT)
- New interconnection between Italy and Slovenia
- Udine Ovest (IT) - Okroglo (SI)
- S. Fiorano (IT) - Nave (IT) - Gorlago (IT) [completed]
- S. Fiorano (IT) - Robbia (CH) [completed]
- Venezia Nord (IT) - Cordignano (IT)
- St. Peter (AT) - Tauern (AT)
- Südburgenland (AT) - Kainachtal (AT) [completed]
- Austria - Italy (Thaur-Brixen) interconnection through the Brenner rail tunnel.

Fig. 11 – The REALISEGRID testing bed

and corridor Italy-Slovenia) for which the costs-benefit trade-off was assessed in order to determine a scoring. The results of the analysis are available on [11].

1.3. The approach adopted by the ENTSO-E methodology

The ENTSO-E CBA approach, described in the document "Guideline for Cost Benefit Analysis of Grid Development Projects" [13], submitted to stakeholders on 14 November 2013 according to Art.11 of Regulation (EU) 347/2013. This document is presently still awaiting its finalization after approval from the European Commission.

The ENTSO-E methodology is at the basis for the characterization of the transmission grid reinforcements of the pan-European transmission network starting from next Ten-Year Network Development Plan (TYNDP) 2014. According to regulation 347/2013, the ENTSO-E methodology will also constitute the basis for the evaluation of the Project of Common Interest (PCI), carried out under the responsibility of the European Regional Groups within the region of their jurisdiction, while the European Commission will be in charge to approve the final list of PCI at the European level.

In summary, the main characteristics of the ENTSO-E methodology are:

- no ranking of different investment alternatives;
- only two indicators are monetized (socio economic welfare and losses), others are represented in their typical measurement units and two of them (resilience and flexibility) are only presented as dimensionless KPIs.
- semi-quantitative approach: the output of the method is a numerical value, that till the 2012 TYNDP was accompanied by a chromatic scale associated to ranges of values for the quantified indicators. In the TYNDP 2014, it was decided to make the ranges explicit and the chromatic scale was eliminated.

The complete list of considered benefits (with their measurement units) is:

- B1 – improved security of supply [MWh]
- B2 – socio economic welfare [€]
- B3 – RES integration
    - B3a: increase of installed RES capacity [MW]
    - B3b: reduction of RES curtailment [MWh]
- B4 – losses variation [€]
- B5 – variation of CO_2 emissions [kt]
- B6 – technical resilience (KPI)
- B7 – flexibility (KPI)

On the costs side, the total project expenditure (C1) is considered, including dismantling and life-cycle costs.

Additional parameters are:

- environmental impact (S1)
- social impact (S2)

Both evaluated in terms of extra-kms located in sensible areas.

1.4. The TEAM approach adopted by the Californian ISO

It is a very known fact that:

- relieving congestion decreases the dead-weight loss (defined as the social welfare lost for the inefficient clearing of the market, see Fig. 12 for the case of a two-zones market) and, by the same token, increases the social welfare. Thus, the market solution is more efficient;
- however, this increase of social welfare is not necessarily matched by a reduction of loads payments in all the market zones. In the two-zones market example in Fig. 13, loads in the export zone pay price $p_2 > p_1$, whereas those in the import zone pay the same.

Capitalizing the remarks above, market efficiency (i.e. increase in social welfare), consumers' expenses and generators surpluses are three different aspects that can be in mutual conflict (Fig. 14). This remark is expensively expanded in the Transmission Economic Assessment Methodology (TEAM, see [15]) adopted by the California System Operator (CAISO) to evaluate potential transmission upgrades.

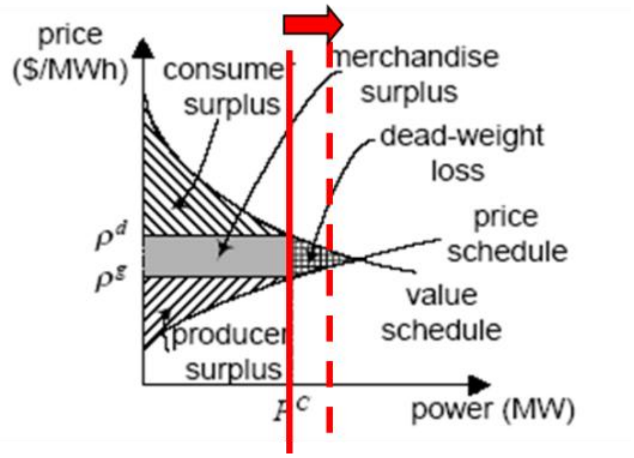


Fig. 12 – Social welfare and transmission investments

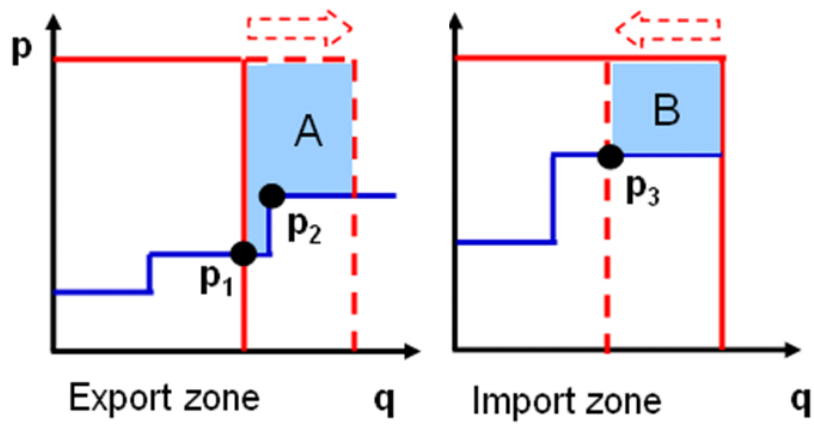


Fig. 13 – Prices shifts in a two-zones system as a consequence of an NTC increase

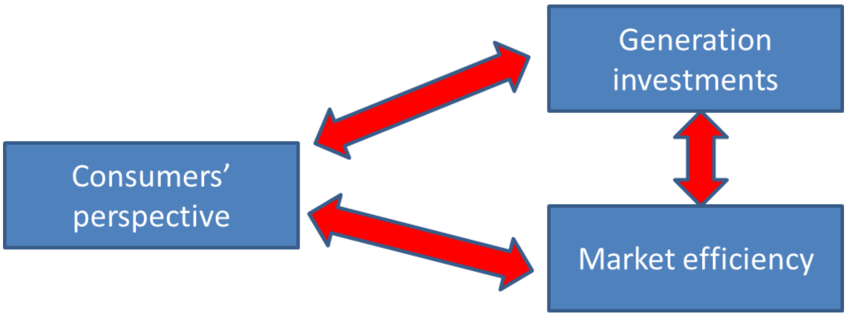


Fig. 14 – Market, consumers' expenses and generators surpluses as three conflicting aspects

The TEAM vision is based on the belief that restructured wholesale electricity markets require a new approach addressing:

- what impact a transmission expansion would have on increasing transmission users' access to generation;
- what incentives it would create for new generation investments;
- what impact it would have on market competition.

In the TEAM methodology, the total change in production costs resulting from a transmission expansion is separated into three separate components:

- Consumer Surplus;
- Producer Surplus;
- Transmission Owner Congestion Revenue.

Positive benefits indicate an increase in consumer, producer, or transmission owner benefits.

It may be claimed that the network is operated to benefit all market participants (or for society in general). So, a critical policy question is which perspective should be used to evaluate projects:

- if the network is operated to maximize benefit to ratepayers who have paid for the network, then some may consider the appropriate test to be the ratepayer perspective;
- however, in the long run, it may be both the health of utility-owned generation and private supply, which is needed to maximize benefits to ratepayers.

In order to rank potential grid upgrades, the benefits for all market participants have to be considered, especially those parties who will ultimately pay for the transmission upgrade. Since there are many ways to allocate the cost of a transmission investment, decision makers must evaluate all aspects of the cost-benefit components as well as who will perceive them.

1.5. The real options approach

Real options [16][17] are a method fit for analyzing investment opportunities, often connected with the alternatives provided by the flexibility of new technologies, while accounting with future uncertainties (market, flows, …). In the following, the basic principle of their application is sketched. For a more in-depth discussion, see Chapter 4.6.

Investment opportunities are seen as American options (i.e. one that can be exercised at any time during its life), considering all alternatives: investment activation, investment deferral, investment abandonment, device relocation.

An actualized profit function is considered at each sample time during the examined time horizon. The value of the option at time "t" is given by the maximum between profits/benefits obtainable investing "now" and the expected actualized value obtainable investing "tomorrow" (according to Bellman optimality principle)

$$\begin{aligned} &F(t_n, X_{t_n}) \\ &\qquad = \max\left\{\Pi\left(t_n, X_{t_n}\right), \mathbb{E}^*_{t_n}\left[F\left(t_{n+1}, X_{t_{n+1}}\right)\right] \cdot df\right\}. \end{aligned}$$

A least-square Monte Carlo method considers possible stochastic variables. The algorithm works starting from last time (maturity year, where investment can't be performed any longer) and proceeds backwards:

$$\begin{gathered} \Phi\left(t_n, X_{t_n}(\omega)\right) = \mathbb{E}^*_{t_n}\left[F\left(t_{n+1}, X_{t_{n+1}}(\omega)\right)\right] \cdot df \\ \text{if } \Phi\left(t_n, X_{t_n}(\omega)\right) \leq \Pi\left(t_n, X_{t_n}(\omega)\right) \text{ then } \tau(\omega) = t_n. \end{gathered}$$

(where df = actualization factor; Φ = continuation value; ω = Monte Carlo realization)

1.6. The sensitivity approach

A family of methodologies can be profitably applied for performing a pre-screening of variants in presence of a high number of alternatives. The approach is based on the concept of Pareto-optimality and of the tied concept of "frontier of the optimal solutions".

In synthesis, the approach can be applied in the following steps:

- first, a score matrix (criteria*variants) is defined (entries between 0 and 100);
- within the score matrix, each criterion is assigned a range of weights (but: sum of weights = 1);
- criteria groupings can be defined as well (e.g. partition all criteria within the three categories: costs, easiness to build, performance) by establishing relative weights between the groupings;
- random values are extracted for the weights set and the alternatives are represented correspondingly in scoring diagrams (Fig. 15);
- finally, a frontier of the optimal solutions is determined and (Pareto) dominated solutions are eliminated.

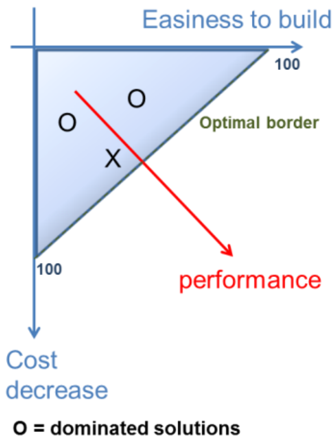


Fig. 15 – representation of a scoring diagram

It has to be underlined that the methodology described here doesn't arrive to a final scoring of a set of alternatives, but can be used in order to clarify the placement of a huge set of solutions in a complex cost-benefit space, helping to visually appraise the sub-optimality of some of them and, at the same time, to assess the trade-off in terms of the single costs and benefits obtained by privileging one of the alternatives placed on the optimal solutions frontier.

2. The proposed BCA approach in the framework of the eHighway2050 project

2.1. Overview of the proposed approach

The basic idea underneath the benefit and cost assessment methodology developed within the WP6 of the project e-Highway2050 is to provide a step forward with respect to the current approaches by getting deeper in all the aspects that make up costs and benefits of a new grid infrastructure with a particular eye to long-distance trans-national transmission infrastructures like electricity highways.

In particular, four main focus topics have been individuated in the analysis, that are supposed to cover all aspects to be included (Fig.16):

- **infrastructure investment costs and economical profitability benefits** (described in detail in Chapter 3) – this section, covered by the project task 6.1, deals with all the cost and benefit aspects that are more typically bound to an economic profitability analysis (subtask 6.1.1): lifecycle costs, social welfare, network losses, CO_2 emissions, capability to integrate further RES generation as an effect of the grid expansion under scrutiny. It also deals with two further important complementary aspects: decrease of potential for the exercise of market power by incumbent generators as an effect of the increase of market competitiveness due to the elimination of grid bottlenecks (covered by subtask 6.1.2) and costs of complementary investments within each single cluster (distribution grid in particular) as an effect of the corridor expansion (covered by subtask 6.1.3);
- **social and environmental aspects** (described in detail in Chapter 4) – this section, covered by

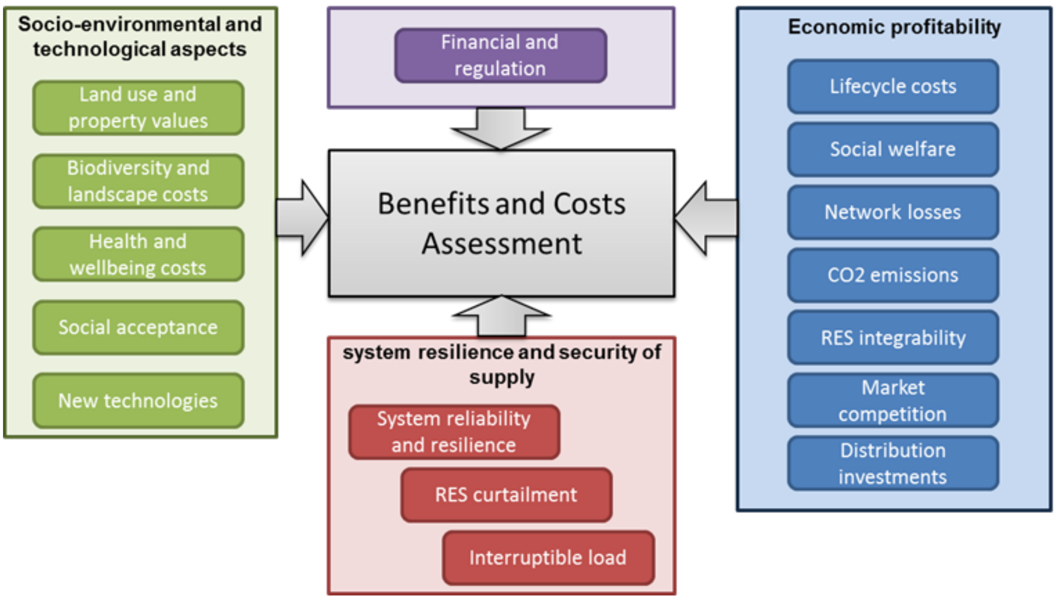


Fig. 16 – ingredients of the e-Highway2050 BCA

subtask 6.2.1, deals with Social and environmental benefits and costs tight with the development of the infrastructure under examination: right-of-way costs, environmental costs, compensations costs concerning health and well-being (noise, visual impact, etc), costs related to public consensus and reflected delays for the completion of the authorization path of the new infrastructures;

- **impact of new technologies** (described in Chapter 4.6) – this section, covered by subtask 6.2.2, cares about those beneficial aspects tied to the introduction of new active technologies (PST, FACTS, WAMS, RTTR, etc) that are not captured by within the social welfare (that is able to capture, for instance, the better management of parallel flows due to the introduction of PSTs or series FACTS devices). The treated elements are: better controllability (in terms of reduced need for reserve activation in real time), better observability (due to PMU and WAMS devices) and higher flexibility of the investment (due to the introduction of relocatable devices and the consequent possible avoidance of sunken costs in lines that are no longer necessary);
- **system security aspects** (described in Chapter 5) – this section, covered by task 6.3, deals with those aspects tied to system security: costs for service interruption and for RES curtailments, system resilience (in terms of capacity to withstand possible unforeseen events that are not included in the reference scenarios);
- **financial and regulatory aspects** (described in Chapter 6) – this section, covered by task 6.4, deals with the different cost of money (directly affecting the Net Present Value calculation) that different grid expansion initiatives could be subjected to due to the different level of risk and to the different regulatory regimes allowing investment recovery.

A final aspect is the one that has to do with the so-called flexibility properties of the scoring obtained with the described BCA. Each scenario will produce its own grid upgrade alternatives and a separate BCA scoring, that is valid provided that this scenario will completely capture the system future. If the future will be different, also the scoring results will be affected by a scenario risk. This is an important further aspect that deserves to be taken into account in the methodology. Supposing that the set of scenarios selected for the analysis (five in the case of the project e-Highway2050) represent the whole space of the possible future scenarios, assumption that is not completely true but either not so false if the scenarios have been accurately selected, and supposing that a probability number can be attached to each scenario (the same for all scenarios in case of no better knowledge), a final analysis, that is carried out on top of the scoring done separately for each scenario, consists of attaching the same probability factor to the grid reinforcement alternatives and produce an overall scoring that encompasses the alternatives of all scenarios. This will allow to provide a higher evaluation to those upgrade initiatives that by being common to all scenarios are “flexible” and can withstand possible changings in the effective future scenario realization (very likely for a so long term projection as 2050). This aspect will be described in detail in Chapter 7 along with the methodology putting together the different BCA ingredients into one scoring parameter.

2.2. Limitations and data criticalities

The project e-Highway2050 adopts a fully quantitative methodology, preferring the BCA approach on the MCA analysis for the motivations already explained in Chapter 1.1. In this frame, the approach described above is very ambitious and aims at exploring all possible aspects having a significant technical-economic reflex. By contrast, the very long time horizon of the project e-Highway2050 bears a difficulty for retrieving and validating a coherent set of data. This problem is also reflected into the deliberate choice not to model the 2050 network in detail but to establish a more simplified model based on clusters and transmission corridors. A third important aspect is that the simulation of the European system for each of the five reference scenarios, carried out within the WP2.3 of the project, is supposed to use a tool (ANTARES, by RTE) that performs a market solution minimizing the yearly dispatching cost while considering the inter-cluster transmission limitations and supposing that each system generator bids at its marginal cost of generation. The WP6 analysis is placed downstream these simulations and, with the exception of the extra evaluations for market power assessment, performs no additional simulations on its own (see Fig.17) but, rather sets-up a toolbox able to use the results of the WP2 simulations as well as the candidate corridors expansion alternatives proposed by the WP2 in order to apply the BCA approach proposed in the present deliverable and match each candidate reinforcement alternative with a scoring parameter, thus indicating the most convenient way to upgrade the system. The choice to use off-the-shelf simulation tools is motivated also by the fact that the entire e-Highway2050 process (scenario analysis, simulation and BCA) is meant to be concretely proposed to the attention of ENTSO-E and of the European TSOs as a viable approach that can be run upon MS-ACCESS, a wide-spread software platform, that is very likely to be available on work-PCs without buying extra licenses.

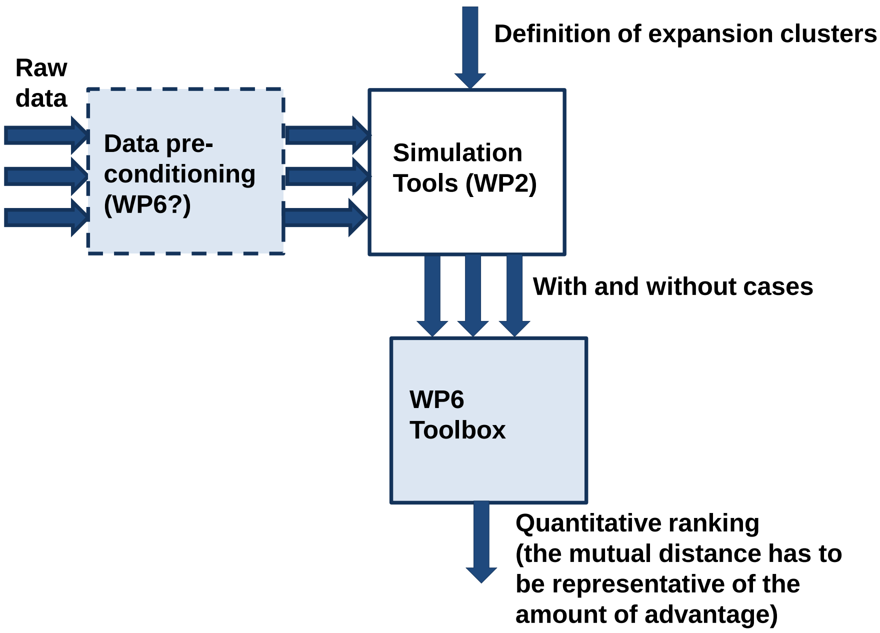


Fig. 17 – interaction of BCA and scenario analysis in the project e-Highway2050

However, in exchange for the simplicity and for the high level of methodology replicability, the fact that the BCA is applied ex-post with respect to the scenario simulations and the fact that no feedback is foreseen from the BCA appraisal to the simulation has placed a particular challenge to the set-up of the BCA methodology, and an important subject of applied research for the WP6. Just to mention an important example: the analysis of the investment needed within each cluster (in particular within distribution) as an effect of the corridors expansion, described in Chapter 3.8, would need to incorporate cluster details into the scenario simulations, that, on one side would make the represented system so complicated to be not treatable with the current means of calculation, on the opposite side it would require grid simulation and data details that are not easily established with a so long time horizon as 2050. Otherwise, we deem that the coordination between TSO and DSO investments is a key point for 2050 and, so, the choice was for an ex-post treatment able to include just a raw estimation (order of magnitude) into the analysis.
All the above considerations should allow the reader to understand how the WP6 BCA explained in the following of this report is a result of a compromise between a few limitations and that this compromise was not easy to reach but requested a lot of research work.

A note regards the relationship between the theoretical approach explained here and the one that will be concretely applied to the analysis of the WP2 scenarios and to the elaboration of the 2050 Modular Plan. According to the way to operate agreed within the e-Highway2050 project, the BCA approach illustrated in the present deliverable will first be applied to the 2050 “target” year. Here, one only year will be analyzed and not a time interval (this means an important simplification in the Net Present Value based approach). Then, the path to achieve the target 2050 architectures will be assessed by analyzing, in series, first the 2040 timeframe and finally the 2030 situation. In this way, the Modular Plan will be assessed.

Finally, it has to be mentioned that notwithstanding the fact that the methodology was kept as general as possible but tuned to the limitations that we could have in its application within the project e-Highway2050, it opinion of the authors that a further fine tuning should be necessary for the creation of the toolbox applying the methodology (D6.2) and for the subsequent practical application to the results of the scenario analysis performed by the WP2. This is the reason why the presentation of the methodology done in the present deliverable is deliberately kept at the methodological level and no explicit reference is done to the set of data that will be used for the practical application. However, each methodological aspect is accompanied by a couple of didactic examples showing its application with reasonable realistic data and highlighting possible critical issues regarding the results that can be obtained.

3. Costs and benefits related to economical profitability analysis

3.1. Overview

This section aims at quantifying and including in the BCA all the transmission expansion planning aspects that have a direct impact on the economical profitability of the system, giving an easy way for their monetization. Thus, a full analysis of lifecycle transmission infrastructures costs is provided, together with the BCA aspects related to energy market and the grid operation.

The effect of a transmission expansion project on the electricity market is identified through the analysis of the social welfare, assessing the variation of its components, decomposing it by market participant (consumers/suppliers) and by market zone. The load demand elasticity is an important issue that may affect the benefits for the market and so a sensitivity analysis approach is proposed, considering load elasticity. Other benefits related to the market efficiency improvement are the CO_2 emission reduction and the capability of a transmission project to allow integrating a higher amount of RES. Such aspects contribute to a lower generation cost, and so their contribution should be accounted for. Moreover the effect of the market power is addressed, in order to evaluate the role of transmission improvements in mitigating the strategic behavior of the suppliers. Its contribution is reflected in higher values for the social welfare.

Concerning the grid operation itself, beside the already cited lifecycle costs, the role of a new project in reducing transmission losses is considered. Finally, the synergy between transmission and distribution networks are also investigated, in terms of additional (or avoided) costs to improve distribution networks.

In the following, each item considered having an impact on the economical profitability is treated individually, describing the methodology developed for the BCA in the context of the project e-Highway2050. Simplicity of application is the key target pursued in the methodology definition, in order to make it flexible and exploitable also for other evaluations outside the project. For a better explanation of the proposed methods, a simple didactical example of application is included.

3.2. Lifecycle costs

Life cycle costing is the process of economic analysis to assess the total cost of acquisition, ownership and disposal of a generic product/service: this analysis could provide important inputs in the decision making process in the product design, development, use and disposal. Fundamental to the concept of life cycle costing is a basic understanding of a product/service life cycle and the activities that are performed during these phases: moreover, it is essential to understand the relationship of these activities to the product/service performance, safety, reliability, maintainability and other characteristics contributing to life cycle cost (LCC).

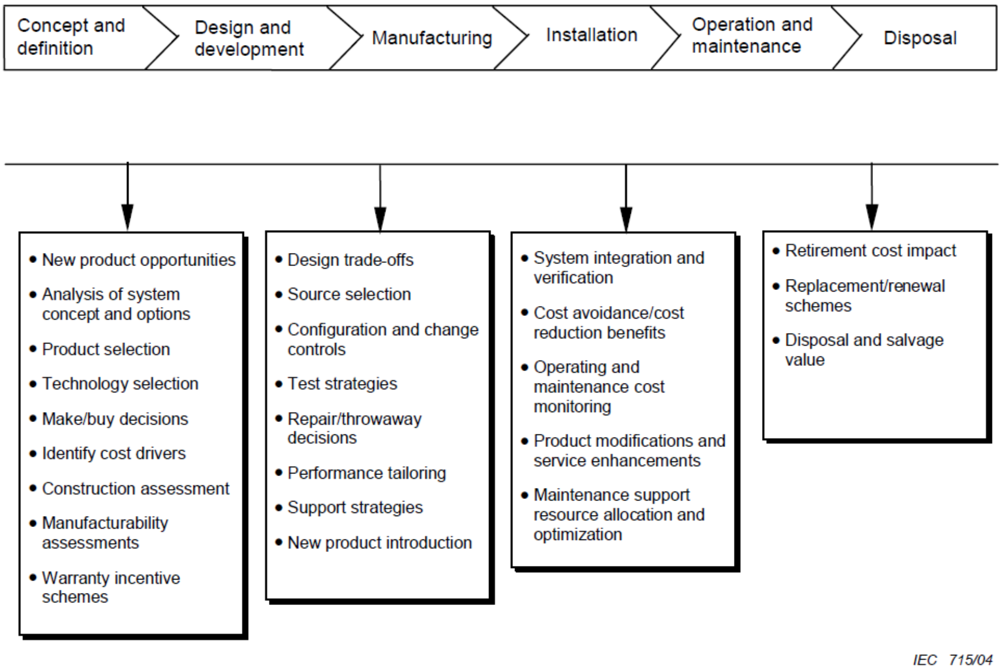


Fig. 18 - Life-cycle costs and related aspects (Source [18])

A product life cycle can be split up in *six cost-causing phases* (Fig.18):

1. *concept and definition*;
2. *design and development*;
3. *manufacturing*;
4. *installation*;
5. *operation and maintenance*;
6. *disposal*.

A life cycle costing model highlights the main features and aspects of the product/service and translates them into cost estimating relationships. In order for the model to be realistic, it should:

a) represent the characteristics of the product/service being analyzed, including the environment where it will be exploited, as well as operating and maintenance concept, any constraints or limitations;
b) be comprehensive in order to include and highlight all factors that are relevant;
c) be simple enough to be easily understood and allow for its timely use in decision making, and future update and modification;
d) be designed in such a way as to allow for the evaluation of specific elements of the LCC that are independent from other elements.

This model is basically an accounting structure that contains mathematical expressions for the estimation of cost associated with each of the cost elements constituting the final life cycle cost: since the close relation between the process to analyze and its life cycle model, usually the latter has to be specifically developed for the problem under study.

LCC modeling includes:

- cost breakdown structure: it represents a breakdown of costs incurred over the major phases (or phases of interest) of the life cycle of a product/service;
- product/work breakdown structure: it is composed of a detailed breakdown of hardware, services and data identifying all major tasks and supporting work packages;
- selection of cost categories;
- selection of cost elements;
- estimation of costs;
- environmental and safety aspects;
- uncertainties and risks;
- sensitivity analysis to identify cost drivers.

The time variable is important in life cycle costing: the discounting of cash flows is a fundamental principle applied to all modern methods of investment evaluation and the impact of the different cost flows in different time steps is measured in the evaluation of the *Net Present Value* (*NPV*), which represents the sum of the actualized economic flows generated by an investment. Therefore, even if a particular life phase is not affected by cost flows (e.g. a delay in realizing a transmission asset), this issue is however accounted for in the *NPV*.

$$NPV\left(i, N_{year}\right) = \sum_{k=0}^{N_{year}} \frac{R(k)}{(1+i)^k}$$

3.2.1. Life cycle costing in transmission expansion planning

Transmission network is a core infrastructure: therefore, it has to be operated with high levels of reliability. Transmission assets should perform their functions safely without any undesirable impact on the whole environment and they have to be easily maintainable throughout their useful lives. Realizing a particular transmission reinforcement is not only influenced by the initial costs that TSOs have to cope but also by the envisaged operating and maintenance costs over the asset operating life and, additionally, by its disposal cost. Therefore, life cycle costing can also be effectively applied to evaluate the costs associated with a specific activity such as transmission network planning, in order to find out how different choices in transmission reinforcement have impact on issues concerning installation, maintenance and disposal costs.

Planning, developing and managing a transmission network are all activities that involve an extensive set of decisions, parameters and variables: therefore, the level of investigation to adopt in LCC modeling should be a trade-off between accuracy, simplicity and data availability.

In [19], information regarding the life cycle costs of transmission lines in the State of Connecticut are provided: in addition to quantitative data, general information about transmission line cost elements that are affected by regulatory requirements, environmental regulations, line type, and maintenance requirements, as well as the role of existing and new technologies and how they could affect future line costs are also reported.

The life phases of a transmission asset, as well as the related monetary flows, are depicted in Fig. 19:

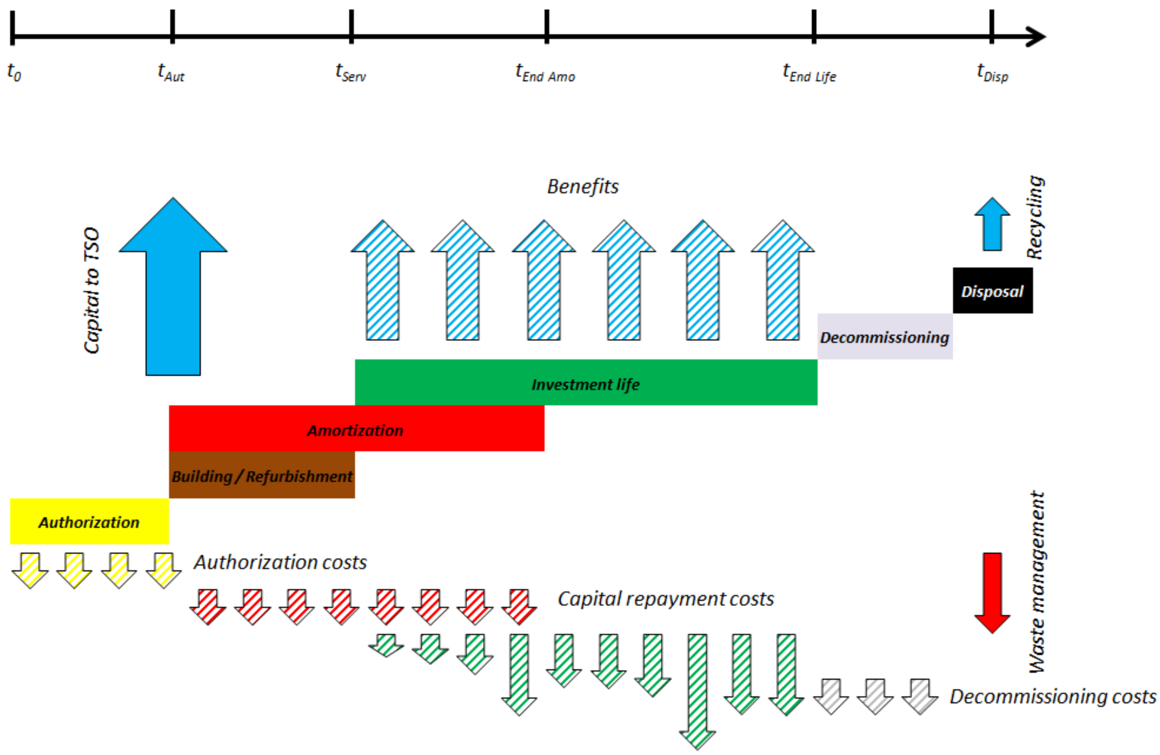


Fig. 19 - Life-cycle costs and benefits flows in transmission planning

- *authorization phase* [t_0, t_{Aut}): this phase encompasses the time span comprising all the activities in preparation antecedent to the start of the realization phase, such as the time period necessary for definition of solutions and technical realizations in order to identify the best localization together with local and centralized government agencies and authorities. Clearly, according to the impact that a particular network reinforcement has on the surrounding environment, the duration of this phase is strictly related to the type of transmission network asset to realize. For what concerns the economic aspect, if compensation costs are not accounted for, the investment in this phase are negligible (they are mainly related to expenses in feasibility/preliminary studies, bureaucracy costs, etc.) but the effect of the duration of this phase is however accounted for by means of the calculation to the NPV of the whole LCC;
- *building/refurbishment phase* [t_{Aut}, t_{Serv}): in this phase the asset is going to be realized. The duration of this phase and the related costs are highly dependent by the type of installation for the transmission asset, as well as for the kind of activity to perform:
    - if a brand new asset is realized, there is only a *building phase* [t_{Aut}, t_{Serv}) (Fig. 20), when the network investment is effectively going to be put in place;
    - if the reinforcement of an old asset it performed, the whole *refurbishment phase* (add link to Fig. 20) consists in a first step [t_{Aut}, $t_{Disp,Old}$) – where the old investment is partially dismantled (decommissioning and waste management for the old infrastructure) – and a second one, [$t_{Disp,Old}$, $t_{Serv,new}$), when the reinforced asset is built;

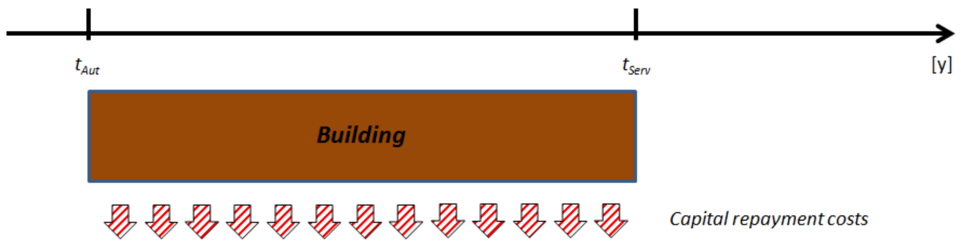


Fig. 20 – Building phase: costs and benefits flows

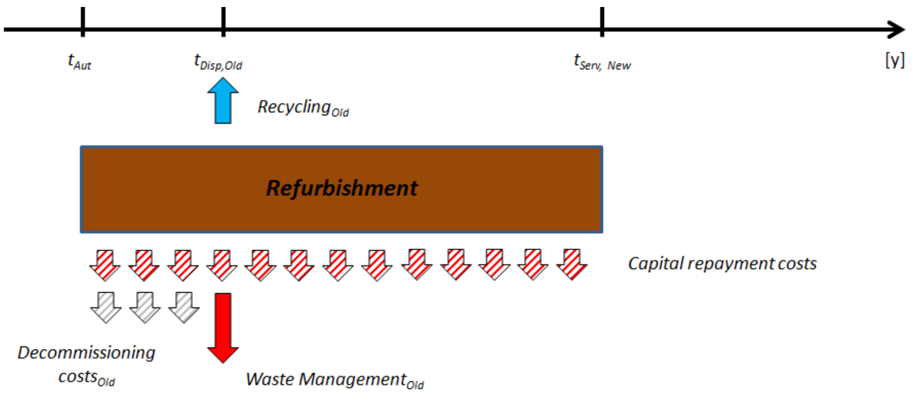


Fig. 21 – Refurbishment phase: costs and benefits flows

With the aim to describe the typical activities and the related costs that refer to the building phase (decommissioning and disposal costs will be treated afterward), they could be different according to the transmission asset to realize, as well as the type of installation: typical activities and expenses that take place in this phase are related to structures, civil works, engineering, materials, spares, manpower, etc.

For what regards the economic flow perspective, at the beginning of this phase (t_{Aut}) the TSO that performs the network investment receives the capital from the financial system in order to cope its investment costs.

This capital can be a combination of retained earnings, equity or debt and it must be paid back to lenders during the *amortization phase* [t_{Aut}, $t_{End\ Amo}$): this phase is not related to the technical life of the network investment, but it is connected to the financial dimension of the investment. Therefore, during the amortization period, the TSO experiences *capital repayment cost flows* in order to repay to the financial system the loaned capital plus a return. As outlined above, the capital may be provided to the TSO by a mix of lenders: a measure of how the lenders mix in composed is the *weighted average cost of capital* (*WACC*):

$$WACC = \frac{\sum_{i=1}^{N} r_i \cdot Q_i}{\sum_{i=1}^{N} Q_i}$$

where N is the number of the different sources of capital, r_i is the required rate of return for the i-th capital and Q_i is the portion of capital received by the i-th source of capital. In general, the

WACC represents the minimum rate of return that a company must realize in order to pay back the financial system and to do not realize an economic loss;

- *investment life* [t_{Serv}, $t_{End\ Life}$): in this phase the transmission asset is effectively in service. Therefore it generates benefits but, at the same time, it is subjected to costs in order to let a sustainable operation of the whole system. These costs are split in *not recurring costs*, (documentation, initial spares, equipment, etc.) and *recurring costs* (power losses, insurance costs, manpower, materials and consumable for preventive and corrective maintenance, etc.). Power losses, failure rates and maintenance requirements are dependent by the type of asset as well as the kind of installation: therefore the costs experienced during the investment life can be significantly different between two or more transmission network technologies. Moreover, considering the statistical behavior of failure phenomena, operating costs should be highly variable during the life of a given transmission asset;
- *decommissioning phase* [$t_{End\ Life}$, $t_{Disposal}$): in this phase the TSO performs all the activities to manage the asset decommissioning, such as the system shutdown, the disassembly and the removal the asset components. In order to do that, economic resources are needed, both in terms of materials and manpower, and these quantities are related to the type of asset and to the environmental conditions;
- *disposal phase*, concentrated in $t_{Disposal}$: in this phase, the resulting materials obtained by the decommissioning phase are managed. Some are recycled (and they generate an economic benefit), others are managed as waste in different ways – according to their hazard level – and then represent a cost for the system. Clearly, the ratio between recycled and sent to landfill waste (and the related economic benefits/costs) depends on the kind of decommissioned transmission network asset.

3.2.2. Proposed methodology

The methodology proposed to account for life cycle costs in the BCA of a transmission expansion planning is based on highlighting different cost components concurring into the total NPV of the LCC: since the temporal dimension in LCC is depicted by the NPV, the time period when different costs components occur is important.

As depicted in previous section, costs in different phases of transmission investment life are a function of two aspects:

- *what transmission technology is adopted?* The variability to this aspect is highlighted by the *i* subscript ($i = 1, 2, \ldots, N_{tech}$, where N_{tech} is the number of transmission technologies identified by WP3);
- *what is the type of installation according to the environmental boundary conditions?* The variability to this aspect is highlighted by the *j* subscript, that identifies the type of installation: flat terrain (FT), rolling terrain (RT), mountainous terrain (MT), undermarine low deep (ULD), undermarine high deep (UHD) [19]. Clearly, not all the transmission technologies are compatible with all the types of installations (e.g. OHL transmission technology is not compatible with ULD and UHD installations).

The main idea is to consider for each stage of the transmission asset life (authorization, installation, operative life, decommissioning) the proper expenses. It is deemed that notwithstanding the many uncertainties affecting the data for the long term time horizon object of the e-Highway2050 project, this rigorous approach will be able to correctly quantify the effects of the temporal cash-flow of the analyzed transmission investments. It has to be noted that the same approach will also be applied to the investments assessment at 2050 conducted in order to assess the final system layout, even if in this phase only one temporal point will be available for benefit calculation: in fact the investment costs will be correctly anticipated wrt this target data so that the new investments are supposed put in service for 2050.

The proposed cost breakdown structure encompasses:

- *authorization expenses* (if applicable) $AUTEX_{ij}$: they could account also compensation costs (in alternative to including them into $INSTEX_{ij}$)
- *installation/refurbishment expenses* $INSTEX_{ij}$: they could account also compensation costs (in alternative to including into $AUTEX_{ij}$);
- *asset capital expenses* $ASSEX_i$;
- *operation and maintenance expenses* $OPEX_{ij}$: in this cost component transmission losses should not be considered, since losses are accounted for separately;
- *decommissioning expenses* $DECOMMEX_{ij}$;
- *disposal net expenses* $DISPEX_i$ (net expense flow between recycling benefits and waste management expenses).

It must be highlighted that:

- the commonly utilized tag CAPEX ("capital expenditure") is meant to result from the sum of ASSEX and INSTEX;
- $ASSEX_i$ and $DISPEX_i$ do not depend by the type of installation, since the intrinsic cost of an asset and its waste management are not related to the type of installation; with the exception of $OPEX_{ij}$, expressed as average yearly expense, all costs are expressed in monetary value and they are assumed to be equal to the value of the whole expense in the specific phase

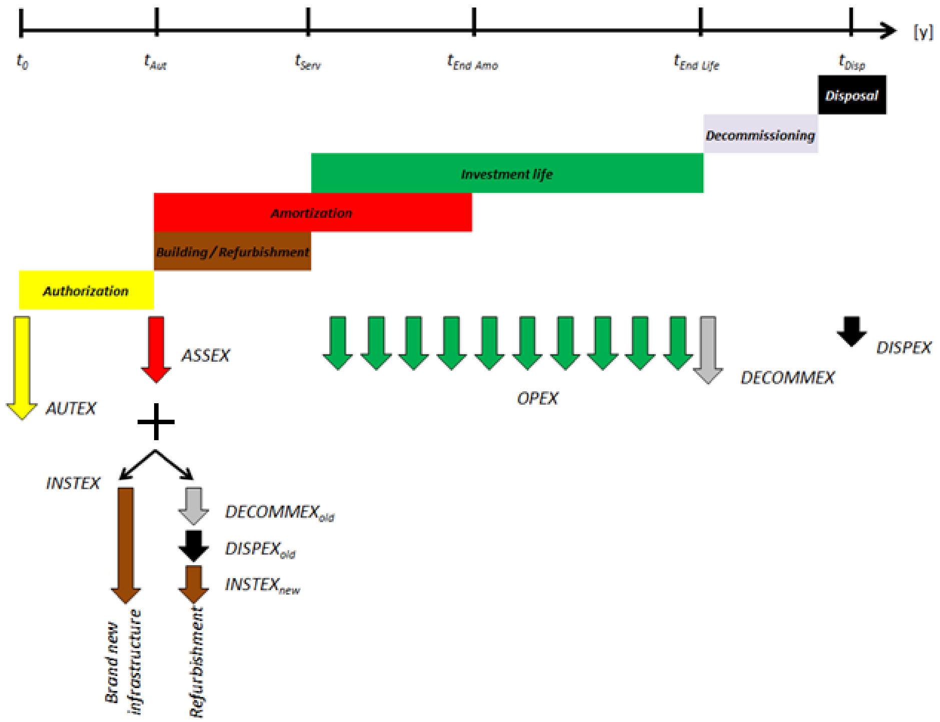


Fig. 22 – Proposed cost breakdown structure

discounted at the beginning of that phase: in other terms, $AUTEX_{ij}$ are expressed as the whole expenditure during the authorization phase concentrated in t_0, $INSTEX_{ij}$ and $ASSEX_i$ are concentrated in t_{Aut}, and so on (see Fig. 22). Clearly, for kilometric transmission technologies (OHL, cables, etc.) the expenses should be given in kilometric monetary values, while for concentrated transmission technologies (transformers, AC/DC converters, etc.), they should be given with respect 1 MW of installed capacity;

- the sum of $INSTEX_{ij}$ and $ASSEX_i$ can be seen as the classical capital expenditure ($CAPEX_{ij}$) necessary to realize the network reinforcement by means of the *i*-th transmission technology according to the *j*-th installation and, moreover, it is the quantity of capital that a TSO asks to the financial system in order to perform the investment. The choice to separate the two cost component has been necessary in order to hive off the cost component which is dependent by the type of installation ($INSTEX_{ij}$) and the other one which reflect the expenditure in buying the specific transmission asset ($ASSEX_i$): e.g. realizing an OHL in a flat terrain will cost less than realizing it in a mountainous terrain, due to emerging additional installation costs (as example, for carry the materials in a more difficult site), while the transmission asset itself (the conductors) is the same[5]. For this reason, $ASSEX_i$ is not dependent by the type of installation. For the same reason, $DECOMMEX_{ij}$ and $DISPEX_i$ are separate, too;
- for what concerns the variation of these costs in time, it is possible to suppose that all cost component typical values, with the exception of $ASSEX_i$, are "steady-state", i.e. they do not vary in time according to technological evolution. For $ASSEX_i$, the possibility that costs for not fully mature transmission technologies (indicated with the index $\bar{i}$) could significantly vary in the future should be accounted for: a well-known methodology [20] let consider this effect by means of *learning experience curves*:

$$\frac{ASSEX_{\bar{i}}(t)}{ASSEX_{\bar{i}}(\tau)} = \left(\frac{P_{\bar{i},inst}(t)}{P_{\bar{i},inst}(\tau)} \right)^{\frac{\ln(1-LR_{\bar{i}})}{\ln 2}}$$

  where $ASSEX_i(\tau)$ is the asset expenses monetary value for a given year τ, $P_{inst}(\tau)$ and $P_{inst}(t)$ are the total installed capacity for the reference year ($P_{inst}(\tau)$ is clearly an estimation) and LR_i is the learning rate for the given technology. These data should be given as an input for the LCC analysis (see Tab. 3);
- $AUTEX_{ij}$, $INSTEX_{ij}$, $OPEX_{ij}$, $DECOMMEX_{ij}$ and $DISPEX_i$ can be estimated according to WP3, manufacturers and TSOs expertise: the possibility to consider different values for different countries is an open point and it should be discussed with partners. In case of a refurbishment of an old investment, costs should be given for the specific case (see Tab. 4);
- for a given transmission infrastructure reinforcement, the duration of the different phases must be given: for the generic *i*-th technology and the generic *j*-th type of installation, typical values can be given by WP3, TSOs and manufacturers expertise. For what regards authorization phase, installation phase, investment life, amortization period and

[5] This is strictly true only if the additional costs that a TSO experiences in order to adapt a transmission infrastructure for a different type of installation are neglected. Nevertheless, these additional costs can be accounted for in the $INSTEX_{ij}$

Tab. 3 - Typical cost component matrix to fill for *$ASSEX_i$ and $DISPEX_i$*

	Asset expenses data			$DISPEX_i$
Transmission technology	$ASSEX_i(\tau)$	LR_i	τ	

Tab. 4 - Typical cost component matrix to fill for *$AUTEX_{ij}$, $INSTEX_{ij}$, $OPEX_{ij}$* and *$DECOMMEX_{ij}$*

	j-th type of installation				
i-th transmission technology	*FT*	*RT*	*MT*	*ULD*	*UHD*

decommissioning phase. In case of a refurbishment, the duration of the two different time period (decommissioning of the old investment and installation of the new investment) should be given for the specific case.

Once all cost components are known, as well as the time instants when they occur, it is possible to calculate the *NPV* of the whole *LCC*:

$$\begin{aligned}
&LCC_{ij,NPV}(\hat{t}) = \\
&= AUTEX_{ij} \cdot DF_{AUTEX}(\hat{t}) + \\
&+ \left(ASSEX_i + INSTEX_{ij}\right) \cdot DF_{ASSEX}(\hat{t}) + \\
&+ OPEX_{ij,TOTAL} \cdot DF_{OPEX,TOTAL}(\hat{t}) + \\
&+ \left(DECOMMEX_{ij} + DISPEX_i\right) \cdot DF_{DECOMMEX}(\hat{t})
\end{aligned}$$

where the generic $DF_{COST}(\hat{t})$ is the discount factor in order to actualize the generic cost component to the reference year $\hat{t}$. Clearly, these factors depend on what interest rate to consider: a natural solution could be to adopt the *WACC*. Once this quantity has been calculated, it is possible to directly compare the $LCC_{ij,NPV}$ of different transmission alternatives (and different type of installation) or calculate an annuity cost factor $A_{LCC_{ij}}$ in order to compare the LCC with the annual benefit given by the transmission reinforcement.

3.2.3. Accounting for residual value of a transmission asset

The LCC methodology allows to account for the whole costs that a product/service experiences during its whole life cycle: however, while performing the whole BCA assessment over a given time interval, an additional benefit to consider is the *residual value* that an investment has at the end of the assessment interval.

According to economic theory, several different alternative approaches can be adopted [21]:

- *liquidation method*: is the value of an entity's assets (supposing to be able to sell it) less the value of its liabilities. Therefore, this liquidation value should reflect what other parties would be willing to pay for buying the asset.
- *terminal multiple method*: is a multiple based valuation method, and it is based on public markets valuations. The terminal value is estimated by applying the appropriate multiple (EV/EBITDA, EV/EBITA, EV/EBIT) to the corresponding metric estimated for the last year in the projection period;
- *perpetuity growth method*: this method assumes that the cash flows of the firm will grow at a constant rate (*g*) forever. Therefore, the residual value of an asset in a given year should be, at least, equal to the capital value necessary to generate the expected cash flow in the following year:

$$Value(t) = \frac{Cash\ Flow(t) \cdot (1+g)}{WACC - g}$$

A conservative choice could be to assume $g = 0$.

However, applying this methodology requires to provide *with-without* (TOOT[6] approach) simulations in order to determine what is the impact (in terms of benefits) that a new transmission asset has on the whole system and, therefore, what cash flow it generates at the target year for estimating its residual value.

A simpler way to estimate the residual value of a transmission asset is to consider it equal to the economic value of the asset that has not been amortized yet:

$$Val\_Resid(\breve{t}) = \sum_{t=\breve{t}}^{t_{End\ Life}} \frac{A_{LCCij}}{(1+\breve{r})^{(t-t_{Serv})}}$$

and:

$$\breve{r} = \left[\frac{\sum_k CostComponent_{k,NPV}(t_{Serv}) \cdot r_k}{\sum_k CostComponent_{k,NPV}(t_{Serv})}\right] = \left[\frac{\sum_k CostComponent_{k,NPV} \cdot r_k}{LCC_{ij,NPV}(t_{Serv})}\right]$$

Clearly, if:

$$\breve{t} = t_{Serv} \Rightarrow Val\_Resid(\breve{t}) = LCC_{ij,NPV}(t_{Serv})$$

$$\breve{t} = t_{End\ Life} \Rightarrow Val\_Resid(\breve{t}) = 0$$

Even if this approach does not allow to consider the capability of a transmission asset to generate a benefit even if it has already been amortized, it can be simply adopted without performing new simulations, fitting the scope of the WP6 BCA.

6 The *Take Out One at the Time* (TOOT) methodology consists in excluding investment items or complete projects from the forecasted network structure on a one-by-one basis and to evaluate the network operating point (in terms of dispatch, power flows, etc.) over the lines with and without the examined network reinforcement.

3.2.4. LCC methodology: example of application

An example of application of the envisaged LCC methodology is reported afterwards[7]. In this example, two alternative (A and B) of brand new network reinforcement are compared.

With respect the proposed example, it must be highlighted:

- the numbers reported are not realistic and they are used in order to be functional to describe the methodology;
- with the exception of *OPEX*, where costs are provided in terms of p.u. of the *CAPEX* in each year, the other costs components are concentrated at the start of each life phase of the transmission asset;
- no learning index approach was used for determining the *ASSEX*;
- for calculating the NPV and the annuity cost factor for the LCC, a 7% interest rate was adopted.

Tab. 5 and Tab. 6 report the main input data needed for calculating the LCC of the investment, while Tab. 7 and Tab. 8 show the output of the LCC calculation.
It can be noted that, even if the Alternative A has lower *CAPEX* that the one related to the Alternative B (500 vs. 650 M€), the effect of higher *OPEX* on the *NPV* (2.5% vs. 1% M€/y) let the Alternative A more expensive that the Alternative B in terms of total LCCs (641.57 vs. 627.45 M€) and annuity cost factors (55.34 vs. 54.12 M€).

[7] In this as in the following numeric examples reported the present report, the values of all the parameters are not meant to reflect real figures but are just provided for didactic reasons.

Tab. 5 – LCC example: Alternative A data

Alternative A	AUTEX	ASSEX	INSTEX	OPEX	DECOMMEX	DISPEX
Start time [y]	0	2	2	4	19	20
End time [y]	1	3	3	18	20	20
Costs (as a percentage of CAPEX)	10%	80%	20%	2.5% [y^{-1}]	8%	2%
Type of installation	Rolling terrain					
CAPEX [M€]	500					
Scaling terrain ratio (with respect flat terrain)	120%	100%	120%	120%	120%	100%

Tab. 6 – LCC example: Alternative B data

Alternative B	AUTEX	ASSEX	INSTEX	OPEX	DECOMMEX	DISPEX
Start time [y]	0	4	4	5	20	
End time [y]	3	4	4	19	20	
Costs (as a percentage of CAPEX)	12%	80%	20%	1% [y^{-1}]	3%	2%
Type of installation	Flat terrain					
CAPEX [M€]	650					
Scaling terrain ratio (with respect flat terrain)	100%	100%	100%	100%	100%	100%

Tab. 7 – LCC example: LCC cost components (NPV)

NPV LCC components [M€]	AUTEX	ASSEX	INSTEX	OPEX	DECOMMEX	DISPEX	**Total**
Alternative A	60.00	349.38	104.81	111.52	13.27	2.58	**641.57**
Alternative B	78.00	396.71	99.18	45.16	5.04	3.36	**627.45**

Tab. 8 – LCC example: LCC annuity cost factor

Annuity cost factor [M€/y]	
Alternative A	**55.34**
Alternative B	**54.12**

3.3. Social Welfare

In the past, power system planning and development was a task carried out by vertically integrated utilities that operated with the only aim of supplying energy to the final consumer in the cheapest and most reliable way. In this context, investments in transmission expansion projects are typically justified for improving the lack of transmission capacity in order to allow all loads of the system to be supplied at the same cost, without network congestions. All the activities related to the power system development such as the generation and transmission expansion are focused exclusively to the consumers, in order to provide the best service. This because the sector was regulated and the costs deriving from expansion are socialized.

The situation changed with the unbundling of the activities of generation, transmission and distribution. While the activities related to the network (transmission and distribution) are universally considered as natural monopolies, and thus regulated by specific authorities, the liberalized market has introduced multiple parties in the electricity industry, especially for what concerns generation and energy sale. In this multi-party business, the focus of the system development is no longer least cost power supply to the consumers, since other actors (the generation companies) are present with different and sometimes conflicting objectives with respect to the consumers. Moreover, with the increasing opening to the international power exchanges for the creation of a common European market, also the national interests may become conflicting with the idea of a wide energy market.

In this new context the traditional criteria adopted for the decision-making appear to be lacking, because the point of view of many actors present on the market are ignored. The old paradigm of the least-costs system development is overcome. Should the new criteria be based on benefits? Whose benefit? How to consider different benefits?

An interesting discussion regarding the new challenges emerging in transmission planning in a liberalized and restructured environment can be found in [13].

The impact of a transmission expansion may have both positive and negative effects on the benefits of the subjects participating in the market, even if the global index of the *social welfare* is increased. Subjects that suffer a loss in their surplus without any sort of compensation may oppose a transmission expansion project. A typical example is provided by the two area market

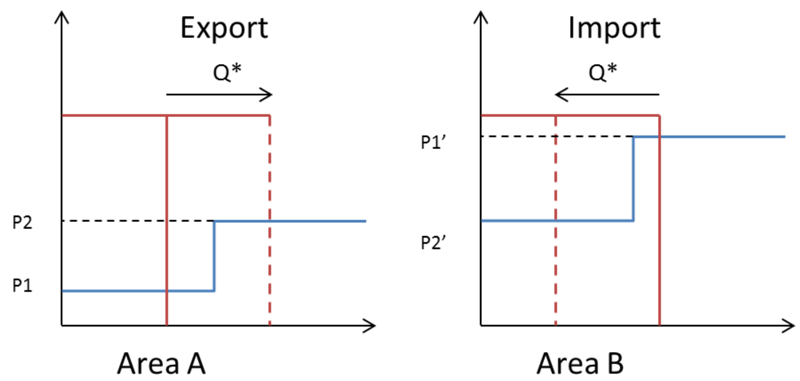


Fig. 23 – Two – area market example

shown in Fig. 23. By increasing the transmission capacity between zones, the cheaper Area A can export to Area B the quantity *Q*.*

This has consequences on the equilibrium of both markets. The consumers in *A* would not be so happy of the new transmission project, since the market price rises from *P1* to *P2*; on the contrary consumers in *B* benefits from a lower market price (*P2' < P1'*). On the other hand the suppliers in *A* are able to produce more energy, getting more profits with an higher price, while generators in *B* suffers a loss because of a load and price reduction.

Even if the global social welfare increases, there are some aspects that should be considered in evaluating the benefits from a new project. The example above shows conflicting interests that would be ignored without an in-depth analysis. For this reason, this aspect is included by CAISO in his “Transmission Expansion Assessment Methodology”[15].

There is an additional aspect that should be considered in the assessment of benefits from a transmission project, related to the modern trend of integrating together the single national electricity markets for improving competition, efficiency and reliability. In the transmission expansion planning focused on increasing the cross border capacity in a multilateral context, conflicting position from the national point of view may arise. A typical situation is the case where a particular zone *B* acts as an hub for power exchanges between *A* and *C;* an increase in transmission capacity for improving benefits of *A* and *C* can results in a loss for the social welfare of zone *B*. This situation is well described in [23], where the concept of *Pareto-improving planning* is introduced to overcome possible conflicts. A transmission expansion project results “Pareto-improving” if any zone of the multilateral market will have a loss in social welfare.

Especially when system simulations are performed with a supranational viewpoint, as in the case of e-Highway2050 where the pan-European system is simulated as a single electricity market, the allocation of costs and benefits can create winners and losers, even if they are not reflected in the main indicator of the social welfare. This is clearly a problem that should be at least analyzed in a complete BCA related to a large multi-market system as the European one. For this reason, in the following, the methodology for splitting in the main components the change in social welfare after a transmission expansion is presented.

3.3.1. Social welfare decomposition

All the aspects above described could be collected in a methodology for the assessment of potential benefits that can provide more information than the simple global social welfare value. A more detailed approach based on the social welfare decomposition allows to present clearly the effect of a transmission expansion on different subjects of the power system and to perform sensitivity analysis on the benefits, analyzing different points of view on the transmission expansion plan. During the analysis of alternative transmission expansion plans the global social welfare value should be used for quantifying the additional benefit to the system, but this analysis goes in deep in the quantification of costs and benefits and constitutes an added value to the standard BCA, providing additional details useful to the decision maker or regulators, providing more information on the effect of the expansion plan.

The social welfare may be decomposed in the sum of three terms, consumers surplus, producers surplus and merchandise surplus (or congestion rent):

$$SW = CS + PS + MS \quad (\textit{decomposition per Stakeholders})$$

Each term may be further decomposed depending on the market zone:

$$CS = \sum_{i \in Zones} CS_i$$
$$PS = \sum_{i \in Zones} PS_i \quad (\textit{decomposition per Zones})$$
$$MS = \sum_{i \in Zones} MS_i$$

The effect of a new transmission expansion project can be quantified by the variation in the social welfare *ΔSW* before and after the transmission expansion. Such variation can be decomposed for each zone in the three terms, consumers surplus, producers surplus and merchandise surplus. The variation in consumer surplus and producers surplus is given by:

$$\Delta CS_i = \left[B_i\left(Q^1_{D,i}\right) - \pi^1_{D,i} Q^1_{D,i}\right] - \left[B_i\left(Q^0_{D,i}\right) - \pi^0_{D,i} Q^0_{D,i}\right]$$
$$\Delta PS_i = \left[\pi^1_{G,i} Q^1_{G,i} - C_i\left(Q^1_{G,i}\right)\right] - \left[\pi^0_{G,i} Q^0_{G,i} - C_i\left(Q^0_{G,i}\right)\right]$$

where $Q^1_{D,i}\left(Q^1_{G,i}\right)$ is the quantity cleared by the market for load (generator) in zone *i* after the transmission expansion, $\pi^1_{D,i}\left(\pi^1_{G,i}\right)$ is the correspondent price. $Q^0_{D,i}\left(Q^0_{G,i}\right)$ and $\pi^0_{D,i}\left(\pi^0_{G,i}\right)$ are the same terms in case without transmission expansion. Finally $B_i\left(Q_{D,i}\right)$ and $C_i\left(Q_{G,i}\right)$ are respectively the benefit function of load in zone *i* and the cost function of the generator in zone *i*.

The definition of the total merchandise surplus of a system is the difference between the payment made by consumers and revenues of the suppliers. Applying this definition to each market zone, the change in its value is given by:

$$\Delta MS_i = \left[\pi^1_{D,i} Q^1_{D,i} - \pi^1_{G,i} Q^1_{G,i}\right] - \left[\pi^0_{D,i} Q^0_{D,i} - \pi^0_{G,i} Q^0_{G,i}\right]$$

However this definition can lead to a different zonal distribution of the surplus, with respect to the actual schemes typically adopted in market structures. For this reason a more practical definition of zonal change is adopted, provided that the whole value of merchandise surplus of the system does not change. The merchandise surplus can be expressed as the sum of shadow prices on congested lines times the power flow[8]. The repartition to the zones can be given by:

$$\Delta MS_i = \sum_{j \in Nt_i} \frac{1}{2} \lambda_j P_j$$

where Nt_i is the set of the lines connecting zone *i*, λ_j is the shadow price of line *j* and P_j is the power flow on line *j*. In this way, the contribution to the whole merchandise surplus of a given line is split between the two market zones in equal part.

[8] This definition holds in case of DC model approximation, without network losses

Tab. 9 – Example of social welfare decomposition

	ΔCS	ΔPS	ΔMS
Zone 1	-	+	-
Zone 2	+	-	-
Zone *i*-th	+	+	-

Reporting the decomposed welfare measures in a table (Tab. 9), a clear indication of all benefits and costs that occur after the expansion is provided, together with the “winners” and “losers” emerging from the project. This decomposition allows a clear evaluation of the effects of the transmission expansion plan on different subjects/zones and can be the starting point for further analysis.

For example, based on such decomposition, a multidimensional analysis can be carried out including all the perspective related to zones and subjects. By means of suitable weights assigned to each term of the decomposition, it is possible to perform a sensitivity analysis on the global benefit; changing the value of the weights it is possible to analyze the network expansion from different points of view and not only in a global way.

3.3.2. Sensitivity to the load elasticity

The topic of the impact of demand elasticity on the market outcomes is well argued in technical literature; generally, an increase in the load elasticity reduces the loss in social welfare for transmission congestion [24] and improve the market efficiency preventing strategic behavior of suppliers [25]. The easiest way to assess the effect of load elasticity is performing several simulations varying its value. However, in order to make the analysis of task 6.1 independent on the results of WP2, a post-processing approach can be adopted. The general idea is to keep fixed the market solution, obtained with inelastic load, and to change the value of the load elasticity in the market equilibrium. The effect is shown in Fig. 24; the change in load elasticity results in an anticlockwise rotation of load curve, around the solution of the market simulation. In this way the benefit function of the consumers changes and the total surplus of consumers will be reduced.

Let (1) be the load elasticity definition, while (2) and (3) represent respectively the load bid curve and the benefit function.

$$e_i\left(Q_{D,i}\right)=-\frac{dQ_{D,i}}{d\pi_{D,i}}\frac{\pi_{D,i}}{Q_{D,i}} \tag{1}$$

$$\pi_{D,i}=b_{2,i}Q_{D,i}+b_{1,i} \tag{2}$$

$$B_i\left(Q_{D,i}\right)=\frac{1}{2}b_{2,i}Q_{D,i}^2+b_{1,i}Q_{D,i}+b_{0,i} \tag{3}$$

Hence the elasticity can be written as (4):

$$e_i\left(Q_{D,i}\right)=-\frac{b_{1,i}}{b_{2,i}Q_{D,i}}-1 \tag{4}$$

Results of WP2's simulations are assumed as reference; let $\pi^*_{D,i}$ and $Q^*_{D,i}$ be the price and quantity cleared by the market for load *i*.

As a consequence the load bid curve can be changed by means of the parameters $b_{1,i}$ and $b_{2,i}$. Combining (2) and (4) and remembering the reference point $\pi^*_{D,i}$, $Q^*_{D,i}$, it results:

$$b_{1,i}=\frac{\left(e_i+1\right)}{e_i}\pi^*_{D,i} \qquad b_{2,i}=-\frac{\pi^*_{D,i}}{e_iQ^*_{D,i}} \tag{5}$$

The load bid curve as a function of the elasticity in the reference point is:

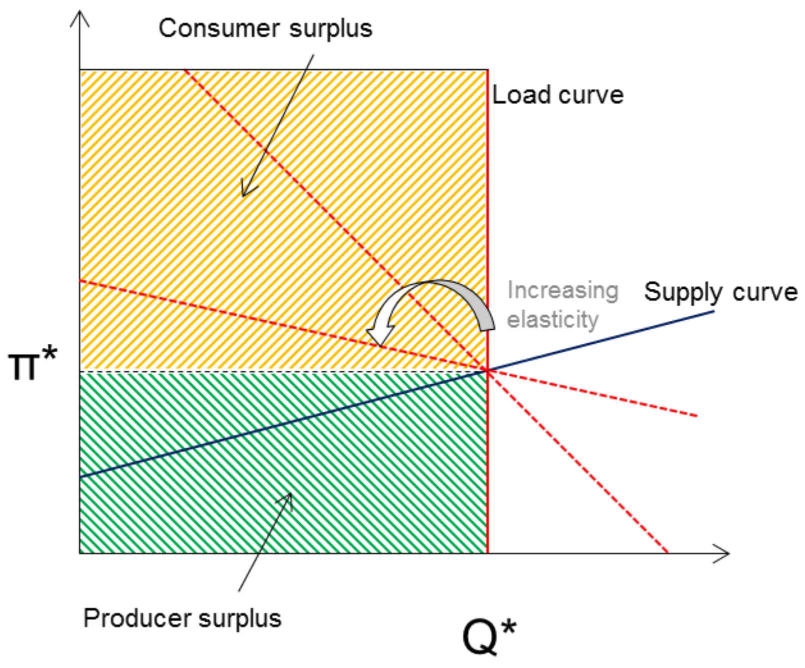


Fig. 24 – Load bid curve as function of load elasticity

$$\pi_{D,i} = -\frac{\pi^*_{D,i}}{e_i Q^*_{D,i}} Q_{D,i} + \frac{(e_i + 1)}{e_i} \pi^*_{D,i} \quad (6)$$

The evaluation of the consumer surplus as a function of the elasticity is given by:

$$CS_i = \left[B_i\left(Q^*_{D,i}\right) - \pi^*_{D,i} Q^*_{D,i}\right] \quad (7)$$

In this way is possible to calculate the consumer surplus for each load *i* depending on the load elasticity.

Following this approach, the producers surplus is not affected by the load elasticity, since the equilibrium point does not change. Also the merchandise surplus is not affected by a change in the load elasticity, because its own definition depends only on the market equilibrium point:

$$MS_i = \pi^*_{D,i} Q^*_{D,i} - \pi^*_{G,i} Q^*_{G,i} \quad (9)$$

Hence, following this approach, all the variations in the social welfare due to the load elasticity changes are produced by the consumers surplus difference.

3.3.3. Externalities from grid exploitation

In a large and meshed grid a transmission expansion results in a higher power flows exchange among areas. This has a positive effect for reducing network congestion and to improve the market efficiency, but implies also externalities for the grid exploitation. Improvements in the transmission capacity on a specific corridor increase power exchanges that would inevitably affect also other interconnectors because of the physical repartition of power flows. Hence the network of an interconnected area may be crossed by ***transit flows*** that burden on the grid, without producing any benefits for the specific area. These externalities could be included as an additional economic term in the computation of the social welfare. In the following, a methodology for the quantification of the transit flows and their monetization is presented.

In a bus-bar system model, the power flows on interconnectors in a single hour can be calculated by means of linear sensitivity factors Power Transfer Distribution Factors (PTDF). The vector of hourly power flows on interconnectors are given by:

$$[T_h] = [PTDF][A_h]$$

where $[A_h]$ is the vector of the hourly net power injections of each zone. The variation of the power flows following a transmission expansion is:

$$[\Delta T_h] = [PTDF][\Delta A_h]$$

assuming that the new expansion affects only the transmission capacity and not the network topology. For each zone *i* is possible to evaluate the change in transit flows crossing the network in hour *h* as:

$$\Delta\Phi_{i,h} = \min\left[\Delta I_{i,h}, \Delta E_{i,h}\right]$$

where $\Delta I_{i,h}$ and $\Delta E_{i,h}$ are respectively the change in total import and export flows of area *i* in hour *h*.

Once defined the effect of new network expansions on the transit flows, it should be quantified in economic terms as a inter TSO compensation to be included in the cost benefit analysis. However, without a clear indication from a regulation that fixes the tariff for the grid exploitation, the economic contribution of this aspects is considered unclear and thus it will be neglected.

3.3.4. Example of application

Let us consider a simple three-area system radially connected as in Fig. 25. Transmission lines are assumed to have the same reactance and a 100 MW of limit in both directions and the market solution is perfomed through a flow based DC constrained dispatch with standard definition of locational marginal price. Fig. 26 shows results of the market in the base case scenario. Both transmission lines are congested and the three areas have different market prices (LMP).

The first planning scenario entails the realization of two new lines with the same reactance for improving branches *1 – 2* and *2 – 3*. The total power limit of both links is increased to 210 MW.

Fig. 27 shows the market results after the transmission improvement. In this case the line *2 – 3* is no longer congested and Area 3 reaches the same price of Area 2, while the *1 – 2* is still at the maximum. The figure shows also the changes in surplus values for each area, respect to the base case.

The second planning scenario introduce a double line between Area 1 and Area 3, with a total limit of 210 MW. Fig. 28 reports the results of the market and the values of the social welfare components. The new line allows Area 1 to export more power, but congestion on line *1 – 2* limits the market exchanges.

Tab. 10 summarizes the social welfare variations due to the planning scenario considered, pointing out the single components and the total change for each area. Globally, both projects will increase the system social welfare, but the second project provides the highest increase.

Proved that the best project in terms of benefit to the system is the second one, it can be noted that the first project allows an increase of surplus for consumers of area 3, while both consumers and producers of other areas do not gain nor lose surplus. On the contrary, according to project 2, consumers of area 1 would lose part of their surplus, while producers of area 1 and consumers of area 3 would improve their surplus. For what concerns the zonal analysis, the total welfare of areas 1 and 3 increase, while that of area 2 decrease because of a reduction in the congestion rent.

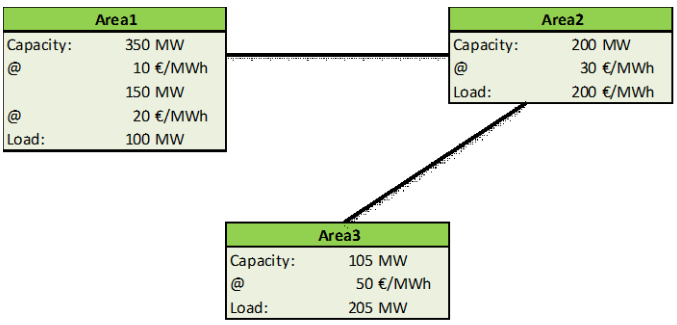
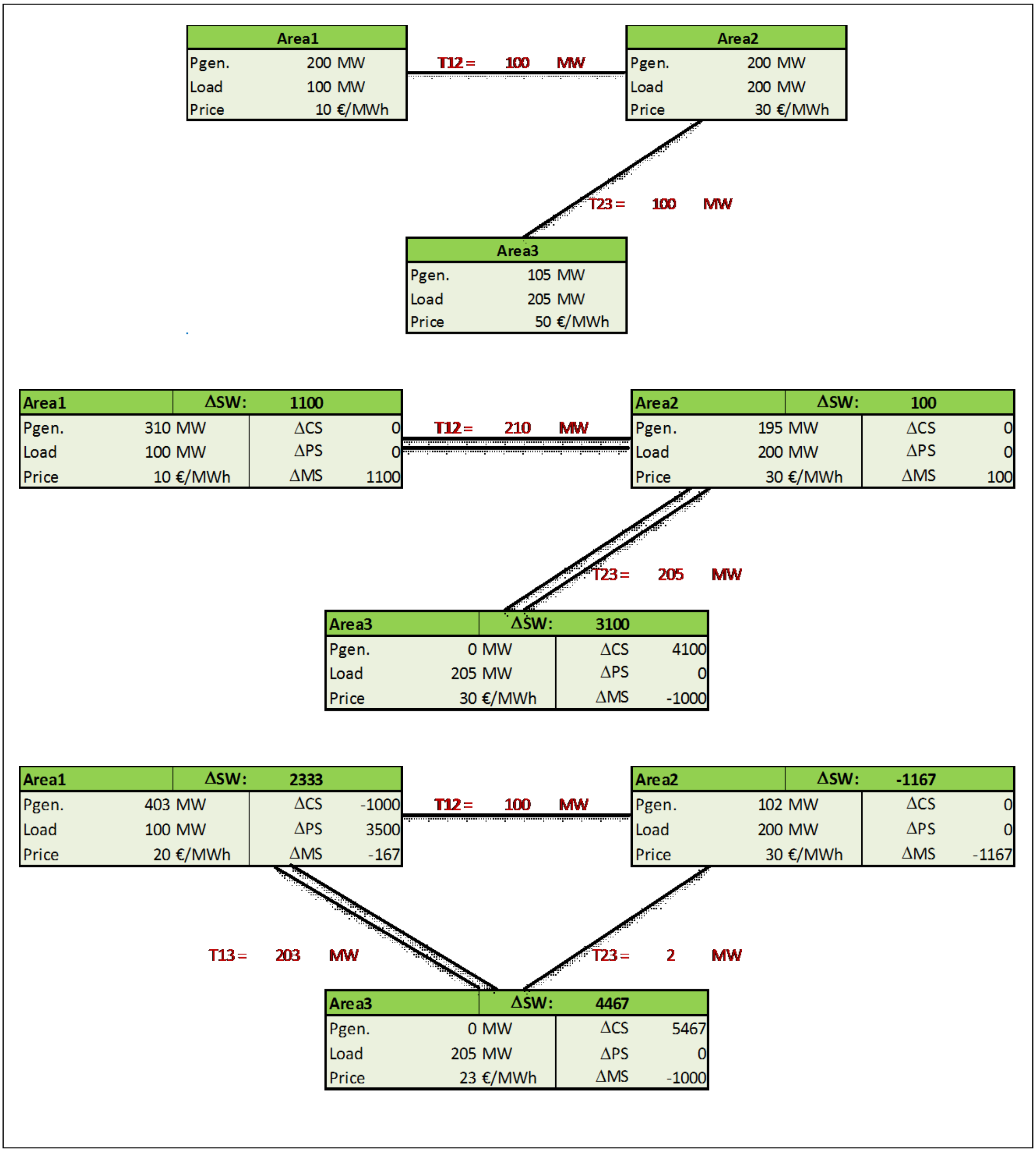


Fig. 25 – Three area system data



This analysis on the splitting of surplus completes the information about the benefit to the system due to the expansion plan, pointing out how the increase of social welfare is split and how its components contribute to that. This kind of analysis can be useful for example to consider other points of view of the transmission planning.

Tab. 10 – Social welfare components for each area [€]

	System	AREA 1				AREA 2				AREA 3			
	TOT	TOT	ΔCS	ΔPS	ΔMS	TOT	ΔCS	ΔPS	ΔMS	TOT	ΔCS	PS	MS
Project 1	4300	1100	0	0	1100	100	0	0	100	3100	4100	0	-1000
Project 2	5633	2333	-1000	3500	-167	-1167	0	0	-1167	4467	5467	0	-1000

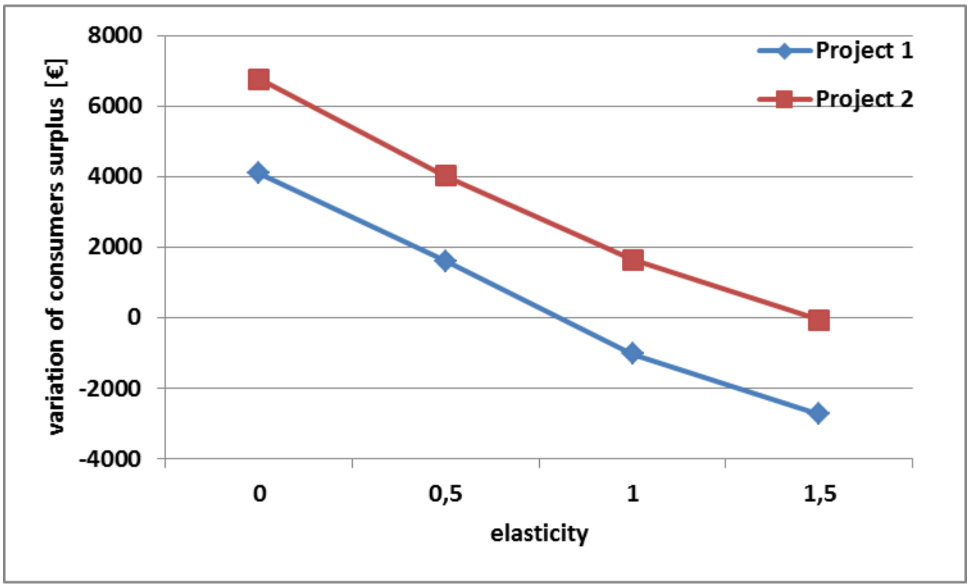


Fig. 29 – Sensitivity analysis of consumers surplus vs. load elasticity in Area 3

Finally a sensitivity analysis of the social welfare respect to the load elasticity is provided. For this purpose we focus on the social welfare of Area 3, that is the one that benefits of higher surplus increase from the transmission planning. According to the methodology presented, the load elasticity affects only the consumers surplus.

It is assumed also that in the base the load remains inelastic; in this way the sensitivity analysis evaluates what are the benefit if the load elasticity increase, together with the transmission improvement. Therefore the change in consumer surplus calculated with different load elasticity is compared with the same value provided by the base case. Results expected should provide a decreasing surplus change as the load elasticity increase (for a perfect elastic load the consumers surplus is zero).

Fig. 29 shows the variation of consumers surplus introduced by project 1 and project 2 with respect to the base case, as a function of the load elasticity. It is interesting to note how the benefits from an increased social welfare are reduced by the elasticity. Such analysis may have an important role in the BCA because allows to asses an aspect that the market simulations do not considers.

3.4. Network Losses

Technical losses in the electric power system are an inevitable consequence of distributing electricity and of transforming from one voltage to another. The main components are:

- *variable* or Copper (Cu) losses, which are due to electrical resistance of conductors and hence have a quadratic relationship with the current passing through the conductor;
- *fixed* or Iron (Fe) losses (also known as *no load* losses), which are incurred as a result of the magnetizing forces involved in transforming electricity. This component is fixed in the sense that, unlike variable losses, the losses are not a function of the load current passing through the conductor.

Other less significant forms of technical losses include: corona, skin effect, cable sheath and dielectric leakage losses (i.e. in conductors and insulators), *stray losses* which relate to flux leakage from the intended magnetic path within the transformer core and eddy current losses (i.e. in transformer cores and windings). A detailed discussion about different losses components is given in [9].

For what regards losses evaluation in the the e-Highway2050 project, the unavailability of a full-detailed (nodal) network model and, conxtually, the impossibility to perform network simulations in WP6 suggested to estimate (*ex-post*) the variable losses starting from the outputs of WP2 zonal simulations based on a macro-zonal model where zonal clusters are interconnected by equivalent corridors. Thus simulations do not take into account explicitly the full network layout. Moreover, the equivalent network connecting macro-zones, is evaluated by a DC model, neglecting the power losses that occur in the transmission grid: therefore, there is the need of a set of intensive parameters (the so called losses parameters) evaluated starting from the output of a load flow on a pre-clusterized full network layout.

The evaluation and monetization of network losses[9] should be done in post processing, starting from the active power flows on the network given as an output of the optimization. According to the equivalent approach adopted for the network layout, the losses estimation can be split in the sum of two contributions: *inter-zonal losses* and *intra-zonal losses.*

Losses on transmission corridors between macro-zones can be evaluated in post-processing starting from inter-zonal flows given by WP2 simulations and considering what transmission infrastructure is adopted for delivering these power flows.

Variable transmission losses on a branch have a quadratic relationship with the current passing through the conductor: then, losses are a quadratic function of the power flow through them. Therefore, knowing these flows from WP2 simulations, as well as what transmission technology is

[9] Total network losses are a sum of two terms: losses in transmission and losses in distribution: although losses at distribution level represent most of the whole amount of losses in the power delivery from generators to load, reliable data concerning losses at distribution level are not normally not available: moreover, WP6 analysis cannot rely on simulation about the distribution level. Therefore, distribution network losses are not accounted for.

adopted to deliver them, an ex-post evaluation of inter-zonal transmission losses is straightforward.

Intra zonal losses could in principle be evaluated starting from load flow outputs given both for peak load (pl) and minimum load (ml) conditions – and profiling it for one year of operation exploiting information given by WP2 market simulation. However, without a detailed knowledge about the forecasted intra-zonal network layout at the target year, only a *scenario-driven* information could be provided based by a known network layout, that cannot be applied in a BCA framework. In the following some hints about the possible ways to account for intra zonal transmission losses are provided. However, the final decision was not to account for those losses because:

- investigating details internal to the single clusters is not compatible with the clusterization choice adopted in the e-Highway2050 project
- it is supposed (but, of course, in cannot be proved) that most of the losses in distribution and in sections internal to the single clusters can stay similar in the two cases with and without the studied corridor expansions and, therefore, will elide what the difference between the "with" and the "without" cases is calculated.

3.4.1. Methodology for accounting inter-zonal losses

The main idea beyond this methodology is to calculate the power losses on a specific corridor as:

$$Losses = Losses\_parameter * Length * (Power\_flow)^2$$

This quantity is summed up over all corridors in order to obtain the overall losses assessment for the whole system.

The losses parameter is estimation of the losess, per unit of length and per unit of (power flow)^2. For an existing corridor, that is an equivalent of several lines with different technologies, it can evaluated by means of an off-line load flow. For a new reinforcement it depends on the specific technology of the line that is added in the network.

The monetization of losses can be done by means of the zonal marginal price. More in detail, since a corridor can link two different market zone, the mean value of the two locational (zonal) marginal price at the ends of the corridor is adopted.

For the specific quantification of the power losses 8 different cases are detected, depending on whether the corridor is a new one, non-reinforced or reinforced and whether the power flow can be imposed or not[10]. A specific methodology is developed for each of these cases. Before presenting the methodology, a suitable common nomenclature is listed:

h,k clusters (or buses) indices

α_h subset of network clusters that are linked to the *h*-th cluster

[10] It is the case of HVDC lines or power flow controlled by PST or FACTS

$M_{LMP_{hk,t}} = \dfrac{LMP_{h,t} + LMP_{k,t}}{2}$ $[€/MWh]$ mean of LMP between clusters *h* and *k*

$P_{hk,t}$ real power flow from bus *h* to bus *k* at time *t* (not imposed flow → it obeys to Kirchhoff and Ohm laws → HVAC links) $[MW]$

$\overline{P}_{hk,t}$ real power flow from bus *h* to bus *k* at time *t* (imposed flow → they are controlled by power electronics → HVDC links) $[MW]$

l_{hk} average distance between two linked clusters $[km]$

λ_{hk} losses parameter $\left[MW_{Losses} / \left(km \cdot MW_{Flow}^{2}\right)\right]$

New corridor with non-imposed flow

If the corridor is a new one, the power flow in the case without reinforcement the power losses are equal to zero.

$$\Delta P_{L00,TOT} = P_{L00,TOT}\big|_{with} - P_{L00,TOT}\big|_{without}$$

$$P_{L00,TOT}\big|_{without} = 0$$

Thus the monetized losses are function of the power flow in the case *with* only:

$$P_{L00,TOT}\big|_{with} = \sum_{h} \sum_{k \in \alpha_{h00}} \left(\lambda_{hk} \cdot l_{hk}\right) \cdot \sum_{t=0}^{tf} \left(P_{hk,t}^{2} \cdot M_{LMP_{hk,t}}\right)\Big|_{with}$$

New corridor with imposed flow

On the other hand, if the new corridor has a controllable power flow the monetized losses are:

$$\Delta P_{L01,TOT} = P_{L01,TOT}\big|_{with} - P_{L01,TOT}\big|_{without}$$

$$P_{L01,TOT}\big|_{without} = 0$$

$$P_{L01,TOT}\big|_{with} = \sum_{h} \sum_{k \in \alpha_{h01}} \left(\lambda_{hk,reinf} \cdot l_{hk,reinf}\right) \cdot \sum_{t=0}^{tf} \left(\overline{P}_{hk,t}^{2} \cdot M_{LMP_{hk,t}}\right)\Big|_{with}$$

The difference with respect to the previous case lies in the active power flow involved in the calculation.

Non-reinforced corridor with non imposed flow

If the corridor has not been reinforced, the difference in power losses before and after the network reinforcement involve the power flow only, as the losses coefficient is the same:

$$\Delta P_{L20,TOT} = P_{L20,TOT}\big|_{with} - P_{L20,TOT}\big|_{without}$$

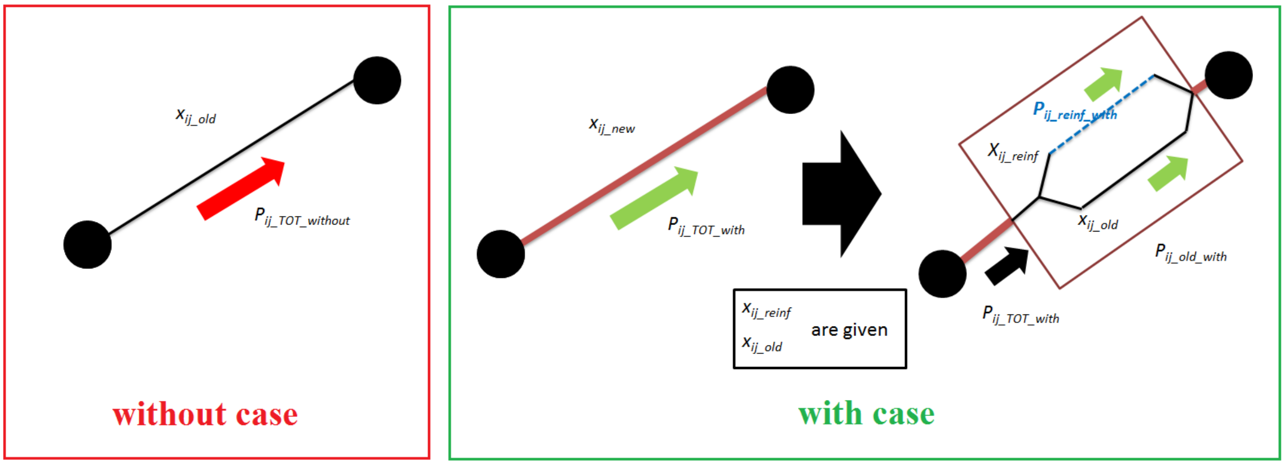


Fig. 30 – Model for splitting the power flow on a reinforced corridor

$$P_{L20,TOT}\big|_{without} = \sum_{h}\sum_{k\in\alpha_{h20}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(P_{hk,t}^{2}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

$$P_{L20,TOT}\big|_{with} = \sum_{h}\sum_{k\in\alpha_{h20}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(P_{hk,t}^{2}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{with}$$

It should be noted that in the monetization of power losses, the price could change between the two cases *without* and *with.*

Non-reinforced corridor with imposed flow

If the existing corridor has a controllable power flow the monetized losses are:

$$\Delta P_{L21,TOT} = P_{L21,TOT}\big|_{with} - P_{L21,TOT}\big|_{without}$$

$$P_{L21,TOT}\big|_{without} = \sum_{h}\sum_{k\in\alpha_{h21}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(\overline{P}_{hk,t}^{2}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

$$P_{L21,TOT}\big|_{with} = \sum_{h}\sum_{k\in\alpha_{h21}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(\overline{P}_{hk,t}^{2}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{with}$$

The difference with respect to the previous case lies in the active power flow involved in the calculation.

Reinforced corridor

Generally, if a corridor is reinforced, the new power flow on it can be split on the old branch and on the new one, depending on the equivalent reactance, as shown in Fig. .

According to the circuit theory:

$$x_{ij\_new} = \frac{x_{ij\_old} \cdot x_{ij\_reinf}}{x_{ij\_old} + x_{ij\_reinf}} \Rightarrow x_{ij\_reinf} = \frac{x_{ij\_new} \cdot x_{ij\_old}}{x_{ij\_old} - x_{ij\_new}}$$

The power flow on the old branch in the case *with* can be determined as:

$$P_{ij\_old\_with} = P_{ij\_TOT\_with} \cdot \frac{x_{ij\_reinf}}{x_{ij\_old} + x_{ij\_reinf}} = P_{ij\_TOT\_with} \cdot \frac{\dfrac{x_{ij\_new} \cdot x_{ij\_old}}{x_{ij\_old} - x_{ij\_new}}}{x_{ij\_old} + \dfrac{x_{ij\_new} \cdot x_{ij\_old}}{x_{ij\_old} - x_{ij\_new}}} =$$

$$= P_{ij\_TOT\_with} \cdot \frac{\dfrac{x_{ij\_new} \cdot x_{ij\_old}}{x_{ij\_old} - x_{ij\_new}}}{\dfrac{x^2_{ij\_old} - x_{ij\_new} \cdot x_{ij\_old} + x_{ij\_new} \cdot x_{ij\_old}}{x_{ij\_old} - x_{ij\_new}}} = P_{ij\_TOT\_with} \cdot \frac{x_{ij\_new}}{x_{ij\_old}}$$

While the power flow on the new branch in the case *with* results:

$$P_{ij\_reinf\_with} = P_{ij\_TOT\_with} \cdot \frac{x_{ij\_old}}{x_{ij\_old} + x_{ij\_reinf}} = P_{ij\_TOT\_with} - P_{ij\_old\_with} \Rightarrow P_{ij\_TOT\_with} \cdot \left(1 - \frac{x_{ij\_new}}{x_{ij\_old}}\right)$$

It can be noted that both $P_{ij\_old\_with}$ and $P_{ij\_reinf\_with}$ depend on the power flow on the whole corridor $P_{ij\_TOT\_with}$ and on the ratio of the equivalent reactance of the corridor before and after the reinforcement.

Once defined this repartition, the different cases of calculation can be described. Depending on whether the power flow on the branches are controllable or not, 4 cases have to be analyzed.

Reinforced corridor, non-imposed flow in the old branch, non-imposed flow in the reinforced branch

The change in monetized power losses between the cases *with* and *without* is:

$$\Delta P_{L1_{NN},TOT} = P_{L1_{NN},TOT}\Big|_{with} - P_{L1_{NN},TOT}\Big|_{without}$$

Losses in the case without are given by:

$$P_{L1_{NN},TOT}\Big|_{without} = \sum_{h\in}\sum_{k\in\alpha_{h1_{NN}}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{t_f}\left(P_{hk,t}^2\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

While losses in the case with are:

$$P_{L1_{NN},TOT}\Big|_{with} = \sum_{h}\sum_{k\in\alpha_{h1_{NN}}} \left[\sum_{t=0}^{t_f}\left[\begin{array}{l}\left(\lambda_{hk,old}\cdot l_{hk,old}\cdot P_{hk\_old,t}^2\right)+\\ +\left(\lambda_{hk,reinf}\cdot l_{hk,reinf}\cdot P_{hk\_reinf,t}^2\right)\end{array}\right]\cdot\left(M_{LMP_{hk,t}}\right)\right]\Bigg|_{with} \Rightarrow$$

$$P_{L1_{NN},TOT}\Big|_{with} = \sum_{h}\sum_{k\in\alpha_{h1_{NN}}} \left[\begin{array}{l}\left(\lambda_{hk,old}\cdot l_{hk,old}\cdot\left(\dfrac{x_{hk,new}}{x_{hk,old}}\right)^2\right)+\\ +\left(\lambda_{hk,reinf}\cdot l_{hk,reinf}\cdot\left(1-\dfrac{x_{hk,new}}{x_{hk,old}}\right)^2\right)\end{array}\right]\cdot\left[\sum_{t=0}^{t_f}\left(P_{hk,t}^2\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{with}$$

It can be noted that the losses in the case *with* depend on two different losses parameter: $\lambda_{hk,old}$ for the old branch and $\lambda_{hk,reinf}$ for the new branch.

Reinforced corridor non-imposed flow in the old branch, Imposed flow in the reinforced branch

In this case, the controlled flow does not follow the flow repartition in an AC network and the total flow of the corridor is:

$$P_{ij\_TOT}\Big|_{with} = P_{ij\_old}\Big|_{with} + \overline{P}_{ij\_reinf}\Big|_{with}$$

Given that, monetized losses are:

$$\Delta P_{L1_{NI},TOT} = P_{L1_{NI},TOT}\Big|_{with} - P_{L1_{NI},TOT}\Big|_{without}$$

Where:

$$P_{L1_{NI},TOT}\Big|_{without} = \sum_{h}\sum_{k\in\alpha_{h1_{NI}}} \left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{t_f}\left(P_{hk,t}^2\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

$$P_{L1_{NI},TOT}\Big|_{with} = \sum_{h}\sum_{k\in\alpha_{h1_{NI}}} \left[\sum_{t=0}^{t_f}\left[\begin{array}{l}\lambda_{hk,old}\cdot l_{hk,old}\cdot\left[\left(P_{hk\_TOT,t}-\overline{P}_{hk\_reinf,t}\right)^2\right]\Big|_{with}+\\ +\left(\lambda_{hk,reinf}\cdot l_{hk,reinf}\cdot\overline{P}_{hk\_reinf,t}^2\Big|_{with}\right)\end{array}\right]\cdot\left(M_{LMP_{hk,t}}\Big|_{with}\right)\right]$$

Reinforced corridor, imposed flow in the old branch, non-imposed flow in the reinforced branch

This case is the specular of the previous:

$$P_{ij\_TOT}\Big|_{with} = \overline{P}_{ij\_old}\Big|_{with} + P_{ij\_reinf}\Big|_{with}$$

Monetized losses are given by:

$$\Delta P_{L1_{IN},TOT} = P_{L1_{IN},TOT}\Big|_{with} - P_{L1_{IN},TOT}\Big|_{without}$$

Where:

$$P_{L1_{IN},TOT}\Big|_{without} = \sum_{h}\sum_{h\in\alpha_{h1_{IN}}}\left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(\overline{P}^{2}_{hk,t}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

$$P_{L1_{IN},TOT}\Big|_{with} = \sum_{h}\sum_{k\in\alpha_{h1_{IN}}}\left[\sum_{t=0}^{tf}\left[\begin{array}{l}\lambda_{hk,old}\cdot l_{hk,old}\cdot\overline{P}^{2}_{hk\_old,t}\Big|_{with} + \\ +\lambda_{hk,reinf}\cdot l_{hk,reinf}\cdot\left(P_{hk\_TOT,t}-\overline{P}_{hk\_old,t}\right)^{2}\Big|_{with}\end{array}\right]\cdot\left(M_{LMP_{hk,t}}\Big|_{with}\right)\right]$$

Reinforced corridor, imposed flow in the old branch, imposed flow in the reinforced branch

In this case, the flow on the whole corridor does not follow the flow repartition in an AC network.

$$P_{ij\_TOT}\Big|_{with} = \overline{P}_{ij\_old}\Big|_{with} + \overline{P}_{ij\_reinf}\Big|_{with}$$

Monetized losses are:

$$\Delta P_{L1_{II},TOT} = P_{L1_{II},TOT}\Big|_{with} - P_{L1_{II},TOT}\Big|_{without}$$

Where:

$$P_{L1_{II},TOT}\Big|_{without} = \sum_{h}\sum_{k\in a_{h1_{II}}}\left(\lambda_{hk,old}\cdot l_{hk,old}\right)\cdot\left[\sum_{t=0}^{tf}\left(\overline{P}^{2}_{hk,t}\cdot M_{LMP_{hk,t}}\right)\right]\Bigg|_{without}$$

$$P_{L1_{II},TOT}\Big|_{with} = \sum_{h}\sum_{k\in a_{h1_{II}}}\left[\sum_{t=0}^{tf}\left[\begin{array}{l}\lambda_{hk,old}\cdot l_{hk,old}\cdot\overline{P}^{2}_{hk\_old,t}\Big|_{with} + \\ +\lambda_{hk,reinf}\cdot l_{hk,reinf}\cdot\overline{P}^{2}_{hk\_reinf,t}\Big|_{with}\end{array}\right]\cdot\left(M_{LMP_{hk,t}}\Big|_{with}\right)\right]$$

Remarks on losses parameter

For what concerns the losses parameter λ_{hk}, a distinction must be done between “old corridor” (which represent an equivalent of lines already present in the without nodal model) and

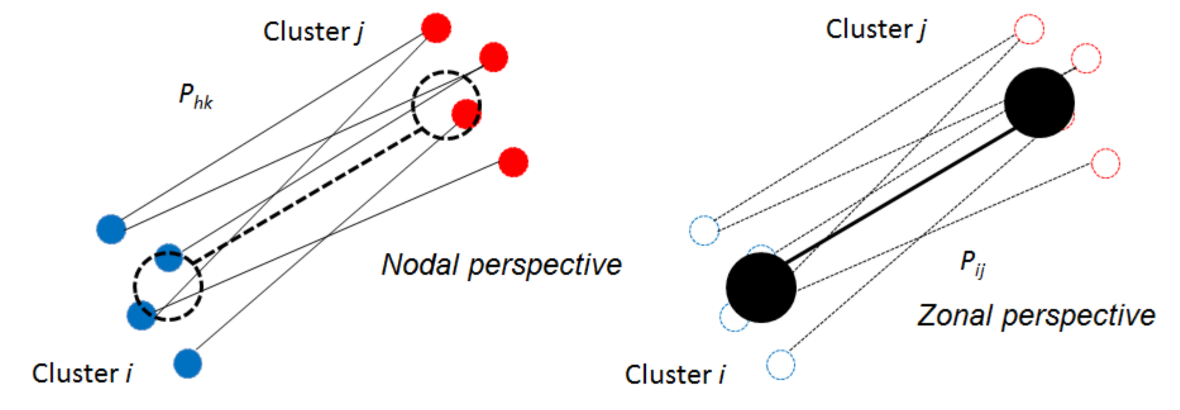


Fig. 31 – Framework of the clusterization process

"reinforced corridor" (which, in theory, should represent the connection realized with a new transmission infrastructure).

The latter ($\lambda_{hk,reinf}$) has to be provided together with the data specification of the technology adopted to realize the reinforcement.

The losses parameter of old corridor instead has to be calculated in advance, starting from an AC load flow on the pre-clustered network layout.

With reference to Fig. , from the nodal perspective the power losses between cluster *i* and *j* are provided as the sum of the power losses on all lines *h*-*k*:

$$P_{L,ij} = \sum_{h \in \alpha_i} \sum_{k \in \beta_j} \lambda_{hk} \cdot l_{hk} \cdot P_{hk}^2$$

From the zonal perspective, losses on the whole corridor between cluster *i* and *j* are given by:

$$P_{L,ij} = \lambda_{ij} \cdot l_{ij} \cdot P_{ij}^2$$

Enforcing the equality of the two perspectives: $\sum_{h \in \alpha_i} \sum_{k \in \beta_j} \lambda_{hk,old} \cdot l_{hk,old} \cdot P_{hk}^2 = \lambda_{ij,old} \cdot l_{ij,old} \cdot P_{ij}^2 \quad \Rightarrow$

$$\Rightarrow \lambda_{ij,old} = \frac{\sum_{h \in \alpha_i} \sum_{k \in \beta_j} \lambda_{hk,old} \cdot l_{hk,old} \cdot P_{hk}^2}{l_{ij,old} \cdot P_{ij}^2}$$

3.4.2. Possible methodologies for accounting intra-zonal losses

Transmission losses are mainly dependent by a set of factors, such as generators and loads topology, power flows, voltage levels, kind of transmission infrastructure, load level, network consistence, technological evolution.

Four different *strategies* were identified in order to account for intra zonal losses: the choice of what kind of strategy to follow is strictly related to the following *aspects*:

- availability of data given as output of market simulations from WP2;
- possibility to run network simulations in WP6;
- availability of data concerning forecasted and known network layouts.

The expression *forecasted network* is applied to a network evaluated at the target year: for the e-Highway2050 project, it could refer to network layouts at 2050, 2040 and 2030, on the basis of what time horizon is the object of analysis: the expression *known network layout* refers to a network evaluated in a different time horizon, previous with respect the target year, for which the requested network data are fully available.

A representation of the connection between data availability and methodology to follow is represented in Tab. 11: rows identify the proposed strategies, whereas columns represent the aspects. Then, four methodological strategies are proposed:

a. *estimation from known network*: this strategy allows to evaluate intra-zonal transmission network losses by means of information on known network situation – starting from load flow outputs given both for peak load (pl) and minimum load (ml) conditions – and profiling them until the target year (2050-2040-2030) for one year of operation exploiting information given by WP2 market simulations. Moreover, data concerning network development are necessary as well as, possibly, information on estimated technological improvements in losses reduction for the different transmission system infrastructures to analyze;
b. *estimation from forecasted network*: this strategy allows to evaluate intra-zonal transmission network losses by means of information on forecasted network situation – starting from load flow outputs given both for peak load (pl) and minimum load (ml) conditions – and profiling it for one year of operation exploiting information given by WP2 market simulation;

Tab. 11 – Intra zonal losses evaluation - Possible methodologies

		Aspects				
		Need of forecasted market?	**Need to run network simulations?**	**Need of forecasted network data?**	**Known network data availability**	**Comments**
Strategies	***1) Estimation from known network***	Yes	No	General information on transmission reinforcements	Load flow outputs (pl, ml)	*Identify a relationship between load and losses from LF outputs and profile some data related to known network framework on forecasted year accounting the available network data and technology improvements.* *Intra zonal losses calculated are scenario driven*
	2) Estimation from forecasted network	Yes	No	Load flow outputs (pl, ml)	Not important	*Identify a relationship between load and losses on forecasted year*
	3) OPF network simulation - ex post evaluation	Yes	Yes	Full network model	Not important	*Run lossless OPF simulations: evaluate losses ex-post*
	4) OPF network simulation - inclusion	Yes	Yes	Full network model	Not important	*Run OPF simulations: include losses in the optimization problem (B-losses coefficients[22], etc.)*

c. *OPF network simulation – ex-post evaluation*: this strategy allows to calculate transmission network losses thanks to the simulation of one year of operation (considering a deterministic or a probabilistic approach): since the optimization is conducted under the hypothesis to neglect losses, these are calculated *ex-post* the starting from the active power flows on the network given as an output of the optimization;
d. *OPF network simulation – inclusion*: this strategy allows to evaluate transmission network losses thanks to the simulation of one year of operation(considering a deterministic or a probabilistic approach): losses formulation is directly expressed in the optimization problem (as example, by means of *B-losses coefficients* [22]). Therefore, the tool is able to provide the optimal generation dispatch that satisfy the overall system balance constraint.

3.4.3. Inter zonal losses: example of application

An example of application of the proposed inter zonal losses methodology is reported afterwards. In this example, two alternatives (A and B) of HVDC inter zonal network reinforcement in a two-zone system is shown. A daily operation has been considered: the relative time slices, as well as their duration and the inter zonal bulk DC power flows are reported in Tab. 12. The data concerning the two alternatives to compare are reported in Tab. 13. The losses calculation is shown in Tab. 14, while the comparison is described in Tab. 15.

Tab. 12 – Inter zonal example – Input data

Time slice	Duration [h]	Bulk power flows (Zone 1 -> Zone 2) [MW]
1	3	250
2	2	1000
3	4	750
4	7	500
5	4	-500
6	4	-250

Tab. 13 – Inter zonal losses example – Alternatives data

	Length [km]	Resistance [Ω/km]	Voltage level [kV]
Alternative A	400	0.03	320
Alternative B	500	0.02	500

Tab. 14 – Inter zonal losses example – Calculation

Time slice	Alternative A			Alternative B		
	I (Zone 1 -> Zone 2) [kA]	P_{losses} [MW]	E_{losses} [MWh]	I (Zone 1 -> Zone 2) [kA]	P_{losses} [MW]	E_{losses} [MWh]
1	0,78	7	22	0,50	3	8
2	3,13	117	234	2,00	40	80
3	2,34	66	264	1,50	23	90
4	1,56	29	205	1,00	10	70
5	-1,56	29	117	-1,00	10	40
6	-0,78	7	29	-0,50	3	10

Tab. 15 – Inter zonal losses example – Comparison

	$E_{losses\ tot}$ [MWh]	$P_{average}$ [MW]
Alternative A	871,58	36,32
Alternative B	297,50	12,40

3.5. CO_2 Emissions

A transmission expansion project leads to a better exploitation of the generation capacity, allowing the cheapest generators to produce without network restrictions. In this framework, often low carbon generators replace conventional thermal generators with high rates of CO_2 emissions. This leads to a general reduction of CO_2 emissions for the whole system, resulting in an economic benefit that can be evaluated by monetizing the carbon emission saving. The monetization of CO_2 emission can be done by means of the forecasted CO_2 price defined as boundary condition for the scenario analysis.

In the framework of eHighway-2050, CO_2 emission prices are included in the scenario inputs for the simulation models and the benefit from the carbon emission reduction is implicitly included in the final results. The simulation tool accounts for the cost of CO_2 of each thermal generator and the effect of CO_2 costs is reflected in the global social welfare.

In order to extrapolate the benefit of CO_2 emission reduction following a transmission project, the total amount of emissions in the case with and without should be calculated. This is done by multiplying the total energy produced by each generation technology times the specific emission rate of corresponding technologies. The difference between the two cases monetized with the CO_2 price, provides the benefit of carbon emission reduction due to the new transmission project.

This value extrapolated from the market results is just an indication of the CO_2 benefit but cannot be included in the BCA because it would be a double counting, since its effect is already included in the whole social welfare. On the other hand, interesting sensitivity analysis can be included in the BCA, evaluating the effect of different CO_2 prices. For example it is interesting to analyze the range of variation of the CO_2 price that does not imply a switch in the merit order of the generation technologies. shows when the upper bound of the range is reached. This analysis is useful to assess the robustness of the solution provided by system simulations, against possible changes of the CO_2 price.

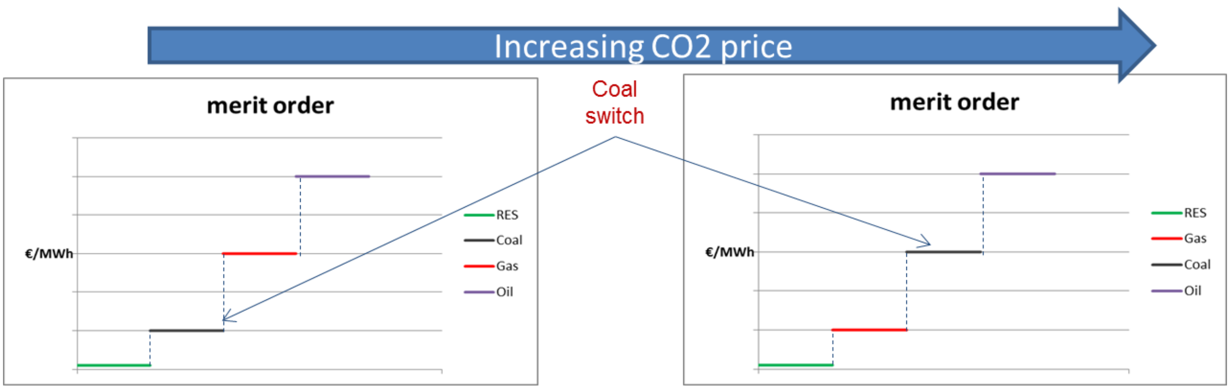


Fig. 32 - Example of switch in the merit order increasing the CO_2 price

3.6. RES Integrability

Transmission network improvements lead to a more efficient exploitation of the generation capacity present in the system, thanks to the removal of grid congestions. For example an expansion project can make fully available cheaper energy produced by a set of RES generators from a zone that was poorly connected to the load centre of the system. This kind of benefit is implicitly accounted for in the increase of market social welfare. However there is another benefit related to the transmission expansion plan, that is the potential of additional RES generation that can be made available by a new transmission upgrade. A specific transmission project may be realised to accommodate the generation dispatch of the existing generation considered in the target scenario, for instance integrating a quota of RES generation from plants supposed to be on service in the target year. On the other hand, the same project could be useful also for integrating additional RES potential, not directly accounted in the scenario hypothesis, but that could be considered for additional a future RES installation. In other words, the benefits of additional RES integrability try to quantify through a sensitivity analysis the residual potential of a transmission improvement in integrating further RES generation.

The objective is to quantify the residual incremental benefit from additional RES in each forecast scenario and for each candidate transmission expansion plan. This is not an easy task, because it depends on several boundary conditions (such as total RES potential, RES installed in each scenario, generation mix of each area…) and it typically requires additional simulations for guaranteeing the feasibility of results. However the aim of this task is to post-process the results from WP2. Additional simulations are avoided favoring by implementing a sensitivity analysis that provides an easy way to calculate approximated results. The challenge is to define a methodology that leads to achieve results as close as possible to the actual ones and sufficient general to be applied to several scenarios.

The evaluation of possible benefit of additional RES can be performed following a two-step procedure:

- computing how much of additional RES can be injected, while preserving system security
- monetizing the benefits of the additional RES generation for the system

Before applying the computing procedure, the boundary conditions for the additional amount of RES should be fixed. A total amount of additional RES is defined for each macro zones as potential power generation; the additional power injection is then moved in each zone in a homothetic way as a percentage of the total available potential[11]. The increase in RES generation should be compensated by a decrease in conventional generation, according to the rules of a constrained economic dispatch.

[11] In this way, some feasible solutions could be excluded, but in an iterative search like that is the only way to prevent the growth of the problem size.

3.6.1. Proposed methodology

The objective is to perform a post-processing analysis without solving again the market problem (which would provide the exact solution but would also need extra-simulations). This is done by using a linear sensitivity approach.

First, a general rule is set for compensating the additional RES generation without replicating the merit order dispatch. This rule establishes how the system will compensate each MW of additional RES power injected in a certain area. The most realistic way to do that is to fix a compensation coefficient for each macro area, in order to share the additional RES among the system. This is done in the easiest way by setting the same coefficient for every zone; in this way it is implicitly assumed that the thermal generation mix is homogeneous along the zones and everyone will compensate in the same way the new RES injection. Other linear metrics can be applied in this phase, in order to account for different generation mix (for example a macro zones that holds a lot of expansive generation may have a greater coefficient, since in an hypothetical merit order dispatch it would be mostly replaced by RES).

In the following, the linear sensitivity approach is described.

Let us indicate the new power injection due to an additional RES injection from the macro zone *i* as:

$$I_i = I_i^0 + k_{\%}\Delta\overline{RES}_i - \rho_i \sum_{j=1}^{Na} k_{\%}\Delta\overline{RES}_j$$

where I_i^0 is the total power injection of zone *i* resulting from market simulations (before the sensitivity analysis), $k_{\%}$ is the percentage of the total RES potential added in the sensitivity analysis, $\Delta\overline{RES}_i$ is the total additional RES potential in zone *i*, ρ_i is the compensation coefficient of zone *i* for an additional MW injected in the system and N_a is the number zones. As we can see by the formula, the change in total power injection in a macro zones is due to two terms: the first adds in each zone the same percentage of the total additional RES potential available in the zone, while the second subtracts in each zone a quota of the whole additional RES injection in the system according to the value of ρ_i, that is the contribution of area *i* to the re-dispatch of the system. In particular for the generic zone *i*, the term $\rho_i \sum_{j=1}^{Na} k_{\%}\Delta\overline{RES}_j$ shows how the thermal generation in *i* changes because of the additional RES injection in the system (in each zone it is assumed to add the same percentage $k_{\%}$ of the RES potential).

The choice of the coefficient ρ_i should be carried out in order to approximate the constrained generation dispatch and thus it should be dependent on the generation mix of each zone. While preserving the relationship $\sum_{i=1}^{N_a} \rho_i = 1$, the coefficients can be defined as follows:

$$\rho_i = \frac{P_i^{th}}{\sum_{i=1}^{N_a} P_i^{th}}$$

where P_i^{th} is the thermal generation capacity of zone *i*. According to this definition, the additional injection from RES in the sensitivity analysis is compensated proportionally to the percentage of thermal generation with respect to the system.

To check if network constraints hold with the new power dispatch approximated by linear sensitivity, the DC load flow approximation can be applied by the PTDF matrix, by simply multiplying it and the vector of new injections. The research of the maximum $k_{\%}$ that complies with transmission limits can be carried out iteratively.

As a first approximation for the monetization of the benefit deriving from additional RES integration, one can adopt the zonal price resulting from market simulation. Since it represent the incremental cost for supplying 1 MW of additional load, in the same way can be interpreted as the save in generation cost for 1 MW of costless RES generation. Assuming a supply curve as a stepwise, this monetization is correct until the change in generation dispatch (induced by the increasing RES) causes a variation in zonal price on another step. However, in the framework of electricity market, the supply function can be considered sufficient flat for large quantities belonging to the same technology and substantial price gaps occur when another technology is intercepted on the curve. Hence, assuming that the RES increase does not imply a change in the marginal generation technology, we can state that monetizing the benefit of additional RES by using the zonal price may be a good approximation for a fast analysis.

3.6.2. Application to a target year

The procedure described above allows to perform a sensitivity analysis of the additional RES integrability in the system for a single time frame of the market. The procedure can be replicated and extended for assessing a whole target year, starting from the results of market simulations.

First of all, the additional RES potential in terms of energy that can be produced in a year has to be defined for each zones, according to the already installed mix and the peculiarity of RES availability. The yearly amount of energy exploitable should be divided in an hourly equivalent generation, respecting possible seasonal characteristics, in order to set up a limit $\Delta\overline{RES}_i$ for each hour of the year.

For a better approximation the coefficients ρ_i have to be computed for each hour, based on the results of market simulations. In order to provide indications of the thermal generation mix available for compensating the RES generation, the coefficient for the *i*-th zone is computed as the ratio of the zonal thermal generation and the system thermal generation in every hour of the time horizon.

Once computed the amount of RES that can be injected without violating the transmission system, the economic benefit is given by the hourly amount of RES introduced times the hourly market price obtained by simulations. The sum of all hourly benefits provide an indication of the benefit of additional RES integrability by linear sensitivity analysis.

Despite it is an highly approximated procedure, it can lead to quantitative results and provides the right indications even if the scenario under analysis already entails large penetration of RES or curtailment occurs in some situations. In fact, by monetizing the additional RES generation with the market price, the higher benefits are expected in those scenarios with low RES penetration, while moving to scenarios with large amount of RES installed the benefits should decrease, since

RES contribute to a general reduction of market price. Also the RES curtailment is not in contradiction with the proposed procedure; in fact, analyzing a whole year, it is reasonable to suppose that the curtailment occurs only in some hours and not systematically. In such hours the proposed methodology will find low benefits from additional RES because low prices and network constraints; on the contrary in the remaining hours new RES could be added, providing a suitable benefit.

3.6.3. Example of application

In order to make an example of application of the methodology proposed, let us consider the

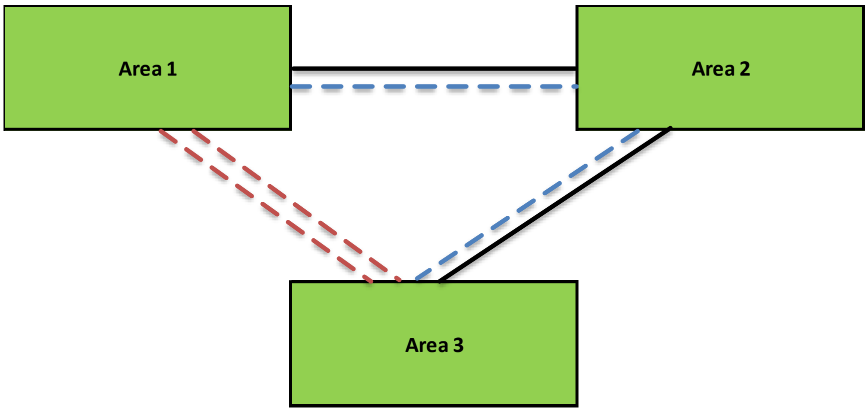


Fig. 33 - Three area system with 2 transmission expansion projects

Tab. 16 – Application of the methodology to the project 1

	Area 1	Area 2	Area 3
Initial Pgen	310	195	0
Load	100	200	205
RES potential	200	100	0
RES injected	**0**	**0**	**0**
Coeff. ρ_i	0,61	0,39	0
New Pgen	310	195	0

Tab. 17 – Application of the methodology to the project 2

	Area 1	Area 2	Area 3
Initial Pgen [MW]	403	102	0
Load [MW]	100	200	205
RES potential [MW]	200	100	0
RES injected [MW]	**200**	**100**	**0**
Coeff. ρ_i	0,80	0,20	0,00
New Pgen [MW]	164	102	0
Market price [€/MWh]	20	30	23
Benefit [€]	**4000**	**3000**	**0**

same test case proposed in 3.3.4 about the social welfare. Fig. 33 shows the two alternative projects considered for the expansion planning: the first (blue lines) entails the doubling of the existing lines, while the second (red lines) entails the construction of two new lines between area 1 and area 3.

We consider a potential of additional RES generation both in Area 1 and Area 2, respectively of 200 MW and 100 MW.

Tab. 16 summarizes the application of the methodology to the Project 1. In this case no additional RES generation is allowed, because the additional power injection in Area 1 is limited by the constraint on power flow on line 1 – 2. Thus for the project 1, the sensitivity analysis results in a zero benefit from additional RES generation.

On the contrary, project 2 allows the integration of 100% of the RES potential available in each zone. The particular network configuration that creates the new lines allows to introduce linearly, according to the methodology proposed, all the RES potential considered without any network violation. Tab. 17 shows the results of the analysis applied to the project 2.

The methodology considers as possible monetization the market price obtained by the market. In this way the total benefit estimated for additional RES generation thanks to the project 2 is 7000 € (Tab. 17).

3.7. Market competition and exercise of market power

Generally, studies performing Benefits and Costs Assessments (BCA) for the transmission planning rely upon marginal cost pricing simulations to evaluate the economic benefit of potential transmission investment projects. Such approach would be reasonable in an old style vertically integrated utility paradigm before deregulation or in a perfectly competitive market consisting of many electricity supplier firms each of whom has a small share in the market. In a liberalized electricity market, suppliers are likely to optimize their bidding strategies to maximize their profits in response to system conditions and behavior of other market participants. In an electricity market characterized by a few large suppliers, these large suppliers can withhold part of their supply and increase the market prices above competitive levels. The ratio of such markup over price is called the "price-cost markup" which is a common measure of market power used in literature [27].

In the assessment of economic benefits of a transmission project, modeling strategic bidding is important because transmission expansion can provide additional benefits to consumers by improving competition. A new transmission project can increase market competitiveness by increasing both the total supply to consumers and the number of suppliers. As a result, price-cost markups decrease and prices converge to marginal cost pricing in favor of consumers. In the next sections, we propose two methodologies modeling strategic bidding in order to evaluate price-cost markups for given supply and demand conditions in a future EU electricity system. The first method described in section 3.7.1 uses an empirical approach that estimates the historical relationships between certain market variables (such as demand levels and supply margins) and price-cost markups similar to the methods used by CAISO [15] and Sheffrin [28]. The second method described in section 3.7.2 uses game theoretical approach that models the strategic behavior of electricity suppliers and estimates the relationships between price-cost markups and the market variables based on simulation outcomes of a game theoretical model. In both methods, we utilize a linear regression analysis to estimate these relationships. The reason of that double modeling is to perform a comparison between empirical approach and theoretic approach. The empirical approach should provide the average actual behavior of the GENCOs that compete in the market. On the contrary, the theoretical approach based on a game theory model, should provide the maximum strategic behavior of the supplier, that compete with the only aim of maximizing its own profit. In this way a sort of upper bound to the strategic behavior derived from empirical approach can be set, providing also a range of variation of the strategic competition. This can be useful to perform interest sensitivity analysis about the impact of growing strategic behavior on the market.

The most common measure of the market power of a supplier is the price- cost markup, known as the Lerner Index [27]. The Lerner Index (i.e., price-cost markups) denotes the percentage of the market price that is above the estimated competitive level (i.e., marginal cost pricing).

$$LI = \frac{P-MC}{P} \qquad (1)$$

where MC is the marginal cost of the system (i.e., perfectly competitive prices) and P is the market price. In an electricity market characterized by a few large suppliers, these large suppliers can withhold part of their supply and inflate the market prices above competitive levels. To incorporate this feature, we use residual supply index (RSI) [28] as an indicator of when suppliers could raise price above a competitive level. The Residual Supply Index (RSI) for the entire market is defined as the ratio of residual supply over demand for the largest supplier in the market:

RSI = (Total Domestic Available Supply + Available import capacity– Available Supply from Largest supplier) / Load

The objective of both methods is to regress price-cost markups LI against two market variables: load level and *RSI* values for each hour, where *e* is the random error term:

$$LI = \frac{P-MC}{P} = a + b * RSI + c * Load + e \qquad (2)$$

The main difference between the empirical and the game-theoretical model is the calculation of oligopolistic market price *P*. In the empirical approach, *P* represents the historical spot market prices whereas in the game theoretical approach *P* is calculated by the a simulation model under strategic behavior that is implemented in the tool MTSIM by RSE. Both methods use hypothetical perfectly competitive prices as marginal cost of the system, calculated by the EU power market models in perfect competition mode minimizing total system cost.

By using (2), price-cost markups for the entire market are estimated at a given time in future. Then for each large supplier, the corresponding strategic bids are calculated based on price-cost markups as explained in section 3.7.3. The calculated strategic bids may have two consequences for the market outcome: (a) the resulting strategic bids may result in a different merit order curve, distorting the dispatch and hence increasing the production cost of the system (b) the equilibrium market prices may be higher than perfectly competitive prices, increasing consumer payments. Both result in lower social welfare compared to a perfectly competitive market outcome. By calculation of the dispatch and the corresponding equilibrium prices under strategic bidding, the impact of market power on social welfare can be estimated:

$$SW = SW^c + \delta \, \Delta SW^{mp}$$

where ΔSW^{mp} is the social welfare decrease under strategic bidding and $0 \leq \delta \leq 1$ is a parameter indicating the level of trustfulness of the estimated social welfare impact. By calculation of ΔSW^{mp} for availability of supply with and without a transmission project, one can also assess the benefits of transmission capacity expansion under strategic bidding. Let $\Delta {SW_w}^{mp}$ and $\Delta {SW_{w/0}}^{mp}$ be the social welfare impact of market power without and with transmission capacity expansion, then the benefit of transmission capacity expansion under market power would be:

$$SW_w - SW_{w/o} = SW_w - SW_{w/o} + \delta \, (\Delta {SW_w}^{mp} - \Delta {SW_{w/0}}^{mp})$$

In order to calculate the benefits of a transmission project, it is required to find the dispatch and the corresponding equilibrium prices in all the regions under strategic bidding. Calculation of equilibrium prices and dispatch under strategic bidding in a meshed network is very complex and requires additional simulations with a generation dispatch model including strategic bid-up curves, that is not our case because no additional simulations are carried out on top of those at marginal cost of generation. Hence, we use a simplified two-region approach where the benefits of a transmission project is calculated only for the regions it is directly connected to, ceteris paribus. This simplified approach is likely to underestimate the benefits of transmission capacity expansion since the expansion of a transmission line in general affects the competitiveness of non-neighboring regions as well.

3.7.1. Empirical approach to model strategic bidding

This approach uses historical relationships between actual market observations for load and RSI values and the estimated price-cost markups representing the difference between the estimated competitive price and actual prices. In our analysis, we regressed the estimated price-cost markups against actual load and estimated RSIs at a given hour.

In Fig. 34 we illustrate the empirical approach adopted here. We first collected the historical spot price, demand, and supply data for all the hours of 2011 and 2012 in various markets such as APX, EEX, EPEX, and BELPEX. We then use the COMPETES model in perfect competition mode to calculate hypothetical competitive prices for these markets. Finally, we use historical data and hypothetical competitive prices to estimate the relationship between price-cost markups and RSI and demand levels.

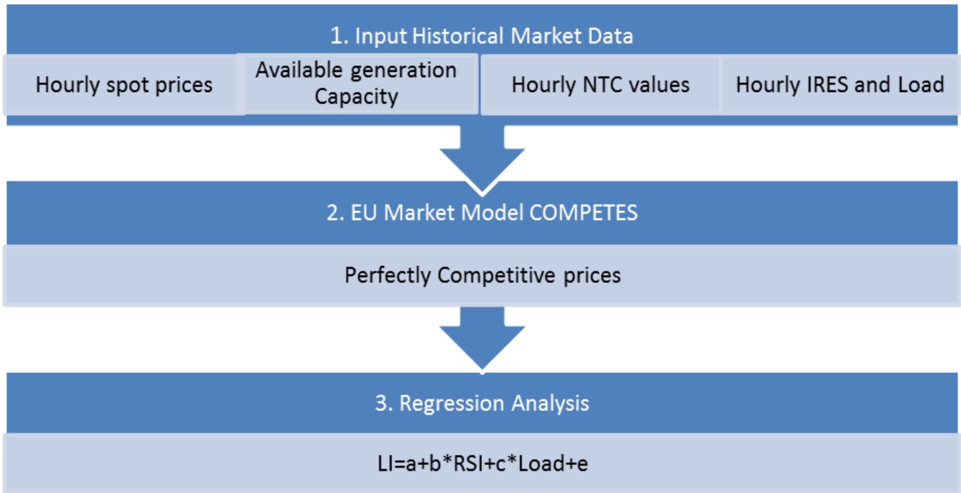


Fig. 34 – Framework of the empirical approach

Step 1: Historical Market Data and Calculation of RSI values

When developing the relationships between mark-ups and market variables, we consider hourly time periods and markets that represent different market conditions. We consider actual hourly data of 2011 and 2012 for four EU countries, namely the Netherlands, Germany, Belgium and France. Among these countries, the Dutch and German markets are characterized by many suppliers with the largest generator having a market share of 28% whereas the markets in Belgium and France is characterized by few large suppliers with the largest generator having a 70-85% market share (Eurostat, 2013). We use actual hourly load patterns and NTC values given by ENTSO-E[12] and the total available supply at each hour given by TSOs of these countries.[13]

[12] www.entsoe.net

[13] Available capacity for the Netherlands was gathered from TenneT TSO, 2013. Available capacity for Germany was gathered from EEX Transparency Platform, 2013. Available capacity for Belgium was gathered from ELIA TSO, 2013. Available capacity for France was gathered from RTE TSO, 2013.

Utilizing the market data, we calculated *RSI* in each hour *h* and country *j*:

$$RSI_{hj} = \frac{TAS_{hj}+AIC_{hj}-Max(AS_{hj})}{Load_{hj}} \qquad (3)$$

where TAS_{hj} is the available total domestic supply capacity, AIC_{hj} is the total import capacities to country *j* (i.e., sum of hourly NTC values to country *j*) , and $Max(AS_{hj})$ is the available capacity of the largest supplier in country *j*.

For example, Fig. 35 and Fig. 36 give an indication how actual 2012 market prices correlate with hourly RSI and load values in the Netherlands. The spot prices are positively correlated with the realized demand and negatively correlated with the supply margin at a given time. For RSI close to or lower than 1, the prices are observed to be high whereas for RSI >1 the prices are low. This may indicate a similar trend for price-cost markups such that markups are likely to be higher when supply is scarce including both peak load hours and when RSI is close to or lower than 1. Even though RSI and load seem to have a nonlinear relationship with actual market prices, the Lerner index $\frac{P-MC}{P}$ being a nonlinear indicator of market price is observed to have a linear relationship with RSI and load in previous studies [28]. Therefore, we also assume a linear relationship between Lerner Index and RSI and Load.

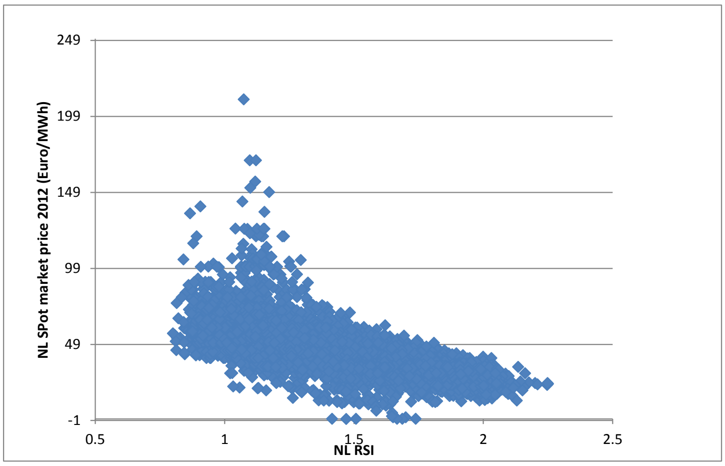


Fig. 35 - The relation between spot market prices and RSI in 2012 in the Netherlands

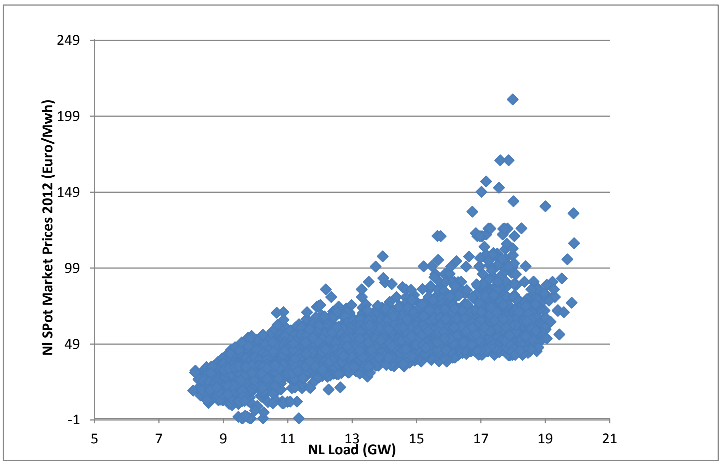


Fig. 36 - The relation between spot market prices and load in 2012 in the Netherlands

Step 2: Derivation of Hypothetical Competitive Prices

The Lerner Index (i.e., price-cost markups) denotes the percentage of the market price that is above the estimated competitive level. In order to calculate Lerner Index for the regression analysis, the historical spot market prices should be compared to its benchmark levels of marginal cost pricing. To this aim, we use hypothetical competitive prices (system cost minimization solution) from COMPETES model which is run under the supply and demand conditions of the year 2012.

COMPETES[14] is an economic electricity market model of Europe which covers EU countries and some non-EU countries. Every country is represented by one node, except for Luxembourg which is included in Germany, and Denmark is split in two nodes due to its participation in two non-synchronous networks. The model assumes an integrated EU market where the trade flows between countries are constrained by "Net Transfer Capacities (NTC)". The input data of COMPETES involves a wide-range of generation technologies. The generation type (thermal), thermal capacity, and the location of existing thermal generation technologies up to 2012 are based on WEPPS 2012 [29]. Installed renewable capacity up to 2010 is based on PRIMES Baseline [30] with updated figures to 2012 for wind (EWEA, 2013) and solar [31], and up to 2011 for hydro and biomass [32].

- COMPETES model includes wind and solar intermittency while simulating the operation of electricity markets. Under perfect competition, the model is formulated as an Linear Program (LP), which is equivalent to the mixed complementarity problem derived from models of generator, TSO, and arbitrageur behavior in an integrated EU market. The LP model minimizes total generation and load-shedding costs subject to electricity market constraints such as *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.

- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.

- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.

Given the specific levels of demand and the characteristics of supply and transmission limits, competitive solution of COMPETES specifies the least-cost/social welfare maximizing allocation of production and transmission for all the countries and the competitive prices calculated at each node represent the locational marginal prices. The least-cost allocation of production implies that the conventional generation technologies and the flexible renewable technologies (e.g., biomass and waste) are dispatched according to their marginal costs and positions in the merit order for each country. Furthermore, pre-calculated hourly intermittent RES and hydro generation are taken as a must-run generation by the model.

[14] COMPETES is developed by ECN in corporation with B.F. Hobbs, who is a professor with the Department of Geography and Environmental Engineering of the Johns Hopkins University, Baltimore, USA and Scientific Advisor to ECN.

Step 3: Regression Model

By using the historical market data from the first step and estimated competitive prices from the second step we estimate the following regression equation:

$$LI_{hj} = \frac{P_{hj} - \mathrm{P}C_{hj}}{P_{hj}} = a + b\, RSI_{hj} + c * Load_{hj} + e$$

where

$P_{hj} =$ Actual market price in hour h and country j

$PC_{hj} =$ Hypothetical competitive price in hour h and country j

$RSI_{hj} =$ Residual supply index for hour h in country j

$Load_{hj} =$ Load for hour h in country j

e = the random error term

3.7.2. Game theory approach to model strategic bidding

The theoretical approach has the aim of deriving the same correlation between Lerner Index and Residual Supply Index looked for in the empirical approach, but in this case, the input data of the regression analysis are provided by the market simulation tool MTSIM [33]. This tool is able to perform simulations of the market in a medium term horizon, both in the classical way, by minimizing the generation costs while preserving the system constraints, and with strategic competition, implementing a game theory model in which strategic competitors aim to maximize their profit by changing the bids.

The general idea behind the use of this approach is to calculate the Lerner Index as a result of simulations only, exploiting the market tool for obtaining both the market prices under perfect completion and strategic competition. The results of the game theory model should provide the maximum level of market power exploitation by suppliers, according to the market power margins allowed by the market conditions. Hence the Lerner Index computed by this approach would set an upper bound to the value extrapolated by empirical analysis, to be considered as the extreme case of market power exploitation.

Fig. 37 shows how the methodology of the theoretical approach changes respect to the empirical one. In the first step all the market data needed for the run of the MTSIM tool have to be collected. These data include all the system characteristics to set up the market scenario, as the network layout (or an equivalent model), the generation data set, the market share of strategic suppliers, RES generation and hourly load. Considering the specific application in the context of e-Highway2050, we decided to simulate a EU forecast scenario referring to the year 2050, in order to consider market conditions closer as possible to the target of the project. The reference scenario chosen is the "Yellow Storyline" developed in the SUSPLAN project [34].

In the second step, the European 2050 scenario is simulated by means of MTSIM. The simulation of the perfect competition is run for the whole European system; the outcomes consist in the hourly prices of each nation, together with the generation dispatch and the energy exchanges among national markets.

Simulation of the strategic competition are run for each single national market, to limit the computational burden. Each regional market is then considered isolated, fixing the hourly power exchanges with neighboring countries to the values resulting from perfect competition. The strategic supplier is assumed to be only the incumbent of the market, owing the largest share of the generation capacity. Such incumbent will strategically compete by varying the quantity offered to the market and the price. Results of strategic competition are a new series of hourly prices for each region, that combined together with those obtained by the perfect competition will lead to a forecast curve for the Lerner Index.

The third step referring to the regression analysis is conceptually the same of the empirical approach. In this case the values considered in the regression is the Lerner Index computed by simulations, while RSI and load are provided by the scenario input.

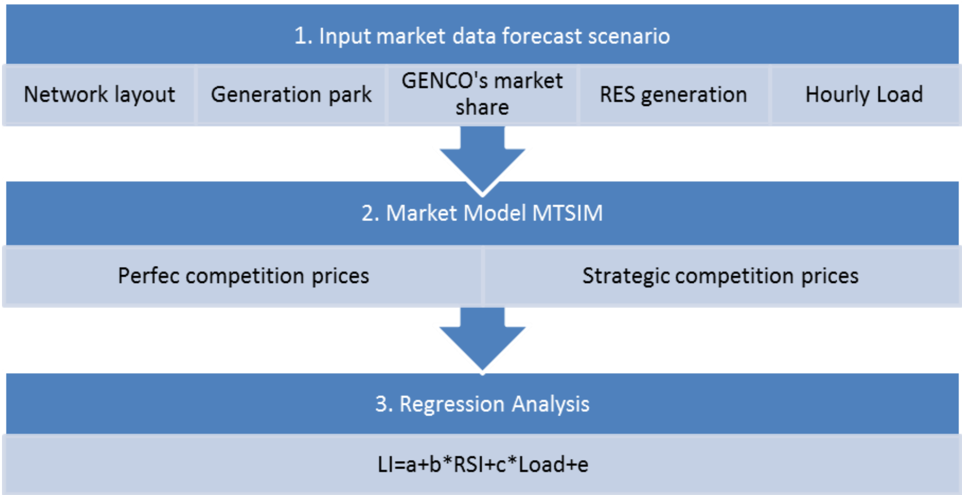


Fig. 37 - Framework of the theoretical approach

3.7.3. Bidding curves estimation and impact on the market

Estimated Lerner index will be used as the bid cost markups to derive strategic bidding curves for each region in a future scenario. In order to derive strategic bidding curves, we first convert the Lerner index to the markup:

$$PCM_{hj} = \frac{P_{hj}-C_{hj}}{C_{hj}} = \frac{LI_{hj}}{1-LI_{hj}} \qquad (4)$$

The calculated bid-cost markup PCM is based on the capacity of the largest local supplier. From the Cournot theory, we know that the price-cost markup of a supplier is proportional to the quantity it supplies. Thus, instead of applying the same bid-cost markups to all strategic suppliers in a region, we calculate bid-cost markups of each strategic supplier proportional to its available capacity in order to take into account to which extent a certain strategic supplier can exert market power. If the capacity of supplier f in region j at hour h is AS_{fhj}, then one calculates the bid-cost mark up for each supplier by:

$$BCM_{fhj} = PCM_{hj} * \frac{AS_{fhj}}{Max_f(AS_{fhj})} \qquad (5)$$

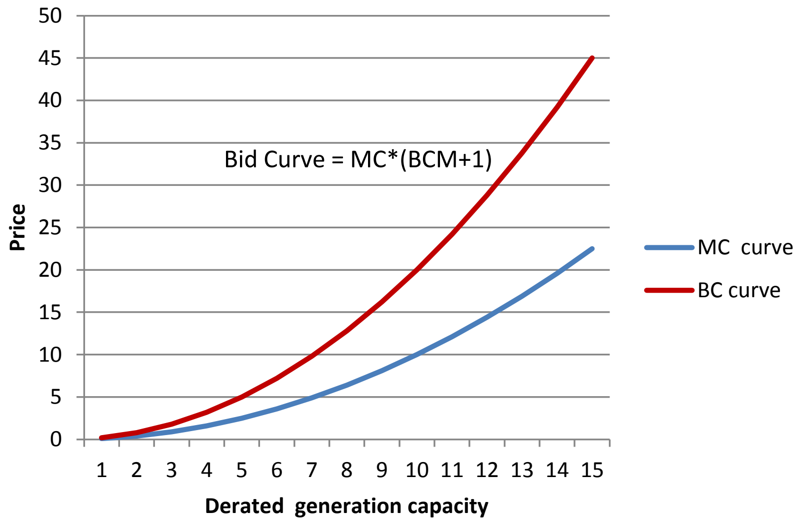


Fig. 38 – Construction of the strategic bid curve from the marginal cost curve

The above equation computes the bid-cost markup for each supplier where the largest suppliers bid-cost markup in a region is PCM_{hj}.

By using the bid-cost markups of all the strategic suppliers in a region, the strategic bid curve in that region can be constructed for each hour as illustrated in Fig. 38, starting from the given marginal cost curve used as input of the market simulations.

As illustrated in Fig. 38, the strategic bidding may result in a different merit order than marginal cost pricing. As a consequence, generation dispatch and equilibrium prices differ compared to a competitive market, having both an efficiency impact (higher generation costs) and a distributional impact (shift of surplus between consumers, producers and congestion revenues) in the corresponding market.

Generally, the impact of strategic bidding on social welfare is the combined outcome of efficiency and distributional impacts on the system:

$$\Delta SW^{mp} = \Delta Mrent + \Delta CS + \Delta GC$$

where $\Delta Mrent$ is the additional profit for producers under market power (market power rent), ΔCS is the loss in consumers surplus respect to the competitive case and ΔGC is the reduction of social welfare due to the increased generation costs.

Calculation of equilibrium prices and dispatch in a meshed network is very complex and requires a generation dispatch model including strategic bid-up curves. This can be done through a re-run of each case analyzed, including bid up curves. The effect of the market power on a specific test case can be evaluated by the difference between the social welfare resulting from system simulations with perfect competition (SW^{PC}) and with strategic competition (SW^{SC}):

$$\Delta SW^{mp} = SW^{SC} - SW^{PC}$$

3.7.4. Regression analysis results

In this section, we summarize the outcomes of the regression analysis carried out following the empirical approach. . Firstly, based on our observations, we made some alternations in the regression model.

Imperfect multicollinearity arises when one of the regressors is not perfectly correlated but very highly correlated with another regressor. This does not mean one chose the wrong set of regressors, or that one cannot estimate the regression but it could result in at least one regressor coefficient being estimated imprecisely [35]. This is also what has been observed in our analysis when we regress LI with both RSI and the load.

Load is directly included in the calculation of RSI, thus RSI is observed to be highly correlated with load in most of the countries. This results in *imperfect multicollinearity* as follows. When we regress LI with load only, it shows a clear positive relation whereas when we regress LI with both RSI and load, it shows a negative relation between load and LI. This is a clear indication of estimation of load's coefficient imprecisely when both RSI and load are regressed. As a result, since there was a clear statistical significance between LI and RSI alone, we decided to leave out load and consider only RSI as a regressor to overcome the issue of imperfect multicollinearity. Thus, we consider the following regression model in our analysis to estimate a and b:

$$Lerner\ Index\ (LI) = a + b * RSI$$

By means of the econometric analysis below, the aim is to find a statistical significance between the so called Residual Supply Index (RSI), an indicator of when the largest supplier in the electricity market is able to raise prices above competitive levels, and the Lerner Index (LI) which is the mark-up above a competitive price level.

To estimate the Lerner Index, estimation of competitive prices are required. ECNs European electricity market model COMPETES is utilized in a perfectly competitive mode to approximate competitive prices. COMPETES model is a simplification of reality under the assumption of a perfectly competitive market, thus results should not be and are not expected to be fully in line with reality but should provide outcomes in line with reality, i.e. in the order of magnitude.

First, the results of COMPETES model are validated for 2012 by comparing its hourly and yearly average outcomes to the actual realized market results (e.g. generation per technology). Firstly, it is observed that it is very difficult to have a one to one correspondence between the model and reality on an hourly basis. There are many factors behind this such as:

- We could not use the exact hourly wind generation in 2012 since the historical wind profiles are not available for many countries except Germany and France. Using the historical wind profiles for Germany and France only and Trade wind profile for other countries worsens the correlation between the countries. Hence, we decided to use Trade wind profiles which show a correlation of total yearly wind production in all the countries consistent with reality.

- There are negative hourly prices observed in some markets; i.e., in Germany. The observation of negative prices is a result of generators paying to get rid of excess generation. However, such a behaviour is not modelled in COMPETES in which the minimum price is zero.

Although there is not a one to one correspondence with the hourly outcomes, the yearly totals and the average daily price profiles resulting from COMPETES are well in line with reality. Thus, we decided to estimate the regression model based on average daily price profiles for each season; that is averages of all 1st, 2nd,..,24th hour of a day in winter, summer, spring, and autumn resulting in 96 observations in total per country. We observed that the fit between RSI and LI has significantly improved by regressing data of daily average profiles rather than each hour in a year.

Data set and limitations

One of the limitations of the analysis was the data availability. The data required to estimate RSI values and spot market prices is found to be available for limited years and countries such as the Netherlands, Germany, Belgium, Italy and France for year 2012. Furthermore, the calculation of RSI value is not corrected for the share of forward contracts since such data was not available. In the (long-term) forward market, the ability of the generators to exert market power is relatively low since demand is more flexible in the longer term, while in the short term (i.e. spot market) demand is highly inflexible.

In all of the countries except France, our regression results shows a good fit and the relation between RSI and LI is statistically significant. For instance, in all other countries, the Lerner Index has a positive relationship with load (i.e., an increase in load results in a higher value for the Lerner Index) and a negative relationship with RSI (i.e., an increase in RSI results in a lower value for the Lerner Index). Only in the case of France the resulting regression function showed a complete opposite relationship between the dependent and independent variables. A reason why these types of relationships were not seen in France is that there are significant regulations in effect in order to mitigate market power. Since the market share of the largest generator in France is high (86% in 2012), regulations are needed to protect the consumer from significantly high electricity prices and to open up the market for alternative suppliers by obliging certain power producers to sell under regulated prices. Hence, spot market prices that were gathered from EPEX are no good measure for calculating the Lerner Index because only a relative small part in France is market-led.

In the following, the results of the regression analyses showing the relation between RSI and the Lerner Index is given. The regression model is first estimated for each country. Then, in order to come up with a more general regression based on the data of all countries, an aggregated regression was executed as well. Both approaches show a statically significant relation between LI and RSI. In this section only the results are presented; the full description of methodology adopted for the estimation of each model is provided in Appendix 1.

Results of regression analysis

In order to analyze whether the regression model is a good fit and that there is a statistical significance between LI and RSI, the following variables are calculated for each regression:

- **P-value**: is an indication of the probability that the coefficient estimated for a certain regressor could have been obtained by chance. Thus, a probability close to zero indicates a correct estimation of the coefficient with a low or negligible probability that the coefficient is just a random number.
- **F significance**: similar to the P-value; indicates the probability that the regression output could have been obtained by chance.
- **(Adjusted) R2** : R-squared measures the goodness of fit. For example if the resulting R-squared is 60%, then 60% of the variation in the dependent variable (e.g. Lerner Index) can be explained by the independent variable (e.g. RSI). A drawback of R-squared is that it will

always increase when another regressor is added to the regression. The adjusted R-squared is corrected for this and will not necessarily increase when another regressor is added [35].

Tab. 18 summarizes the coefficients estimated and the related statistical variables. Fig. 39 shows the comparison among the linear models.

Tab. 18 – Results of the regression analysis

	Coefficients		F-significance	R-square	Adjusted R-square	P-value	
	a	b				intercept	RSI
the Netherlands	0.6783	-0.4905	0	66%	66%	0	0
Germany	1.2805	-1.3222	0	63%	62%	0	0
Belgium	0.4935	-0.7513	0	29%	28%	0	0
Italy	0.7454	-0.2412	0	35%	35%	0	0
EU - market	0.7023	-0.5031	0	56%	55%	0	0

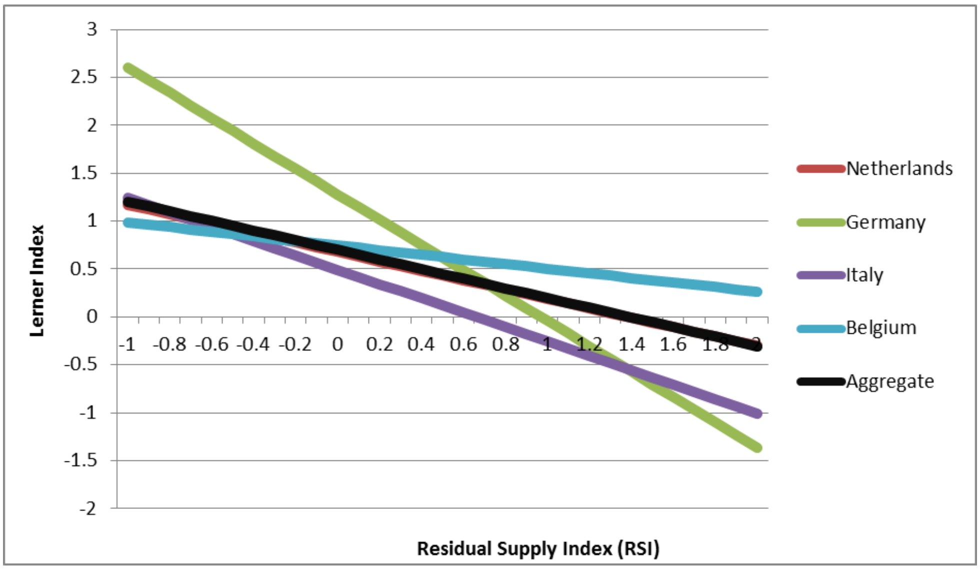


Fig. 39 – Comparison of the regression models per country and for the aggregated EU market

3.7.5. Example of application

In this section, we give a fictitious example to calculate the social welfare impact of strategic behavior for given regions A and B. We assume that Line AB connecting regions A and B is one of the projects to be expanded from 10 GW to 15 GW. To estimate the benefits of such expansion, social welfare impact of strategic behavior with and without expansion of Line AB should be calculated.

Below, we give an example to calculate the social welfare impact of strategic behavior in case of no expansion of Line AB (i.e., T_{AB} =10 GW) at a given hour (e.g., hour 35). The calculation in case of expansion of Line AB is similar (i.e., T_{AB} =15 GW) and omitted here.

First, it is assumed that the competitive simulation results from WP2 are obtained for regions A and B with and without expansion of Line AB for all the hours. Tab. 19 gives an example of such competitive simulation results for the case of Line AB without expansion (T_{AB} =10 GW). Note that IRES denotes generation from intermittent resources and the negative value for imports implies net exports from that region (i.e., Region B). From Tab. 19, it is observed that Region A is an importing region and Region B is an exporting region. Furthermore, Line AB without expansion is congested at hour 35 with a 10 GW flow.

Tab. 19 - Example of competitive simulation results from WP2

Competitive simulation results for Region A in hour 35			
Technology	**MC (Euro/MWh)**	**Derated Capacity (GW)**	**Generation (GWh)**
Biomass	20	8	8
Gas CHP	28	12	12
Coal PC	43	16	16
Gas CCGT	55	20	20
Gas GT	65	15	5
IRES Generation (GWh)			19
Generation excl IRES (GWh)			61
Net Imports excl Line AB (GW)			15
Import flows on Line AB (GW)			10
Load (GW)			105
Competitive Price (Euro/Mwh)			65
Generation Cost (kEuro)			2609
Competitive simulation results for Region B in hour 35			
Technology	**MC (Euro/MWh)**	**Derated Capacity (GW)**	**Generation (GWh)**
Biomass	20	10	10
Gas CHP	25	20	20
Coal PC	39	25	25
Gas CCGT	50	20	17
Gas GT	59	15	0
IRES Generation (GWh)			30
Generation excl IRES (GWh)			72
Net Imports excl Line AB (GW)			-5
Import flows on Line AB (GW)			-10
Load (GW)			87
Competitive Price (Euro/Mwh)			50
Generation Cost (kEuro)			2525

A second requirement for input assumptions is the number and the capacity share of strategic generators in each region. Example of such an input is given in Tab. 20 and is assumed to be provided with WP2 scenarios. According to Tab. 20, the capacity of strategic suppliers in both regions sum up to 60% of the flexible generation capacity. However, Region A is less competitive since fewer strategic players own the 60% of the flexible generation capacity.

Tab. 20 - Assumptions for strategic generators in regions A and B

	Ownership % in Region A			
Technology	**Supplier 1A**	**Supplier 2A**		**Competitive Fringe**
Biomass	20%	20%		60%
Gas CHP	0%	0%		100%
Coal PC	100%	0%		0%
Gas CCGT	40%	30%		30%
Gas GT	0%	50%		50%
Capacity (GW)	25.60	15.10		30.30
	Ownership % in Region B			
	Supplier 1B	**Supplier 2B**	**Supplier 3B**	**Competitive Fringe**
Biomass	0%	0%	0%	100%
Gas CHP	0%	0%	0%	100%
Coal PC	15%	60%	25%	0%
Gas CCGT	35%	50%	15%	0%
Gas GT	15%	30%	15%	40%
Capacity (GW)	13.00	29.5	11.50	36

The input assumptions from Tab. 20 and the estimated regression model in 3.7.1 can be used to calculate the price-cost markups for each region. Let's assume the aggregate EU – market regression model:

$$LI_{hj} = \frac{P_{hj} - \mathrm{P}C_{hj}}{P_{hj}} = 0.7023 - 0.5031\ RSI_{hj} \quad (6)$$

Tab. 21 illustrates RSI and Lerner Index values calculated for each region based on the formulations (3) and (6) respectively and the information from Tab. 20. Note that in formulations (3) and (6), net load is used to calculate RSI and the Lerner Index, respectively. Net load is the adjusted load by taking into account net imports and exports from other regions. Furthermore, IRES generation and capacity of Line AB is added to the available supply in both regions to calculate RSI values by using formulation (3).

The Lerner Index values in Tab. 21 indicate the price cost markup for the corresponding region. In Region B, the RSI value is above 1 and the largest supplier has 30% of the capacity. This results in a competitive market and generators with zero bid-cost markups. However, due to the tight supply (RSI<1) and fewer strategic generators in Region A , there is an estimated price-cost markup of 0.36. Thus, we calculate the bid-cost markups (BCM) for each strategic generator in Region A proportional to their capacity share by using the formulations (4) and (5). The resulting BCMs for Suppliers 1A and 1B are 0.57 and 0.34 respectively.

Tab. 21 - The Regression Model results for regions A and B

	Region A	Region B
IRES supply (GWh)	19	30
Total Available Supply (excl IRES)	71	90
Max capacity of strategic suppliers (GW)	25.60	29.50
Import Capacity between A and B	10	10
Imports from other regions	15	0
Exports to other regions	0	-5
Load	105	87
Net Load (excl. Line AB)	90	92
RSI	0.85	1.09
LI	0.27	0.00
BCM Supplier 1A	0.38	
BCM Supplier 1B	0.22	

By using the ownership assumption and BCMs in Tab. 21, the strategic bidding curves for both regions are constructed and the corresponding solution of the generation dispatch and prices for each region are calculated for hour 35. The solution under strategic bidding is still the constrained solution where the capacity of Line AB is congested. Next, we illustrate the comparison between the competitive solution from WP2 simulation and the strategic bidding for regions A and B.

As illustrated in Tab. 22, Region A being the importing region and with a tight supply capacity is significantly affected by the strategic bidding. There is an efficiency impact and Strategic supplier 1A withholds its generation from unit *Gas CCGT S1A* by bidding high and as a consequence more expensive Unit *Gas GT Comp* generates more. Thus, the total generation cost increases by 25 kEuro. Furthermore, the market price of Region A increases by 11 Euro/MWh and consumers pay 1155 kEuro more in this hour. The total social welfare reduction in Region A due to strategic bidding is 1180kEuro.

As illustrated in Tab. 23, Region B is not affected by strategic bidding since the estimated markup is zero. The generation dispatch and prices in Region B remains the same, thus there is no social welfare impact in Region B due to strategic bidding.

Tab. 22 - Comparison of competitive and strategic generation in region A at hour 35

Technology	Derated Capacity (GW)	MC	Strategic Bid	Generation Competitive	Generation Strategic	Impact strategic bidding
Biomass Comp	4.8	20	20	4.8	4.8	0
Biomass S2A	1.6	20	24	1.6	1.6	0
Biomass S1A	1.6	20	28	1.6	1.6	0
Gas CHP Comp	12	28	28	12	12	0
Coal PC S1A	16	43	59	16	16	0
Gas CCGT Comp	6	55	55	6	6	0
Gas GT Comp	7.5	65	65	5	7.5	2.5
Gas CCGT S2A	6	55	67	6	6	0
Gas CCGT S1A	8	55	76	8	5.5	-2.5
Gas GT S2A	7.5	65	79		0	0
Gas GT S1A	0	65	90		0	0
IRES Generation (GWh)				19	19	0
Generation excl IRES (GWh)				61	61	0
Net Imports excl Line AB (GW)				15	15	0
Import flows on Line AB (GW)				10	10	0
Load (GW)				105	105	0
Competitive Price (Euro/MWh)				65	76	11
Generation Cost (kEuro)				2609	2634	25
Consumer Payments (kEuro)				6825	7980	1155

Finally, the same calculations can be done for the case of Line AB with expansion (i.e., T_{AB} =15 GW). In this case, due to more import capacity, the RSI of region A will be higher and the corresponding BCMs for strategic suppliers will be lower. This may result in a lower price in Region A and the efficiency impact may also be lower. The difference of social welfare impact in both cases can indicate to the benefits of expansion of Line AB.

Tab. 23 - Comparison of competitive and strategic generation in region B at hour 35

Technology	Derated Capacity (GW)	MC	Strategic Bid	Generation Competitive	Generation Strategic	Impact strategic bidding
Biomass Comp	10	20	20	10	10	0
Gas CHP Comp	20	25	25	20	20	0
Coal PC S3B	15	39	39	15	15	0
Coal PC S1B	4	39	39	3.75	3.75	0
Coal PC S2B	6	39	39	6.25	6.25	0
Gas CCGT S3B	10	50	50	10	10	0
Gas CCGT S2B	7	50	50	7	7	0
Gas CCGT S1B	3	50	50		0	0
Gas GT Comp	6	59	59		0	0
Gas GT S3B	4.5	59	59		0	0
Gas GT S2B	2.25	59	59		0	0
Gas GT S1B	2.25	59	59		0	0
IRES Generation (GWh)				30	30	0
Generation excl IRES (GWh)				72	72	0
Net Imports excl Line AB (GW)				-5	-5	0
Import flows on Line AB (GW)				-10	-10	0
Load (GW)				87	87	0
Competitive Price (Euro/Mwh)				50	50	0
Generation Cost (kEuro)				2525	2525	0
Consumer Payments (kEuro)				4350	4350	0

3.8. Analysis of investments needs in distribution networks

This subtask deals with the interface between transmission and distribution. Investments in transmission and in distribution can be sometimes in competition and a methodology has to be set up in order to assess the optimal compromise. In particular, the simulations performed within the WP2 of the project eHIGHWAY2050 are going to deliver to the WP6 a list of transmission upgrade variants for each scenario and the methodology set up by the WP6 has to rank them on the basis of costs and benefits for the system. However, limiting the analysis to the transmission bottlenecks risks not to consider how transmission could help alleviating network congestion effects in distribution that otherwise would require massive local investments. Thus the aim of this subtask is to provide a rough estimation of the investments necessary in distribution as an effect of the implementation of the reinforcements foreseen by the variants of each WP2 scenario.

The main input data for this subtask will be provided by WP2, including:

a) A reduced node model of the pan European electricity system built up of 100 macro-zones ("clusters") approximately, each representing major load and/or generation centres. The node model is generated through a dedicated clustering algorithm, using ENTSO-E's *Ten Years Network Development Plan* (*TYNDP*) as input data. Each macro-zone is considered hereby as a "copper plate", which means that all problems related to congestion inside the single clusters are ignored.
b) A network model representing the transmission grid's structure without any reinforcements, the so called "without case" or "base case". This network model can be used as a reference case for further calculations as it represents the starting point described in ENTSO-E's *TYNDP*.
c) A list of transmission upgrade variants for each scenario. Each variant consists of a network model with reinforcements of the transmission grid and is validated by a power flow calculation with the corresponding time series for load and generation.
d) Time series for load and generation dispatch in each cluster on an hourly basis, calculated by a market simulation for each transmission upgrade variant. Amongst others, the time series for the load contain information about the use of electric heating and electric vehicles.

The challenge in this subtask is to estimate investment needs in the distribution grid while simulations in WP2 consider the transmission corridors between macro-zones only. That said no distinction will be made in the input data between demand and generation on transmission and distribution side.

Besides the investment costs for each transmission upgrade variant given by WP2, an economic ranking of all grid variants should be achieved by assessing the supplemental, individual investment costs in distribution for each grid variant. Alternatives that require smaller investments in transmission could lead to higher levels of energy not provided and RES curtailment due to lower help from the adjoining macro-zones. Thus it could be necessary to intervene at distribution level on one side by further developing the network in terms of building new lines and, on the other side, by increasing the system flexibility by means of "smart" technologies. In the end, cheap transmission alternatives could turn out to be the most expensive because they require huge investments in distribution.

3.8.1. Proposed methodology

A modified generation dispatch and adapted load curves through load shifting and shedding in each cluster will lead to a modified power flow in each cluster. This may increase congestion in the distribution grid in some clusters. In order to assess the required investment costs in building new assets on distribution side (i.e. lines, transformers and stations), the "without case" is chosen as reference point. The basis hypothesis is that the distribution grid is correctly dimensioned for the existing load and generation dispatch in each macro-zone in the "without case", i.e. before reinforcing the transmission corridors. This can be justified with the fact that the "without case" serves as the basis for all grid reinforcements for the grid variants in each scenario. Further it is assumed that the market simulation in WP2 will generate different generation dispatches and possibly load curves for each transmission grid variant due to differing transmission capacities, thus leading to different power flows between and inside the clusters. The difference between load and generation in each cluster will be used as a sizing parameter in the further reading as it allows comparing the transmission grid variants with the reference case.

Let $P_L(k,t)$ be the real power consumed (load) and $P_G(k,t)$ the real power injected (generation) in a given cluster k at a given time t (see Fig.). $P_L(k,t)$ and $P_G(k,t)$ can be extracted directly from the time series for each cluster.

Further let $P_{diff}(k,t)$ be the positive difference between generation and load in a given cluster k at a given time t:

$$P_{diff}(k,t) \ = |P_G(k,t) - P_L(k,t)|$$

Without using the absolute value, the difference would be greater than zero for clusters and time steps with a surplus of generation, otherwise it would be negative. Thus it can be seen as the exchange power with the transmission grid which compensates the power imbalance of the clusters (see Fig. 40-41).

For making a rough estimation about the required grid expansion, it does not matter if the power is flowing either into or out of a cluster.

Let $P_{diff,max}(k)$ be the maximum of this parameter for a cluster k along the 8760 hours of the simulation year:

$$P_{diff,max}(k) = \max\left(P_{diff}(k,t)\right)$$

The exchange power for a cluster k of the "without case" serves as a reference and will be noted

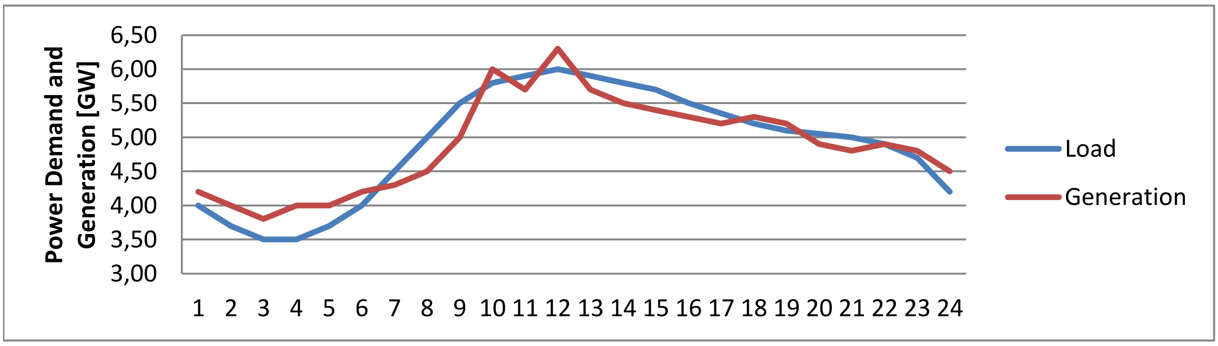


Fig. 40 - Load and generation in a cluster for a period of 24 hours

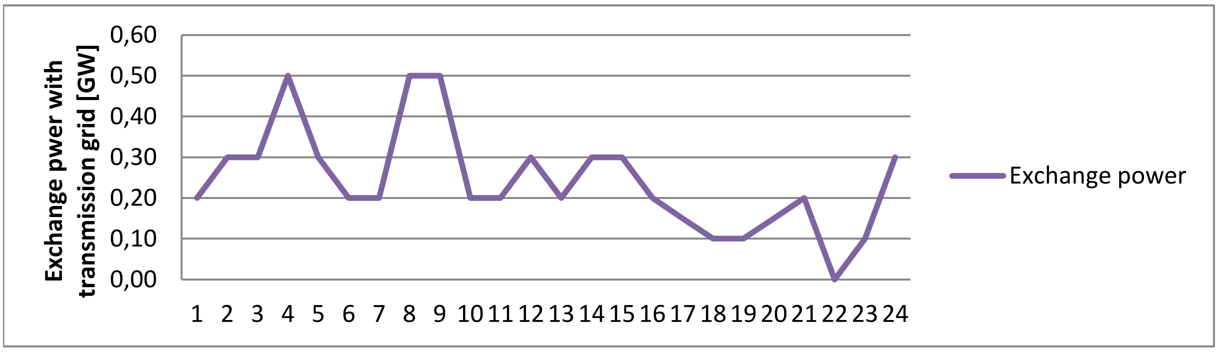


Fig. 41 - Exchange power with transmission grid

as $P_{diff,max}(k)\big|_{base}$. The corresponding values for all transmission grid variants will be noted similarly, e.g. for "variant x": $P_{diff,max}(k)\big|_{variant\ x}$.

Effects of demand side management

The use of technologies for realising demand-side management (DSM) has an impact on the load curve elasticity by means of load shifting in time. It is envisaged that the future electricity demand will rise by the deployment of new technologies on consumer side, such as electric heaters (EH) and electric vehicles (EV). Both the environment of electric heaters and the batteries of electric vehicles can be considered as storage, either for heat or electricity. Thus both technologies do not require a constant availability of electric energy and can be seen as perfect candidates for demand-side management applications. The investment costs for DSM are not considered hereby as we assume DSM technology to be included directly in new electric heating and electric vehicle deployments.

By shifting their use in time or by controlling their power demand, both technologies have the potential to have a positive impact on the load curve. This can be expressed by a reduction of the exchange power of the corresponding cluster with the transmission grid. Here the load curve must be modified in a way that it follows the generation curve in order to reduce the maximum difference between demand and generation. In practice this process of load shifting poses a major optimisation problem and has to take into account multiple market-based parameters, technical requirements and consumer behaviour. Since this methodology focuses on the maximum exchange power of macro-zones, only the effect of DSM on this parameter is considered. That said for a given value of $P_{diff,max}(k)\big|_{variant\ x}$ for a grid expansion variant, an appropriate value for the shiftable load must be found. This can be achieved by considering the electricity demand of electric heaters $P_{EH}(k,t)$ and electric vehicles $P_{EV}(k,t)$.

There are two possibilities to reduce the difference between demand and generation:

- A **demand surplus** at the time t should be reduced by shifting a part of the load to other points in time. The maximum possible value is the current electricity demand of shiftable loads (minus the correction factors $c_{f,EH}$ and $c_{f,EV}$) at the time t (the time where the maximum exchange power is encountered):

$$P_{shiftable}(k,t) = c_{f,EH} \cdot P_{EH}(k,t) + c_{f,EV} \cdot P_{EV}(k,t)$$

- A **generation surplus** at the time t should be reduced by shifting parts of the load from other points in time. The temporal distance to the time t is dependant of the shifting time

h. The maximum possible value is the sum of the current electricity demand of shiftable loads in the time interval $[t-h, t-1] \cup [t+1, t+h]$:

$$P_{shiftable}(k,t) = \sum_{\tau=t-h}^{t-1} P_{shiftable}(k,\tau) + \sum_{\tau=t+1}^{t+h} P_{shiftable}(k,\tau)$$

By considering only the current electricity demand of shiftable loads at the time t (as this is done in the case of a demand surplus), the fully available amount of shiftable power in the time interval is not taken into account and thus a more conservative approach is taken:

$$P_{shiftable}(k,t) = c_{f,EH} \cdot P_{EH}(k,t) + c_{f,EV} \cdot P_{EV}(k,t)$$

With the simplification for the generation surplus, both load shifting operations may be described by a single formula and it is sufficient to consider the absolute value of the exchange power only. Thus the maximum exchange power per cluster will be reduced by the amount of shiftable load at the corresponding time step t. Since this process will modify the maximum exchange power, the calculation must be repeated for all values greater than the reference value for the base case:

$$\begin{aligned} P_{diff}(k,t) &= |P_G(k,t) - P_L(k,t)| - P_{shiftable}(k,t) \\ &= |P_G(k,t) - P_L(k,t)| - c_{f,EH} \cdot P_{EH}(k,t) - c_{f,EV} \cdot P_{EV}(k,t) \end{aligned}$$

$$\text{for all } P_{diff}(k,t) > \left. P_{diff,max}(k)\right|_{base}$$

This methodology assumes that the time steps, where the values for the exchange power are greater than the reference value for the base case, are adequately distant (i.e. at least one hour between them). This means that DSM cannot be used in two consecutive time steps. To maximize the effect of DSM, the inclusion of DSM should start in the time steps with the highest values of exchange power.

Investments in distributed storage technologies

The use of distributed storage facilities can help to further reduce the maximum exchange power with the transmission grid by storing energy in times with a surplus of generation and by supporting the grid with previously stored energy in times with a demand surplus.

This methodology assumes the use of small and distributed storage facilities, in contrast to e.g. large pumped-storage on transmission side. Thus the full charging and discharging of the storage is assumed to be possible in one hour, allowing expressing the storage capacity $\left. Cap_{storage}(k)\right|_{variant\ x}$ for grid expansion variant “x” as maximum charging/discharging power $P_{storage}$. Thus it is sufficient to consider the absolute value of the exchange power only. Further a single storage technology will be considered whose cost will be expressed with $Cost_{technology}$ in the unit €/MWh. The storage capacity is dimensioned hereby by the remaining maximum exchange power minus the maximum exchange power of the base case.

This methodology foresees a similar effect of storage on the load curve as for DSM. The exchange power can be reduced at maximum by the full charging/discharging power of the storage, leading to a modified maximum exchange power. Thus the calculation must be repeated for all values greater than the reference value for the base case:

$$P_{diff}(k,t) = |P_G(k,t) - P_L(k,t)| - P_{storage}(k,t) \text{ for all } P_{diff}(k,t) > \left. P_{diff,max}(k)\right|_{base}$$

The investment costs for distributed storage in grid expansion variant “x” are calculated by multiplying the storage capacity (which is determined by the required charging/discharging power) with the $Cost_{technology}$ parameter:

$$Cost_{storage}(k)\big|_{variant\ x} = Cap_{storage}(k)\big|_{variant\ x} \cdot Cost_{technology}$$

This methodology assumes that the time steps, where the values for the exchange power are greater than the reference value for the base case, are adequately distant (i.e. at least one hour between them). This means that storage facilities cannot be used in two consecutive time steps. To maximize the effect of storage, the inclusion of storage should start in the time steps with the highest values of exchange power.

Investments in traditional grid expansion

The basis hypothesis assumes that the distribution grid is correctly dimensioned for the reference exchange power but may require reinforcements for the exchange power of the grid variants. Thus an upgrade of the distribution grid is supposed to be needed if the exchange power of a cluster exceeds the exchange power of the corresponding cluster in the reference case. The ratio between the exchange powers of the grid variant “x” and the reference case will be used as sizing factor:

$$\Delta P_{diff}(k)\big|_{variant\ x} = \frac{P_{diff,max}(k)\big|_{variant\ x}}{P_{diff,max}(k)\big|_{base}}$$

A ratio greater than one indicates that the exchange power in a cluster is higher than in the reference case and that an upgrade is necessary therefore. This ratio permits setting the additional amount of exchange power in relation to the current distribution grid’s structure, which is assumed to be appropriate for the reference exchange power. Since the macro-zones represent regions across Europe on both transmission and distribution level, the underlying distribution structures are highly differing and a standard layout for distribution grids would not be feasible. Thus this approach foresees an upgrade which will be proportional to the dimension of the existing distribution grids inside the clusters. Hereby the dimension is estimated by the total length of existing lines in km in each cluster. We assume that the costs for the upgrade of the distribution grid $Cost_{grid}(k)$ will be proportional to this dimension:

$$Cost_{grid}(k)\big|_{variant\ x} = \left(\Delta P_{diff}(k)\big|_{variant\ x} - 1\right) \cdot \left(\sum_{V} L(k,V) \cdot Cost_{line}(k,V)\right)$$

where $L(k,V)$ is the total length of the distribution lines within cluster *k* of the voltage level *V* and $Cost_{line}(k,V)$ describes the specific costs per extra km of line of the voltage level *V* that depends on the characteristics of the cluster (e.g. mountains, hills, densely populated areas or agricultural zones).

Cumulative investment costs in distribution

The exchange power is first reduced by the effects of DSM. With the remaining maximum exchange power, a storage capacity can be derived, whose costs must be compared to a traditional grid expansion. If the latter is a cheaper investment, the use of storage will be discarded. Otherwise their effect on the exchange power must be taken into account. Based on the remaining exchange power, investments in a traditional grid expansion are evaluated.

The exchange power is reduced both by the effects of DSM and the use of storage facilities:

$$P_{diff}(k,t) = |P_G(k,t) - P_L(k,t)| - c_{f,EH} \cdot P_{EH}(k,t) - c_{f,EV} \cdot P_{EV}(k,t) - P_{storage}(k,t)$$

$$\text{for all } P_{diff}(k,t) > \left. P_{diff,max}(k) \right|_{base}$$

Based on $P_{diff}(k,t)$ the maximum exchange power can be calculated for a year. The cumulative investment costs consider investments both in storage facilities and the traditional grid expansion:

$$Cost(k)|_{variant\,x} = \left. Cost_{grid}(k) \right|_{variant\,x} + \left. Cost_{storage}(k) \right|_{variant\,x}$$

The overall target is to minimise the investment costs by making a trade-off between all investments in distribution, i.e. an optimal storage capacity must be found for every cluster in all grid expansion variants.

3.8.2. Example of application

The following example tries to illustrate how the approach can be employed in the benefit and cost assessment of WP6. It will demonstrate the use of this methodology for a fictitious macro-zone with a given distribution grid structure. Moreover time series for load and generation are assumed for a base case and a single transmission grid expansion variant. The latter also contains data about the use of electric vehicles and electric heating. The example data is supposed to be of the same kind as the input data delivered by the WP2 and WP3, even if a single macro-zone and time series for a single day are considered only. However the approach should be easily adaptable for a higher number of clusters and yearly time series.

The macro-zone considered in this example is build up with high and medium voltage facilities:

- 7 500 km high voltage lines (>60 kV to < 220 kV);
- 50 000 km medium voltage lines (6 kV to < 60 kV).

The investment costs for building and installing new lines are assumed to be in this macro-zone:

- 500 T€/km for high voltage lines;
- 100 T€/km for medium voltage lines/cables.

Base case

The following time series for load and generation are considered for the base case. The difference between load and generation, and thus the exchange power, is noted in the last row.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Load	4,00	3,70	3,50	3,50	3,70	4,00	4,50	5,00	5,50	5,80	5,90	6,00	5,90	5,80	5,70	5,50	5,35	5,20	5,10	5,05	5,00	4,90	4,70	4,20
Generation	4,20	4,00	3,80	4,00	4,00	4,20	4,30	4,50	5,00	6,00	5,70	6,30	5,70	5,50	5,40	5,30	5,20	5,30	5,20	4,90	4,80	4,90	4,80	4,50
Exchange power	0,20	0,30	0,30	0,50	0,30	0,20	0,20	0,50	0,50	0,20	0,20	0,30	0,20	0,30	0,30	0,20	0,15	0,10	0,10	0,15	0,20	0,00	0,10	0,30

The maximum exchange power is encountered in hour 4, 8 and 9 and is 0.5 GW. The curves for load and generation are contained in Fig. while the exchange power is shown in Fig. .

Grid expansion variant

The following time series for load and generation are considered for the grid expansion variant. The time series contain information about the energy use for electric heating and electric vehicles too. The overall load consists of a static load amount and the load sum of EV and EH.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EH	0,80	0,74	0,70	0,70	0,74	0,80	0,90	1,00	1,10	1,16	1,18	1,20	1,18	1,16	1,14	1,10	1,07	1,04	1,02	1,01	1,00	0,98	0,94	0,84
EV	0,40	0,37	0,35	0,35	0,37	0,40	0,45	0,50	0,55	0,58	0,59	0,60	0,59	0,58	0,57	0,55	0,54	0,52	0,51	0,51	0,50	0,49	0,47	0,42
Load	4,00	3,70	3,50	3,50	3,70	4,00	4,50	5,00	5,50	5,80	5,90	6,00	5,90	5,80	5,70	5,50	5,35	5,20	5,10	5,05	5,00	4,90	4,70	4,20
Load, Sum	5,20	4,81	4,55	4,55	4,81	5,20	5,85	6,50	7,15	7,54	7,67	7,80	7,67	7,54	7,41	7,15	6,96	6,76	6,63	6,57	6,50	6,37	6,11	5,46
Shiftable load, Sum	0,60	0,56	0,53	0,53	0,56	0,60	0,68	0,75	0,83	0,87	0,89	0,90	0,89	0,87	0,86	0,83	0,80	0,78	0,77	0,76	0,75	0,74	0,71	0,63
Generation	5,50	5,30	5,80	5,70	5,00	5,30	5,70	6,10	6,60	7,20	7,80	8,20	7,50	7,20	7,70	8,20	7,50	7,20	6,80	6,50	6,30	6,10	6,50	6,20
Exchange power	**0,30**	**0,49**	**1,25**	**1,15**	**0,19**	**0,10**	**0,15**	**0,40**	**0,55**	**0,34**	**0,13**	**0,40**	**0,17**	**0,34**	**0,29**	**1,05**	**0,55**	**0,44**	**0,17**	**0,06**	**0,20**	**0,27**	**0,39**	**0,74**
Load with DSM	5,20	4,81	5,08	4,55	4,81	5,20	5,85	6,50	6,33	7,54	7,67	7,80	7,67	7,54	7,41	7,98	6,96	6,76	6,63	6,57	6,50	6,37	6,11	6,09
Ex. Power with DSM	**0,30**	**0,49**	**0,73**	**1,15**	**0,19**	**0,10**	**0,15**	**0,40**	**0,27**	**0,34**	**0,13**	**0,40**	**0,17**	**0,34**	**0,29**	**0,22**	**0,55**	**0,44**	**0,17**	**0,06**	**0,20**	**0,27**	**0,39**	**0,11**
Load with DSM, Storage	5,20	4,81	5,08	5,20	4,81	5,20	5,85	6,50	6,33	7,54	7,67	7,80	7,67	7,54	7,41	7,98	7,61	6,76	6,63	6,57	6,50	6,37	6,11	6,09
Ex. Power with DSM, Storage	0,30	0,49	0,73	0,50	0,19	0,10	0,15	0,40	0,27	0,34	0,13	0,40	0,17	0,34	0,29	0,22	0,11	0,44	0,17	0,06	0,20	0,27	0,39	0,11

The maximum exchange power is encountered in hour 3 and is 1.25 GW. The amount of shiftable power is the sum of EV and EH with a correction factor of 0.5 for both EV and EH, i.e. 50% of the power demand of EV and EH is considered as shiftable.

Demand side management

The effect of demand-side management is included in all time steps where the exchange power is higher than the maximum exchange power in the base case (i.e. in the time steps 3, 9, 16 and 24). Here the shiftable load is used to reduce the exchange power (the modification of the load is not necessary and was only done for this example). Note that DSM could not be used in the hour 4 since it was already used in the time step before. With the use of DSM, the exchange power could be reduced to 0.73 GW in hour 3. Thus the remaining maximum exchange power is encountered in hour 4 with a value of 1.15 GW.

Distributed storage

The use of storage is envisaged to further reduce the maximum exchange power. The storage capacity is dimensioned hereby by the remaining maximum exchange power minus the maximum exchange power of the base case. Thus the charging power of the storage should be at least 1.15 GW – 0.5 GW = 0.65 GW, leading to a storage capacity of 0.65 GWh. Assuming storage costs of 250 T€/MWh, this leads to investment costs of 162.5 million Euro for distributed storage. These costs must be compared to a traditional grid expansion in order to justify the investments in storage. This will lead to:

$$\Delta P_{diff}(k)\big|_{variant\ x} = \frac{P_{diff,max}(k)\big|_{variant\ x}}{P_{diff,max}(k)\big|_{base}} = \frac{1.15\ GW}{0.5\ GW} = 2.3$$

$$\begin{aligned} Cost_{grid}(k)\big|_{variant\ x} &= \left(\Delta P_{diff}(k)\big|_{variant\ x} - 1\right) \cdot \left(\sum_{V} L(k,V) \cdot Cost_{line}(k,V)\right) \\ &= (2.3-1)(7\,500\ km \cdot 500T€ + 50\,000 km \cdot 100T€) = 11.4\ billion\ € \end{aligned}$$

Comparing the investment costs, the use of storage facilities is much cheaper in this case, thus their use is envisaged in the following.

Again the effect of storage facilities is included in all time steps where the exchange power is higher than the maximum exchange power in the base case (i.e. in the time steps 4 and 17). Here the charging/discharging power is used to reduce the exchange power (the modification of the load is not necessary and was only done for this example). Note that storage could not be used in the hour 3 since it was already used in the time step behind. With the use of storage, the exchange power could be reduced to 0.5 GW in hour 4. Thus the remaining maximum exchange power is encountered in hour 3 with a value of 0.73 GW.

Traditional grid expansion

The remaining maximum exchange power of 0.73 GW is used to calculate the investment costs for a traditional grid expansion, where it will be used as a sizing factor:

$$\Delta P_{diff}(k)\big|_{variant\ x} = \frac{P_{diff,max}(k)\big|_{variant\ x}}{P_{diff,max}(k)\big|_{base}} = \frac{0.73\ GW}{0.5\ GW} = 1.46$$

$$Cost_{grid}(k)\big|_{variant\ x} = \left(\Delta P_{diff}(k)\big|_{variant\ x} - 1\right) \cdot \left(\sum_V L(k,V) \cdot Cost_{line}(k,V)\right)$$
$$= (1.46 - 1)(7\ 500\ km \cdot 500T€ + 50\ 000km \cdot 100T€) = 4\ billion\ €$$

Thus the overall investment costs (storage and lines) total 4.13 billion Euros in this example.

The time series for load and generation as well as the effects of DSM and storage on the load can be seen in Fig. 42, while the effect of DSM and storage on the exchange power can be seen in Fig. 43.

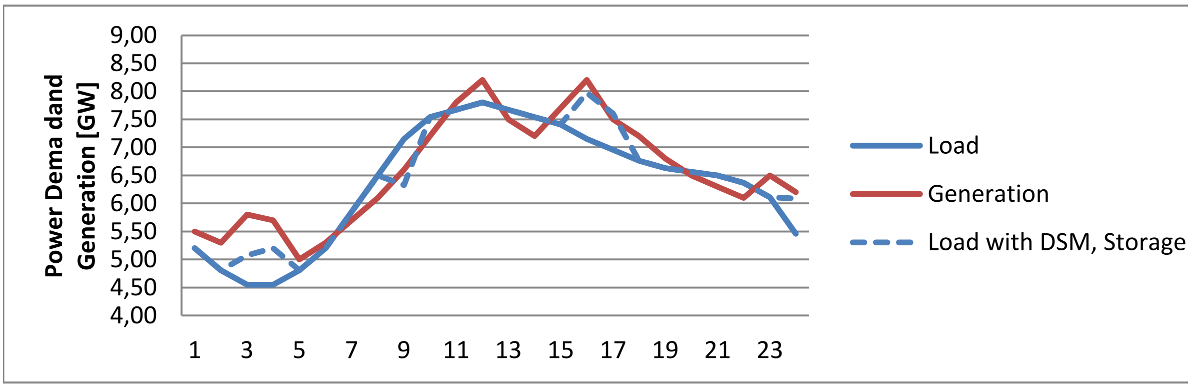


Fig. 42 - Load and generation in the grid expansion variant

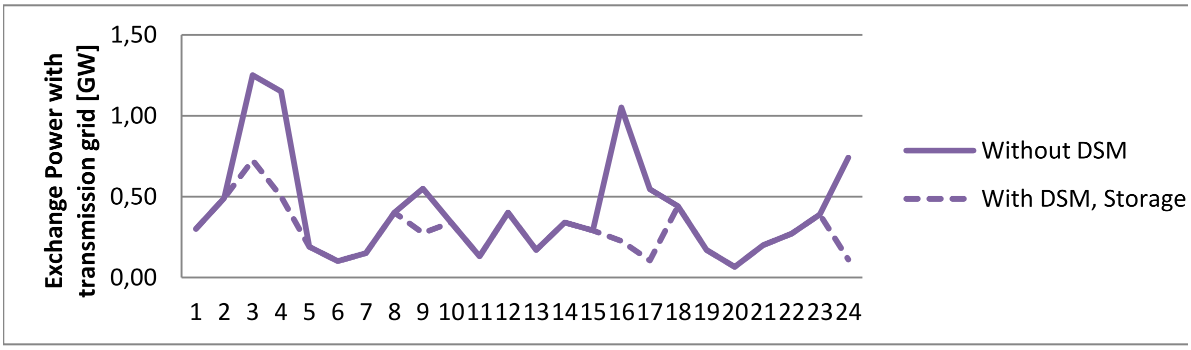


Fig. 43 - Exchange power with the transmission grid in the grid expansion variant

4. Costs and benefits related to social, environmental and technological aspects

4.1. Overview

This chapter discusses how a variety of social, environmental and technological impacts of pan-European transmission highway systems can be included in a comprehensive cost-benefit approach for analyzing the deployment of alternative options for the upgrade of these systems up to 2050. More specifically, this chapter aims at setting out an approach to assess costs and benefits of the impacts of such alternative systems on:

- Land use (*right-of-way*) and other property values (Section 4.2);
- Biodiversity and landscape (Section 4.3);
- Health and wellbeing (Section 4.4);
- Public attitudes and actions (Section 4.5);
- Innovative technological aspects such as controllability, adaptability/relocatability and observability (Section 4.6).

Whereas the analysis of the technological aspects presents important peculiarities, all social-environmental aspects (former four bullets) have similar characteristics. Social and environmental costs related to the impact of new infrastructures can be assessed based on the following steps:

- Identifying the type of (sensitive) areas through which a proposed new transmission infrastructure will be located. To this aim, a taxonomy of the different kinds of area should be introduced in advance (e.g. areas destined to agriculture, sub-urban areas, urban areas, touristic areas, zones of natural interest) matching each type of area with the relevant characteristics and, in particular, an average cost for its acquisition in €/km^2 (or €/km). This requires collecting present data on impact factors and costs for different areas across the EU.
- Estimating the size, i.e. either the length (in km) or, better, the surface (in m^2 or ha), of the areas through which a transmission highway will be located. A surface is identified for the portion of infrastructure crossing each kind of area belonging to the identified taxonomy. Concerning the path followed by the new infrastructure, lacking a detailed study of the tracking, a straight line is tracked on the map connecting the two extremes of the line[15]. This line can possibly be adapted in order to fit with already existing electrical corridors.
- Multiplying the average cost and benefits per type of area by the size (i.e. length or surface) of the portion crossed by the transmission infrastructure under scrutiny;
- Projecting/extrapolating present data on costs and benefits to future periods (up to 2050).

Even if the methodology outlined above seems simple and straightforward, its detailed analysis highlights that there are a lot of critical points. Indeed, developing and applying a cost-benefit

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[15] This approach is acceptable during the first stages of the feasibility study for a new infrastructure or for long-term projections (like the one studies by e-Highway2050) and must be replaced by an attentive study of the territory during the subsequent phases of the study.

approach to analyze the main social and environmental impacts of new trans-European transmission infrastructures up to 2050 faces some major challenges and difficulties, in particular:

- The costs and benefits related to these impacts depend not only on the (exact) routing of the transmission highways, i.e. the type and size of (sensitive) areas crossed, but also on (i) the type of the transmission technology used, and (ii) the (additional) measures to avoid, mitigate or compensate these impacts. As a result, developing and applying a benefit and cost assessment during the initial phases of the transmission planning process is very hard (as little relevant details on the project are known), while it becomes rather complex and site-specific during later phases of the planning process (when more details become known);
- Moreover, for the reasons mentioned above, the costs and benefits of some social and environmental aspects are not only very site-specific but also vary significantly across sites, occasionally by a factor of 100 or more. This implies that using average figures per area – or even a range of figures – has only limited meaning;
- The costs and benefits of some social and environmental aspects are hard to quantify in an objective, widely accepted way;
- Data on the costs and benefits of some social and environmental impacts – e.g. on compensation costs of income or property value losses – are often scarce and confidential and, therefore, hardly publicly available.

These issues will be further discusses and illustrated in the sections below.

4.2. Compensation costs for land use and property value losses

Transmission grids have an impact on land use and other property owner issues. For instance, in order to achieve rights-of way on agricultural land, grid operators pay a certain amount of compensation to the owner of the land. Moreover, new transmission lines affect the value of residential buildings and other properties that are located close to these lines. These issues will be discussed below, notably how these impacts can be measured and what are the involved data needs.

4.2.1. Right-of-way easements

From now on, we will identify with the term *right-of-way* (ROW) the strip of land used to construct, operate, maintain and repair a given transmission facility and for which a fee is paid. A transmission line usually is centred on the ROW. The width of a ROW depends on whether a line is overhead or underground, the voltage of the line and the height of the (overhead) structures. For an overhead line, it varies usually between 25 to 50 metres. The ROW generally must be clear of trees, vegetation and structures that could interfere with a power line [36].

The most common ROW arrangement for a grid operator to obtain certain land rights is an easement.[16] More specifically, a ROW easement is a legal arrangement between a land owner and

[16] Another arrangement is the so-called ‘fee simple’ or ‘fee title’ ownership. In this arrangement, a landowner sells the strip of land to the grid operator outright. In this situation, the landowner gives up ownership of the land along with all the rights and responsibilities that ownership entails. This is a common arrangement for new substations, but it is used only occasionally for power lines [45].

a grid operator that provides certain rights to the grid operator – notably to construct, maintain and protect the power line – but allows the land owner to retain general ownership and control of the land.

As part of the ROW arrangement, a payment is usually made to the land owner as a compensation for the transfer of land rights, losses in incomes and/or land values, and other damages or costs to the land owner due to the construction and maintenance of the power line. These losses and costs may be permanent or only temporary, i.e. only during the construction or maintenance phase of the line. In general, however, the ROW compensation is a one-time, upfront payment – for 25 or 50 years, or even for the project lifetime as a whole – but occasionally annual or (ir)regular payments are made in case of significant annual income losses or other, (ir)regular costs or damages during the ROW easement [46][42][44][45][39][37].

Proposed approach to quantify ROW compensation costs

ROW costs depend not only on the width of a ROW – and, hence, on the type of transmission facilities, as mentioned above – but also on the type and quality of the land and, therefore, on the routing of the grid. Since both the type of transmission facilities and the type/quality of the land are largely unknown during the initial stages of the transmission grid development process, we propose the following approach to quantify the ROW compensation costs:

- In the early stages of the grid development process, the ROW compensation costs can be roughly estimated by multiplying (i) either the length (in km) or the surface (in hectares) of the ROW track, and (ii) the average (or range of) ROW costs per km or ha. In formula:

  $$C_{row} = A * B \qquad (1)$$

  where C_{row} is total ROW compensation costs (in €), A is length or surface of the ROW track (in km or ha), and B is the average (or range of) ROW costs per km or ha (in €). For instance, if the length of the transmission line is 500 km and the average ROW compensation cost are 10,000 €/km, the total ROW cost amount to € 5 million. Alternatively, the (average or range of) ROW costs can also be expressed as a certain percentage of the capital investment costs of a transmission line and just added to these costs.
- In later stages of the grid development process – when more specific details are known on the type of transmission facilities as well as on the routing of the power line and, hence, on the type and quality of the land crossed – a more precise estimate of the ROW compensation costs can be made by multiplying (i) the length or surface of specific ROW tracks, and (ii) the specific ROW costs of each respective track. In formula:

  $$C_{row} = \sum A_{f,l} * B_{f,l} \qquad (2)$$

  where $A_{f,l}$ is the length or surface of a specific ROW track of land with a certain type of transmission facility (f) and a certain type/quality of land (l), and $B_{f,l}$ is the (average or range of) ROW costs for a specific ROW track of land with a certain type of transmission facility (f) and a certain type/quality of land (l). A simple example of such a calculation is provided in Tab. 24 below. In our e-HIGHWAY2050 methodology we will assume a classification of the ground typologies based on a pre-defined taxonomy and then we analyze the portion of the new infrastructures under scrutiny crossing each type of area, matching it with the associated costs. These costs will be the result of an analysis based on present documents and of an extrapolation of average cost values per type of area.

- In order to extrapolate costs up to 2050, we propose to just simply assume that (i) all costs are expressed in real terms for a given base or reference year (for instance, 2010 or 2013), and (ii) all costs remain the same in real terms – i.e. follow the general rate of inflation – up to 2050, unless there are well-motivated considerations that costs will behave differently, i.e. either increase or decrease in real terms by a certain percentage up to 2050.

Tab. 24 - Estimation of ROW compensation costs

Type/quality of land	Type of transmission facility	Length of ROW track (in km)	ROW costs per track (in € per km)	Total ROW costs (in million €)
Agricultural, high quality	High, wide structures	100	15,000	1.5
Agricultural, high quality	Low, small structures	100	12,000	1.2
Agricultural, low quality	Low, small structures	100	9,000	0.9
Meadows	Low, small structures	100	6,000	0.6
Recreational	Low, small structures	100	3,000	0.3
Total				4.5

Data needs and availability

In order to estimate the ROW compensation costs mentioned above, the following data are needed:

- Length and routing of the transmission line;
- Type and quality of the land crossed;
- Type of transmission facilities;
- ROW compensation costs per type of land/transmission facility.

With regard to the latter category (ROW compensation costs), data availability is presently quite scanty. Some findings from a questionnaire launched by the WP6 of eHIGHWAY2050 and directed to the TSOs include:[17]

[17] Note that in several cases compensation mentioned in the TSO questionnaire is broader than ROW compensation only.

- Italy (TERNA):
    - In the initial phase of the transmission project planning, compensation for land use and maintenance activities is assumed as less than 6% of the total project investments costs (capex). The compensation for land use are calculated according to expropriation values defined by law. Generally a consensual agreement is reached with the landowner on the basis of the market value of the area to be expropriated. Data are available only in an advanced status of the project (i.e. construction phase).
- Greece (IPSO/ADMIE):
    - Compensation for land use follows the expropriation rules according to the existing laws. It varies from 1000 to 50,000 €/km of overhead transmission line. There are no relevant data for underground transmission data.
- Sweden (SVK):
    - Estimated costs for compensation to land owners (staff costs and compensation): 700,000 – 750,000 SEK (i.e. about € 80,000 – 85,000) per km for overhead lines;
    - Compensation costs vary between overhead and buried lines;
    - In woodland, costs amount to 100 000 SEK (approximately € 11,000) per square hectares, with about 44 meters width for overhead lines and 20 meters width for buried lines;
    - No extra for zones of recreational, economic, cultural or natural relevance;
    - Different compensation rates depending on the land, woodland or farmland;
    - For loss of activity with economic consequences compensation is offered;
    - The cost of the construction of the line depends on the design from normal design tower (two legs) 4 million SEK (€ 450,000) per km and 6-7 million SEK (€ 680,000 – 790.000) with pylons (one leg);
    - Land owners are compensated for the area of land in use for the lines. Different designs of the towers also lead to different amounts of land used for the construction and different amounts of land compensated to the land owners;
    - Compensation to land owners is based on rules and principles laid down by law.
- Switzerland (Swissgrid);
    - Land owners are compensated for each tower and per meter of overhead line or cable;
    - The amount of compensation depends on:
        - The amount of land use;
        - The site (e.g. inclination);
        - The types of tower and line ;
        - Some special cases;
    - The compensation is paid in general every 25 years so that future generation can also profit from it. However the contracts are signed for the lifetime of the line or the cable;
    - *Compensation for the Deterioration of Property*: the servitudes for lands for agriculture are not equally compensated for lands for building. If the line runs through a land for buildings, a construction restriction is typically set on the servitude and it is therefore protected against proven loss of value. When a property loses value to an extent that it is dispossessed, the governmental compensation commission will determine the amount of compensation;

- *Compensation for Missing Harvest*: farmers are compensated for their loss of harvest during the construction. The amount depends on the surface area and the concrete financial losses;
- *Compensation for cultural damages*: if, for example, because of the new infrastructure a forest track is impaired, then the incurred costs for restoration will be compensated. The restoration can also be overtaken by the farmer, in this case he will be paid according to his hourly rate and the incurred materials;

In addition, Swissgrid has sent two documents published by the Swiss Farmer Association (SBV) and the Association of Swiss Electrical Utilities (VSE). These documents (in German) include recommendations on rates of compensation to farmers for overhead lines, underground cables and other power transmission facilities on their land [47] and [48]. For instance, for overhead lines, the rates of compensation vary from 1.94 to 9.69 CHF/m (i.e. about 1.58 – 7.88 €/m), depending on the type of the pylon and the type of line (voltage, width). In addition, farmers receive compensation for each pylon on their land, varying from 126 to 12,012 CHF per pylon (i.e. approximately 102 – 9762 €/pylon), depending on the type and size of the pylon and the type and quality of the land (e.g. low-quality meadows versus high-quality, intensively-cultivated arable farm land).

The Swiss compensation rates mentioned above refer to a compensation period of 25 years. For a compensation period of 50 years, the rates are multiplied by a factor of 1.42 [47].

4.2.2. Other property issues

In addition to exerting a potential negative effect on land values – which is usually, either partly of fully, compensated by ROW payments – transmission grids may also have a negative impact on other property values, in particular on the value of residential properties. When negative impacts are evident, the loss in property value is usually attributable to the visual unattractiveness of the lines, disturbing sounds, potential health hazards and safety concerns [43].

Since the 1950s, the potential losses in property values due to the proximity to a new transmission line have been assessed by a large variety of studies.[18] Most of these studies, however, refer to residential properties in metropolitan and suburban areas in the USA. To some extent, however, the findings of these studies may also be relevant to other regions such as the EU. In brief, the major findings of these studies include [43][44][40][41]:

- While several studies are inconclusive or statistically insignificant, other studies find reductions in residential property values due to tower line proximity ranging from 0 to 10 per cent;
- Higher-end properties (i.e. more expensive houses) are more likely to experience a reduction in property value than lower-end properties;
- Reductions in property values diminish as distance from the line increases and usually disappears at a distance of 70 to 100 meters from the line;
- Some studies find that value losses attributable to tower line proximity usually decreases over time and may even disappear in a number of years.

[18] See, inter alia, the following (summaries of these) studies: [43][44][40] [41].

Proposed methodology to quantify property value losses

Losses in residential property values attributable to tower line proximity are sometimes compensated by grid operators [46][38]. However, regardless of whether these losses are compensated or not, if they are real and permanent they have to be included in the social benefit and cost assessment of a power grid investment. To do so, however, requires that the routing of the new transmission line is known. This is not always the case during the initial phases of the grid development process and is definitely not the case for the long-term scenarios analysed in e-Highway2050. Therefore:

- In the initial stages of a grid development process (and in the case of long-term projections like the ones by e-Highway2050), an average figure could be added to the capital investment costs of the grid project. This cost figure accounts for the average loss in residential property value (or may even account for all losses in all property values – including damages and income losses – and even including the ROW costs discussed above). It could be expressed either as a percentage of the capital investment costs (in %) or, equivalently, as a fixed, absolute amount of money (in €/km of transmission line or in € per transmission facility). Multiplying the average cost figure by the total length of the transmission line – or the number of transmission facilities – results in the total costs accounting for losses in (residential) property values;
- In later stages, when more details are known on the routing of the transmission line, a more precise estimate of potential losses of residential (and other) property values can be made. For instance, once the routing is known, the number of houses (and other properties) impacted by the new transmission line can be estimated. Based on the average value of the type of houses concerned and the average loss of residential property values attributable to a new transmission line (say 5% of the property sales value), the total loss of property values can be estimated.

Data needs and availability

in order to estimate the losses in residential (and other) property values due to a new transmission line, the following data are needed:

- Length and routing of the transmission line;
- Type of transmission facilities;
- Number of houses (and other properties) affected;
- Average loss of property values.

With regard to the latter category (average loss of property values), the availability of robust data for EU countries seems rather limited. Little is known whether grid operators pay compensation for (presumed/real) losses in property values attributable to transmission line proximity and, if yes, to which extent. In the already quoted questionnaire sent by the WP6 of e-HIGHWAY2050 to TSOs, this issue is hardly mentioned besides some general statement on compensation of costs, damages and (income) losses (see previous section). As said, there is a large variety of studies on the impact of transmission lines on (residential) property values, but the findings of these studies are not always conclusive and statistically significant. Moreover, most of these studies refer to residential properties in the USA. Hence, it may be questioned to which extent these findings are applicable to other regions, in particular the EU.

In order to deal with the presently, limited availability of robust data on property value losses attributable to the presence of transmission lines, possible options include:

- Just take an average amount (in €) or an average percentage to be added to the capital investment costs of a transmission project in order to account for the losses in property values (or, alternatively, for the total costs of losses in property values, ROW compensations, other compensations of damages, income losses, etc.);
- Neglect this issue as not significant in percentage to the total amount of costs.

Within the e-HIGHWAY2050 context, in consideration of the great difficulty to establish a detailed extra cost projected to 2050, we propose to neglect the point, supposing that the entailed extra-cost is not significant in percentage to the total investment amount.

4.3. Biodiversity and landscape

The development of an electricity highways system could be expected to entail a number of costs related to impacts on biodiversity and on landscapes. For biodiversity, these impacts can include habitat loss, fragmentation or damage; alteration of hydrology; and hazards to birds including collision and/or electrocution with power lines [50]. Impacts on landscape can include disruption to visual amenity as well as to cultural heritage and other factors. Costs relating to these impacts can include:

- loss of 'natural capital', amenity value or ecosystem services;
- compliance costs from meeting biodiversity and landscape conservation requirements;
- delays relating to public opposition on the grounds of biodiversity or landscape impacts (accounted for later in this chapter);
- re-routing of lines to avoid protected areas;
- additional expenditure for environmental management;
- loss of landscape visual amenity;
- compensation costs to create equivalent habitats or to compensate residents.

Positive benefits to biodiversity can also occur, for example through:

- habitat management below overhead lines or in the vicinity of transmission routes;
- avoidance of generation or other infrastructure with a negative biodiversity impact.

The impacts of high voltage transmission projects, however, are highly contingent on the spatial alignment of the grid, specific structures and technologies used, the extent to which pre-existing corridors are used, and how the transmission line is operated and maintained [60]. Specific biodiversity and landscape impacts are highly localised and depend on the interaction of specific projects and routes with local ecologies. Impacts will be highest at sensitive sites; these include but are not limited to protected areas such as Natura 2000 designated sites.

It is challenging to monetise biodiversity and landscape impacts at the level of European grid architectures, as impacts tend to depend on specific project routes and designs rather than system effects.

Nevertheless, proxy values indicating the scale of the costs and benefits can be derived from estimates of the cost of damage mitigation, particularly in relation to protected areas.

4.3.1. Categories of costs and benefits for consideration

A summary of relevant costs and benefits and options for evaluation is provided in Tab. A2-1 in annex. These fall into the following broad categories:

Compliance costs

Developers of new transmission infrastructure must comply with a range of international, European and national regulations. At European level these include: EIA Directive, SEA Directive, Birds and Habitats Directives, Water Framework Directive (WFD), Marine Strategy Framework Directive (MSFD), Seveso II and Seveso III Directives, and Industrial Emissions Directive replacing the Integrated Pollution Prevention and Control (IPPC) Directive (DG ENER 2013).

The regulations are designed to limit negative environmental impacts. Compliance with the regulations entails costs to project developers (for example through performing Environmental Impact Assessments), representing up to 10% of project development costs.

As compliance is a legal requirement, however, the basic cost of compliance should already be internalised within project development costs. It should therefore not be accounted for separately, except where compliance costs are unusually high (such as where a line crosses a protected area).

In some cases, public concern over biodiversity or landscape impacts can prolong planning and permitting procedures, which can delay the project or add costs. These costs should also be seen as compliance costs. Costs and delays can be reduced through application of best practice in public engagement (see Section 4.5).

Mitigation costs

Negative impacts on biodiversity and landscape can be minimised or averted through mitigation measures. These can include:

- Re-routing to avoid sensitive habitats or landscapes[19];
- Undergrounding of power lines to reduce visual impact and habitat disruption [52]. This may alter but not eliminate impacts to habitats and landscapes;
- Design measures to reduce risk of bird collisions and electrocution [49];
- Provision of alternative habitats.

Residual costs

Residual costs result from negative impacts on biodiversity and landscape that have not been fully mitigated against through legal compliance and other measures. There are different approaches to evaluating such costs:

- *Ecosystem services and natural capital*: biodiversity has a utility value to the economy through the provision of 'ecosystem services'. For example insects provide a service through pollination of crops; the value of these services can be approximated through the cost of alternative provision [53]. Natural capital relates to the ability of natural environments to provide such services into the future [54]. However such services are highly localised as they relate to specific habitats and functions. As a result few evaluations of transmission grids have been able to directly monetise these dimensions.
- *Willingness to pay*: Biodiversity and landscapes can also be understood as having non-use values – or the value that people attach to their preservation. These can be evaluated through 'willingness to pay' approaches, where people are questioned on how much they would pay to avoid an impact. To calculate visual amenity value, this approach has been applied to evaluate willingness to pay to avoid impacts through undergrounding of power lines [57]. The range of values is significant: from the equivalent of €0.0005 per km per year per household outside protected areas to €0.12 within National Parks (high enough to pay for undergrounding). Other studies have revealed values as high as €4 per km per household [55].

[19] See e.g. TSO questionnaire response from Elia.

- *Hedonic pricing*: Values can also be determined through hedonic pricing approaches such as impacts on house prices (Furby et al 1987) and tourism revenues. Again, such methods are highly site-specific and may not be generalisable to system level.

Protected areas

In recognition of the value and sensitivity of particular habitats and landscapes, governments have created a number of different designations aimed at conservation. Such protected areas are now widespread: 18% of the EU land area is covered by the Natura 2000 designation under the Habitats Directive, and 21% of European land area is covered by at least one protected area designation (EEA 2012). Most sites are small and in many cases can be avoided through routing decisions: the vast majority of protected area sites in Europe (90 %) have an area of less than 1 000 ha and 65 % range between 1 and 100 ha (EEA 2012).

System costs and benefits

In addition to the above costs and benefits, the development of electricity highways can also be expected to impact the wider power system including through changes to the volumes, type and location of electricity generation. Fossil fuel mining and extraction, generation technologies (including renewables) and resulting pollutants all have biodiversity and landscape impacts. The benefits to biodiversity of avoided coal generation have been assessed as high, avoided nuclear generation has been assessed as medium high and avoided gas generation is low [59]. However the magnitude of the biodiversity/ecosystem services component of the generation impacts is considerably lower than other factors such as water use and greenhouse gas emissions [56].

As the eHIGHWAY2050 project scenarios incorporate fixed values for electricity generation, consumption and exchange, it will not be possible to fully account for such benefits within the Cost Benefit Analysis. One possible approach is to account for natural protected areas in terms of extra length (and, consequently, extracosts) to get around them (see below).

4.3.2. Existing approaches

Tools have been developed in a number of contexts to assess potential environmental costs and benefits from transmission lines, including biodiversity and landscape impacts.

The current ENTSO-E methodology does not monetise biodiversity or landscape costs and benefits. However it does include as a Key Performance Indicator the length of the proposed line that crosses a sensitive landscape, the type of sensitivity encountered and the stage of the project. The ENTSO-E definition of environmental sustainability is given in Box 1 below.

Box 1: ENTSO-E Definition of environmental sensitivity

- Sensitivity regarding biodiversity: protected under the following Directives or International Laws:
    - Habitats Directive;
    - Birds Directive;
    - RAMSAR site;
    - IUCN key biodiversity areas;
    - Other areas protected by national law.
- Sensitivity regarding landscape: protected under the following Directives or International Laws:
    - World heritage;
    - Other areas protected by national law.

Some TSOs use more detailed landscape categorisation and valuation approaches to influence routing decisions. Terna[20] for example categorises landscapes according to terrain, protection status and other socio-environmental factors, and applies weighted values ranging from 1 to infinity according to the classification. Swissgrid[21] uses a similar system that quantifies and evaluates 'impact and equilibrium in natural space, biotope and landscape'. Such methodologies are highly relevant for routing decisions at local and regional level. However they may be less applicable to benefit and cost assessment at European system level due to the data intensity required and potential differences in national classifications and weightings.

A number of other studies on the costs of transmission networks identify and categorise the impacts that transmission grids have on biodiversity and landscapes but do not attempt to monetise these impacts given the complexity of measurement and their site-specific nature (e.g. [58][60][45][50]).

4.3.3. Proposed approach

The proposed approach seeks to quantify and monetise the costs of mitigating negative biodiversity and landscape impacts in protected areas. Mitigation options that can be considered from a cost-benefit perspective, although usually rather expensive, include: re-routing to avoid sensitive areas or follow existing corridors, undergrounding to reduce visual impact and some biodiversity impacts, or compensation through provision of alternative habitats and payments to affected residents.

[20] See http://portalevas.terna.it/

[21] Response to TSO questionnaire.

This cost is treated as a proxy for overall biodiversity and landscape impacts, while acknowledging that there will be costs and benefits that cannot be effectively monetised or incorporated for the costs of BCA.

Assumptions

The following assumptions and considerations are made:

- Basic compliance costs with environmental legislation are already internalised within project development costs. To avoid double-counting, compliance with regulation is assumed for all lines.
- The Strategic Environmental and Sustainability Assessment should be used to evaluate options and to develop an approach for minimising negative impacts.
- For projects outside of specially protected areas, it is assumed that many of the negative impacts can be mitigated through project design. Given the difficulties in calculation and the site-specific nature of impacts, residual impacts outside of sensitive areas are not monetised.
- Potential local environmental benefits through habitat management in the vicinity of a route corridor are not assessed due to the site specific nature and difficulty of calculation.

Proposed method

5) *Identify assumed route*: the assumed route is defined as the shortest pathway between two nodes.
6) *Identify length of assumed route that crosses sensitive areas*: the definition of sensitive areas is assumed to be the same as identified.
7) *Identify costs of mitigation options*:
    a. Re-routing to avoid sensitive areas or to follow existing infrastructure corridors: additional costs from increase in route length.
    b. Undergrounding cables through sensitive areas: cost difference between OHLs and underground cable for length of route through protected area.
    c. Compensation through provision of alternative habitats and payments to affected residents: where data is available, the costs of provision of alternative habitats and payments to affected residents can be taken into account. (c.f. existing methodologies in Germany, Switzerland and Italy).
8) *Apply the cost of the cheapest mitigation measure to the overall cost of the line*.

Data requirements

- Proposed system architectures, including geospatial data on locations of nodes and proposed links;
- Geospatial data on locations of sensitive areas;
- Geospatial data on existing infrastructure pathways;

- Costs associated with underground cables;
- Where available, costs of providing alternative habitats and compensation affected residents, according to national methodologies.

4.3.4. Illustrative examples

- *Illustrative Example 1*: The proposed system architecture identifies the need for a link between Node 1 near Ljubljana in Slovenia and Node 2 near Prague in the Czech Republic, a distance of 450km in the most direct pathway. In the most direct pathway, 90 km of this assumed route crosses sensitive areas. Three mitigation options are considered:
    a) A route diversion of 50km in total would avoid all sensitive areas. This would increase the cost from €900m to €1000m.
    b) Undergrounding the line through the sensitive areas would raise the total cost from €900m to €1250.
    c) Insufficient data is available to calculate the total costs of habitat replacement and compensation to residents for visual impacts.

In this example, the assumed cost for the link between Ljubljana and Prague would be €1000m, as it represents the cheapest of the options considered.

- *Illustrative Example 2*: The proposed system architecture identifies the need for a link between Node 5 near Milan in Italy and Node 6 near Cologne in Germany, a distance of 450km in the most direct pathway. 90km of this assumed route crosses sensitive areas. Three mitigation options are considered:
    a) A route diversion of 200km in total would be required to avoid all sensitive areas (due to the presence of the Alps). This would increase the cost from €900m to €1300m.
    b) Undergrounding the line through sensitive areas would raise the total costs from €900m to €1250m.
    c) Sufficient data exists to calculate the costs of provision of alternative habitats and compensation of residents where the route crosses sensitive areas, according to national methodologies. This raises the total costs from €900m to €1100m.

In this example, the assumed cost of the Milan to Cologne link is €1100m, as this represents the cheapest of the three options.

- *Illustrative Example 3*: The proposed system architecture identifies the need for a link between Node 3 near Lisbon, Portugal and Node 4 near Madrid, Spain, a distance of 500km. 60km of the assumed route passes through sensitive areas. Three mitigation options are considered:
    a) A route diversion of 200km in total would be required to avoid all sensitive areas. This would increase the cost from €1000m to €1400m.
    b) Undergrounding the line through sensitive areas would raise the total costs from €1000m to €1250m.

c) Sufficient data exists to calculate the costs of provision of alternative habitats and compensation of residents where the route crosses sensitive areas, according to national methodologies. This raises total costs from €1000m to €1300m.

In this example, the assumed cost of the Lisbon to Madrid link is €1250m, as this is the cheapest of the three options.

4.4. Health and wellbeing

This section presents a conceptual explanation of the suggested methodology to measure the effects related to health and well-being in relation to the development of the new electricity grid architecture.

To begin with we outline the types of effects that are considered to be relevant, how the effect might be assessed and how that assessment might be monetised so that costs can be extracted. The approach to the costing uses the general framework proposed in Section 4.1 of this document.

It should be noted that costs for any of the activities carried out to reduce negative effects are not readily available either from TSOs or from other sources. However, we have been able to gather some information on what costs might be the important ones to gather. Secondly, processes and procedures vary hugely between countries, it will be very hard to have an average cost or even a range of costs that is meaningful for the BCA.

For this section on health and well-being effects we have split it into physical and psychological health effects, noise pollution and visual pollution.

4.4.1. Health and well-being effects of transmission lines

Physical and psychological health effects

Almost all electrical systems generate electromagnetic fields (EMFs) which are the result of links between electric and magnetic fields. Power lines are a notable source of EMFs. There is some, inconclusive, evidence that EMFs can cause negative health effects particularly at the wavelengths of radio and microwaves which are at much higher wavelengths than power lines [72]. With regard to extremely low frequency (ELFs) fields (which are what power lines generate) there remains a conclusion that ELFs are possibly carcinogenic with regard to child leukaemia but probably not with regard to breast cancer. Recent research has also suggested that supposed links between this sort of EMF and cardiovascular and neurodegenerative diseases / brain tumours are unlikely and uncertain respectively [75]. Considering these findings, a World Health Organisation has concluded that there are no substantive health issues related to ELF electric fields [78].

Regardless of the actual health effects there are indirect health and wellbeing effects associated with the perception that power lines (and other sources of EMFs) may be damaging people's health. There is a high awareness that high voltage power lines are sources of EMFs with 58% of respondents stating this – a level of response that is stable from 2006-2010 [74]. Research has suggested that more than two thirds of respondents across Europe believe their health is somewhat affected by EMFs from high voltage power lines but 25% believe there is no health risk. In terms of trends there is a small decrease in people who believe their health is greatly affected (2-3%) between 2006 and 2010 (European Commission, 2010). To put it into context, power lines are viewed as more significant health risks than other potential sources of EMF such as mobile phone masts, computers, household electrical equipment and mobile phones but less than environmental conditions such as exposure to the sun, noise, air quality, water quality and waste dumping [74]. There is clearly a debate around the health effects from transmission lines together with a certain amount of public concern and this suggests that steps may well need to be taken to reduce or mitigate these physical and psychological health effects.

Visual pollution effects

There is evidence that overhead pylons create visual intrusion in rural and suburban landscapes [67] with that leading to a desire to underground the lines, to have different types of design or to fuel local opposition to developments [73]. Cotton and Devine-Wright highlight that these have been shown to affect property and local amenity values in the areas where they are sited [71]. [61] sums up: "*In sum, research has shown that the visual impact of pylons is one of the main dimensions influencing negative perceptions of high voltage power lines and that people tend to prefer alternative designs to the conventional one*". Given this it is important to look at how visual pollution effects are reduced or removed and the costs associated with that.

Noise pollution effects

There is some evidence as well that overhead lines generate noise and this too can cause negative effects on wellbeing. The quote below is from UK National Grid *:*

"High voltage overhead lines can generate noise. The level of this noise depends on the voltage of the overhead power line. Sometimes a 'crackling' sound accompanied by a low frequency hum can be heard. Noise from an overhead power line is produced by a phenomenon known as 'corona discharge'. Overhead power lines are constructed to minimise this, but surface irregularities caused by damage, insects, raindrops or pollution may locally enhance the electric field strength sufficient for corona discharges to occur".(National Grid, A Sense of Place, Design Guidelines for development near high voltage overhead lines).

The health effects of environmental noise in general are well documented [77] and can include cardiovascular disease, cognitive impairment, sleep disturbance, tinnitus and annoyance. This suggest it is important to look at how noise issues and associated costs are addressed.

4.4.2. Types of activities and costs associated with addressing health and well-being effects

From our review of literature and consultation with TSOs types of activities and in some cases costs associated with reducing or mitigating health and well-being impacts, visual impacts and noise were gathered.

With respect to physical and psychological health effects the main response from the TSOs to the questionnaires raised within the WP6 of eHIGHWAY2050 was that they would operate within the national guidelines for safety on EMF and that generally there would be no compensation. One TSO did say that if they had to place the line close to a house so that the EMF levels were too high then they would offer to buy the house. Rather their approaches would be to minimizing the use of overhead transmission lines near areas of high population density and in some cases to use underground or cable tunnels to house transmission lines as opposed to overhead lines which reduces the health risk and the visual impact associated with overhead lines. The literature and TSO interviews reveal that overhead lines are the cheapest option, with underground cables being more expensive and cable tunnels being the most expensive option.

[64] estimated that the cost of an overhead line was between €1.88 to €2.11 million/km, the cost of an underground cable was between €21.11 to €25.81 million/km and the cost of a cable tunnel was between €30.50 to €52.78 million/km. [65] found that underground cable cost approximately €1.54 million more and were 2.5 times more expensive than overhead lines.

The underground capital cost is more, relative to transmission capacity, than overhead lines, and is also more expensive with increased voltages (See Fig. 44).

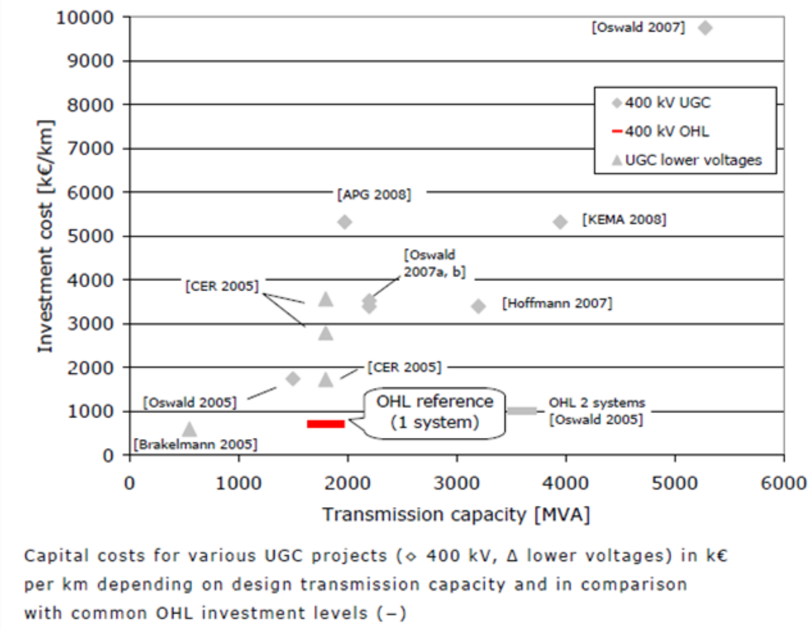


Fig. 44 – Capital cost vs. transmission capacity for different projects [62]

However, the finding by [68] that there is no risk to health if the cables are underground may justify the additional costs. There is public concern on the health risks of new transmission lines, with one report finding that 474 out of 522 people cited health risk concerns with new transmission lines [62]. The costs also vary depending on the maintenance strip surrounding the lines. It was estimated to cost €800,000 for 1km of overhead line with a maintenance strip of 70m (35m each side) in Poland [63].

A further aspect relating to physical and psychological health would be the implementation of monitoring systems to make transparent EMF levels which would have costs associated with them.

In terms of visual pollution the types of approaches carried out include implementing mitigation measures by TSOs to reduce visual impact concerns such as land compensation[22] which could involve offering to buy the house at market value or offering to financially compensate the land owner for the loss of property value resulting from the addition of overhead lines/energy grid infrastructure (see Section 4.2).

[22] Note: There is a lack of clarity over the reasons behind land compensation. If the land compensation is for activities foregone, then it belongs in Section 4.2, however, if it is for disruptions to health and wellbeing, or to compensate for ill feeling towards the energy grid development, then it might belong in Sections 4.4 or 4.5

[69] uses compensation/mitigation measures in response to any visual damage that their developments cause. The second option is for RTE to refund the difference between the selling price of the property (providing it's clearly not underestimated) and the market value of the property before the construction of the line.

A further option as discussed above is to have underground cables which is more expensive. There is also evidence that people respond differently to different designs of overhead pylon and so this might be another way to compensate for visual pollution.

In terms of noise pollution, if noise levels are too high, then noise reduction measures such as switchgear housings can be taken (Amprion, TSO) or relating to corona discharge, one solution is to increase the number of bundle conductors (Terna, TSO).

4.4.3. Proposed approach for BCA

From our research, we believe that the underlying differentiation associated with social costs is whether the transmission lines are in a sensitive area or not.

We define 'sensitive areas' here using the same methodology as [13]:

- Sensitivity regarding population density: potentially crossing densely populated areas as defined by national legislation. As a general guidance, a dense area should be an area where population density is superior to the national mean;
- Sensitivity regarding landscape: protected under the following Directives or International Laws:
    - World heritage;
    - Other areas protected by national law.

Assessing sensitivity

From our research, we suggest that areas of increased sensitivity should be defined in terms of population density (more people living closer together: this could create negative effects of physical and psychological health, noise pollution and visual pollution).

In terms of sensitivity regarding landscape, we would suggest to check for noise and visual pollution those sites that are known for their tranquillity/visual beauty which could be negatively impacted by grid development (most notably touristic areas).

Costs related to physical and psychological health

In terms of costs we suggest these might be:

- costs of compensation if houses have to be bought;
- costs of monitoring equipment for EMF levels.

Costs related to visual pollution

In terms of costs we suggest these might be:

- costs of changing the design of the pylons;

- costs of underground cable or cable tunnel.

Costs related to noise pollution

- costs of mitigation measures e.g. switch gear housing or increasing the number of bundle conductors.

For each situation it would be important to decide what types of measures would need to be taken and gather costs accordingly.

Data needed

In order to provide total costs we need the following data:

a) # of km of transmission grid per sensitive area;

b) Costs of the different aspects highlighted above, per km per sensitive area (per country/type of grid technology; in absolute cost figures and/or as a percentage of total project costs);

c) If we had this data, it might be possible to calculate the following:

Total costs = ∑ a * b (in absolute cost figures and/or as a percentage of total project costs).

Tab. A2-2 in Annex 2 presents a summary of the assessment of the impacts of transmission infrastructures on health and wellbeing.

4.5. Public attitudes and actions

This section presents a conceptual explanation of the suggested methodology to measure the effects related to public attitudes and actions in relation to the development of the new electricity grid architecture.

To begin with, we outline the types of effects that are considered to be relevant, how the effect might be assessed and how that assessment might be monetized so that costs can be extracted. The approach to the costing differs from the general framework proposed in Section 4.1 of this document in that public attitudes are usually translated into extra time required by the approval procedures. This extra-time is translated into a delay interval before the entering into service of the new infrastructure. The extra delay affects costs for two main reasons:

- the benefits that could be extracted are actually not achieved over a certain time period. If the new infrastructure is highly needed, this will mean extra dispatching costs;
- the benefits will be extracted later, implying that the (discounted) net present values of these benefits will be lower.

4.5.1. Public attitudes and actions associated with the development of transmission lines

Public attitudes and actions are important to understand as they can have a large impact on the deployment time of a new transmission infrastructure, depending whether it is accepted or opposed by both national and local communities. The Aarhus Convention [76] provides a framework for the right of everyone to receive environmental information held by public authorities, to participate in environmental decision-making, and to review procedures to challenge public decisions that have not respected the previous two rights. Therefore, it is important that the public is informed and consulted on the development and construction of new energy grid infrastructure.

Local opposition to overhead power lines is a clear issue which is acknowledged and understood by the TSOs and has also been researched [73]. This opposition can stem from two key sources: a) anxiety about possible health and well-being impacts and b) the process by which people are engaged in the different stages of the project, or what has been termed “procedural justice”, i.e. the fairness of the processes that are used to take decisions. If procedures are perceived by the public to be fair then there is likely to be greater legitimacy of the final outcome. Public engagement activities, allowing the public to provide input and influence decisions on development issues, can enhance the perceived fairness of these processes. It can also reduce opposition to new developments by taking the views of those affected into account before construction begins. In doing this, energy companies may reduce the likelihood of both costly and lengthy legal challenges associated with the development.

In the previous section we discussed a possible approach to calculating the costs of health and well-being effects, so in this section we focus on quantitatively assessing costs and time delays in relation to public engagement processes.

4.5.2. Types of activities and costs associated with engagement processes in relation grid development

In terms of the types of activities carried out in order to reduce controversy or public opposition the key one is to carry out early and effective engagement processes. This is what the TSOs would do as a norm with some of them highlighting the legal requirements for consultation etc. The quote below shows how one TSO goes about this:

"The residents are proactively informed before the submission of the application for new construction projects. The information is given at public events, where the status of the project, its technical and environmental aspects are presented. If required a project board of advisors is formed during the approval process. The board unites the municipalities, key stakeholders and environmental organizations. The goal of the advisory board is to optimally use the organization freedom in each project. Members of the board are given opportunities to express their concerns, to present the different options how to resolve them and to participate into discussions in a constructive way. The board forms a consulting forum, where one can bring forth mutual understanding and different concerns. Through this the communication on the project can be optimized and the public acceptance is increased" (SWISSGRID, 2013 response to questionnaire)

The TSOs have provided us with some of the key criteria that they consider lead to the need for increased engagement. For example :

- Longer lines cover more regions and may need more events;
- Areas of high population density may have many land owners with small properties and have greater engagement costs as a result (Swissgrid; Svenska Krafnaet).

Only one TSO provided information on costs for public consultation events during the approval stage (€121,619) and €81,080 for information disclosure events during the construction phase (Swissgrid).

Another issue that can be appraised in economic terms concerns delays in realizing "project benefits". These delays can be translated into costs for the system in the framework of the Net Present Value appraisal. As Terna (Italy) states:

" local opposition may delay the project realization up to several years with basically two costs amount: the first related to lack of project benefits for the entire transmission system along the delaying years, the second is the additional costs amounts related to designing updating, investigation of alternatives, effort proving the "goodness" of the projects" (TERNA, 2013 response to questionnaire).

Some indication on the dependency of deployment time on the typology of the new transmission infrastructures can be derived from the periodic planning documents published by the European TSOs.

4.5.3. Proposed approach for BCA

The two extra-costs bound to public acceptance may be classified into two categories:

- extra costs of increased up front consultation e.g more events at approval stage or more information disclosure at the construction stage or. We only received some information on this kind of costs from Swissgrid (see above). In consideration of the negligible amount of this kind of costs, we propose not to take them into account in the e-HIGHWAY2050 BCA;

- extra costs quantified in terms of delays in realizing project benefits**.** Periodic TSOs' planning documents could be consulted with the aim to identify a series of intervention typologies and a typical deployment time (divided into authorization phase and realization phase) to be then matched with the variants proposed within the scenario analysis of the project e-HIGHWAY2050.

Tab. A2-3 presents a summary of the assessment of the impacts of transmission infrastructures on public attitudes and actions.

4.6. Impact of new technologies

Transmission expansion benefits provided by the investment in innovative technologies need to be carefully evaluated and possibly quantified towards the build-up of the overall WP6 BCA methodology.

In addition to the benefits provided by investments in conventional transmission devices [9][11], more widely addressed in Task 6.1 (Economical profitability analysis) and Task 6.3 (System security aspects), other benefits which typically result from the implementation of innovative technologies have been treated in Task 6.2. In particular, elements related to *controllability*, *adaptability and relocatability*, and *enhanced observability*, provided by innovative transmission technologies, have been investigated, with the goal to properly take them into account towards their quantification and monetization in the BCA methodology. On the other hand, it has to be also highlighted that further benefits, such as system dynamic behavior improvement, that may be provided by advanced transmission devices, are not taken into account in the following.

4.6.1. Controllability

The controllability of a power system can be intended as its capability to flexibly react to rapid and large imbalances, such as unpredictable fluctuations in demand or in variable generation, by handling system variables in a way that keeps a reliable supply. It can be measured in terms of megawatts (MW) available for ramping up and down, over time [81].

Resources that contribute to system controllability may include dispatchable power plants, demand-side management and response devices, energy storage facilities, as well as transmission grid technologies[23] like FACTS, HVDC, DLR/RTTR, PST, PMU/WAMS. The issue of controllability evaluation can be seen in different perspectives, depending on the timeframe considered and the corresponding task target (long-term planning, operational planning, operation) by the involved TSO.

Approaches to account for controllability

Given the different boundary conditions, controllability can be taken into account by two parallel and independent ways. In the first approach, since controllability is connected to the capability of a wide set of facilities and/or transmission technologies to cope with different operating conditions, the benefit that these devices may generate can be seen as a component of the total Social Welfare (SW) increase. In practical terms, this benefit can be evaluated by means of system analyses comparing conditions with and without the device(s) under scrutiny, detracting the SW components that are already accounted for in other WP6 tasks (see Chapter 3).

In the second approach, controllability benefit can be considered in terms of savings derived to a TSO from a reduced reserve power acquisition in a balancing market. This benefit may be quite

[23] FACTS: Flexible Alternating Current Transmission System; HVDC: High Voltage Direct Current; DLR: Dynamic Line Rating; RTTR: Real-Time Thermal Rating; PST: Phase Shifting Transformer; PMU: Phasor Measurement Unit; WAMS: Wide Area Measurement System.

challenging to capture nowadays: advanced tools for balancing markets simulation in real-time would be needed. An approximation to evaluate this aspect could be based on the estimation of the avoided reserve power acquisition monetized at a possible standard/reference price.

4.6.2. Adaptability and Relocatability

Overview

The adaptability can be intended as the ability of the proposed reinforcement plan to adapt to different possible future development patterns or scenarios. In a sense, this concept complements the one expressed by the flexibility of an investment (see also Section 7.1) which reflects the full usefulness and feasibility of an investment in presence of changing scenarios. In fact, long-term uncertainties involved in the transmission expansion planning are better coped with flexible transmission investments (TI). Planners are looking for flexibility and adaptability for seizing opportunities or avoiding losses upon the occurrence of unfavorable scenarios. This adaptability may include various actions at different stages of the investment horizon, such as the options to defer, expand, or even abandon the project. In this context, the adaptability may have a substantial value, and it appears suitable to be taken into consideration within the decision-making process.

In this category, also the feature of relocatability, potentially offered by transmission grid technologies, such as some FACTS[24] devices (shunt, series), PSTs, back-to-back HVDC systems, PMUs of WAMS architectures, and also by battery devices, could be interestingly addressed. The relocatability feature has so far particularly concerned shunt FACTS like SVCs, resulting in installations of relocatable SVCs (RSVCs) in some substations in South Africa and in the UK [79][80]. In this way it is possible to fully exploit the potential of these devices to adapt to changed needs in the power system. To this purpose SVC installations need to be compact in order to make relocation possible within 3-6 months. It is evaluated that relocation might occur up to 5 times in a 40 year-operating life of a RSVC [80]. Also, devices like STATCON (with or without battery storage) can be currently designed for being relocated. Other FACTS technologies that may have in the future a high relocatability potential are series-connected devices (TCSC, SSSC), and in general VSC (Voltage Source Converter)-based controllers for their compactness with respect to thyristor-based devices. It has to be highlighted that, in a BCA methodology, the additional relocatability costs related to design oversizing and uninstallation/transport/re-installation of the device must be carefully taken into account[25].

[24] Shunt-connected FACTS may include SVC (Static VAR Compensator), STATCON (STATic CONdenser), while series-connected FACTS may include TCSC (Thyristor Controlled Series Capacitor) and SSSC (Static Synchronous Series Compensator).

[25] Additional costs for relocatability may amount to 20% up to 40% of the total investment cost, depending on the device design and type as well as on local conditions [3][5].

Real option approach and literature review

In terms of advantages, FACTS[26] technology may not only be relocated but also reduce/postpone the need and the dimension of new transmission lines. To analyze the potential adaptability of a FACTS in comparison to a new transmission overhead line, an interesting possibility could be given by the real option (RO) approach developed in [16][17].

In fact, classic grid reinforcements such as transmission lines (TL) have an important level of irreversibility, which leads to a high risk in terms of long-term uncertainties. Alternative to TL, FACTS devices represent a class of more flexible network investments: therefore, the inclusion of FACTS in TI portfolio adds a new, strategic option to the transmission planning. Traditionally, expansion alternatives with FACTS have been investigated with the same criteria adopted for TL (such as the NPV criterion); though, this approach does not address appropriately uncertainties on future market conditions nor the controllability added by FACTS in transmission planning. On the other hand, the RO approach could provide a well-founded framework to assess investments under uncertainty, since it is able to quantitatively account the risk and the flexibility/adaptability value. This approach, which is directly derived from financial option theory, is a risk management method that allows to properly handle uncertainties which are unresolved at the time of making investment decisions [16][17]: with this aim, TI evaluation should include flexible investments since they act as an hedge against adverse scenarios.

According to RO theory, different operational options can be considered:

a. defer option;

b. abandon option;

c. switch (or relocation) option;

d. expansion option;

e. contraction option;

f. temporary suspension option.

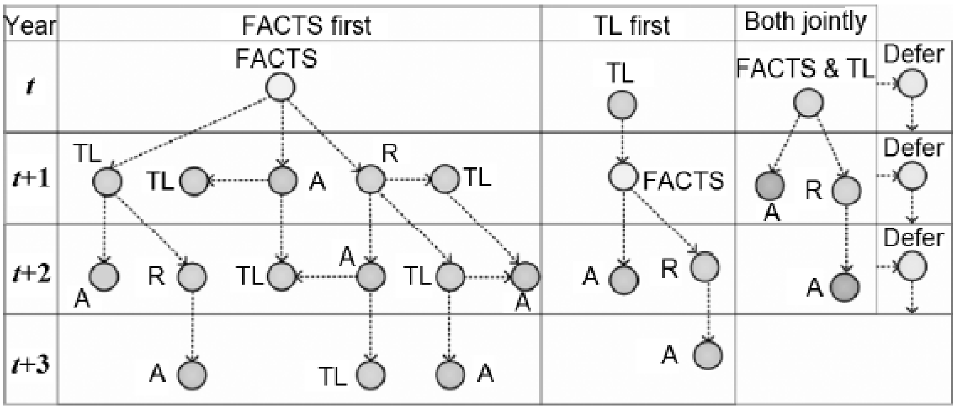
In [16][17], the a.-c. options are evaluated to compare a FACTS (TCSC) with a TL. Typically, it is possible to defer TI: therefore, the postponement option importantly provides flexibility to consider, since keeping the investment option open can protect from adverse evolution of the future. In other words, the defer option can be seen as an extension of the capital opportunity cost: the choice to invest in a specific time implies, de facto, renouncing to the chance to undertake the investment in a future moment when that could be more profitable.

New FACTS designs allow installation so that they can be easily relocated. The option to relocate the device according to the development of system uncertainties should be also taken into account. This can play an important role, as investments in a TL do not have such potential and can be executed or deferred or abandoned, if the evaluation of the power market uncertainties unfolds unfavourably.

[26] The approach taking into account relocatability potential refers to FACTS application, but it can be extended and considered for other relocatable devices.

Considering an approach which exploits a stochastic, chronological simulation based on a Least Square Monte Carlo (LSM) method, investment projects can be seen as a portfolio of American options[27]. The approach shown in [16][17] pursuits a LSM method [86] in order to estimate the continuation for all the previous time stages.

The optimal policy of exercising the options is derived by comparing the intrinsic value of the deferral option with the value of keeping alive the option using, as example, backward dynamic programming techniques. In this case the problem starts from the latest year and working backward is completed in the first year. Fig. 45 shows an example of a case of RO application in a comparison TL vs. FACTS (TCSC) investing first in FACTS (1st strategy), or first in TL (2nd strategy), or first in FACTS and TL jointly (3rd strategy). The options of relocating and abandoning the FACTS project, in addition to the option of FACTS/TL deferral, have been considered [16][17].



Strategies—option map. (R: Relocate option, A: Abandon option).

Fig. 45 - Example of RO approach application [16]

In [16] a practical application of a FACTS (TCSC) option compared to TL option is considered at the France-Switzerland-Italy cross-border interface. The model of the system is based on the equivalent representation of few nodes per country: the applicability of the approach based on RO is proven [16][17].

Adaptability and Relocatability evaluation approach

In order to assess adaptability and relocatability, it should be highlighted that two different dimension, temporal and spatial, are to be considered. Therefore, the net benefit that could be obtained by a relocatable device is a function of the location of the device in different time instants. The same word “relocatability” recalls a dynamic approach: therefore, it appears to be quite challenging to statically address this kind of benefit at 2050 without any information

[27] An American option is an option that can be exercised anytime during its life: conversely, an European option can only be exercised at maturity.

available in the previous years. Considering the framework of the e-HIGHWAY2050 project and the aim to provide a Modular Plan for 2030-2040 after identifying the pan-European transmission network layout at 2050, it can be noted:

- since the whole e-HIGHWAY2050 project analysis accounts three different time instants (2050, 2040, 2030), it is assumed that a relocatable device (FACTS but also PSTs) may be moved every 10 years. Moreover, since the network framework at 2040 and 2030 will be evaluated after identifying the 2050 layout, a backward approach (2050 to 2040, 2040 to 2030) has to be accounted for;
- considering the DC approximation and investigating on the effect that transmission investments have on real power flows, flexible shunt devices for reactive power supply (like SVC and STATCON) cannot be accounted for;
- the abandon option for a relocatable device is not regarded as realistic[28];
- considering the operating constraints in the project, a stochastic approach as the one proposed in [16][17] cannot be followed.

In accordance with the above constraints, the benefit given by a relocatable device may be calculated as follows (Fig. 46):

1. consider the location of the relocatable device at 2050, x_{2050};
2. perform a simulation at 2040 without the relocatable device;
3. identify for the without simulation at 2040 what is the transmission corridor for which, considering the transmission constraint in the optimization problem, the highest Lagrange Multiplier (LM) is reached: by definition, it should represent the maximum benefit obtainable in the objective function *OF* if 1 MW of the binding transmission constraint is relaxed;
4. use the indication given by point 3 as an indication in order to identify where the relocatable device can be installed at 2040, $\bar{x}_{2040}$. Clearly, if $x_{2050} = \bar{x}_{2040}$, then there is no further benefit in relocating the flexible device. Then proceed in a similar way with 2040-2030;
5. if $x_{2050} \neq \bar{x}_{2040}$, evaluate the benefit in relocating the flexible device by means of two simulations (the first one with the relocatable device in x_{2050} at t_{2040}, the second one with the relocatable device in $\bar{x}_{2040}$ at t_{2040}:
$$Benefit\left(t_{2040}, x_{2050}, \bar{x}_{2040}\right) = OF_{2040}\left(Flexible\ \ device@\bar{x}_{2040}\right) - OF_{2040}\left(Flexible\ \ device@x_{2050}\right)$$
6. evaluate the costs in relocating the device from x_{2050} to $\bar{x}_{2040}$: $Cost_{reloc}\left(x_{2050}, \bar{x}_{2040}\right)$;
7. evaluate the net benefit obtainable in relocating the device:

[28] The abandon option for a relocatable device means that the device can be re-sold without installing it.

$$Benefit_{Net}\left(t_{2040}, x_{2050}, \bar{x}_{2040}\right) = Benefit\left(t_{2040}, x_{2050}, \bar{x}_{2040}\right) - Cost_{reloc}\left(x_{2050}, \bar{x}_{2040}\right)$$

8. proceed in a similar way for 2040-2030.

Then, the overall benefit obtainable in relocating the device at 2040 and 2030 can be evaluated at the same reference year (2050, …) by means of the NPV formula.

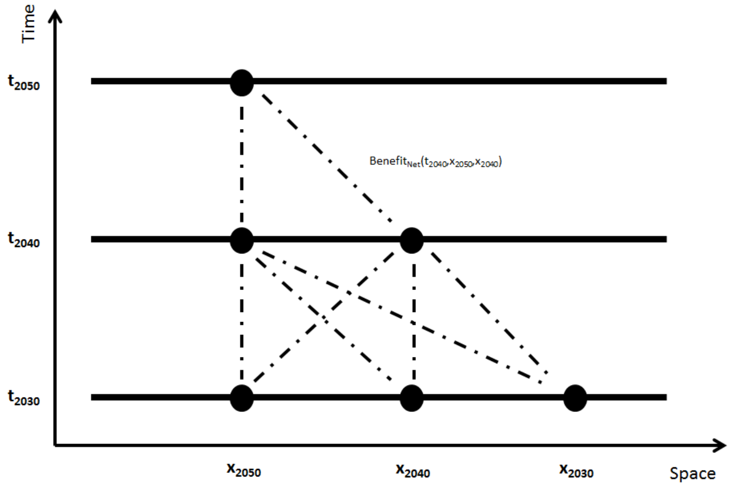


Fig. 46 – Relocatability net benefit – Possible approach (for sake of simplicity, the net benefit obtainable in relocating at 2030 is not represented)

It is important to highlight that the set of possible location of a relocatable device is dependent on the transmission asset ownership and regulation: for the time being, given current regulation in place it would be reasonable to restrict the relocation option to the domain of the single respective TSO; however, considering future evolutions of European regulation, the approach could be extended to have relocation option applicable at regional or at European level as well.

Example of RO application

A simple example, inspired by [16], is described in the following. A system with 3 zones (clusters), A, B, C, with the respective equivalent generation (G) and load (L), is depicted in Fig. 47. These zones are mutually interconnected through 5 corridors (C1, C2, C3, C4, C5). In addition, there is a transmission line L1 linking zone A and zone C, while zone B and zone C are tied by transmission line L2 too. It is here assumed that corridors C4 and C5 and line L1 between zone A and zone C are congested: a long-term solution should be the reinforcement of the interconnection by adding a new line TL. However, this solution implying a large-scale irreversible investment could be excessive in case of uncertain evolution scenarios over the years. This is especially true if there is still available transfer capacity on the interconnections between zone B and zone C. Hence, the deferral of the investment in TL, waiting for the unfolding of the uncertainties, could be worthwhile. The deployment of a FACTS device may provide a possible way to address the issue, at least in a short/mid-term, while the investment in TL may be possibly postponed to mid/long-term, until more certain elements become available. Thus, a proper mix of transmission controllers like FACTS devices and TL would be required.

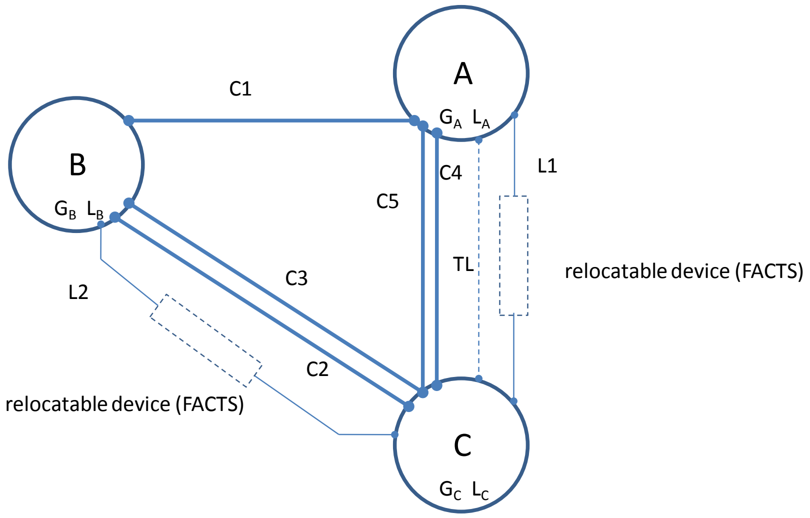


Fig. 47 – Example of RO application

In this example, two investment alternatives are evaluated: 1) a TL between zone A and zone C; 2) a relocatable series FACTS device connected to L1 between zone A and zone C, with the option to relocate it on L2 between zone B and zone C. Then, three mutually exclusive options like strategies S1 (investing first in FACTS), S2 (investing first in TL) and S3 (investing in FACTS and TL jointly) can be assessed. A numerical example can be useful for the comparison of the strategies (see Tab. 24).

Tab. 25 – Comparison of strategies

Strategies	Option value	NPV	Added value
S1	60 M€	35 M€	25 M€
S2	52 M€	40 M€	12 M€
S3	45 M€	28 M€	17 M€

The values in Tab. 25 show that, by applying traditional NPV criterion for investment assessment, strategy S2 would be selected. However, by considering the options provided by FACTS strategy S1 gains the highest flexibility/adaptability benefit, taking into account relocatability features. In fact, for S1 the option value exceeds the one for S2. The fact that the strategy S1 of investing in FACTS first is the most convenient by RO approach is mainly due to the flexibility provided by FACTS allowing a better adaption to possible adverse scenarios in the long-term, exploiting the relocatability potential. On the contrary, in TL expansion alternatives, this potential is not available and only the deferral option is present. Accordingly, the economic value of such expansion projects is lower than more flexible/adaptable investment portfolios [16].

4.6.3. Enhanced observability

An enhanced observability is a feature that can be provided by transmission grid technologies able to monitor the system, such as WAMS, whose key components are the PMUs. A WAMS architecture may potentially widely coordinate controlling technologies such as DLR/RTTR cables/lines, FACTS, PST, HVDC [82]. This benefit is also indirectly linked with the system security increase (treated within Task 6.3).

The enhanced observability granted by PMUs/WAMS has been kept into account and studied from the transmission planning viewpoint in different papers (see for example the references [83][84][85]). In these analyses, given the important features provided by WAMS in terms of speed and precision, a crucial starting point that must be here highlighted is that WAMS is assumed to be the key entity in charge of monitoring and control functions for the power system under scrutiny [84]. The first stage in PMU planning refers to addressing the optimal PMU amount and placement: this consists in solving an optimization problem in order to find the minimum number of PMUs as well as their placement to make the power network topologically observable [85]. The objective function to be minimized is then given by the amount of PMUs which can be extended to consider PMU installation costs.

The condition of complete network observability over the system faults and operation status is generally assumed in power system reliability studies. This also supposes specific remedial actions and applies load shedding as the last resort at any load points requested [84]. These procedures imply a reliable monitoring and control system (which could reflect an ideal situation): this assumption is considered also in the following.

It must be also said that the constraint of complete network observability means that all network buses are observable. The observability of a network bus depends on the installation of a PMU at that bus or at one of its incident buses [85]. The optimal PMU amount and placement can be then deterministically calculated, also taking into account specific situations (effect of zero-injection network buses) and contingencies (single PMU outage, single line outage, measurement limitations), as proven in [85].

Further stage to be carried out is then in terms of cost-benefit investigation [83]. In this analysis both costs and benefits of a WAMS architecture configuration, in which PMUs represent the main building blocks, are to be taken into account.

The calculation of implementation cost of a WAMS configuration can be carried out by considering cost elements, referred to: procurement, installation, commissioning, and periodical calibrations of PMUs and related accessories such as software, measurement devices, panel, cables, and communication link; control center hardware facilities as well as WAMS control center software [83]. On the other hand, the quantification of benefits provided by WAMS may be a complicated task. Theoretically, one of main static benefits provided by WAMS can be expressed in terms of system security increase by a reduction of EENS (Expected Energy Not Supplied) and monetized through the VoLL (Value Of lost Load) parameter [83]: this would require the assessment of EENS variation (without and with the WAMS under scrutiny), keeping unchanged all other boundary conditions. For this analysis, a probabilistic modeling approach might be needed [84].

In practical terms, an estimation of WAMS benefit in terms of security increase may be performed by taking into account, if available, statistics of EENS variation with respect to PMU amount.

Moreover, observability aspect should be considered as a feature that impacts both to transmission system operation and transmission expansion planning. Therefore, the evaluation of the costs and the benefits associated to devices that make the network more observable must account for this duality.

4.7. Applying the socio-environmental methodology to eHighway2050

As shown in the previous sections, the methodology for assessing the social and environmental aspects will actually take into account an extra cost items condensing together the follow aspects: land use and property value, biodiversity and landscape costs and health and wellbeing costs. Additionally, a delay parameter will be calculated in order to take into account a delay factor due to the length of the approval procedures, that take into account a public opposition factor. Whereas the cost factor will be algebraically summed with all other benefit and cost parameters, the information on the delay time will be used for the Net Present Value calculation.

Determining the socio-environmental cost parameter is on one side difficult for the number and complexity of the implied factors, on the other side the clusterized representation of the European system adopted by the e-Highway2050 is not coherent with the analysis of environmental factors, that would require a full detail of the infrastructure tracking in order to assess its impact on the territory. This detail can, otherwise, not be available for expansions that are foreseen in a so long time horizon.

In order to take into account the difficulties above, a simplified approach was decided, based on a brown field assumption. As a matter of fact, the deployment of new infrastructures is facilitated when these infrastructures are located next to already existing transmission corridors. So, a socio-environmental costs-benefit assessment can be done by creating a table that for each couple of clusters assesses calculates a cost factor per unit of length of a new infrastructure by considering the typology of the territory crossed by the already existing lines. This cost will be also a function of the technology choice for the corridor reinforcement.

There will only be one cost factor for each couple of clusters and not three different ones to cope with land use and property value, biodiversity and landscape costs and health and wellbeing costs. The reason for this is that, as it was clarified in the previous sections of the present chapter, most of the analysed factors are either too difficult to quantify or depend too much on the analysis of the exact tracking of the new lines. By contrast, land use seems to be the most clearly assessable parameter and also the prevailing one from the quantitative point of view. So, the cost factor will essentially be based on the land use aspect. Land use depends on the area occupied by the infrastructure. The length factor depends on:

- the distance between the two clusters, measured on the average length of the already existing lines in-between
- the width of the stripe, that depends on the technology used, whether it there is a grounded or overhead line, etc. These variables will be all considered in the table.

5. Costs and benefits related to security of supply and system resilience

5.1. Overview

This section aims at providing the main features of the methodology so far designed to compute system security costs associated with each network architecture provided by WP2. Each of the main aspects related to system security is dealt with separately. Thus, sections 5.2, 5.3, 1.1 and 5.5 dealt with reliability, resilience, demand side management and RES energy curtailment, respectively.

The methodology proposed in this document is highly conditioned by the structure of the whole project. The methodology must take into account the fact that only results from the market simulations performed for each network architecture in WP2 will be available. No specific security-oriented results will be available to feed the adopted methodology. This methodology should therefore be understood as the best effort to estimate security related costs from market simulation results provided in WP2 of this same project.
Besides, the methodology should be appropriate to be programmed within a “Cost & Benefit calculation tool” making use of a) input data, and b) formulas to be applied, to compute c) output data, without resorting to any additional specific simulation or computation outside the “tool”.

5.2. System reliability

There is a large body of technical literature devoted to computing reliability costs, see for example [72] for a description of different methodologies for the computation of the cost if service interruptions, and [88] for the use of guidelines set by CEER for the computation of these costs. Provided that the set of available input data for this computation is the one delivered by the market simulations performed in WP2, the reliability costs in this project are to be computed as the cost of non-served energy resulting from service interruptions. Therefore, given a unitary value of non-served energy, VoLL (Value of Loss of Load in €/MWh)[29], the cost of interruptions could be computed as the amount of load interrupted times the VoLL.

Therefore, the reliability cost RC for each proposed network architecture and for each time horizon considered (2030, 2040, 2050), will be expressed as

$$RC = \sum_{h} (VoLL \cdot \mathrm{NSE_h})$$

where $\mathrm{NSE_h}$ represents the amount of Non Served Energy in hour has provided by WP2 market simulations. Both RC and $VoLL$ values will be expressed in €/MWh 2013.

[29] Technical literature refers to this value using different names Value of Loss of Load, Value of non served energy, Utility value of curtailed energy. In this text we always refer to the unitary value of a MWh of energy been interrupted (€/MWh).

However, the VoLL is not uniform. It depends on the use that would have been made of non-served energy. The use to be made of that energy shall be estimated according to the value adopted by several factors, namely a) the composition of load existing in each node of the network; b) the amount of interrupted load in this node; and c) the duration of the interruption affecting this node. Next, the influence of each of these factors on the VoLL is discussed:

a) Assuming technology deployment in years 2030-2050 allows demand to be curtailed selectively, load interrupted in each node should be the one with the lowest value existing in the node. Therefore, the value of load curtailed in a node depends on the **amount of energy used for each economic activity in this node**. Within the E-Highway2050 project, the amount of electric energy consumed in each type of economic activity in a node is to be computed based on the gross amount of load in the node (adding up served and non-served load) and the composition of electricity load in the year 2012 in the corresponding country. The latter is to be computed as the set of weights of the types of economic activities in national electricity consumption (data to be gathered from Eurostat database). Since no assumption regarding the composition of load at each node is to be made available from the load data scenarios adopted in WP1 and WP2, we implicitly assume that the composition of load is the same for all the nodes of the same country at any moment of the year and will remain unaltered up to the year 2050, regardless of the different load scenarios adopted in WP1 and WP2. However, the methodology is prepared to consider other input values for the demand composition by time horizon and scenario, if available.
b) Obviously, the larger the **amount of load affected by an interruption**, the more valuable will be the uses made of energy that will have to be disrupted.
c) Finally, for any economic activity affected by an interruption, the longer the **duration of an interruption**, the more capable consumers are to manage internal processes so as to preserve the most critical ones from being curtailed. Thus, for example, auxiliary generation may be started sometime after an interruption takes place in order to supply the more critical processes, leading therefore to a lower unit value of energy curtailed

Therefore, the detailed formulation of the reliability cost, RC , for each proposed network architecture and for each time horizon considered (2030, 2040, 2050) will be:

$$\mathrm{RC} = \sum_{\mathrm{h,n \in c,k}} (\mathrm{VoLL_{k,hi,c}} \cdot \mathrm{NSE_{h,n,k,hi}})$$

where $\mathrm{VoLL_{k,hi,c}}$ represents the Value of Loss of Load associated to demand type k, number of hours of interruption ‘hi’ and country c (in €/MWh 2013); and $\mathrm{NSE_{h,n,k,hi}}$represents the amount of Non Served Energy of type of demand k, in hour h, at node n, that has been interrupted for a number of hours hi. Note that hi represents the number of hours passed since the start of the interruption in node n until hour h.

For the detailed specification of the process, each of the two components of the above expression (VoLL and NSE) have to be detailed. The methodology followed for the estimation of the parameter VoLL is detailed in section 5.6. The following section 5.2.1 is dedicated to the detailed assessment of NSE, split by node, hour and type of activity.

5.2.1. Non Served Energy

The amount of Non Served Energy of type of demand k, in hour h, at node n, and that has been interrupted for a number of hours hi, will be computed from WP2 market simulations results in the following steps.

1) The total amount of load curtailed in each hour of the year in each node of the network for each network architecture will be obtained from the results of the simulation of the hourly operation of the system in the target year (2050, 2040, 2030) computed in market analyses in WP2. Let's denominate it Gross Non Served Energy by hour and node $\mathbf{GNSE_{h,n}}$.
2) Some countries resort to the mobilization of interruptible contracts, or other equivalent reliability driven DSM mechanisms, to avoid Non Served Energy. Since the cost of these mechanisms are considered separately in section 3 of this document, if these mechanisms have not been considered in market analyses in WP2 to reduce, to the extent possible, the amount of load curtailed in each node and hour, the latter will be decreased up to the point where any of the following two conditions is met: i) either the amount of load curtailed is reduced in the amount of interruptible load available in this node or ii) load curtailed is reduced up to the point where it is made zero.

$$\mathrm{NSE_{h,n}} = \max\left(\mathrm{GNSE_{h,n}} - \mathrm{IL_{h,n}}\ ;\ 0\right)$$

where $\mathrm{IL_{h,n}}$ represents the amount of interruptible load available in hour h and node n[30]

An indicative value for the amount of interruptible load existing in each node of a country at each hour of the year $\mathrm{IL_{h,n}}$ is to be computed as the overall amount of load in that country deemed to be interruptible times the fraction of load in this country corresponding to that node. The overall amount of load deemed to be interruptible in a country is going to be estimated according to DSM levels provided in ENTSO-E SOAF analyses. This indicative value may be modulated according to answers received to the questionnaire related to this issue.

$$\mathrm{IL_{h,n\in c}} = \mathrm{IL_c} * \frac{\mathrm{L_{h,n\in c}}}{\sum_{\mathrm{n\in c}} \mathrm{L_{h,n\in c}}}$$

where $\mathrm{L_{h,n}}$ represents the gross load demand at hour h and node n (the one used in WP2 market's simulations), and $\mathrm{IL_c}$ represents the total load deemed to be interruptible in country c.

3) The resulting total amount of load interrupted in each node of the network in each hour of the year will be then assigned to the demand of the least valuable types of economic activities taking place in this node in this hour.

$$\mathrm{NSE_{h,n}} \xrightarrow{\text{yields}} \mathrm{NSE_{h,n,k}}$$

[30] Interruptible load is deemed to be used locally, i.e. within the same node of the network (representing a zone of the system) where Non Served Energy is occurring

where the allocation of Non Served Energy to each type of demand k in that hour h and node n will be driven by the Value of Loss of Load corresponding to the type of demand k in the country c that node n belongs to, $\mathrm{VoLL}_{k,c,hi=1}$.

Obviously, it cannot be allocated more unserved energy to type of demand k than the total amount of load of demand of type k existing in hour h and node n

$$\mathrm{NSE}_{h,n,k} \leq \mathrm{L}_{h,n,k}$$

where $\mathrm{L}_{h,n,k}$ represents the gross load of type of demand k, in hour h in node n.

If Non Served Energy in anode happens to be larger than the total amount of load of the least valuable types of demand, the remaining Non Served Energy will be allocated to the next type of demand with the lowest VoLL, and so on, till all Non-Served Energy is allocated.

This requires knowing the amount of load corresponding to each type of activity in each node and hour. These values are to be computed as the gross level of load in this node and this hour times the fraction of the total annual load in the country corresponding to this type of activity. This is implicitly assuming that the composition of electricity load in a country is representative of that in all the nodes in the country at all the times of the day and the year.

$$\mathrm{L}_{h,n,k} = \mathrm{PTL}_{k,c} * \mathrm{L}_{h,n}$$

where $\mathrm{PTL}_{k,c}$ represents the proportion of the total annual load corresponding to type of demand k with respect to the total demand in country c.

4) Finally, given the amount of Non Served Energy in node n and hour h for type of activity k, one must determine for how many hours this load has been curtailed. In order to make the consideration of the effect of the duration of load curtailment on the cost of NSE tractable, it is assumed here that the amount of non-served load in each node for the same kind of demand in previous hours of a certain supply interruption is, if non-zero, at least as large as that in the considered hour h.

$$\mathrm{NSE}_{h,n,k} \xrightarrow{\text{yields}} \mathrm{NSE}_{h,n,k,hi}$$

Then, given the value of $\mathrm{NSE}_{h,n,k}$, one must check for how many of the immediately previous hours in a row, t, the value of Non Served Energy in this node and type of activity is non zero. In other words, one should check what is the largest number of hours t for which $\mathrm{NSE}_{h-t',n,k}$ is non zero for t'=1➔t. If t=0, the VoLL corresponding to 1 hour of interruption will be applied to that Non Served Energy, if t is in between 1 and eleven, the VoLL corresponding to an interruption of between 2 and 12 hours will be applied; and if t is greater than 11, the VoLL corresponding to more than 12 hours of interruption will be applied.

5.2.2. Example of application

Let's consider a system comprising two countries c=1,2 and four nodes n=1,2,3,4, belonging nodes 1 and 2 to country 1, and nodes 3 and 4 to country 2. Consider 13 consecutive hours of operation h=1,2,3,4,5,6,7,8,9,10,11,12,13. Consider two types of demand k=1,2.

For a given scenario, network architecture and time horizon, let's compute the associated Reliability Cost, RC

Input data

A) WP2 provides the following data for a the given network architecture corresponding to a scenario and time horizon,

Tab. 26 - Load values at all nodes n and for all hours h

$\mathbf{L_{h,n}}$ (MWh):													
Hour nº	1	2	3	4	5	6	7	8	9	10	11	12	13
Load Node 1	200	250	300	300	250	250	200	150	100	150	150	200	200
Load Node 2	300	350	400	400	350	350	300	250	200	250	250	300	300
Load Node 3	200	250	300	300	250	250	200	150	100	150	150	200	200
Load Node 4	500	550	600	600	550	550	500	450	400	450	450	600	600

Tab. 27 - Gross Non Served Energy values at all nodes n and for all hours h

$\mathbf{GNSE_{h,n}}$ (MWh):													
Hour nº	1	2	3	4	5	6	7	8	9	10	11	12	13
GNSE Node 1	0	0	0	0	0	20	0	0	0	0	0	0	0
GNSE Node 2	0	30	20	20	0	0	0	0	0	0	0	0	0
GNSE Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
GNSE Node 4	40	40	30	30	30	30	30	20	20	20	20	20	20

B) Expertise and questionnaire answers provide the following data

Tab. 28 - Value of Loss of Load for all countries c, all types of demand k, and for the three types of duration of the interruption 'hi'

$\mathbf{VoLL_{k,hi,c}}$ (€/kWh):				
Country	Type of demand	hi=1 (less than 1 hour)	hi=2 (in between 2 and 12 hours)	hi=3 (more than 12 hour)
c=1	k=1	0.6	0.4	0.2
	k=2	0.3	0.2	0.1
c=2	k=1	0.4	0.2	0.1
	k=2	0.5	0.3	0.2

Tab. 29 - Proportion of types of demand for all countries 'c', all types of demand 'k'

$\mathbf{PTL_{k,c}}$(%):		
country	Type of demand k=1	Type of demand k=2
c=1	60%	40%
c=2	30%	70%

Tab. 30 - Total interruptible load per hour in country 'c' (same for any hour)

$\mathbf{IL}_c$ (MWh):	
country	Interruptible load
c=1	5
c=2	4

Step 1: Computation of $\mathbf{L_{h,n,k}}$

The load for each hour 'h' and each node 'n' is allocated to the type of demand k=1 and k=2 according to the proportion of each type of demand in the country the node belongs to. Therefore from Tab. 26 and Tab. 29 we compute:

Tab. 31 – Computation of $\mathbf{L_{h,n,k}}$

$\mathbf{L_{h,n,k}}$ (MWh):														
	Type of demand	Hour nº												
		1	2	3	4	5	6	7	8	9	10	11	12	13
Load Node 1	k=1	120	150	180	180	150	150	120	90	60	90	90	120	120
	k=2	80	100	120	120	100	100	80	60	40	60	60	80	80
Load Node 2	k=1	180	210	240	240	210	210	180	150	120	150	150	180	180
	k=2	120	140	160	160	140	140	120	100	80	100	100	120	120
Load Node 3	k=1	60	75	90	90	75	75	60	45	30	45	45	60	60
	k=2	140	175	210	210	175	175	140	105	70	105	105	140	140
Load Node 4	k=1	150	165	180	180	165	165	150	135	120	135	135	180	180
	k=2	350	385	420	420	385	385	350	315	280	315	315	420	420

Step 2: Computation of $\mathbf{IL_{h,n}}$

The total amount of demand associated to interruptible contracts for each country is allocated to all nodes in proportion to the load at each node with respect to the total load in the country. Besides, overall levels of interruptible load per country are assumed equal for all the hours considered. Therefore from Tab. 26 and Tab. 30 we compute:

Tab. 32 – Computation of $\mathbf{IL}_{h,n}$

$\mathbf{IL}_{h,n}$ (MWh):													
	Hour nº												
	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	2	2.1	2.1	2.1	2.1	2.1	2.0	1.9	1.7	1.9	1.9	2.0	2.0
Node 2	3	2.9	2.9	2.9	2.9	2.9	3.0	3.1	3.3	3.1	3.1	3.0	3.0
Node 3	1.1	1.25	1.3	1.3	1.3	1.25	1.1	1.0	0.8	1.0	1.0	1.0	1.0
Node 4	2.9	2.75	2.7	2.7	2.8	2.75	2.9	3.0	3.2	3.0	3.0	3.0	3.0

Step 3: Computation of $\mathbf{NSE_{h,n}}$

If interruptible load has not been taken into account during WP2, Interruptible load is deducted from the Gross Non Served Energy values to obtain the actual amount Non Served Energy.

Therefore, from Tab. 27 and Tab. 30 we compute:

Tab. 33 – Computation of $\mathbf{NSE_{h,n}}$

$\mathbf{NSE}_{h,n}$ (MWh):													
	Hour nº												
	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	0	0	0	0	0	17,9	0	0	0	0	0	0	0
Node 2	0	27,1	17,1	17,1	0	0	0	0	0	0	0	0	0
Node 3	0	0	0	0	98,8	0	0	0	0	0	0	0	0
Node 4	37,1	37,3	27,3	27,3	27,3	27,3	27,1	17	16,8	17	17	17	17

Step 4: Computation of $\mathbf{NSE_{h,n,k}}$

We must allocate the amount of Non Served Energy to the different types of demand according the corresponding VoLL of each type of demand in each country. The Non Served Energy is allocated to the type of demand with the lowest associated VoLL, with the limit of the total load of this type of demand in that node and hour.

Therefore, from Tab. 28, Tab. 31 and Tab. 33 we compute:

Tab. 34 – Computation of $\mathbf{NSE_{h,n,k}}$

		$NSE_{h,n,\mathbf{k}}$ (MWh):												
		Hour nº												
Node	Type of demand	1	2	3	4	5	6	7	8	9	10	11	12	13
1	k=1	0	0	0	0	0	0	0	0	0	0	0	0	0
	k=2	0	0	0	0	0	17.9	0	0	0	0	0	0	0
2	k=1	0	0	0	0	0	0	0	0	0	0	0	0	0
	k=2	0	27.1	17	17	0	0	0	0	0	0	0	0	0
3	k=1	0	0	0	0	75	0	0	0	0	0	0	0	0
	k=2	0	0	0	0	23.5	0	0	0	0	0	0	0	0
4	k=1	37.1	37.3	27.3	27.3	27.3	27.3	27.1	17	16.8	17	17	17	17
	k=2	0	0	0	0	0	0	0	0	0	0	0	0	0

Step 5: Computation of $\mathbf{NSE_{h,n,k,hi}}$

In this step we compute for how many hours in a row load for each type of activity in each node and hour has been curtailed. We are assuming that the total amount of non served energy for each type of demand k that exists in an hour h and node n corresponds to load that has been also curtailed in all the immediately previous hours in a row when curtailed load for this type of demand, in this node also exists. This irrespective of the amount of load of type of demand k curtailed in hour h and node n.

Therefore from Tab. 34 we compute:

Tab. 35 – Computation of $NSE_{h,n,\mathbf{k},\mathbf{hi}}$

$NSE_{h,n,\mathbf{k},\mathbf{hi}}$(MWh):															
			Hour nº												
Node	Type of demand	Duration of interruption	1	2	3	4	5	6	7	8	9	10	11	12	13
1	k=1	hi=1	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
	k=2	hi=1	0	0	0	0	0	17.9	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
2	k=1	hi=1	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
	k=2	hi=1	0	27.1	0	0	0	0	0	0	0	0	0	0	0
		hi=2	0	0	17	17	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
3	k=1	hi=1	0	0	0	0	75	0	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
	k=2	hi=1	0	0	0	0	23.5	0	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0
4	k=1	hi=1	37.1	0	0	0	0	0	0	0	0	0	0	0	0
		hi=2	0	37.3	27.3	27.3	27.3	27.3	27.1	17	16.8	17	17	17	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	17
	k=2	hi=1	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=2	0	0	0	0	0	0	0	0	0	0	0	0	0
		hi=3	0	0	0	0	0	0	0	0	0	0	0	0	0

Step 6: Computation of RC

To end up, the Reliability Cost for network architecture 'a' in scenario 's' and time horizon 'th' can now be computed as the VoLL for each type of demand, duration of interruption, node and hour of operation, times the respective amount of non-served energy, summed over all hours, nodes, and types of demand and as a function of the duration of the interruption. From Tab. 28 and Tab. 35 and taking into account the country each node belongs to, we compute:

$$\boldsymbol{RC = 130.3\ k€}$$

5.3. System resilience

We haven't found any explicit definition of system resilience in ENTSO-e documents. Therefore, in this document we propose a definition and proceed accordingly. System resilience is defined as the ability of the electric system to cope with extremely adverse conditions associated to climate and a combination of system contingencies whose probability of occurrence is below a certain threshold level. Some of the climate-associated causes that impact the electric system are, for example, increases in temperatures up to extreme values (hot in summer and cold in winter), decreasing water availability, storm events, etc., see [89] for a more in-depth analysis of the causes of extreme events.

Increasing temperatures will increase electricity demand, reduce the available transmission capacity of lines, and reduce the efficiency of thermal power plants. Extreme low temperatures can damage transmission lines and wind generation facilities and also increase demand. Low water availability will affect primarily cooling power plants and hydropower generation and, collaterally, biomass availability. Storm events can damage transmission and distribution lines and cause a sudden drop in wind generation.

This resilience concept comprises events associated with the classical reliability of the system approach that takes into account mainly the effects associated with single or multiple failures of system elements (namely normal, rare and out-of-range contingencies).

The Scenario Outlook and system Adequacy Forecast (SOAF) studies [90] conducted by ENTSO-e every year are adequacy studies that consider both types of adverse effects. The amount of generation capacity termed non-usable capacity of the generation probably corresponds to a reduction of generation capacity associated with climate effects. Maintenance and overhauls and outages in generation essentially capture forced and scheduled outages of the units.

Thus, we shall determine the threshold of capacity margin required to endure an extreme event as that corresponding to the aggregate reduction of generation capacity caused by all types of events considered in the SOAF study. This aggregate reduction is the sum of the reductions of generation capacity available termed "Non-usable capacity of generation" and "Maintenance and overhauls and outages" and "System Service Reserve" in the SOAF study. Given that the SOAF study is conducted for certain load and generation conditions, the values of the previous reductions so computed will be expressed in relative terms with respect to the (RES and conventional) generation capacity and extrapolated to conditions considered in the scenarios of the e-HighWay 2050 analysis in each node of the system to compute the absolute value in MW of the threshold of capacity margin required to endure extreme events in this scenario and node.

The existing capacity margin in market analyses for each node n and hour h of the year, $\mathrm{Capacity.Margin}_{h,n}$, is to be computed as the amount of locally installed generation less the amount of demand in the node n in this hour.

$$\mathrm{Capacity.Margin}_{h,n} = \mathrm{Installed.Generation.Capacity}_{n} - L_{h,n}$$

where $\mathrm{Installed.Generation.Capacity}_{n}$ is the installed generation capacity in each node n (in MW) and $L_{h,n}$ is the load in node n and hour h (in MWh).

Besides local generation, neighboring nodes may also provide support to those nodes affected by the occurrence of an extreme event. Thus, the total amount of power that a node undergoing an extreme event is able to import from third nodes is also to be considered. Available imports from third nodes can be computed as the minimum between the amount of available transmission interconnection capacity with these third nodes and the amount of power available in these nodes to be exported to the one concerned.

$$\mathrm{Available.\,Imports}_{h,n} = \min(\mathrm{Available.\,Interconnection.\,Capacity}_{h,n}, \mathrm{Available.\,Power.\,Neighbours}_{h,n})$$

Where $\mathrm{Available.\,Interconnection.\,Capacity}_{h,n}$ is the amount of available transmission interconnection capacity between node n and neighbors in hour h, and $\mathrm{Available.\,Power.\,Neighbors}_{h,n}$ is the amount of power available in these nodes to be exported to node n in hour h.

When computing $\mathrm{Available.\,Power.\,Neighbors}_{h,n}$ and $\mathrm{Available.\,Interconnection.\,Capacity}_{h,n}$ we shall assume that neighboring nodes to node n are also undergoing an extreme event in hour h, but not the neighbors to the neighbors of n. Then, $\mathrm{Available.\,Power.\,Neighbors}_{h,n}$ is to be computed as:

$$\begin{aligned}\mathrm{Available.\,Power.\,Neighbours}_{h,n} &= \max(0, \mathrm{Installed.\,Generation.\,Capacity}_{\mathrm{neighbors}-n} \\ &\quad - \mathrm{Threshold.\,Capacity.\,Margin}_{h,\mathrm{neighbors}-n} - L_{h,\mathrm{neighbors}-n} \\ &\quad + \mathrm{Available.\,Imports}_{h,\mathrm{neighbors}-n})\end{aligned}$$

Where neighbors-n are the set of nodes that are immediately contiguous to n; $\mathrm{Installed.\,Generation.\,Capacity}_{\mathrm{neighbors}-n}$ is the installed generation capacity in all neighbors to n considered jointly; $\mathrm{Threshold.\,Capacity.\,Margin}_{h,\mathrm{neighbors}-n}$ is the overall reduction in available generation capacity occurring in hour h in all neighbors to n, considered jointly, due to the extreme event; $L_{h,\mathrm{neighbors}-n}$ is the overall load in all neighbors to n in hour h; and $\mathrm{Available.\,Imports}_{h,\mathrm{neighbors}-n}$ is the overall amount of imports available from third nodes into all the neighbors to n, where third nodes include all those neighbors to neighbors to n, not including n. Hence, $\mathrm{Available.\,Imports}_{h,\mathrm{neighbors}-n}$ is to be computed as:

$$\mathrm{Available.\,Imports}_{h,\mathrm{neighbors}-n} = \min(\mathrm{Available.\,Interconnection.\,Capacity}_{h,\mathrm{neighbors}-n\ \mathrm{and\ third}}, \mathrm{Available.\,Power.\,Neighbors}_{h,\mathrm{third}})$$

Where $\mathrm{Available.\,Interconnection.\,Capacity}_{h,\mathrm{neighbors}-n\ \mathrm{and\ third}}$ is the total amount of available interconnection capacity between neighbors to n and third nodes/countries in hour h; and $\mathrm{Available.\,Power.\,Neighbors}_{h,\mathrm{third}}$ is the total amount of power available in third nodes to be exported to neighbors to n in hour h. $\mathrm{Available.\,Power.\,Neighbors}_{h,\mathrm{third}}$ is, in turn, to be computed as:

$$\mathrm{Available.\,Power.\,Neighbors}_{h,\mathrm{third}} = \max(0, \mathrm{Available.\,Generation}_{h,\mathrm{third}} - L_{h,\mathrm{third}} + \mathrm{Existing.\,Imports}_{h,\mathrm{third}})$$

Where $\text{Available. Generation}_{\text{third}}$ is the total amount of generation available in third countries in hour h; $L_{\text{h,third}}$ is the amount of load in these third countries in hour h; and $\text{Existing. Imports}_{\text{h,third}}$ is the total amount of net imports into third countries, from other countries than neighbors to n, in hour h according to the schedule. Note that we are assuming here that, due to the fact that third countries are not undergoing an extreme event, they have to make the support they provide to neighbors to n compatible with the compliance with scheduled exchanges with their neighbors not including neighbors to n. Given that thirds countries are deemed not to be affected by the extreme event, the amount of generation available in these, $\text{Available. Generation}_{\text{h,third}}$, is to be computed as the total amount of conventional generation capacity available in third countries, $\text{Available. Conv. Generation. Capacity}_{\text{h,third}}$ plus the amount of power production available from renewable energy sources in these in hour h, $\text{Available. Renewable. Power}_{\text{h,third}}$.

$$\text{Available. Generation}_{\text{h,third}} = \text{Available. Conv. Generation. Capacity}_{\text{h,third}} + \text{Available. Renewable. Power}_{\text{h,third}}$$

Lastly, both the amount of available interconnection capacity between n and neighbors to n, $\text{Available. Interconnection. Capacity}_{\text{h,n}}$ and that between neighbors to n and third countries, $\text{Available. Interconnection. Capacity}_{\text{h,neighbors}-\text{n and third}}$ is to be computed as the overall amount of installed interconnection capacity in each case, $\text{Existing. Interconnection. Capacity}_{\text{h,n}}$ and $\text{Existing. Interconnection. Capacity}_{\text{h,neighbors}-\text{n and third}}$, respectively, multiplied by a reduction factor corresponding to the decrease in the net transfer capacity between the respective groups of nodes that has historically occurred as a consequence of extreme events, $\text{Reduction. Factor}_{\text{neigh}-\text{n,n}}$ and $\text{Reduction. Factor}_{\text{third,neigh}-\text{n}}$, respectively.

$$\text{Available. Interconnection. Capacity}_{\text{h,n}} = \sum_{\text{neigh.n}} \text{Existing. Interconnection. Capacity}_{\text{h,n}} * \text{Reduction. Factor}_{\text{neigh}-\text{n,n}}$$

$$\text{Available. Interconnection. Capacity}_{\text{h,neighbors}-\text{n and third}} = \sum_{\text{neigh.n}} \text{Existing. Interconnection. Capacity}_{\text{h,neighbors}-\text{n and third}} * \text{Reduction. Factor}_{\text{third,neigh}-\text{n}}$$

The threshold level of the capacity margin in each node n and hour h, $\text{Threshold. Capacity. Margin}_{\text{h,n}}$, is computed based on the consideration of the same reduction concepts used in SOAF studies.

$$\text{Threshold. Capacity. Margin}_{\text{h,n}} = \text{Installed. Generation. Capacity}_{\text{n}} * (\text{NonUsable. Generation. Capacity}_{\text{h,n}} + \text{Maintenance. Overhauls. Outages}_{\text{h,n}} + \text{System. Service. Reserve}_{\text{h,n}})$$

where $\mathrm{NonUsable.Generation.Capacity}_{h,n}$ is the reduction of generation capacity associated with climate effects in node n and hour h (in per unit of the installed generation capacity[31]); $\mathrm{Maintenance.Overhauls.Outages}_{h,n}$ is the amount of unavailable generation capacity resulting from forced and scheduled outages in node n and hour h (in per unit of the installed generation capacity); and $\mathrm{System.Service.Reserve}_{h,n}$ is the capacity required to maintain the security of supply according to the operating rules of each TSO in node n and hour h (in per unit of the installed generation capacity).

Once the threshold level of the capacity margin appropriate to endure extreme events has been computed (as an example, in scenario A conservative of the SOAF study [4] for year 2020, this capacity margin is 446 GW at European level over 1092 GW of installed generation capacity), this will be compared with the capacity margin available at each node and the available imports into this node in each of the 8760 hours of operation of the system simulated in WP2 market analyses for each time horizon. Deficits of the existing capacity margin with respect to the threshold one will be deemed to correspond to not-served energy if an extreme event occurs.

The amount of not-served power in each node n and hour h if an extreme event occurs in the system, $\mathrm{NSEextreme}_{h,n}$, is to be computed as the maximum between zero and the difference between the threshold capacity margin for this node and the sum of its actual capacity margin and available imports into it. Note that given that non served energy under normal conditions, $\mathrm{GNSE}_{h,n}$, has already been considered in the reliability analysis, this will be deducted from total non served energy here computed under extreme events, in order to avoid double counting it.

$$\begin{aligned}\mathrm{NSEextreme}_{h,n} \\ &= \max\big(0, \mathrm{Threshold.Capacacity.Margin}_{h,n} - (\mathrm{Capacity.Margin}_{h,n} \\ &\quad + \mathrm{Available.Imports}_{h,n}) - \mathrm{GNSE}_{h,n}\big)\end{aligned}$$

where $\mathrm{GNSE}_{h,n}$is the amount of Gross Non Served Energy at hour h and node n obtained from WP2 market simulation results (in MWh)[32].

Finally, the cost of the lack of resilience of the system, $\mathrm{Cost.Resilience}$, is computed as the result of valuing extra NSE occurring under an extreme event at the VoLL and multiplying this by the probability of occurrence of this extreme event in this hour. NSE in each node and hour should be valued separately because its value may be different from that in other nodes. The probability of occurrence of extreme events may also vary from one node or country to another one.

$$\mathrm{Cost.Resilience} = \sum_{h,n}(\mathrm{NSEextreme}_{h,n} \cdot \mathrm{VoLL}^*_n \cdot \mathrm{Prob.Ocur.Extreme}_{h,n}) \quad (4)$$

where VoLL^*_n is the Value of Lost Load in node n and hour h associated to an extreme event. It is not the same as the VoLL computed under normal conditions, because under a extreme event

[31] Representative reductions values can be drawn from last SOAF studies available for each country [4]

[32] The Non Served Energy should be computed from the Gross Non Served Energy provided by WP2 market simulations results, detracting the interruptible load available in the system if WP2 simulations have not included this effect. The calculation process will be the same as the one already applied in the Reliability Cost assessment.

large amounts of NSE are expected to occur, which will affect the value of electricity uses to be curtailed. For the sake of simplicity, a standard value can be assumed for lost load curtailed under any extreme event in any node. This value is to be estimated from answers by stakeholders to a questionnaire.

$\text{Prob. Ocur. Extreme}_{h,n}$ is the probability of occurrence of an extreme event in node n at hour h. This probability is estimated from answers from stakeholders to a questionnaire.

5.3.1. Example of application

Consider two countries c=1,2 and four nodes n=1,2,3,4 belonging nodes 1 and 2 to country 1 and nodes 3 and 4 to country 2. Nodes 1 and 2 are connected with node 3, and Node 4 is also connected with Node 3. Consider 13 hours of operation h=1,…,13.

Input data

A) WP2 provides the following data for a given network

Tab. 36 - Load values in all nodes n and for all hours h

$\mathbf{L_{h,n}}$ (MWh)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Load Node 1	200	250	300	300	250	250	200	150	100	150	150	200	200
Load Node 2	300	350	400	400	350	350	300	250	200	250	250	300	300
Load Node 3	200	250	300	300	250	250	200	150	100	150	150	200	200
Load Node 4	500	550	600	600	550	550	500	450	400	450	450	600	600

Tab. 37 - Gross Non Served Energy values in all nodes n and for all hours h

$\mathbf{GNSE_{h,n}}$ (MWh)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
NSE Node 1	0	0	0	0	0	20	0	0	0	0	0	0	0
NSE Node 2	0	30	20	20	0	0	0	0	0	0	0	0	0
NSE Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
NSE Node 4	40	40	30	30	30	30	30	20	20	20	20	20	20

Tab. 38 - Installed capacity in each node n

$\mathbf{Installed.Generation.Capacity_n}$ (MW)	
	Capacity
Node 1	450
Node 2	550
Node 3	500
Node 4	900

Tab. 39 - Available Conventional Generation Capacity in each n and hour

$\mathbf{Available.Conv.Generation.Capacity_{h,n}}$ [MW]													
hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	300	300	300	300	300	300	300	300	300	300	300	300	300
Node 2	200	200	200	200	200	200	200	200	200	200	200	200	200
Node 3	200	200	200	200	200	200	200	200	200	200	200	200	200
Node 4	500	500	500	500	500	500	500	500	500	500	500	500	500

Tab. 40 - Available Renewable Power in each node n and hour h

$\mathbf{Available.Renewable.Power_{h,n}}$ [MW]													
hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	125	50	50	50	50	50	125	125	125	125	125	125	125
Node 2	300	300	300	300	300	300	300	300	300	300	300	300	300
Node 3	150	0	0	0	0	0	150	150	150	150	150	150	150
Node 4	300	400	400	400	400	400	300	300	300	300	300	300	300

Tab. 41 - Available Renewable Power in each node n and hour h

$\mathbf{neighbors-n}$	
	Neighbors
Node 1	2,3
Node 2	1,3
Node 3	1,2,4
Node 4	3

Tab. 42 - Flows along each interconnection

Flows [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Line 1-2	0	-50	-50	-50	-50	-50	0	0	0	0	0	0	0
Line 1-3	100	50	50	50	50	50	100	100	100	100	100	100	100
Line 2-3	100	50	50	50	50	50	100	100	100	100	100	100	100
Line 3-4	100	-100	-100	-100	-100	-100	100	100	100	100	100	100	100

Tab. 43 - Interconnection capacity between each node n and its neighbors in each hour h

$\mathbf{Existing.Interconnection.Capacity}_{\mathbf{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	200	200	200	200	200	200	200	200	200	200	200	200	200
Node 2	200	200	200	200	200	200	200	200	200	200	200	200	200
Node 3	300	300	300	300	300	300	300	300	300	300	300	300	300
Node 4	100	100	100	100	100	100	100	100	100	100	100	100	100

Tab. 44 - Reduction factor of the amount of available capacity on each interconnection between nodes when they are affected by an extreme event

$\mathbf{Reduction.Factor}_{\mathbf{neigh.n,n}}$ (p.u.)	
	Reduction
Node 1	0.8
Node 2	0.8
Node 3	0.8
Node 4	0.8

Tab. 45 - Reduction factor of the amount of available net transfer capacity between the neighbors to each node n affected by an extreme event and the neighbors of them with the exception of node n

$\mathbf{Reduction.Factor}_{\mathbf{third,neigh-n}}$ [p.u.]	
	Reduction
Node 1	0.8
Node 2	0.8
Node 3	0.8
Node 4	0.8

Tab. 46 - Reduction of generation capacity associated with climate effects in node n and hour h

$\mathbf{NonUsable.Generation.Capacity}_{\mathbf{h,n}}$ (p.u.)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Reduct Node 1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Reduct Node 2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Reduct Node 3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Reduct Node 4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

Tab. 47 - Unavailability of generation capacity by forced and scheduled outages in node n and hour h

$\mathbf{Maintenance.Overhauls.Outages}_{\mathbf{h,n}}$ (p.u.)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Maint Node 1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Maint Node 2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Maint Node 3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Maint Node 4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Tab. 48 - Capacity required to maintain the security of supply according to the operating rules of each TSO in node n and hour h

$\mathbf{System.Service.Reserve_{h,n}}$ (p.u.)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Resv Node 1	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Resv Node 2	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Resv Node 3	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Resv Node 4	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

B) Expertise and questionnaire answers provide the following data

Tab. 49 - Value of Loss of Load for all countries c, all the nodes n associated to an extreme event

$\mathbf{VoLL_n^*}$ (€/kWh)		
Country	Nodes	Extreme event
c=1	Node 1, Node 2	0.8
c=2	Node 3, Node 4	0.8

Tab. 50 - Probability of occurrence of an extreme event in node n and hour h. We have assumed that only in certain hours of the year there can be extreme events

$\mathbf{Prob.Ocur.Extreme_{h,n}}$ (p.u.)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Prob Node 1	0	0	0	0.0001	0	0	0	0	0	0.0001	0	0	0
Load Node 2	0	0	0	0.0001	0	0	0	0	0	0.0001	0	0	0
Load Node 3	0	0	0	0.0001	0	0	0	0	0	0.0001	0	0	0
Load Node 4	0	0	0	0.0001	0	0	0	0	0	0.0001	0	0	0

Computation of $\mathbf{Capacity.Margin_{h,n}}$

The capacity margin is the amount of local installed generation less the amount of demand in the node n in this hour.

Tab. 51 – Computation of $\mathbf{Capacity.Margin_{h,n}}$

$\mathbf{Capacity.Margin_{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	250	200	150	150	200	200	250	300	350	300	300	250	250
Node 2	250	200	150	150	200	200	250	300	350	300	300	250	250
Node 3	300	250	200	200	250	250	300	350	400	350	350	300	300
Node 4	400	350	300	300	350	350	400	450	500	450	450	300	300

Computation of $\mathbf{Threshold.Capacity.Margin_{h,n}}$

The threshold capacity margin is computed by applying the reduction corresponding to the non usable capacity, the forced and scheduled maintenance and the system operation reserve to the existing generation capacity.

Tab. 52 – Computation of $\mathbf{Threshold.Capacity.Margin_{h,n}}$

$\mathbf{Threshold.Capacity.Margin_{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	324	324	324	324	324	324	324	324	324	324	324	324	324
Node 2	396	396	396	396	396	396	396	396	396	396	396	396	396
Node 3	360	360	360	360	360	360	360	360	360	360	360	360	360
Node 4	648	648	648	648	648	648	648	648	648	648	648	648	648

Computation of $\mathbf{Available.Imports_{h,n}}$

Imports into a node n under an extreme event in hour h are determined as the minimum between available interconnection capacity and available power from neighbors. These in turn are computed as the existing generation margin in these countries when the extreme event is occurring in them as well, and taking into account the support received from third nodes. The support received by neighbors from third nodes is computed as the minimum between available interconnection capacity between neighbors to n and third countries, and the available power in third countries to support neighbors to n, assuming the extreme event is not affecting these third countries and they stick to scheduled power exchanges with other neighboring countries not affected by the extreme event.

Tab. 53 – Available power in third nodes to support neighbors to n

$\mathbf{Available.Power.Neighbors_{h,third}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	400	250	200	200	250	250	400	450	500	450	450	300	300
Node 2	400	250	200	200	250	250	400	450	500	450	450	300	300
Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Node 4	225	150	50	50	150	150	225	325	425	325	325	225	225

Available interconnection capacity between neighbors to n and third countries, which results from applying the corresponding reduction factor to existing interconnection capacity between the two groups of nodes

Tab. 54 – Available interconnection capacity

$\mathbf{Available.Interconnection.Capacity_{h,neighbors-n\ and\ third}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	80	80	80	80	80	80	80	80	80	80	80	80	80
Node 2	80	80	80	80	80	80	80	80	80	80	80	80	80
Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Node 4	160	160	160	160	160	160	160	160	160	160	160	160	160

Tab. 55 – Support received by neighbors from third nodes

$\mathbf{Available.Imports_{h,neighbors-n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	80	80	80	80	80	80	80	80	80	80	80	80	80
Node 2	80	80	80	80	80	80	80	80	80	80	80	80	80
Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Node 4	160	150	50	50	150	150	160	160	160	160	160	160	160

Power available to n from neighbors

Tab. 56 – Power available to n from neighbors

$\mathbf{Available.Power.Neighbors_{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	0	0	0	0	0	0	0	0	74	0	0	0	0
Node 2	0	0	0	0	0	0	0	46	146	46	46	0	0
Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Node 4	100	40	0	0	40	40	100	150	200	150	150	100	100

Available interconnection capacity between neighbors and n, which results from applying the corresponding reduction factor to existing interconnection capacity between neighbors and n

Tab. 57 – Available interconnection capacity

$\mathbf{Available.Interconnection.Capacity_{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	160	160	160	160	160	160	160	160	160	160	160	160	160
Node 2	160	160	160	160	160	160	160	160	160	160	160	160	160
Node 3	240	240	240	240	240	240	240	240	240	240	240	240	240
Node 4	80	80	80	80	80	80	80	80	80	80	80	80	80

Tab. 58 – Imports into a node n under an extreme event in hour h

$\mathbf{Available.Imports_{h,n}}$ [MW]													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Node 1	0	0	0	0	0	0	0	0	74	0	0	0	0
Node 2	0	0	0	0	0	0	0	46	146	46	46	0	0
Node 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Node 4	80	40	0	0	40	40	80	80	80	80	80	80	80

Computation of $\mathbf{NSEextreme_{h,n}}$

The amount of non served power in each node n and hour h is to be computed as the maximum between zero and the difference between the threshold capacity margin for this node and hour and the sum of the actual capacity margin, available imports from neighbors and interruptible load occurring in the system in the absence of an extreme event (in order not to double count it).

Tab. 59 – Computation of $\mathbf{NSEextreme_{h,n}}$

$\mathbf{NSEextreme_{h,n}}$ (MW)													
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
NSEex Node 1	74	124	174	174	124	104	74	24	0	24	24	74	74
NSEex Node 2	146	166	226	226	196	196	146	50	0	50	50	146	146
NSEex Node 3	60	110	160	160	110	110	60	10	0	10	10	60	60
NSEex Node 4	128	218	318	318	228	228	138	98	48	98	98	248	248

Computation of $\mathbf{Cost.Resilience}$

Finally, the cost of the lack of resilience of the system is computed as the result of valuing NSE under an extreme event at the VoLL times the probability of occurrence of this extreme event in this hour and added for all the nodes and hours.

Tab. 60 – Computation of cost resilience

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
Resil Node 1	0	0	0	13.9	0	0	0	0	0	1.92	0	0	0
Resil Node 2	0	0	0	18.1	0	0	0	0	0	4	0	0	0
Resil Node 3	0	0	0	12.8	0	0	0	0	0	0.8	0	0	0
Resil Node 4	0	0	0	25.4	0	0	0	0	0	7.84	0	0	0

$$\mathbf{Cost.Resilience} = 84.80\ €$$

5.4. Demand side management

The cost of DSM measures applied to avoid service interruptions shall be deemed equal to that of interruptible contracts, or equivalent reliability driven measures like regulating energy markets, since most other DSM actions are not aimed at preserving the security of the system but at increasing the economic efficiency of system operation.

The cost of interruptible contracts comprises two different types of costs: 1) the cost of procuring a load available to be interrupted if necessary, which is a cost incurred per MW of interruptible load at any hour and 2) that cost corresponding to the use of this available service, that is the cost of actually calling this load to be interrupted.

$$\mathrm{ILMCO} = \mathrm{ILFCO} + \mathrm{ILVCO}$$

where ILFCO is the total cost related to the reservation (through either contracts or any reliability market scheme) of a given amount of load (MW) to be available to be interrupted whenever necessary (in € 2013); and ILVCO represents the total cost related to the use (through either contracts or any reliability market scheme) of the amount of energy (MWh) that has been interrupted for reliability purposes (in € 2013).

Both costs could be either written down in a so called interruptible contract (with a fix payment for the availability and/or a variable payment in case of using this availability) or come up through a reliability oriented kind of market where the availability for the service and/or the use of the service can be auctioned by the System Operator:

1) The fix cost of signing interruptible load contracts (reserve power to be curtailed for a certain number of hours if necessary) is to be computed as the amount of interruptible load to be contracted times the cost of these contracts per unit of power contracted.

$$\mathrm{ILFCO} = \sum_{\mathrm{c}} (\mathrm{IL_c} \cdot \mathrm{ILUFCO_c})$$

where $\mathrm{ILUFCO_c}$ represents the unitary cost related to the reservation (through either contracts or any reliability market scheme) of an amount of energy (MWh) available per hour to be interrupted for reliability purposes if necessary in country ‘c’ (in €/MWh 2013); and $\mathrm{IL_c}$ represents the amount of interruptible load available (contracted) in country c.

The indicative amount of interruptible load contracted is going to be estimated according to DSM levels provided in ENTSO-E SOAF analyses. This indicative value may be modulated according to answers to task 6.3 questionnaire that are related to this issue. The cost of these contracts per unit of power contracted is to be estimated based on answers to the questionnaire on this issue provided by TSOs. A different value will be considered per country both for the amount of interruptible load and the unit cost of contracting this load, which may be zero in some countries.

2) The cost of mobilizing interruptible contracts (variable cost of the contracts) is to be computed as the amount of load curtailments avoided by calling these contracts times the cost of these contracts per unit of energy supply interrupted according to the terms of the contract.

$$\mathrm{ILVCO} = \sum_{\mathrm{h,n} \in \mathrm{c}} (\mathrm{USIL_{h,n}} \cdot \mathrm{ILUVCO_c})$$

where $\mathrm{ILUVCO_c}$ represents the cost (compensation) per unit of demand (MWh) reduction carried out for reliability purposes (through either contracts or any reliability market scheme) in country c (in €/MWh 2013); and $\mathrm{USIL_{h,n}}$ represents the amount of Interruptible Load actually interrupted at hour h and node n (in MWh).

If DSM mechanisms modeled in WP2 include reliability driven ones, WP2 results shall include the use that has been made of these services. If DSM mechanisms modeled in WP2 do not include reliability driven ones, the amount of NSE avoided in each node shall be computed for all the hours of the year as the lower of the amount of gross Non Served Energy provided by WP2 market simulation results, $\mathrm{GNSE_{h,n}}$, and the amount of interruptible load in that node and hour $\mathrm{IL_{h,n}}$.

$$\mathrm{USIL_{h,n}} = \min\left(\mathrm{GNSE_{h,n}};\ \mathrm{IL_{h,n}}\right)$$

An indicative value for the amount of interruptible load existing in each node of a country at each hour of the year $\mathrm{IL_{h,n}}$ is to be computed as the overall amount of load in that country deemed to be interruptible times the fraction of load in that node with respect to the total amount of load for the country. The overall amount of load deemed to be interruptible in a country is going to be estimated according to DSM levels provided in ENTSO-E SOAF analyses. This indicative value may be modulated according to answers to the questionnaire related to this issue that are received.

$$\mathrm{IL_{h,n\in c}} = \mathrm{IL_c} * \frac{\mathrm{L_{h,n\in c}}}{\sum_{\mathrm{n\in c}} \mathrm{L_{h,n\in c}}}$$

where $\mathrm{L_{h,n}}$ represents the gross load demand at hour h and node n (the one used in WP2 market's simulations), and $\mathrm{IL_c}$ represents the total load deemed to be interruptible in country c.

On the other hand, the amount to be paid to consumers signing interruptible contracts per unit of energy consumption reduction $\mathrm{ILUVCO_c}$ is to be estimated separately for each country based on responses of TSOs to task 6.3 questionnaire on this issue. If the latter is not available for some countries, values found in the literature will be considered for it.

5.4.1. Example of application

Assume there are two countries c=1,2 and four nodes n=1,2,3,4 belonging nodes 1 and 2 to country 1 and nodes 3 and 4 to country 2. Consider 3 consecutive hours of operation h=1,2,3. For a given scenario and network architecture and time horizon, let's compute the Cost associated to the reservation and use of interruptible load services.

Input data

A) WP2 provides the following data for a given network architecture corresponding to a scenario and time horizon

Tab. 61 - Load values at all nodes n and for all hours h

$\mathbf{L_{h,n}}$ (MWh):			
Hour nº	1	2	3
Load Node 1	200	250	300
Load Node 2	300	350	400
Load Node 3	200	250	300
Load Node 4	500	550	600

Tab. 62 - Gross Non Served Energy values at all nodes n and for all hours h

$\mathbf{GNSE_{h,n}}$ (MWh):			
Hour nº	1	2	3
GNSE Node 1	0	0	0
GNSE Node 2	0	30	20
GNSE Node 3	0	0	0
GNSE Node 4	40	40	30

B) Expertise and questionnaire answers provide the following data

Tab. 63 - Total interruptible load per hour in country c (same for all hours)

$\mathbf{IL}_c$ (MWh):	
country	Interruptible load
c=1	5
c=2	4

Tab. 64 - Unitary cost related to the reservation of an amount of energy (MWh) available per hour to be interrupted in country c for reliability purposes

$\mathrm{ILUFCO_c}$ (€/MWh):	
country	Interruptible load
c=1	20
c=2	25

Tab. 65 - Cost (compensation) per unit of demand (MWh) reduction carried out for reliability purposes in country c

$\mathrm{ILUVCO_c}$ (€/MWh):	
country	Interruptible load
c=1	35
c=2	30

Step 1: Computation of $\mathbf{IL_{h,n}}$

The total amount of demand associated to interruptible contracts for each country is allocated to nodes in proportion to the load at each node with respect to the total load in the country. Besides, total interruptible load per country is assumed equal for all the hours considered. Therefore fromTab. 61 and Tab. 63, we compute

Tab. 66 – Computation of $\mathbf{IL}_{h,n}$

$\mathbf{IL}_{h,n}$ (MWh):			
	Hour nº		
	1	2	3
Node 1	2	2.1	2.1
Node 2	3	2.9	2.9
Node 3	1.1	1.3	1.3
Node 4	2.9	2.8	2.7

Step 2: Computation of $\mathbf{USIL_{h,n}}$

Assuming that WP2 does not consider interruptible contracts, the amount of interruptible load that will be actually called is computed from Tab. 62 and Tab. 66. If WP2 would have taken this effect into account $\mathrm{USIL_{h,n}}$will be input values for this process

Tab. 67 – Computation of $\mathbf{USIL_{h,n}}$

$\mathrm{USIL_{h,n}}$ (MWh):			
	Hour nº		
	1	2	3
Node 1	0	0	0
Node 2	0	2.9	2.9
Node 3	0	0	0
Node 4	2.9	2.8	2.7

Step 3: Computation of ILVCO

The total cost of making use of interruptible load services is computed as its unitary cost times the load reductions actually called. From Tab. 65 and Tab. 67:

$$\mathrm{ILVCO} = 450.3\ €$$

Step 4: Computation of ILFCO

The total cost of having interruptible load services available (will them be used or not later on) is computed as the unitary cost of the interruptible demand available times the amount of interruptible load available in the system. From Tab. 63 and Tab. 63:

$$\mathrm{ILFCO} = 200\ €$$

Step 5: Computation of ILMCO

The total cost associated to Interruptible Load is the sum of both previously computed costs.

$$\boxed{\mathrm{ILMCO} = 650.3\ €}$$

5.5. Compensation for RES energy curtailments

Curtailments affecting power produced by RES generation may be subject to some sort of compensation. In this case, these compensations could be considered as part of the cost of system security.

Currently, some countries apply compensations for RES energy curtailments, though the advisability of preserving large compensations in the long term future, when RES energy producers should probably compete on equal terms with conventional generation in the market, is arguable. Costs associated with replacing power production from clean RES generation with that from more pollutant conventional generation shall be internalized in market agents' energy bids through the application to agents of appropriate carbon prices.

However, not providing any compensation for curtailments to RES producers may result in weak incentives to install this type of generation if uncertainty of RES producers on future market revenues is substantial. Then, a sensitivity analysis will be carried out considering different values of compensations to be paid to RES operators per unit of RES energy curtailed (unit compensation). These values will be obtained from expert knowledge within the consultant team and stakeholders' answers to task 6.3 questionnaire on system security issues.

For each level of compensation per unit of RES energy curtailed, the cost of curtailments will be computed as the amount of energy curtailed times the aforementioned unit level of compensations. In principle, a common level of unit compensations for curtailments is to be considered for all RES technologies and countries, though it may vary across time horizons. Unit compensation levels considered will in principle range between zero and those values provided by associations of renewable energy producers, including as an option the energy market price in the corresponding hour and node.

Therefore, for each network architecture and time horizon the RES Curtailment Cost for each hypothesis on the unit value of compensation is computed as

$$\mathrm{RESCCO_{vc}} = \sum_{\mathrm{h,n \in c}} (\mathrm{COMP_{vc,c}} * \mathrm{RESCU_{h,n}})$$

where $\mathrm{RESCU_{h,n}}$ represents the RES energy curtailments in node n and hour h (provided by WP2 market simulations), and $\mathrm{COMP_{vc,c}}$ represents the unitary value of the compensation for RES curtailments for the hypothesis vc on the value of compensation for country c; (in €/MWh 2013).

5.5.1. Example of application

Assume there are two countries c=1,2 and four nodes n=1,2,3,4 belonging nodes 1 and 2 to country 1 and nodes 3 and 4 to country 2. Consider 3 consecutive hours of operation h=1,2,3. Consider two different hypothesis on the value of compensation for curtailment vc=1,2.

For a given network architecture and time horizon, let's compute the associated RES Curtailment Cost, $\mathrm{RESCCO_{vc}}$ for vc=1,2.

Input data

A) WP2 provides the following data for a given network architecture ‘a’ corresponding to a scenario ‘s’ and time horizon ‘th’,

Tab. 68 - Amount of RES curtailments at all nodes ‘n’ and for all hours ‘h’

$\mathrm{RESCU}_{\mathrm{h,n}}$ (MWh):			
Hour nº	1	2	3
Load Node 1	200	250	300
Load Node 2	300	350	400
Load Node 3	200	250	300
Load Node 4	500	550	600

B) Expertise and questionnaire answers provide the following data

Tab. 69 - Value of the RES curtailment compensation to be applied in each country ‘c’, for scenario ‘s’ and time horizon ‘th’, for both hypothesis on that value vc=1,2

$\mathrm{COMP}_{\mathrm{vc,c}}$ (€/MWh):		
Country	Hypothesis of compensation value	COMP value
c=1	vc=1	10
	vc=2	45
c=2	vc=1	5
	vc=2	40

Computation of $\mathbf{RESCCO_{vc}}$

The RES Curtailment Cost associated to network architecture ‘a’ for scenario ‘s’ and time horizon ‘th’ for the hypothesis on the value of compensation “vc” can now be computed as the compensation value $\mathrm{COMP}_{vc,c}$ in the corresponding country c for each hypothesis vc times the RES energy curtailed $\mathrm{RESCU}_{h,n}$ in hour h and node n added over all hours and all nodes, for each of the two hypothesis on the value of the compensation.

From Tab. 68 and Tab. 69 and taking into account the country each node belongs to, we compute

For hypothesis on compensation value vc=1

$$\mathrm{RESCCO}_{\mathrm{vc=1}} = 550\ €$$

For hypothesis on compensation value vc=2

$$\mathrm{RESCCO}_{\mathrm{vc=2}} = 3175\ €$$

5.6. Reliability cost: Value of Lost Load (VoLL)

5.6.1. Methodology for estimating VoLL

In this section, the VoLL is calculated for some European countries based on available data or estimates available on questionnaires from TSOs.

The **Value of Lost Load (VoLL)** is the estimated amount that customers receiving electricity with firm contracts would *i)* be willing to pay to avoid a disruption in their electricity service; *ii)* expect to be paid [by TSOs] when such a disruption in their electricity service occurs. The value of these disruptions can be expressed as a customer damage function (CDF). A CDF is given in **€/kW** and is, generally, a function ***f*** of **duration** of the disruption, **season** and **time of the day** when the disruption occurs and whether it is a '**planned**' or a '**unexpected**' disruption:

CDF (€/kW) = f (duration, season, time of day, notice)

The CDF relates the magnitude of customer losses (per kW interrupted) for a given duration of a power outage. A CDF can be obtained for various customer sectors. Typically, there are three distinct groups of customers: *i) residential*, *ii) commercial* and *iii) large industrial sectors*. The function is therefore generally called 'sector customer damage function' (SCDF).

Focus is on calculating the so-called "Composite Customer Damage Function (CCDF)" from available SCDF. The CCDF represents the total interruption cost as a function of the interruption duration for the combined customers in a particular country. The CCDF for a service area is obtained by weighting the sector CDF by the customer load composition for that country:

$$CCDF = \sum_{x=1}^{S} SCDF_x(t).\ W_x$$

Where:

- *SCDF* is the Sector Customer Damage Function
- W_X is the weighting ratio of electrical consumption in each sector and
- *S* is the number of sector

The demand data used in this methodology is 2012 demand data from ENTSO-E[33] split into sectors by use of Eurostat 2011 statistics[34]. The annual peak load percentage is usually used for weighting short durations (below 1 hour), and the annual energy consumption percentage is used for weighting the longer durations.

*The Value of Lost Load reported in this memo is equal to the Composite Customer Damage Function for **1-hour** duration (VoLL =CCDF)*

[33] https://www.entsoe.eu/data/data-portal/consumption/

[34] http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Electricity_production,_consumption_and_market_overview

Estimation of SCDFs

Electricity interruption costs are usually quantified by means of customer surveys. Such quantification typically allows defining the so-called Sector Customer Damage Functions (SCDFs).

Customer surveys: An appropriate normalization factor is used in conjunction with specific interruption costs obtained from **customer surveys** in Euros or equivalent thereof. In general, different normalization factor in SCDFs could be used. In general any of the following three normalization factors can be found in the literature:

-kW of Average Load (Annual energy consumption divided by 8760),

-kW of Maximum Load,

-kW of interrupted load.

In this methodology, "*kW of Maximum Load for 1-hour duration*" has been used as normalization factor. This means that SCDFs considered here are defined as

SCDF [€/kW] = 'Cost in EUR for each kW of Peak Load Lost during a period of 1-hour"

The use of data with the same normalization factor provides a consistent and harmonized approach, and allows to obtain values which can be compared between each other.

Calculating the VoLL == CCDF for different countries, therefore requires access to the following two parameters:

- Sector Customer Damage Functions (SCDFs) for the various demand sectors
- Electricity consumed by each demand sector

SCDFs as a function of duration of interruption are collected from available literature for the following countries:

a. **Norway**
b. **UK**
c. **Sweden**
d. **Finland**
e. **Greece**
f. **Latvia**
g. **Austria**
h. **Slovenia**
i. **Albania**
j. **Bulgaria**
k. **Croatia**

Focus has been to use comparable SCDFs based on some common normalization factor. SCDF values used in the CCDF calculation later, have been chosen to be values reported with "*kW of Maximum Load for 1-hour duration*" as normalization factor.

For **Norway** and **Latvia** the normalization factor used in customer surveys was Energy Non-Served (ENS). The following assumption is therefore made to allow comparison and to ensure consistency: ENS values for 1 hour duration reported in customer surveys are assumed to typically happen during "peak load" periods so *kW of Maximum Load for 1-hour duration == kWh of ENS for 1-hour duration periods* ". If ENS events of 1-hour duration reported in the customer surveys happened during off-peak periods however, our assumption will introduce a slight overestimation of the SCDF reported, since interpreted as "*Cost in EUR for each KW of Peak Load Lost during a period of 1 hour*". We consider this assumption to be reasonable, especially since the period of time used is 1-hour to calculate CCDF from SCDFs.

Production Function Approach: In the case that customer surveys are not available in the literature, another way to quantify the electricity interruption costs is used. In this case, a '**production function approach**' is chosen. This approach uses the ratio of an economic measure such as Gross Value Added (GVA) and a measure of electricity consumption (in kWh), to estimate interruption costs by sector. This (purely) economic estimate can be understood as of being the average over all Sector Customer Damage Functions for different disruption periods. Our assumption here is that this average is dominated by the same 'disruption features' than the Sector Customer Damage Functions for 1-hour duration during Peak Load periods.

Production Function Approach has been used as SDCF directly to calculate VoLL == CCDF for the following countries:

a. **Spain**
b. **The Netherlands**
c. **Germany**
d. **Ireland**
e. **Italy**

By use of both **Customer surveys** and **Production Function Approach**, we have been able to arrive at a common benchmarking set of values for the VoLL for the above mentioned EU countries.

Estimation of SCDFs

In order to calculate CCDF from SCDF, the demand in each country per sector should be provided. The following steps have been followed in this memo:

- We initially gathered overall energy & electricity consumption in different sectors of 27 EU countries from Eurostat (2011)
- We obtained overall electricity consumption from hourly metering records from ENTSO-E. ENTSO-E database is for the overall electricity energy consumption while Eurostat database is more detailed, differentiated by electricity energy consumption in each of the sectors *e.g.*, residential, industrial, commercial and transport. These two databases, Eurostat and

ENTSO-E, were compared for 2011 first. It was found that although Eurostat based electricity consumption figures are relatively more conservative, they are fairly comparable with ENTSO-E figures.

- After this 'database cross check ' for 2011, the assumption has been to use the Eurostat 2011 database division as a baseline scenario for the different demand sectors when dividing ENTSO-E sector-based projections of the following year data 2012.

The calculated demand proportion in each sector from the Eurostat database of 2011 could be used as baseline division of projected load scenarios in 2050 among different sectors.

The VoLL computed according to the methodology presented above express the current values in each country. In order to exploit these values in a 2050 scenario evaluation, they have to be projected to the target year.

A base hypothesis can be fixed, that is the VoLL is correlated to the GDP growth rate of each country. In this way the methodology takes into account the evolution of each country, especially for what concerns the industrial development and the related consumptions. According to the assumption, for each country, the values of SCDF for the industrial and commercial sectors are increased according to the GDP growth rate. The residential is kept fixed to the current values because it is supposed that this sector is already mature and the further development of a country affects mainly the industrial and commercial sector. This is reflected in the willingness to pay for the consumption of each category.

Starting from the formula describing the Composite Customer Damage Function that will describe the VoLL, we can distinguish between current values (2013) and projected values (2050):

$$CCDF^{2013} = \sum_{x=1}^{s} SCDF_x^{2013}(t).\ W_x$$

$$CCDF^{2050} = \sum_{x=1}^{s} SCDF_x^{2050}(t).\ W_x$$

To project the Sector Customer Damage Functions SCDF of the generic country *j* up to the year 2050:

$$SCDF_x^{2050}(t) = SCDF_x^{2013}(t) * K_j^{2050}$$

Where

$$K_j^{2050} = \sum_{t=1}^{2050-2013} (1 + r_{GDP,j})^t * \frac{People_j^{2050}}{People_j^{2013}}$$

is the factor that apply growth rate, being $r_{GDP,j}$ the GDP pro capita increase rate in country *j*, $People_j^{2050}$ and $People_j^{2013}$ are respectively the population of country *j* in 2050 and 2013.

In this way the increase in the GDP of each specific country is applied to the SCDF. As assumed, such capitalization should be applied only to the industrial and commercial sectors, while the SCDF of domestic customers stays unchanged.

6. Costs and benefits related to system financing

The main objective here is is to develop financial and regulatory indices in quantitative terms which will be integrated in the cost benefit analysis for grid architecture evaluation. In traditional BCA methodologies, they are not taken into account, which might be an oversimplification of the reality. As such it is the objective to investigate which aspects are the most important and determine how they have to be taken into account during the BCA analysis and assess the impact of those financial and regulatory aspects which are deemed relevant on the prosed architectures for the transmission system. The subtask financing and regulatory aspects specifically searches for a methodology to take these effects into account and a method to determine (quantitative) indices for the BCA analysis. In later subtasks of this work package they will be integrated in the BCA tool.

Within most projects which investigate long term planning of pan-European systems, and also in the basic analysis from the E-Highway project, the cost benefit analysis is primarily performed from social welfare perspective. In particular, the benefit is considered for users and wider society. This means that investments are done when they are beneficial to the system as a whole. Such a method inherently builds on a framework that aims at providing the highest social welfare. It is generally accepted that such methods are suitable to investigate future grid architectures in their completeness. Some adjustments are provided in WP6 to capture a number of the limitations of the methodology and provide a methodology which is closer to reality, or at least allow to see how different aspects alter the results. In the task “financing and regulatory influences to the BCA”, we attempt to approach the investment problem from the investor perspective. More specifically, not all the benefit of users and society are directly captured by the investor. Furthermore, the highest social welfare is not an objective of the investor. It is rather to maximize its own profit. For example, the elimination of price difference between two zones could lead to optimal results from both economic and security of supply considerations as well as from a user point of view. But a merchant interconnection investor usually[35] depends on the price difference of the zones to earn his profit. The elimination of price difference would incur revenue losses to the merchant investor. So the merchant investor will be tempted to invest in socially suboptimal capacity, with the presence of regulatory scrutiny.

Therefore, WP6.4 provides an alternative transmission investment evaluation perspective from market investors, adding up to the social cost benefit analysis. It is an attempt to analyse the cost and benefit seen from the investor side. The cost for investors links with macroeconomic situation and the risk perception. We try to perform the evaluation by answering the following questions: what are the most important investment aspects seen from investor side? How do they influence the required rate of return by market for transmission investment? What are the main risks and in return how do they price their capital cost according to the perceived risks? These aspects are then translated into indices which alter the cost benefit assessment as developed within the work package.

35 Depending on the regulatory framework that is applied to the merchant connection

However, the methodology used is also limited and cannot take all the complexity of the financing and regulation aspects in transmission investment into account. The methodology tries to assess the effect on the 2050 grid investment as a single project investment, by a single (average) investor and as a one-time investment decision. The other dimensions such as country specific differences in Europe, grid investment portfolio for various investors and capital market competition for investment are not included. Furthermore, the integration of the investment options as an adaptation of the BCA, which is done in this work, is a significant simplification of reality. Yet, the method should provide additional insight into the BCA analysis and the effects of ownership, regulation, financing and risk. Given the time schedule and data constraints, it is believed that this method is the only realistic approach.

Initial analysis on BCA impacts of financing and regulation

An initial investigation of the different aspects that influence financing and regulation has been performed, identifying the different components that potentially have an important influence on the actual outcome of the BCA analysis. The initial analysis also grouped the different components. Ownership, pricing regulation, financing indicators and risk were seen as the main categories, with each of them a number of components.

This wide range of components that are organized as follows:

- Ownership => Section 1
    - System operator collaboration: multiple national SO/regional SO/ single European SO
    - Investment type: public/private investment
    - System owner/operator framework: TSO, ISO/TO
    - Asset ownership structure: regulated investment/merchant investment
- Pricing regulation => Section 2
    - Cost based regulation
    - Incentive based regulation
- Financing indicators => Section 3
    - Investment feasibility
    - Cost of capital
    - Financeability ratio
- Risks => Section 4
    - Regulatory risks
    - Financial risks
    - Scenario risks
    - Other risks

6.1. Methodology

After the identification of the different components, they were prioritized. This was done through a literature study and analysis on the one hand, and by the use of the results from a survey held with relevant stakeholders on the other hand (TSOs, ACER and EIB were asked, only TSOs responded). Focusing on the components that were selected as important, a more detailed study towards the actual determination of a useable index which is quantifiable is performed. For this two aspects needed to be determined.

The first analysis is how (which aspect) the component influences the cost benefit analysis. Not all components influence the BCA in a similar manner (e.g. some aspects are related to the discount rate, while others are related to a specific part of the costs or benefits). A part of the analysis also consists of analyzing whether the component is quantifiable.

In the second step of the analysis, the actual value of the influence is determined. The translation into an index for the BCA is also part of this analysis. Given the limited availability of data (both for 2050 as for the current time frame), the use of different ranges (high – medium – low) is employed.

The overall methodology of WP6.4 is depicted in the flow chart Fig. 48.

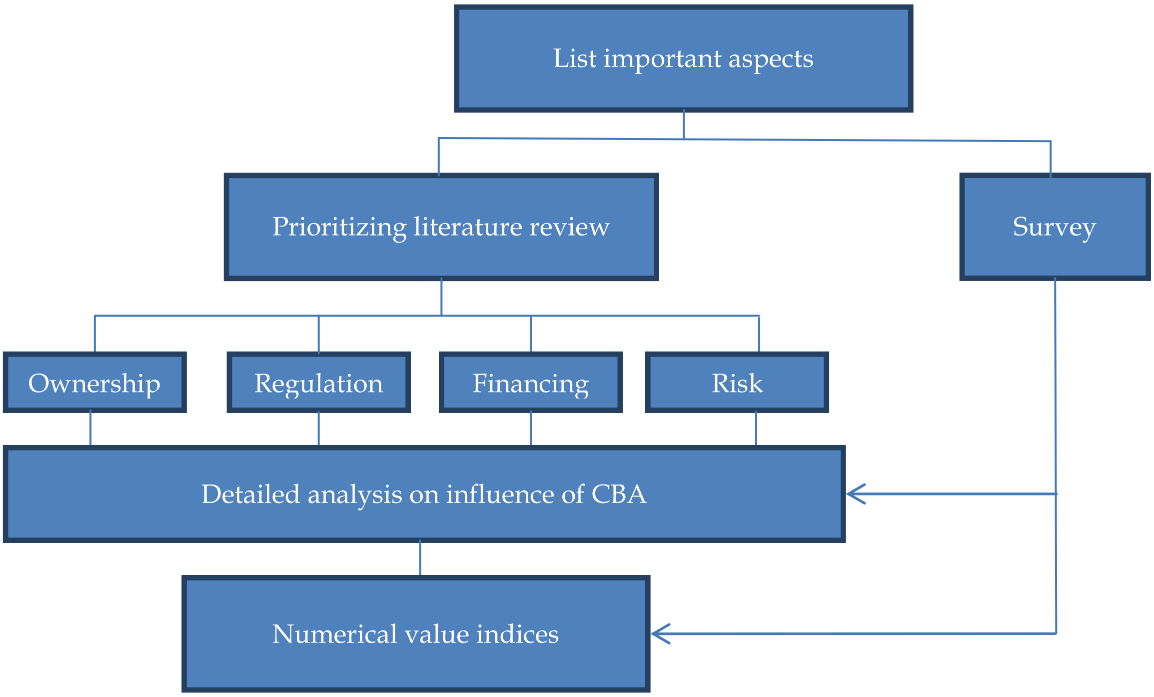


Fig. 48 – Methodology development for WP6.4

6.1.1. Questionnaire

Part of the analysis was conducted by means of a questionnaire that was sent to the relevant stakeholders, more specifically, the European TSOs, the European Investment Bank and ACER. Responses were received from X TSOs. The questionnaire aims to identify the most important financial and regulatory aspects, as seen by the current stakeholders. It also serves as input to investigate the methodologies to evaluate them. The results of the questionnaire have been included in the annex.

The proposed methodology of financial and regulatory evaluation is seen as a correction of the existing BCA approach. It intends to separate the landscape of cost and benefit analysis into three parts, based on the aspects identified at the beginning of the investigation: cost of capital, life cycle cost calculation and social welfare calculation. Fig. 49 depicts the outcome of the analysis on the effects of financing and regulation.

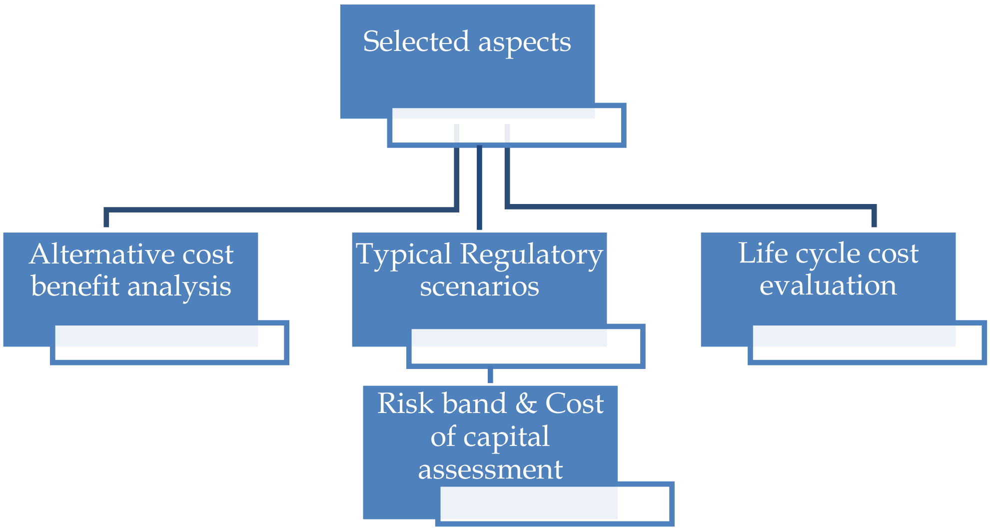


Fig. 49 – Contribution of WP6.4 to cost benefit analysis

6.1.2. Life cycle cost

Inspired by the life cycle cost calculation as presented by WP6.1, a matrix analysis (as shown in Tab. 70) is proposed to analyze the effect on various cost terms and their respective discount factors on the LCC.

$$
\begin{aligned}
LCC_{ij,NPV}(\hat{t}) = {} & AUTEX_{ij} * DF_{AUTEX}(\hat{t}\,) \\
& +\left(ASSEX_{ij} + INSTEX_{ij}\right) * DF_{ASSEX}(\hat{t}\,) \\
& +OPEX_{ij,TOTAL} * DF_{OPEX,TOTAL} \\
& +\left(DECOMMEX_{ij} + DISPEX_{i}\right) * DF_{DECOMMEX}(\hat{t}\,)
\end{aligned}
$$

While the LCC approach as proposed is commonly used, it assumes inherently that a system optimization approach is used. However, it is recognized that different aspects can influence the LCC in different manners. For instance the ownership might be different for different parts of the costs and the benefits, possibly requiring different discount factors. The effect of each combination of financing and regulation and the corresponding LCC aspect is investigated.

Tab. 70 – Matrix on life cycle cost elements brought by WP6.4 aspects

	AUTEX	ASSEX	INSTEX	OPEX	DECOM	DISPEX	DF
Ownership							
Regulation							
…							

6.1.3. Cost of capital

Cost of capital is seen as an important influencer of the overall BCA (and LCC) and is dealt with separately. Diverse ownership structures, regulations and the financial portfolio of a company result in distinct investment characteristics. It changes the attractiveness and perception of risks from investor perspective. Uncertainties brought by the aforementioned three aspects and exogenous risks determine the cost of capital. Therefore, overall systematic risk is categorized into risk bands and priced into capital cost accordingly in this document.

6.1.4. Social welfare

A second item which influences the overall BCA in a fundamental manner is the way in which the social welfare is taken into account. Social welfare evaluation as the core part of cost and benefit analysis (BCA) has been common practice. However, in some investment schemes, social welfare increase does not always align with investor's interest. As a result of the conflict, preferred investment by the individual investor is not necessarily the social optimal, particularly in the case where the investor is faced with more financial and scenario risks such as merchant investments. Even in the social welfare optimization from a public perspective, different system collaboration schemes would require different sets of cost benefit analysis.

6.1.5. Non-quantifiable aspects

As for aspects that fundamentally alter the methodology of cost benefit analysis such as system operator (SO) collaboration, it is not possible, or insufficient to quantify its effect on investments only by indicators. Instead, if an alternative SO collaboration scheme is applied, multiple separate benefit and cost assessment calculations, possibly with different objective functions (e.g. optimizing local returns) are needed. However, it is important to note the underlying assumption taken for the benefit and cost assessment and the implication for BCA procedures with a changing SO collaboration scheme.

6.2. Integrating ownership, regulation, financing and risk

6.2.1. Integrated methodology

The ownership, regulation, financing and risk aspects are not unrelated. Therefore, a methodology has been developed and described during the E-highway project, to integrate these aspects.

The interplay of ownership, regulation, financing and risk is crucial; it is pointless to consider the different aspects separately: ownership determines regulation, ownership and regulation determine risk and risk determines financing. Furthermore, the level of risk allocated to the regulated firm has a severe impact on the incentives, and eventually, the market perception of the firm. An analogy to this is in the definition of scenarios for any kind of energy system planning (such as generation or transmission planning): The different elements do have to fit together. Besides the very 'mechanical' inter-relations between different aspects, the powers and objectives of the regulator, and what might be more, the other stakeholders will have a severe impact on how the regulated firm is encouraged to act.

Therefore, the approach chosen here uses stylized examples which are inspired by "real-world" situations but are consistent to show how the methodology can be used.

As future numbers are very uncertain, a methodology is developed that integrates the different aspects in a qualitative manner, yet resulting in actual indicators that can be used to show the effects on the BCA. The methodology consists of splitting the problem in those that require an adjustment of the BCA methodology and those that influence the different parts of the BCA. The latter affects are covered by selecting an appropriate range for all indicated aspects individually: low, medium and high. The rationale in this is that the different technical and economic parameters in some manner influence the costs or the benefits in the future system. In a later stage, these individual ranges are combined into a single index which modifies the discount factor. The combination is done by assigning weights to the ranges and integrating them to a single systematic risk factor which is in turn used to determine the asset beta value.

6.2.2. Ownership

The level of system operator collaboration determines the boundary of zonal welfare calculation: whether national, regional or an integrated European cost benefit analysis should be performed. The owner/system operator separation implied that different discount factor could be applied on investment cost and operation cost. The choice of regulated investment or merchant investment, will lead to different investment size based on their distinctive objectives.

When differentiating ownership on a very abstract level, one ends-up with the question whether assets are private or public. If assets are public, then the pressure for very strict regulation may be lower as the public administration might be able to redistribute the rents collected. However, regulation might be stricter in the case of private ownership as regulatory schemes are then the only measure to ensure that public/social objectives are met. As intrinsic to the different impacts of regulatory schemes onto firms, the level of risk attributed to the firm varies. As it is obvious, risk directly impacts financing possibilities: not only will required rates be higher if risk is higher, also the split between equity and debt may be different, and thus different financing instruments may be available or not.

6.2.3. Systematic risk, regulation and cost of capital

Financing theory suggests that cost of capital required by the market mainly depends on the systematic risk exposure in the business. Therefore, a risk band approach is proposed to determine the cost of capital.

Systematic risk is defined as the non-diversifiable risk. Systematic risk can be shared by investor, users and tax payers. The latter two referring to more or less the same group in network industry, and risks are borne by users directly and by tax payers indirectly. In this document, we only evaluate the systematic risk exposed to the investors by analyzing the regulation design in combination with exogenous risks and translate the sum of the systematic risk for investors into cost of capital. It is represented by beta in the WACC (weighted average cost of capital) formula, which reflects covariance of return of a particular project in relation to the market portfolio. There are two types of beta in cost of capital calculation: asset beta and equity beta. The asset beta is unlevered beta value, which is independent of capital structure. The equity beta measures both fundamental business risk and financial risk. In WP6.4 risk band and cost of capital methodology, asset beta is used because it corrects the gearing and better reflects the market risk of an asset.

The design of regulation parameters is vital for the degree of systematic risk borne by investors. The twofold regulation effect on systematic risk of a regulated firm was characterized by Pedell [91]. On one hand, regulation design influences the covariance of the firm's cash flow in relation to the market portfolio return. On the other hand, parameter design impacts the symmetry and kurtosis [36]of cash flow distribution. Regulation is seen as risk buffer [92] for cost of capital implication. In general, the stronger rate of return element in regulation design to allow investor passing on cost to customers implies absorption of external shocks for investors and less systematic risk exposure, which will in turn result in lower cost of capital.

To summarize, the envisaged integrated methodology to interlink pricing regulation, financing and risk is depicted in Fig. 50. First, a set of systematic risk indicators is proposed, which reflect the underlying business risk of transmission network investment. The next step is to extract information from the governance model for regulation scenario construction. As an example the existing cases that are analyzed in WP5 are used as input. Then the parameter settings in the regulation scenario is analyzed and translated into risk band selection for each risk indicator, while considering different level of exogenous risks. Afterwards, the overall risk score of all the regulation scenarios could be obtained. In the end, their respective cost of capital could be calculated and compared.

[36] In probability theory and statistics, kurtosis (from the Greek word κυρτός, kyrtos or kurtos, meaning curved, arching) is any measure of the "peakedness" of the probability distribution of a real-valued random variable.[

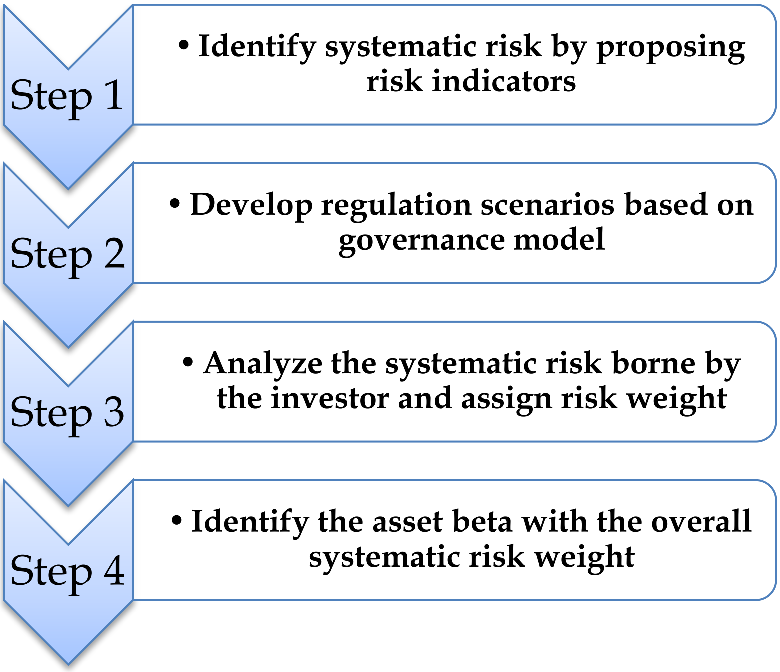


Fig. 50 – Pricing regulation general methodology

The representative parameter of cost of capital: asset beta is selected according to the overall systematic risk category. In weighing the risk indicators, the low ranges are assigned 1 point, the medium ranges 2 points and the high risks 5 points. When adding the factors from the different categories, a combined risk factor or systematic risk score is obtained. When this risk score is between 6 and 9 is considered low, 10-21 is considered medium, and 22-30 is considered to represent a high systematic risk. As the next step, the asset beta value or value range will be set, which corresponds to column 3 of Tab. 71, for each systematic risk category [93][94].

Tab. 71 - Financing and systematic risk

Systematic risk score	Systematic risk category	Asset Beta	Market risk premium	Risk free rate	Project discount rate
	Low				
	Medium				
	High				

6.2.4. Financeability impact on cost of capital

Roland Berger [95] suggests that within the investment grade, differences in credit rating have little impact on cost of debt, while the non-investment grade will constrain financing sources for the TSOs and a higher return on capital is required.

Financeability ratio plays a significant role in determine credit rating. According the Moody's credit rating metric, the four financeability ratios together account for 40% of weight for the overall rating. Financeability ratios such as the ones mentioned in the questionnaire may indicate ex-post whether thresholds are breached.

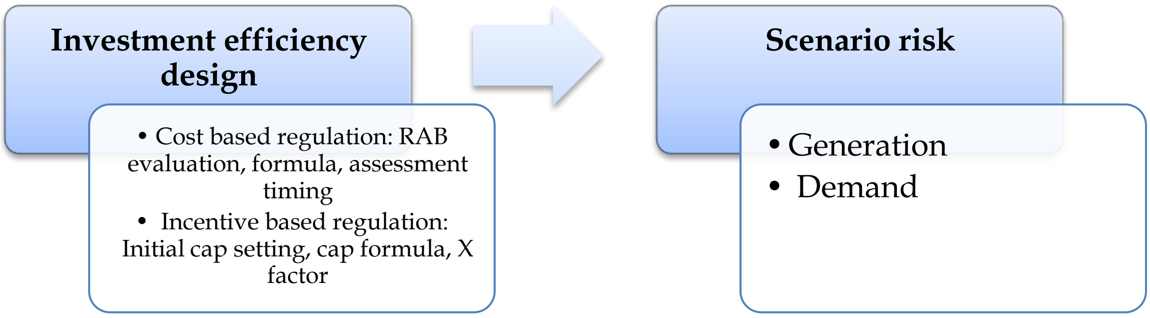
Therefore, it is proposed to investigate the possible impact of breaching financeability threshold by comparing the average cost of capital net of risk free rate between the two groups of credit rating: investment grade and non-investment grade.

6.3. Regulatory Framework and Systematic Risk Indices

6.3.1. Regulatory framework

Investment efficiency

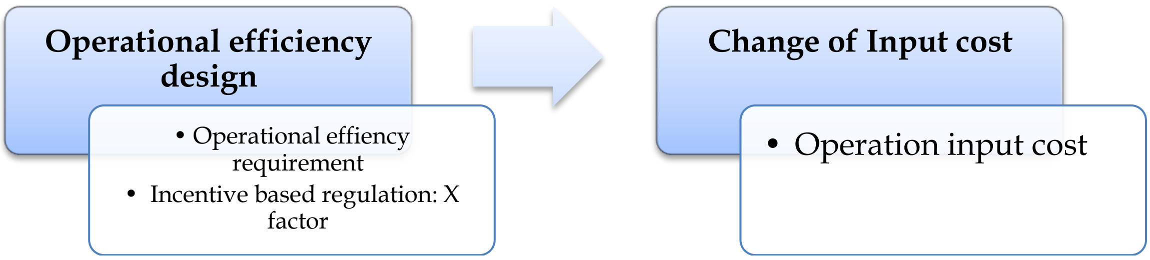
Cost pass-through is the determinant factor to reduce risk of sunk investment for investors. And the investment efficiency regulation is strongly linked with scenario risk exposed to investors. Here we define the guaranteed recoverable cost as a proportion to the overall investment cost to reflect the uncertainty hedge brought by cost pass through regulation design. The degree of cost pass through is closely related to the regulatory asset base evaluation methodology, formulation and assessment timing for the cost based regulation. For incentive based regulation, the cost-pass-through element incorporation in initial cap setting, cap formulation and X factor determination.



Pass-through cost/investment cost	
Low	
Medium	
High	

Operational efficiency

The cash flow of a firm is directly linked with its operation performance. The operational efficiency design exerts direct impact on changes in input costs. Under the regulation scheme which applies incentive based regulation on the OPEX part, the network company is required to achieve a rate of productivity growth each year and face higher pressure than the peer companies with cost based regulation for OPEX. Hence, the productivity growth rate is proposed as the operation efficiency uncertainty indicator for incentive based regulation.



Operational efficiency requirement	
Low	
Medium	
High	

Productivity growth rate X	For incentive based regulation where X factor is applied
Low	
Medium	
High	

Regulatory period & Regulatory delay

Regulatory period and regulatory lag will play a role to keep stable cash flow for regulated companies. A longer regulatory period is generally preferred (also supported by questionnaire results). A longer regulatory lag will bring more financial uncertainty for regulated companies, even for the part of the pass through cost.

Regulatory period	
Low	
Medium	
High	

Regulatory lag	
Low	
Medium	
High	

6.3.2. Systematic risk

Considering literature survey findings [93] [96] [97] and questionnaire results, some risk indices are proposed below. In the next step, the value range corresponding to risk category in the right column of the tables presenting risk indices needs to be determined.

1) Scenario risk

To assess the scenario risk, considering the nature of transmission investment which requires a large upfront capital as sunk cost, it is proposed to use the proportion of fixed cost in relation with the total revenue as an indicator. The scenario risks brought by long term generation, load uncertainties are assessed separately. However, the scenario risk faced by investors in particular the revenue is closely related to investment efficiency regulation design, which could shield risk exposure for investor.

Total fixed cost/ revenue	Generation
Low	
Medium	
High	

Total fixed cost/ revenue	Demand
Low	
Medium	
High	

2) Changes in input cost

Changes in input cost are closely related with the overall economy and considered systematic risk. It includes changes in construction cost and changes in operation cost.

Input cost/ revenue	
Low	
Medium	
High	

3) Financial risk

Interest rate movement

Risk free interest rate directly influences the costs of financing, in particular for debt with floating interest rate payback arrangement. Moreover, the part of cost of capital reflecting investor attitude towards the industry, which is the total cost of capital minus risk free interest rate, exhibits fundamental difference between countries with high interest rate and low to medium interest rate [6]. Therefore, interest rate is proposed as an indicator.

Interest rate	
Low	
Medium	
High	

Inflation risk

Inflation impacts the whole economy. Therefore it is considered to be a systematic risk. Inflation affects the real costs/revenues of the investor. If the inflation alleviates from expected value, the current and future cash cost of the investor is subject to inflation risk and impacts the cash flow of the project. The extent of inflation risk to which investors are exposed can be largely influenced by regulatory lag, RAB evaluation or price/revenue cap setting, whether inflation adjustment is included and in how long is the inflation compensated after the cost has been incurred.

Operating cash cost/ total operating costs	
Low	
Medium	
High	

-Wages, overheads, maintenance are included in the operating cash costs.

Allowed return risk

Financial theory suggests systematic risk is the determinant factor for cost of equity by measuring correlation of asset return and market return. Moreover, financial risk due to leverage is not considered in the risk band methodology, so we focus on the unlevered asset beta as if the firm is solely equity financed.

In order to keep the attractiveness to investors, the regulated return on equity should be commensurate with that of the peer companies subject to similar risks. Therefore, we propose to use the Return of regulated equity (RoRE) less the risk free rate of the country as indicator to represent this peer pressure, while the country specific risk free rate influence is excluded.

RoRE less the risk free rate	
Low	
Medium	
High	

To establish a common standard for financing risk evaluation, for risk free interest rate indicator, we define 0-5% as low risk for interest rate movement, 5-10% as medium risk, 10-15% as high risk. For RoRE – risk free rate, 0-5% is defined as low allowed rate of return, which corresponds to high risk, 5-10% as medium risk and 10-15% as low risk.

6.3.3. Cost of capital

Risk severity criteria could be defined using the scale from 1 to 5 to reflect the severity of each risk category.

Added risk categories	Systematic risk category	Asset Beta (assumed example value)	Indicated overall risk	Market risk premium	Risk free rate	Project discount rate
6--9	Low	0.3				
10--21	Medium	0.43				
22--30	High	0.57				

6.4. Example 1: Risk evaluation of the Brazilian Governance Model

6.4.1. Regulatory framework analysis

Investment efficiency

"Low" investment efficiency uncertainty is selected because

- The investor is guaranteed long-term annual revenues. The investor itself sets the revenue it needs to recover the costs of delivering the reinforcement/new transmission asset when bidding for the contract. During the first 15 years of contract, the transmission owners earn a constant annual rent that is only increased annually according to inflation rates. In the second 15 years of contract, annual rents are halved.
- The formula used by the regulator to calculate the cap of yearly allowed revenue includes:
  (1) Investments composed by the standard costs of the related equipment;
  (2) Weighted average depreciation rate for each type of equipment
  (3) Standard costs for operation and maintenance;
  (4) Optimal capital structure for the transmission business;
  (5) Own or third party cost of capital obtained according to CAPM and WACC
  (6) Taxes and charges as established by legislation

Pass-through cost/investment cost	
Low	☒
Medium	
High	

Operational efficiency

In general we can state that from an OPEX perspective, the uncertainty is medium. *The risks borne by transmission promoters are the non-justified delays in the entry into operation of transmission assets and the non-availability of these assets they have entered into operation, which may result in penalizations to be paid by the promoters.*

Operational efficiency	
Low	
Medium	☒
High	

RAB assessment timing & Regulation period

In the Brazilian case, the regulatory period is long, i.e. 30 years, hence the investor knows what to expect over the lifetime of the asset he will own and operate ==> the risk considered here on the regulatory period is 'Low'.

The fact that there is a yearly evaluation on availability & quality – which might result in penalties – is an element to consider for the investment efficiency (CAPEX), but not for the regulatory stability itself (otherwise stated: this 1 year rule is stable for 30 years).

Regulatory period	
Low	☒
Medium	
High	

The uncertainty brought by regulatory lag is also evaluated as "Low"

- Thanks to the auction process facilitated by the regulator, there is a short time between submitting your business case as an investor and getting a possible "go".
- The recognition of grid projects as strategic investments means that there is also a short time between receiving the "go" and going into operation and thus receiving your annual payment: *"Transmission projects, especially those most relevant, are deemed of strategic importance, which results in a short process of collection of required permits and thus in short durations to realize the projects (rarely above 5 years, mostly under 3 years)"*

Regulatory lag	
Low	☒
Medium	
High	

6.4.2. Systematic risk

1) Scenario Risk

Given the investment efficiency regulation design, low risk is selected for generation and demand scenario with the following reasoning: under this governance model, the scenario risk is not borne by the investor but by the electricity system.

- Grid expansion plans are defined by central authority (in Brazil, research arm EPE) using a cost minimization approach, and in coordination with generation expansion plans. Pending the government's approval of the grid plans, the construction and operation of the necessary reinforcement and expansion projects are assigned through an auction facilitated by the regulation authority; the investors with the lowest bids win the contracts.

- Consumers and generators pay transmission charges whose level is set each year so as to be able to recover the regulated cost of the transmission activity.
- The grid investor is guaranteed an annual rent for 30 years, according to its bid at the time of the auction. Its revenues are independent of the volatility of the economic benefits yielded by the operation of transmission assets.

Total fixed cost/revenue	Generation
Low	☒
Medium	
High	

Total fixed cost/revenue	Load
Low	☒
Medium	
High	

2) Change in input cost

Considering operating efficiency design, Medium risk is chosen for change of input cost because

- Revenue of transmission owners results from the transmission auctions and are modulated according to the availability record of the transmission facilitates they own. All transmission assets are subject to quality control according to technical rules and grid procedures. The investor will be penalized for non-justified delays in operations, unavailability and inadequate performance of its transmission asset. Costs unforeseen at the time of the auction will not be compensated for.
- Non-compliance with transmission facilities availability requirements results in financial penalties.

Input cost/revenue	Technology
Low	
Medium	☒
High	

3) Financial risk

Inflation risk

The inflation risk for investors is low due to the regulatory design: investors acquire the right to perceive predetermined revenues that are **adjusted by inflation**.

Operating cash cost/ total operating cost	
Low	☒
Medium	
High	

Interest rate movement

The risk free interest rate in Brazil falls in the interval of 5-10% most of time during the last decade, therefore is evaluated "Medium".

Risk free interest rate	
Low	
Medium	☒
High	

Allowed return risk

Under this governance model, projects are subject to a medium risk of market competition for capital provision.

- These projects have a targeted IRR by the regulator (10-15%)
- However, empirical data shows that the WACC sometimes have very similar value to the risk free rate, which implies cost of equity approaches the risk free rate

RoRE – risk free rate	
Low	
Medium	
High	☒

6.4.3. Cost of capital

Using the weighting system defined in previous section, an overall risk score of 12 is obtained, which belongs to the low overall risk category.

Added risk categories	Systematic risk category	Asset Beta (assumed example value)	Indicated overall risk	Market risk premium	Risk free rate	Project discount rate
6--9	Low	**0.3**				
10-21	**Medium**	**0.43**				
22--30	High	**0.57**				

6.5. Example 2: Risk evaluation of the U.S. Governance Model

6.5.1. Regulatory framework analysis

Investment efficiency design

The regulatory setting we are assuming in this section is a stylized example of regulation in the U.S. under the oversight of FERC, the Federal Electricity Regulatory Commission. There, the transmission owners are eligible to receive "rates" which are determined in *rate cases*. Though TOs are generally protected from ex-post expropriations, these rate cases are negotiations, where the regulator, the firm and the relevant (private and public) stakeholders are included. The negotiation is deemed to bring uncertainty for cost remuneration, so medium uncertainty for investment is assumed.

Pass through cost/investment cost	
Low	
Medium	☒
High	

Operation efficiency design

OPEX tends to be handled more generally in the U.S. regulatory process; therefore, pressure on operating cost can be considered to be low.

Operational risk	
Low	☒
Medium	
High	

RAB assessment timing & Regulation period

"Regulatory periods" as such do not exist in the U.S. system, as the intervals between "rate cases" differ. However, it can be assumed that under dynamic circumstances, regulatory periods are short and longer if the situation is less dynamic. Therefore, uncertainties from both the length of the regulatory period and the regulatory lag (as transmission companies can apply for opening a case) can both be considered to be low.

Regulatory period	
Low	☒
Medium	
High	

Regulatory lag	
Low	☒
Medium	
High	

6.5.2. Systematic Risk evaluation

Scenario risk

Transmission network project investment is capital intensive and a significant part is sunk cost. Furthermore, combining the considerable variability of long term generation, load and technology advancement assumed in this example, the scenario risks are high. For this scenario risk to materialize, regulation needs to attribute the risk of changes in the pattern of generation and load to the transmission company, which is indirectly true for the U.S.: There, line investments are assessed according to a “used-and-useful” criterion, which implies to test whether lines are needed. If generation and load develop differently than expected, some or all of this risk will be directed to the investor.

Total fixed cost/revenue	Generation
Low	
Medium	☒
High	

Total fixed cost/revenue	Demand
Low	
Medium	☒
High	

Change in input cost

OPEX tends to be handled more generally in the U.S. regulatory process; therefore, risk pressure on operation input cost can be considered to be low.

Input cost/revenue	
Low	☒
Medium	
High	

Inflation risk

Inflation risk can be considered to be low as (i) inflation in the U.S. has generally been limited in the recent past and (ii) rates can be re-negotiated.

Operating cash cost/ total operating cost	
Low	☒
Medium	
High	

Interest rate movement

In the U.S, a stable and healthy macroeconomic situation is assumed in past decade. Hence, we assign the risk due to fluctuating interest rates to the low category.

Risk free interest rate	
Low	☒
Medium	
High	

Allowed return risk

Both reported values of 10% return on equity as reported by Network Economics Consulting Group (2003) and RAP (2011) and the fact that negotiations take place assert that rate of equity is moderate.

RoRE	
Low	

Medium	☒
High	

6.5.3. Cost of capital

Using the weighting system defined in previous section, an overall risk score of 9 is obtained, which belongs to the low overall risk category.

Added risk categories	Systematic risk category	Asset Beta (assumed example value)	Indicated overall risk	Market risk premium	Risk free rate	Project discount rate
6--9	**Low**	**0.3**				
10--21	Medium	**0.43**				
22--30	High	**0.57**				

6.6. Final considerations

This document discusses the different financial and regulatory aspects that may alter the cost benefit analysis of future grid architectures. Ownership, regulation, financing and risk are seen as the main aspects and covered separately.

First, the ownership structure in general defines the scope of cost benefit analysis for grid expansions. The level of system operator collaboration determines the boundary of zonal welfare measure: whether national, regional or an integrated European cost benefit analysis should be performed. The owner/system operator separation implied that different discount factor could be applied on investment cost and operation cost. The choice of regulated investment or merchant investment, will lead to different investment size based on their distinctive objectives.

Second, cost of capital is the result of perceived investment uncertainties. Risk allocation by ownership and regulation design is the focus to facilitate investment and attract capital. The risk band and cost of capital methodology applied in WP6.4 provides a tool to estimate forward looking capital cost from investor perspective by examining comparable systematic risk profile. Important aspects to take into account for cost of capital consideration are:

i) In practice, cost based elements are often included in the incentive based regulation and incentives are added to the cost based regulations, so prudent examination of regulation parameters is essential to identify risk allocation on investor side.

ii) Treatment of CAPEX and OPEX matters to provide investment incentive. CAPEX-OPEX splitting is in some cases engineered to impose efficiency improvement requirement on controllable cost for system operator rather than on the sunk investment.

iii) The extent to which cost pass-through is applied is the most important consideration for investor. In general, systematic risk exposure for investor is higher and the consequential asset beta is higher:
(1) The more uncertainties about future generation, load and technology advancement related remuneration in the regulatory design;
(2) Under cost based regulation, fewer elements are included in the regulated asset base;
(3) Under incentive based regulation, the fewer cost-pass-through incorporation in the parameter design;
(4) Ex-post “used and useful test” on sunk investment;
(5) The longer the regulation period and regulation lag.

In collaboration with WP5, risk analysis is performed using Brazilian governance model and US governance model to demonstrate the WP6.4 methodology. The results indicate Brazilian model corresponds to medium systematic risk and the U.S. model corresponds to low systematic risk.

Third, investment grade credit ratings helps network project to gain access to capital market and fund investment at reasonable cost. Since financeability ratios constitute a large part of the credit evaluation metrics, investment grade implicitly constrains the level of finaneability ratios of the network companies. The effect of breaching financeability ratio is investigated by comparing the cost of capital of system operator with investment grade credit rating and those with non-investment grade.

Annex 2 provides a further description of assumptions and methodology adopted in Task 6.4.

7. Assembly of a thorough cost-benefit approach integrating all the selected indicators

The proposed methodology represent a theoretical framework of possible indicators that can be included in the assessment of future network expansion planning, developed with particular reference to the e-Highway2050 project, that has the purpose of developing the optimal grid architecture for the year 2050 and the modular plan 2030 – 2040 to reach such results in 2050. The first idea in the definition of the methodology was to propose and evaluate the widest set of aspects related to the transmission planning, trying to express them in terms of quantitative indicators. Since this phase was conceived as a sort of "theoretical brain storming", less relevance has been addressed to the real feasibility of implementation, that can be constrained by several factors during the application of test cases, such as lack of data, simplified simulations and so on.

In a second phase, before the final application of the methodology in the e-Highway2050 project, for the assessment of grid architectures provided by the WP2, a concrete set of indicators has to be selected, among those proposed in the theoretical framework.

With reference to the specific application in the e-Highway2050 project and considering all the constraints to the methodology deriving from it, the selection has been done, so as to retain only those indicators that:

- are **adequately supported by data** in the WP2 simulations. Some extra input parameters may be employed, e.g. split of the VoLL per macro-zone and load typology, only if they can be reliably acquired on the basis of existing sources. Also there, agreement has to be sought with the WP2 scenario hypotheses.
- have a **clear regulatory, technological or economical foundation**. Factors whose importance at 2050 is either not clear or depending on uncertain factors (like un-foreseeable technological evolution or strong regulatory changes that are not evident from the scenario narratives) should not be implemented.
- entail **calculations that are feasible in the toolbox** (ex-post assessment starting from the results provided by WP2-WP4, no additional simulations in WP6). The toolbox should be a simple tool making straightforward evaluations. It should be implementable on an Excel/Access platform including VBA macros.

On the basis of what considered above, it is possible to outline what should be the main indicators, what the sensitivity factors and what indicators should not be implemented.

Tab. 72 shows the list with a brief description of the **main indicators that constitute the set of benefits and costs included in the ranking assessment** of different network architectures.

On the other hand, Tab. 73 shows the set of parameter selected for possible further sensitivity analyses for completing the assessment of the architectures. **Being sensitivity factors, they do not concur in defining the final rank of the architectures**, but they provide additional information to the study as a function of the varying parameters.

Finally it can be noted that the indicators related to the "Intra-zonal losses" and the "Effect of new technologies" are not included at all.

Tab. 72 – Set of main indicators selected for the assessment of the e-Highway2050 scenarios

MAIN INDICATORS	
INDICATOR	**DESCRIPTION**
Lifecycle costs	Costs incurred during the lifecycle of the new infrastructures, divided by category and temporal phase
System social welfare	Market benefits provided to the system by a new infrastructure
Network losses	Economic impact of inter-cluster losses
CO2 emissions	Costs for CO2 allowances sustained by thermal generation (implicitly accounted in simulations)
Distribution investments	Estimation of the economic value of the investment needs within the single market clusters as a consequence of the inter-cluster transmission development
Market competition	Quantification of the impact on market results of the exercise of market power by incumbent thermal producers
Socio-environmental costs	Costs related to land use, property values, biodiversity and landscape, health and wellbeing
Social acceptance	Assessment of extra deployment delays due to public opposition
System reliability	Costs of system interruption due to unexpected events accounted for by the market simulation scenarios
System resilience	Capacity of the system to face unexpected (extra scenario) events
DSM costs	System costs tied with interruptable loads management
Financing and regulation	Evaluation of the WACC parameter to be used for the actualization of incurred costs and benefits, depending on an analysis of financing risks

Tab. 73 – Set of sensitivity factors selected for further analysis of the e-Highway2050 scenarios

SENSITIVITY FACTORS	
INIDCATOR	**DESCRIPTION**
Social welfare split	Split of social welfare by stakeholders (generators, consumers) and areas to show different viewpoints (losers/winners)
RES integrability	Potential extra economic benefits that could be extracted from a further deployment of RES generation made possible by the transmission upgrade
CO2 price	Evaluation of price interval that does not imply a change in the generation merit order resulting from simulations
RES curtailment costs	Economic appraisal of possible refunds provided to the RES generation in case of curtailment
Risk driven vs “standard” rates	Comparison of the NPV calculated with risk driven WACC and standard rates
Scenario flexibility	Evaluation of the flexibility of each architecture against the change of the different scenarios
Pillars weighing sensitivity	Sensitivity of the final score of an architecture grouping the main indicators as: economical profitability, socio-environmental factors, security of supply (the three pillars of the EC energy policy)

As shown in the previous chapters, all the factors considered in the proposed BCA approach are monetized and can finally be algebraically added up to provide an unambiguous factor to be used for scoring proposed alternative grid investments. In this way, the assembly of a thorough BCA approach given the previously introduced ingredients appears simple and straightforward. Of course, the placement of costs and benefits in different years that span a long-time horizon requires actualizing all items with respect to a unique time reference by considering the Net Present Value algorithm ([9]). On this regard, taking the same model that was assumed in the REALISEGRID project (see section 1.2 and Fig.12), the life of an investment can be divided into three distinguishing times: authorization phase, investment phase and amortization phase. The first of these three phases is significant also in order to implicitly account for all non-extracted benefits during the period in which the authorization path is carried out: overly-prolonged delays are actually readable as true costs for the system.

The approach hinted above, yet straightforward, leaves unsolved the following questions:

- Provided that the future will exactly comply with one of the scenarios proposed by the e-HIGHWAY2050 project, the whole what-if chain, starting with the scenario hypotheses, continuing with data collection and simulation and finishing with the ex-post application of the proposed BCA approach is correct and provides the most convenient grid reinforcements till 2050. However, it is not clear what scenario will really constitute the future at 2050: even if we suppose that the five scenarios proposed by the e-HIGHWAY2050 project exhaust the space of all possible futures (that is already a simplification), then it still stays uncertain which of the five analysed alternatives will correspond to the realized future at 2050. This problem becomes more and more important as the time horizon becomes longer (and the 2050 horizon is very long!) and constitute the problem of scenario “flexibility” of the BCA results already well identified by the ENTSO-E approach [13]. However, the ENTSO-E approach doesn’t provide a quantitative solution of this problem (the effect of system flexibility is treated there as a non-numerical KPI, thus as an additional information on top of the other factors that are treated in a quantitative manner). In the approach proposed here, we provide a way to quantify also this aspect so as to be able to include it in the scoring analysis. This can be done provided that it is assumed that the five scenarios proposed by the e-HIGHWAY2050 project exhaust the space of the possible futures at 2050. As already stated above, this is a significant approximation, but it allows to provide a quantitative appraisal of scenario flexibility and, e.g. consider with a more important weigh those investments that are common to all scenarios.

- Coming back to the scoring obtained by means of an algebraic sum of costs and benefits of a single scenario, the problem is that the scoring parameter obtained in this way is less “sure” than it could seem, because:
    - There can be important uncertainties in the data that were used for quantify each single parameter; these uncertainties could affect the BCA evaluation and, at least in principle, modify the obtained scoring.
    - Even if there were absolutely no uncertainties in the data, it could be opportune to check how the final scoring could be affected by establishing different priority orders (i.e. weighing factors) among the different benefits than a sheer economic evaluation in which an algebraic sum of costs and benefits is performed.

The considerations of the two bullets above suggest to match the final scoring obtained for the investment alternatives within each scenario with a sensitivity analysis able to check if the final scoring value can be affected by a variation of the weighing factors within pre-imposed limits. This analysis can be easily done by exploiting the sensitivity analysis tool already introduced in Chapter 1.6 by resorting to the concept of Pareto-optimality.

7.1. Scenario flexibility analysis

The main objective of a transmission planning is to ensure the development of an adequate transmission system for future time horizons. The more far is the planning horizon the more are uncertainties to be considered in the planning analysis. Dealing with very long term horizons for the transmission planning the large uncertainties of several parameters have to be accounted for: generation portfolio, demand forecast, policy targets and so on, deeply influence the future context of the transmission system and thus it becomes difficult to define a certain scenario to which apply the analysis. For this reason several scenarios representing plausible future realizations are usually defined, accounting for the volatility of scenario variables. The results of the scenarios definition is a set of possible future realizations sufficiently different from each other to fix an edge on the space of future scenarios, which borders a realistic range of situations that may happen.

Each scenario entails specific peculiarities that have to be faced by the transmission expansion plan; this means that a particular transmission project may have different impacts with different benefits on the system, depending on the scenario. However it is not possible to plan all the transmission projects that best comply with all scenarios analyzed, but the best alternative that complies with the most probable scenario is chosen, possibly taking care also to the reliability if the scenario changes.

This is an important point, because the uncertainty linked to the occurrence of the scenario actually exists and affects the assessment of different transmission expansion plans.

We define the robustness of a transmission project as the ability to preserve the effectiveness for the system against possible changes in the scenario realization. In other words, a project (that may include a set of investments) is robust if it keeps high standards in the benefit and cost assessment, resulting a good choice for all scenarios defined. Such parameter results crucial in the BCA and provides a deep indication about a project, including the risk associated to the scenarios; this can help the decision maker in developing power systems with high degree of flexibility.

As result from the BCA each transmission project is ranked on the base of costs/benefits provided; this rank typically differs from a scenario to others and the differences may be also significant (a project that results the best in a specific scenario may result useless in another one). A possible way to merge all the ranks obtained from the scenario analysis is to define a global index performing a weighted mean for each project, based on the probability of occurrence of scenarios:

$$\hat{SCORE}_i = \sum_{j=1}^{Scenarios} P(j) * SCORE_i^{(j)} \text{ with } \sum_{j=1}^{Scenarios} P(j) = 1$$

where $\hat{SCORE}_i$ is the global score of project *i*, $SCORE_i^{(j)}$ is the score of project *i* in scenario *j* and $P(j)$ is the probability of occurrence of scenario *j*. By means of this parameter we can compare several projects on a single scale and then select the most profitable taking into account the effect of boundary conditions set up by scenarios.

A metric for indicating the robustness of a transmission project can be provided by the standard deviation of the scores obtained in different scenarios, with respect to the global score index:

$$\sigma_i = \sqrt{\frac{\sum_{j=1}^{N_s}\left(SCORE_i^{(j)} - \hat{SCORE}_i\right)^2}{N_s}}$$

The following Tab. 74 shows an example of calculation of the robustness for 4 different projects in 5 scenarios with a probability of occurrence estimated in [0.1 0.2 0.3 0.3 0.1]. The chart in Fig. shows the spread of the score for each project, depending on the scenario.

Tab. 74 – Example of global score computation

	SCORE					Global SCORE	σ_i
	Scenario 1	*Scenario 2*	*Scenario 3*	*Scenario 4*	*Scenario 5*		
Project 1	100	80	110	30	60	74	28.77
Project 2	80	50	20	130	90	72	37.25
Project 3	80	70	75	85	85	78.5	5.85
Project 4	30	20	100	40	25	51.5	30.46

Clearly the project number 3 is the most robust, even if it is never the first choice looking at the single scenario analysis, since it provides the best flexibility across all scenarios. This aspect is not the only one that compete in the expansion plan selection, but it should be included in the BCA to account for robustness.

Remarks on the application

The index accounting for robustness and scenario flexibility is based on a main hypothesis that the risk of scenario occurrence is known and it is an input of the BCA. Probably this is unknown during the scenario definition, since scenarios are not driven only by technical and economic factors, but also by policy and regulations. A possible way to overcome this issue is to increase the number of scenarios (in a reasonable number compatibly with the size of the study), or, in any case, assuming them with an equal probability of occurrence.

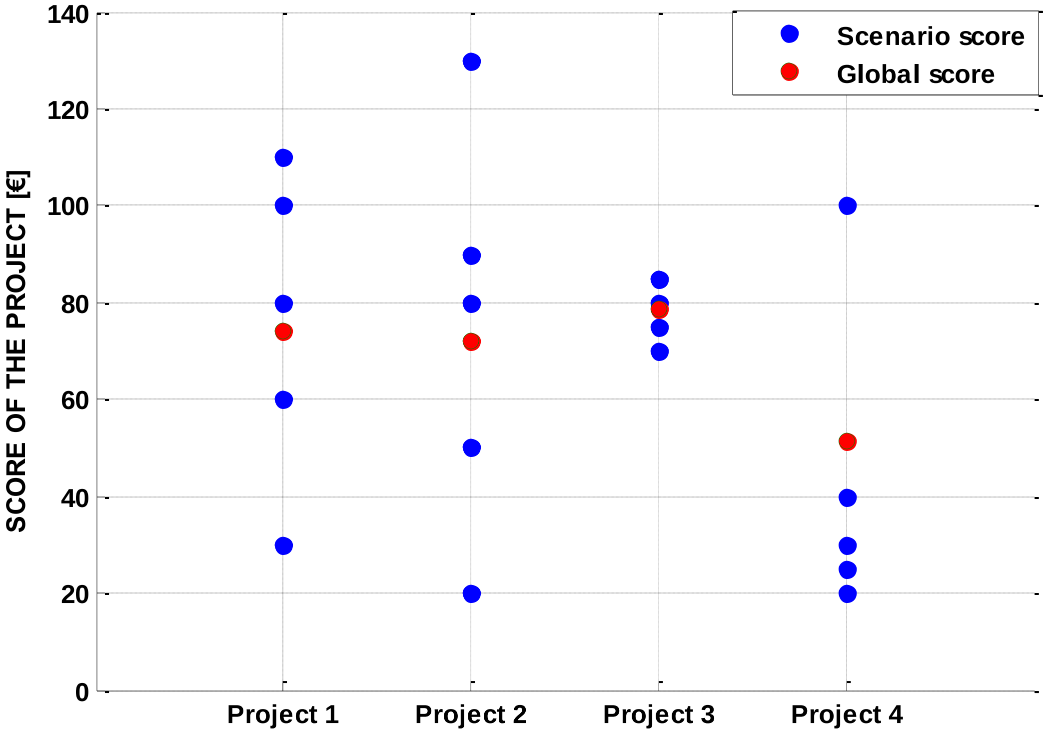


Fig. 51 – graphical representation of scenario scoring vs. global scoring

7.2. Scenario sensitivity analysis

As illustrated above, it can be opportune to carry out a sensitivity analysis of the scoring result obtained for a single scenario by checking its variability with the weighing of the different costs-benefits factors considered within the proposed BCA approach.

Due to the high number of factors affecting the proposed BCA approach, a sensitivity analysis singularly involving all of them would not be possible. A simplification is necessary in order to maintain the problem within a dimension that can be both treated and easily visualized.

On the basis of this consideration, it is proposed to divide the benefits into three macro-categories, according with the grouping already carried out in the previous chapters:

- Costs and benefits related to economical profitability analysis
- Costs and benefits related to social, environmental and technological aspects
- Costs and benefits related to security of supply and system resilience.

This distinction broadly reflects the distinction in the three pillars of the EC energy policy (markets integration, RES integration and security of supply).

In this way, the final scoring parameter would be split into the sum of three parameters, each of which in monetary terms:

$$(SCORE_{Si})_j = (SCORE_{Si}^{EP})_j + \left(SCORE_{Si}^{SE}\right)_j + \left(SCORE_{Si}^{SoS}\right)_j \quad (1)$$

where:

- $SCORE_{Si}$ is the score of a given variant j within scenario Si
- $SCORE_{Si}^{EP}$ is the score of the economic profitability factors for a variant j within scenario Si
- $SCORE_{Si}^{SE}$ is the score of the socio-environmental factors for a variant j within scenario Si
- $SCORE_{Si}^{SoS}$ is the score of the security-of-supply factors for a variant j within scenario Si

Once the split into the three factors listed above is assumed, each solution j within scenario Si can be represented as a point of a three-dimensional solutions space $\mathcal{S}$, as represented in Fig. 52.

In this three-dimensional space we can introduce an evaluation metrics like the one in equation (1), where the three factors are just added up. In this metrics, parallel dihedrals can be defined as the locus of all the points with the same scoring. Variants that are placed on a lower dihedral can be discarded as suboptimal (not Pareto-optimal) and should two different variant be per chance placed on the same dihedral, they would be both belong to the frontier of the optimal solutions. In this case, the actual choice would depend on the "prevailing" of the three axes.

The concept of prevailing axis can be better seen if we allow the weighing of the three axes to be modified:

$$(SCORE_{Si})_j = W_{EP} * (SCORE_{Si}^{EP})_j + W_{SE} * \left(SCORE_{Si}^{SE}\right)_j + W_{SoS} * \left(SCORE_{Si}^{SoS}\right)_j \quad (2)$$

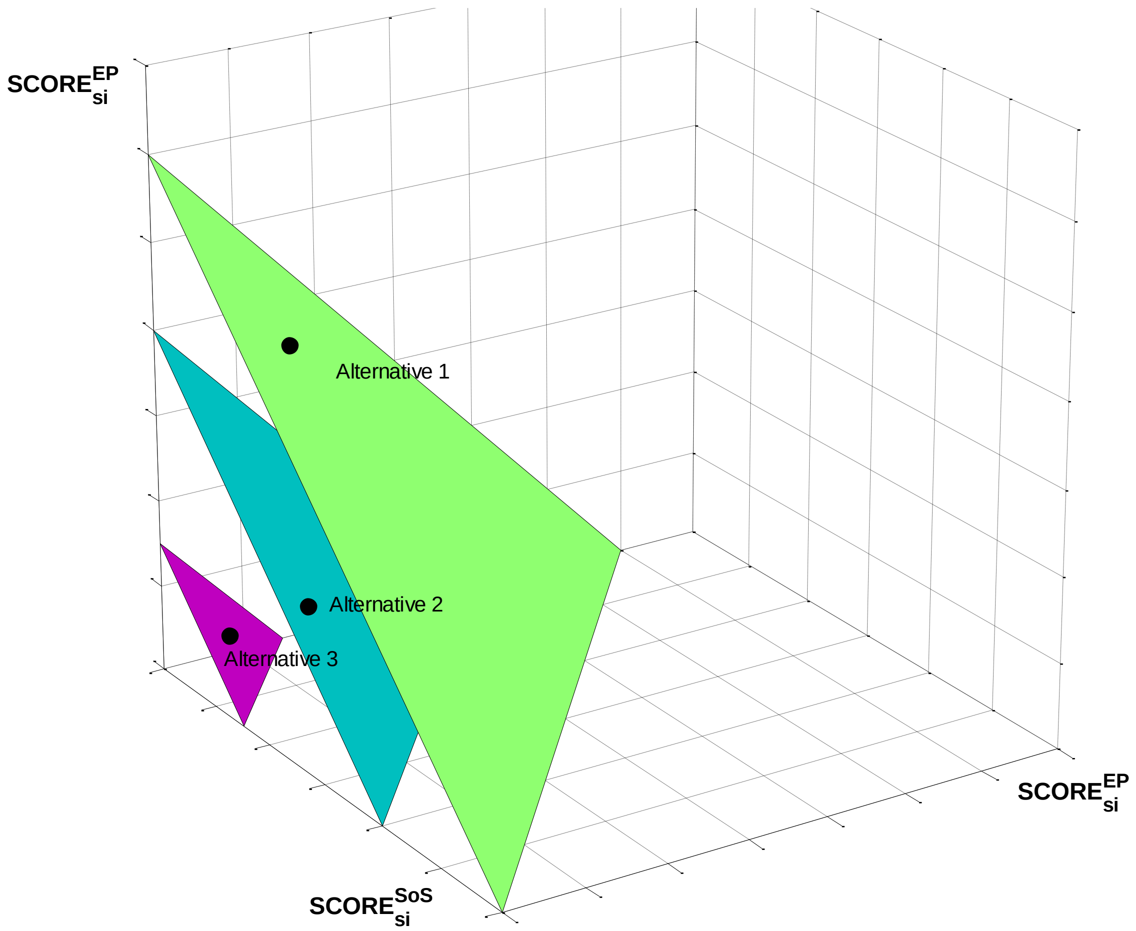


Fig. 52 - The space $\mathcal{S}$ for the sensitivity analysis

where the three weighing factors W_{EP}, W_{SE} and W_{SoS} sum up to one and are allowed to vary within established ranges.

While each of the three weights moves along the admissible values, the dihedral orientation is changed and, as a consequence, the overall scoring metrics is modified. This could bring:

- to disambiguate the scoring among solutions that are both Pareto-optimal in the default metrics
- to understand whether within the admissible region for the weighing parameters it can happen that the solution that is ranked as first in the default metrics is overtaken by another one. In this case, the discussion should be moved establishing which values should be assumed preferentially for weighing the different benefits, that not any longer a technical issue but, rather a regulatory issue or, more broadly, a parameter to be tuned with the scale of values of the society (this is the "Weltanschauung" factor already mentioned in Chapter 1.1).

8. Conclusions

Today's planning is intrinsically insecure due to structural uncertainties:

- scenarios of economic growth in the mid-long term are uncertain
- the three EU-pillars are not completely in mutual agreement
- generation deployment and bidding are no longer integrated
- RES generation is stochastic and flows in the network very variable

The methodology here illustrated is an attempt to take in consideration all the aspects above, by considerably extending the number of considered benefits well beyond the usual planning practice.

The resulting approach is being implemented in a Toolbox, that with the subsequent deliverable D6.2 will be put publicly available to whoever wants to test the methodology on a given set of data. The same Toolbox will then experimented on the five reference scenarios of the project in order to select the best investment path (Modular Plan) till the target year 2050.

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ANSWERS TO THE CONSULTATION REMARKS

Remark	Answer
In Figure 34, Area 2 has a price lower than area 3 and exports 2 MWh to it: the energy is flowing from an expensive area into a cheaper area.	The example is the result of an optimal linear dispatch constrained with DC network constraints, imposed by a PTDF matrix. Since it is not an optimization of the commercial ATC, it is fairly possible that in an optimal equilibrium solution of a meshed grid, energy circulates from a zone with higher prices to one with lower prices provided that this flow is imposed by the PTDF constraints and the net area power injections respect the market principles, i.e. cheaper areas export to areas with higher prices (that is the case in the example).
Proposing a methodology able to distinguish “loser” and “winner” zones (i.e. zones whose local social welfare is, respectively, decreasing or increasing by effect of the transmission expansion) is not correct because separately considering (and weighting) distorts the zonal figures for the social welfare distorts the overall assessment.	A global social welfare optimization, while creating the conditions for an overall minimum dispatching cost for the system, can also imply wealth (social welfare) transfers between markets/zones, making the people locally less well-off and causing a possible opposition to expansion plans. However, we have classified what elements should be considered for the automatic scoring of costs and benefits and what only as sensitivity factors, the latter calculated only in order to enrich the decision-maker perspective and allow to arrive to a final decision that, beyond the automatic scoring factor, also allows to consider other aspects when needed. In this analysis, we included the overall SW within the automatic scoring and the analysis of winners and losers only as an extra sensitivity factor. Additionally, our initial idea to create a new index that differently weighs “winner” and “loser” zones has been abandoned. We will only provide a table with the difference between the SW values “before” and “after” the investment has been carried out, zone by zone as well as the split between generators and consumers surpluses. The analysis of this table and its possible usage for

	calculating extra indices will be left to those who will use the toolbox.
Again about “winner” and “loser” zones: any country exports in some hours and imports in some other hours, mitigating potential issues. And second, for a clearly net exporter country, the NRA (National Regulatory Authority) has many tools at his hand to re-distribute the total benefits of the new interconnection (if he considers it necessary), for example through the grid tariffs. So, it is never possible to conclude that the consumers will suffer a price increase, even in strong exporting countries of electricity.	National regulators may apply many kinds of provisions to compensate an increase of prices for the consumers. However, a monitoring tool is needed showing to the decision-makers if the problem subsists and when. This is exactly what we want to make available, as a sensitivity analysis support to a possible action, whatever nature it can have.
The examples presented in the D6.1 are not real cases but reduced examples with a few nodes.	In order to show a methodology, shorter didactic examples can be more effective. Additionally, real cases will be tested only when the toolbox will be available (D6.2) and, most notably, when the WP2 scenarios will be available for applying the methodology.
The example reported in D6.1 for the social welfare parameter is correct but is referred to a nodal/locational pricing market and that there are no such markets in Europe.	What we have represented as a node, could be easily thought as a market zone and zonal markets do exist in Europe (the Italian IPEX is one example). Furthermore, the European markets are more and more tied by coupling and rather soon we will have a whole-Europe-encompassing area of price coupled markets. This architecture corresponds to something very similar to a market splitting arrangement among the different European markets that are sometimes zonal themselves. This in a relatively close future, but, in e-Highway2050, we are speaking about 2050. If we look at the representation modeled by the WP2 of e-Highway2050, the European space is divided into nearly 100 clusters separated by corridors with limited capacity and a market splitting solution is carried out. So, nothing particularly different from what is assumed in our small example.
About valuation of impacts on the natural environment: internalising impacts on protected areas by re-routing, undergrounding or creating compensatory habitat.	We have to bear in mind an important limitation that has to do with the fact that the simulation model considered by e-Highway2050 divides the European territory in

This may overestimate costs, as not all protected areas are unsuitable as locations for overhead power lines. Second, the cheapest option may not be acceptable in certain protected areas and to assume it will always be selected could go against well-established principles and legal provisions. 1. Significance of impacts - Some protected areas would not be damaged significantly by an overhead power line (e.g. a Natura 2000 area designated for a moss or shrub species). It would be preferable to be specific about the impacts under consideration (e.g. bird collisions, loss of forest cover, etc.) and to consider only those protected areas where there is a real concern that the impacts would arise. In the case of bird collisions, attaching deflectors to the lines can be highly effective, and may be the cheapest option to reduce impacts to an acceptable level. 2. Cheapest options and the mitigation hierarchy - The proposal to always go with the cheapest of the three options is problematic. In some protected areas undergrounding would not be permissible (e.g. if it required cutting a trench through a very rare habitat type, or keeping a swathe of land free of trees in an areas designated for forest/woodland species).	around 100 zones ("clusters") each of which is considered as a bus-bar system. So, in our representation, we don't have connection lines but connection corridors between clusters. Consequently, we have no track information on where the new lines would pass. This makes it impossible to perform detailed evaluations on the territory characteristics. In practice, what we will try to do is to assume a "brown field" philosophy and suppose that new lines will be built around the already existing ones between couples of corridors. This is an approximate evaluation, but, nonetheless, we hope to be able to capture at least partially the order of magnitude of the environmental externalities.
Concerning the assessment of social-economic cost items. The design of the network model used in the e-Highway 2050 project only allows for connections between a limited number of clusters. Therefore it is not possible to determine project routes or project lengths where appropriate, not even by approximation in some cases. How do you see these indicators practically leading to results?	We are going to analyse the borders between clusters and assess what are the prevailing land characteristics. In case of too much dis-uniformity, a "brown field" approach will be applied, consisting in analysing the characteristics of the land on the main lines already operated between the two analysed clusters.
Considering the very long time horizon (2050) of the analysis to be carried out in e-Highway2050, a simplified approach should be preferred on a complicated one giving the perception of a data accuracy that is actually	Long term analyses are, paradoxically, more well defined in data and assumptions than short term ones. In fact, if for short term analyses, uncertainties in the prevision of the many parameters conditioning the evolution of

not real.	the electrical system have to be considered attentively, long term analyses are “what if” scenario analyses. In a scenario analysis, every datum is certain provided the scenario hypotheses are realized. Within each scenario, we can do accurate analysis because data and assumptions are uncertain. The uncertainty is shifted on the percentage of realization of every single scenario, that is, of course, highly uncertain. We have tried to cope with this last aspect by setting up additional sensitivity parameters that combine the scoring obtained in the single scenarios and show the variability in dependency of the main policy headways (represented by the three pillars of the EC energy policy).
A BCA on long time horizon as 2050 should not introduce other uncertainty factors more than ones already introduced by the long time horizon itself and it is suggested an alignment with the BCA methodology currently defined by ENTSO-E.	e-Highway2050 is funded as a research project and has different motivation wrt the ENTSO-E methodology, that is aiming at finding the best investments for the near future. For this reason, while most of the “core” elements of the benefits and costs assessment stay reasonably similar to the ones considered by ENTSO-E, the sensitivity parameters allow to make supplementary analyses, experiment additional indices and analyse additional technical-economic factors that could bring to an advance in the knowledge on the subject.
In order to tune a regression curve for the assessment of market power and generators’ bidding, considering only a set of three years is inappropriate and unsuitable for estimating and forecasting a possible producers bidding strategy in 40 years ahead horizon. Market capacity per generation company according is a parameter that can hardly be forecasted for 2050.	The problem of projecting data for the bidding analysis to 2050 is not different from projecting generation installed capacity per technology/country or availability of new transmission technologies. All this is part of the scenario analysis logics. If there was no important uncertainties on the future 40 years ahead we would not need to consider different scenarios. About the methodology, based on regression curves tuned on historical values, this approach was first proposed by the Californian ISO, so cannot be classified as an academic approach. Finally, the tuning was done for several European markets, thus trying to encapsulate the different peculiarities of the markets. Three

	years of regression analysis are not too little, considering that the data are hourly: this brings to a wide variety of considered situations.
It's not necessary to split costs into categories (see chapter on lifecycle costs). Due to the long term horizon, it could be sufficient splitting costs in % of the total amount (i.e. CAPEX= new asset costs; Authorization=XX%CAPEX, OPEX=YY %/year, DECOMMEX=ZZ% CAPEX) and share them according to a predetermined cost curve detailed per technology of project.	It is not clear what the proposed approach would change: it is always possible to calculate the proposed percentages. What matters is that the different cost categories act differently wrt to the Net Present Value calculation, that is the fundamental basis of any benefit-cost assessment.
With regard to the "Socio– environmental issues" the monetary evaluation may be arduous due to the fact that the local territories should usual feel a different sensibility towards the network infrastructure and these environmental issues may be tackled in the phase of executive project design. On the other hand, the e-Highway2050 grid architecture in a very long term horizon would have the target to define the macro needs of the transmission system at an high level of analysis. Without a feasibility analysis, no consistent data are available and consequently the monetary evaluation for option comparison might introduce uncertainties of results and no impartial assessment.	Converting into money socio-environmental costs may be difficult, but not impossible because these factors are actually costs for the system and some historical data are available. A numerical value comparable with the social welfare should be available in order to include these costs in a general ranking. Alternative to monetization would be the so-called multi-criteria approach, that presents possibly more arbitrary aspects than the monetization approach, for which at least some uncontroversial historical values are available. About the criticality of projecting values in the long term, we have already dealt with this topic in the previous points of the table.
With regard to "technological issues", the transmission system technologies in the last ten years have been strongly developed (e.g. HVDC systems technologies), so the estimation regarding the technologies trends in the next 40 years – even if it was the best - could affect the analysis results quality invalidating the trustworthy level of these kind of assessments.	We agree on the criticality of including the so-called "technological benefits". For that reason, after a debate with manufacturers and TSOs we have decided not to include these factors in the list of those to be implemented in the toolbox.
It is suggested not to provide the VoLL parameter per cluster (taking into account the dependency on different sectors (such as industry), on time, etc. This may lead to a picture of exactness for the situation at 2050 which certainly does not exist.	Not quantifying the VoLL would eliminate the security of supply from the list of parameters considered for the ranking. Being security of supply one of the three pillars of the EU energy policy, this would not be acceptable. Regarding the alleged approximation of the VoLL quantification, this is deemed not more relevant than, e.g., the attribution of an economic value to each expansion technology,

	to CO2 prices or to fuel prices for 2050. In any case, from purely R&D perspective, we consider that some research works need to be conducted on the assessment of the VoLL. That's why it is today presented in our approach. When receiving results from WP2 and using our WP6 methodology, we will see whether or not our approach to compute VoLL is consistent or not and whether should be kept or not. Same logic applies to all parameters selected in D6.1.
The e-Highways2050 project ranks the different architectures to find a "best" solution per scenario. But that analysis should avoid a ranking which is based on one global monetised Euro figure. The risk is that, even with lots of all disclaimers, this will provide the reader with a sense that the results were derived from a fully precise calculation that is not subject to any sort of uncertainty, which is simply not the case. An approach is proposed where the ranking is based on a % value or based on a point system without unit. This allows one to create a ranking without giving the reader a feeling of 100% precision analysis.	Before the inclusion of any project in the TYNDP by ENTSO-E, each TSO has to assess alternative solutions, so as to select the most efficient one which will be included into the TYNDP list of projects. e-Highway2050 proceeds in the same way. A methodology must be defined with the objective to assess different solutions, different expansion alternatives. Finally, these solutions should be compared, therefore ranked, in order to select the "best" one from the technical-economic point of view. This in accordance to the DoW statements and to the necessity to take a reasoned choice among alternative architectures within each scenario so as to achieve the Modular Plan at the year 2050, final goal of the project. A ranking based on % values would provide no different info wrt to one based on economic values: if imprecision of the BCA results is what is complained here, a different way to present results would improve nothing, but, for sure, would provide a very unclear information towards the external readers, and, in this way, could really be misleading. It must be highlighted that e-Highway will provide grid architectures, not a list an individual projects. In this respect the BCA to apply should rank grid architectures, complete development plan, and not individual projects.
Market power, and more specifically abuse of market power is a practice to be fought by regulators; embedding this in a long term	The usual simulation approach, based on marginal cost of generation is not reflective of the real bidding, that is the real price diver.

benefit estimation of grid reinforcement seems out of place and scope. This is not a Market design project. How to assess market design in 2050?	Even in an assessment for the planning (that is not a market study), differences in bidding create differences in merit order and in the dispatch, modifying flows in the network and in principle creating new bottlenecks. Indeed, one of the exercise modalities of market power consists in artificially create bottlenecks by an opportune bidding strategy so as to favour its own local generation. Uncertainties on bidding at 2050 are comparable to many other uncertainties considered in the project.
Factors like market competition, exercise of market power - producer strategy, bidding costs - and distribution network developments, …) introduce arbitrary aspects defined at CBA analysis operator level rather than at pan European border level, led to conditions in which different architecture may not be compared. It is preferred a simplified and confident approach rather than a complicated and academic if this last one may be bring to a wider variability of the economical profitability benefits conditioning the perceptibility of the final result.	The fact that some aspects like market power are not incorporated into usual planning practice doesn't mean that these aspects are useless. Our analysis started from clarifying what aspects condition costs and benefits for the system and we wanted to elaborate a methodology for assessing all of them, yet with the limitations of the approach of the project for the long term (clusterization, etc). It is in the spirit of a research project like e-Highway2050 to analyse all elements even those that entail a new approach. This in sight of an experimentation of the new aspects and that could bring in the future, provided the experimentation is successful, to an inclusion into operative planning procedures.

Annex 1

10. Empirical market power analysis in the Netherlands

In the Netherlands the market share of the largest generator is estimated at **25**% in 2012. This indicates that the electricity market in the Netherlands is relatively competitive.

In order to show whether load and the Lerner Index are related as expected, Fig. 53 shows the plot of load versus the Lerner Index. As expected, load has a positive relationship with the Lerner Index and a relative high goodness of fit as shown by the (adjusted) R-square. In Fig. 54 RSI is plotted against the Lerner Index showing a negative relationship as is also in the line of expectations, with a relative high goodness of fit. The linear regression of RSI against the Lerner Index that will determine the change in the price cost mark-up with a change in the level of RSI by one unit is statistically significant (Tab. 75). Both the F significance and the P values show a 0% probability that the estimation of the regression and the coefficients is obtained by chance.

For the Netherlands, the regression model that is well able to “predict” (future) strategic prices based on a hypothetical (competitive) price can be defined as follows:

$$\frac{Market\ price - Hypothetical\ price}{Market\ price} = -0.4905 * RSI + 0.6783$$

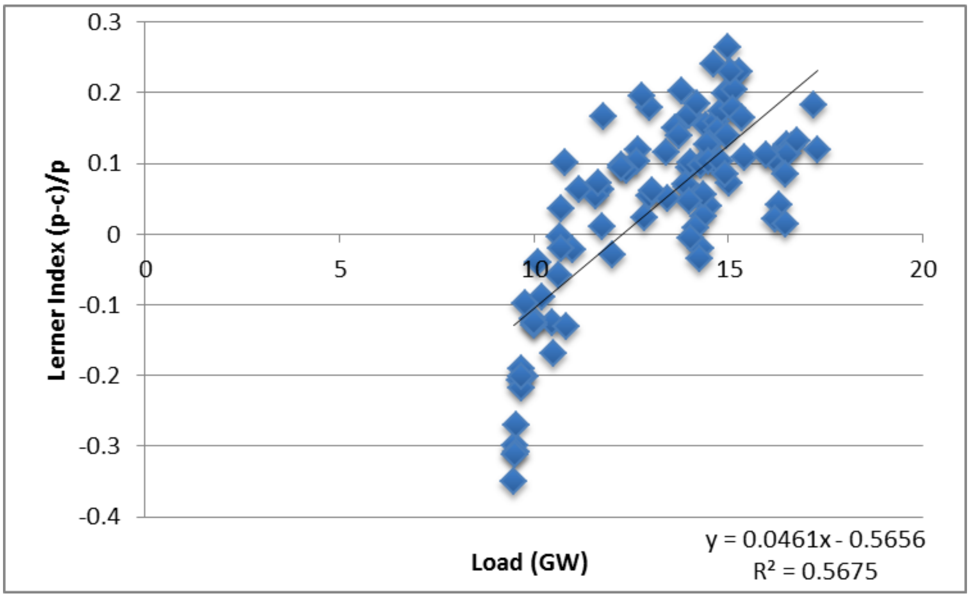


Fig. 53 - Relation between Load (GW) and the Lerner Index in the Netherlands in 2012 showing a clear positive relation with a relative high measurement of fit (57%)

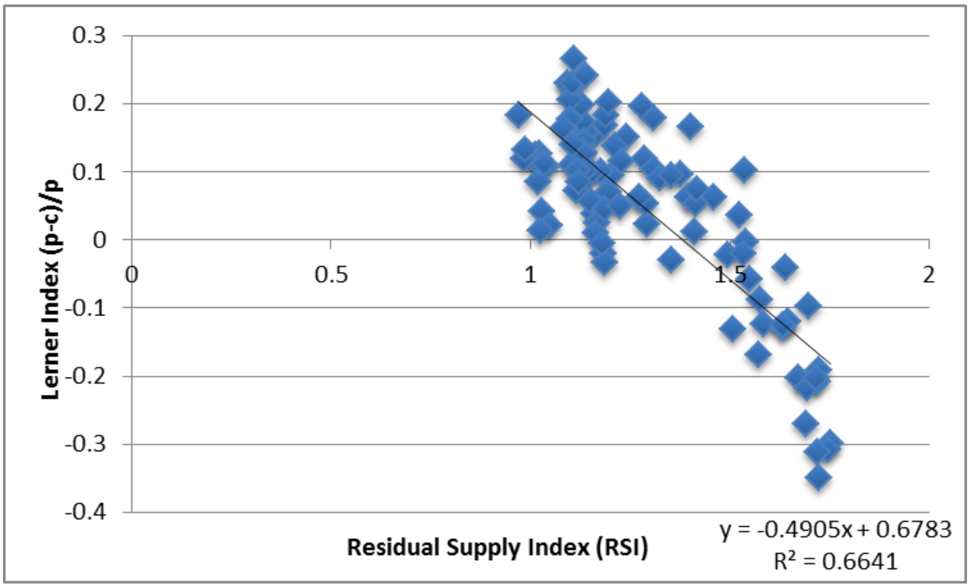


Fig. 54 - Relation between the Residual Supply Index (RSI) and the Lerner Index in the Netherlands in 2012 showing a clear negative relation with a relative high measurement of fit (66%)

Tab. 75 – Statistical variables for the Dutch case

Significance F	R-square	Adjusted R-square	P-value		Lower 95% Confidence Interval		Upper 95% Confidence Interval	
			Intercept	RSI	Intercept	RSI	Intercept	RSI
0	66%	66%	0	0	0.584332	-0.56194	0.772264	-0.41906

10.1. Empirical market power analysis in Germany

In Germany the market share of the largest generator is estimated at 30% in 2012. This indicates that the electricity market in Germany is relatively competitive.

In order to show whether load and the Lerner Index are related as expected, Fig. 55 shows the plot of load versus the Lerner Index. As expected, load has a positive relationship with the Lerner Index with a relative high goodness of fit as shown by the (adjusted) R-square. In Fig. 56 RSI is plotted against the Lerner Index showing a negative relationship as is also in the line of expectations with a relative high goodness of fit. The linear regression of RSI against the Lerner Index that will determine the change in the price cost mark-up with a change in the level of RSI by one unit is statistically significant (Tab. 76). Both the F significance and the P values show a 0% probability that the estimation of the regression and the coefficients is obtained by chance.

Hence, in Germany the regression model that is well able to “predict” (future) strategic prices based on a hypothetical (competitive) price can be defined as follows:

$$\frac{Market\ price - Hypothetical\ price}{Market\ price} = -1.3222 * RSI + 1.2805$$

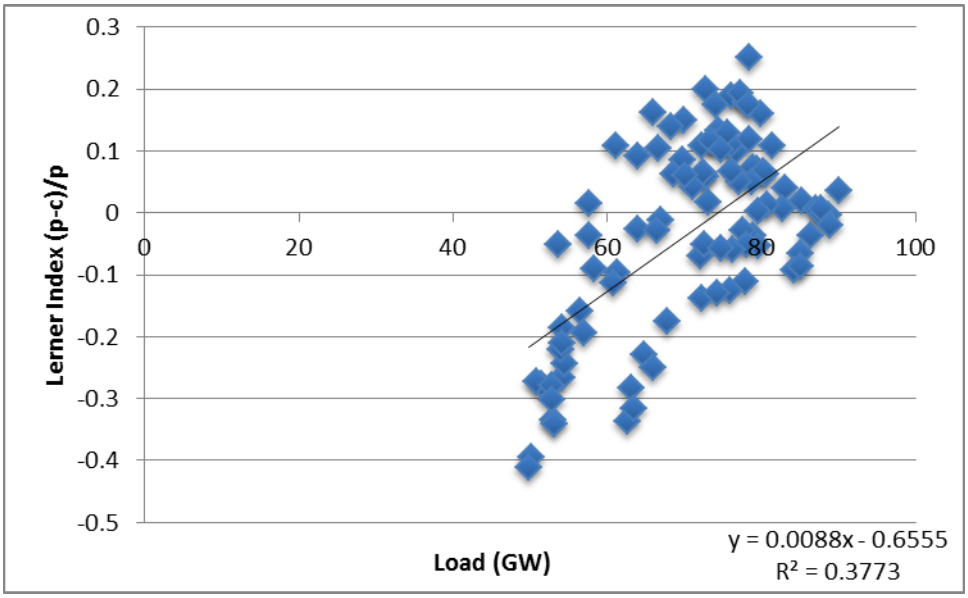


Fig. 55 - Relation between Load (GW) and the Lerner Index in Germany in 2012 showing a clear positive relation with a medium measurement of fit (38%)

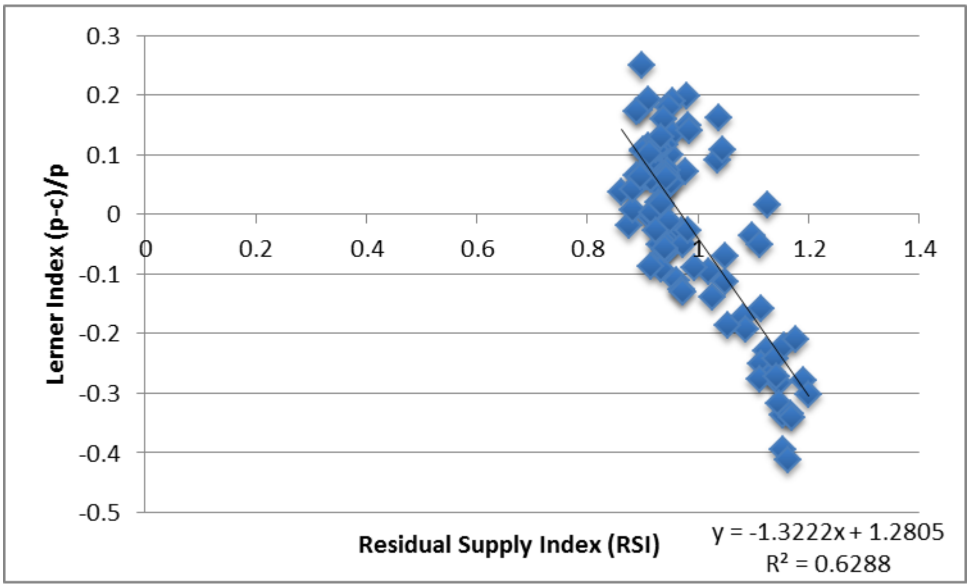


Fig. 56 - Relation between the Residual Supply Index (RSI) and the Lerner Index in Germany in 2012 showing a clear negative relation with a relative high measurement of fit (63%)

Tab. 76 - Statistical variables for the German case

Significance F	R-square	Adjusted R-square	P-value		Lower 95% Confidence Interval		Upper 95% Confidence Interval	
			Intercept	RSI	Intercept	RSI	Intercept	RSI
0.00	63%	62%	0.00	0.00	1.0733752	-1.5302449	1.4875896	-1.1141825

10.2. Empirical market power analysis in Belgium

In Belgium the market share of the largest generator is estimated at 70% in 2012. This indicates that the electricity market in Belgium is relatively non-competitive. though the range of RSI in Fig. 57 is between 0.4 and 0.8, it is not proven in the Belgian electricity market that market power actually has been exerted. Even though the regression resulting from the analysis in Belgium is a shows a better fit and more interpretative results than in France, the (adjusted) R-square of regression RSI and load suggests that 71% of the variation in the Lerner Index *cannot* be explained by RSI. Therefore there are regressors that are omitted and that should be included in order to estimate the dependent variable (e.g. policy which is difficult to include as a regressor).

In order to show whether load and the Lerner Index are related as expected, Fig. 57 shows the plot of load versus the Lerner Index. As expected, load has a positive relationship with the Lerner Index, though with a low goodness of fit as shown by the (adjusted) R-square. In Fig. 58, RSI is plotted against the Lerner Index showing a negative relationship as is also in the line of expectations but again with a relative low goodness of fit. The linear regression of RSI against the Lerner Index that will determine the change in the price cost mark-up with a change in the level of RSI by one unit is statistically significant (Tab. 77). Both the F significance and the P values show a 0% probability that the estimation of the regression and the coefficients is obtained by chance.

Hence, in Belgium the following regression that is able to "predict" (future) strategic prices based on a hypothetical (competitive) price, given the relative low (adjusted) R-square can be defined as:

$$\frac{Market\ price - Hypothetical\ price}{Market\ price} = -0.7513 * RSI + 0.4935$$

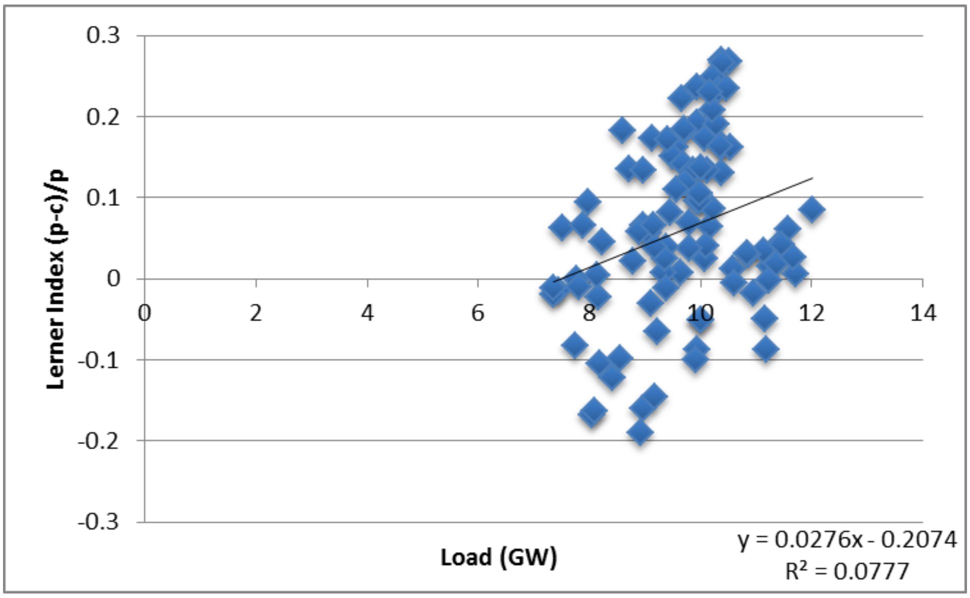


Fig. 57 - Relation between Load (GW) and the Lerner Index in Belgium in 2012 showing a clear positive relation with a relative low measurement of fit (8%)

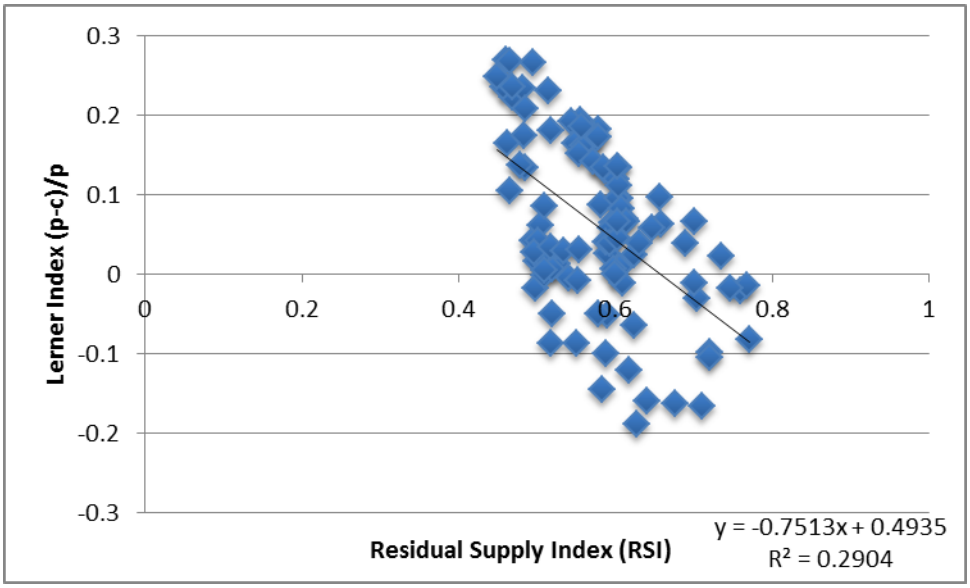


Fig. 58 - Relation between the Residual Supply Index (RSI) and the Lerner Index in Belgium in 2012 showing a clear negative relation with a medium measurement of fit (29%)

Tab. 77 – Statistical variables for the Belgian case

Significance F	R-square	Adjusted R-square	P-value		Lower 95% Confidence Interval		Upper 95% Confidence Interval	
			Intercept	RSI	Intercept	RSI	Intercept	RSI
0.00	29%	28%	0.00	0.00	0.3533592	-0.9918554	0.6336009	-0.5108022

10.3. Empirical market power analysis in Italy

In Italy the market share of the largest generator is estimated at **27**% in 2012. This indicates that the electricity market in Italy is relatively competitive.

In order to show whether load and the Lerner Index are related as expected, Fig. 59 shows the plot of load versus the Lerner Index. As expected, load has a positive relationship with the Lerner Index, though with a medium goodness of fit as shown by the (adjusted) R-square. In Fig. 60, RSI is plotted against the Lerner Index showing a negative relationship as is also in the line of expectations but again with a medium goodness of fit. The linear regression of RSI against the Lerner Index that will determine the change in the price cost mark-up with a change in the level of RSI by one unit is statistically significant (Tab. 78). Both the F significance and the P values show a 0% probability that the estimation of the regression and the coefficients is obtained by chance.

Hence, in Italy the regression model that is well able to “predict” (future) strategic prices based on a hypothetical (competitive) price can be defined as follows:

$$\frac{Market\ price - Hypothetical\ price}{Market\ price} = -0.2412 * RSI + 0.7454$$

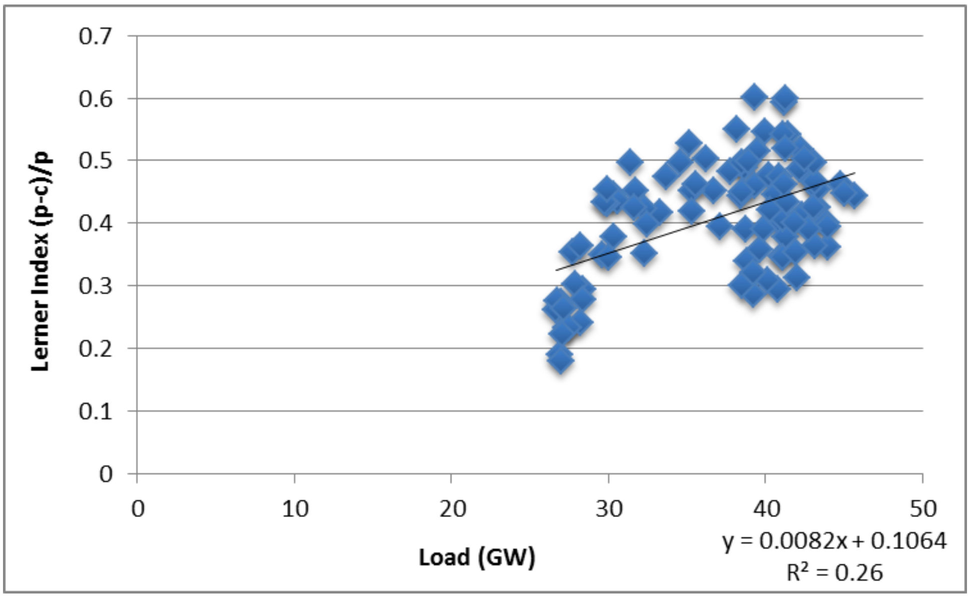


Fig. 59 - Relation between Load (GW) and the Lerner Index in Italy in 2012 showing a clear positive relation with a medium measurement of fit (26%)

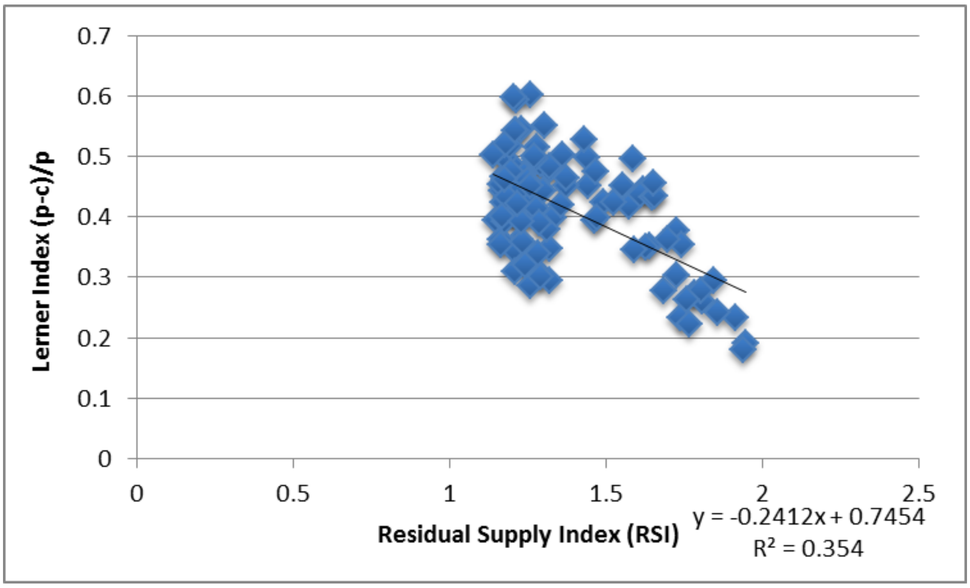


Fig. 60 - Relation between the Residual Supply Index (RSI) and the Lerner Index in Italy in 2012 showing a clear negative relation with a medium measurement of fit (35%)

Tab. 78 – Statistical variables for the Italian case

Significance F	R-square	Adjusted R-square	P-value		Lower 95% Confidence Interval		Upper 95% Confidence Interval	
			Intercept	RSI	Intercept	RSI	Intercept	RSI
0.00	35%	35%	0.00	0.00	0.6512435	-0.3078899	0.8396301	-0.1744547

10.4. aggregated regression model for all EU countries

In order to come up with a regression model to capture the relation between RSI and the Lerner Index on an aggregated level for all countries, a single seasonal average of all 1st, 2nd,..,24th hour of a day for Italy, the Netherlands, Germany and Belgium is calculated. In Fig. 61 the RSI is plotted against the Lerner Index showing a clear negative relationship with a relative high goodness of fit. Also the regression variables shown in Tab. 79 confirm that the regression is statistically significant in order to capture the relation between RSI and the Lerner Index, even for an aggregate of countries:

$$\frac{Market\ price - Hypothetical\ price}{Market\ price} = -0.5031 * RSI + 0.7023$$

In Fig. 62 all five regression models are plotted. An interesting outcome is that the aggregated regression model is highly in line with the regression model of the Netherlands.

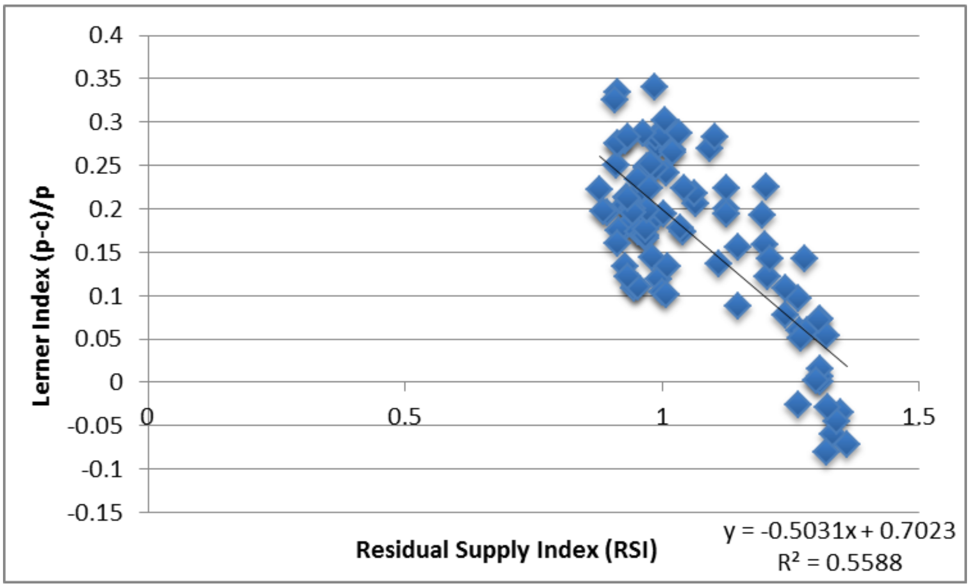


Fig. 61 - Relation between the Residual Supply Index (RSI) and the Lerner Index in 2012 based on the aggregated data for The Netherlands, Italy, Germany and Belgium showing a clear negative relation and a relative high measurement of fit (56%)

Tab. 79 – Statistical variables for the aggregated EU case

Significance F	R-square	Adjusted R-square	P-value		Lower 95% Confidence Interval		Upper 95% Confidence Interval	
			Intercept	RSI	Intercept	RSI	Intercept	RSI
0.00	56%	55%	0.00	0.00	0.6039874	-0.5945935	0.8006505	-0.4115115

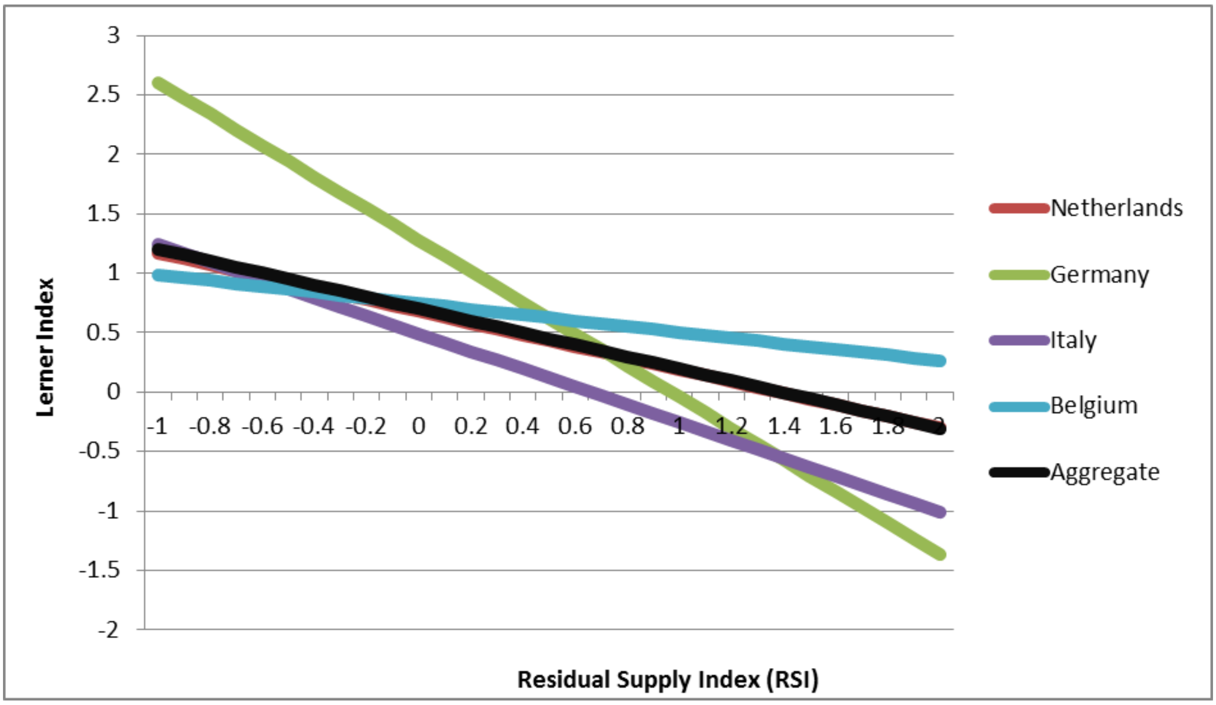


Fig. 62 - Comparison of regression models per country and for the aggregated regression model

Annex 2

Tab. A2-1 – Impacts on biodiversity and landscapes: assessment of costs and benefits

Costs					
Components	**Potential measures/ indicators**	**(Relative) magnitude?**	**Comments**	**Proposed approach**	**Sources**
Compliance costs					
Compliance costs from meeting biodiversity conservation requirements	- Additional costs to TSOs from compliance with regulations (e.g. additional surveys); - Delays or additional project development length relating to additional compliance requirements	Up to 10%-15% of costs in total	Basic cost of compliance with regulations should already be included within investment costs for projects. Additional compliance costs may be experienced when a route crosses protected areas or impacts protected species. This is site specific.	Cost uplift for SPAs	Terna, Swissgrid responses
Delays relating to public opposition to	Delays to project implementation	Low (in context of overall	Also covered in 6.4.5. Costs are highly site specific	Exclude (as covered	

biodiversity or landscape impacts		project lifetime)		elsewhere)	
Mitigation costs					
Re-routing of lines to avoid protected areas	Additional line costs from additional length	Medium	Highly site specific	Cost uplift for SPAs	
Components	**Potential measures/ indicators**	**(Relative) magnitude?**	**Comments**	**Proposed approach**	**Sources**
Undergrounding of OHLs to protect SPAs/habitats/species/ landscapes	Additional investment costs for undergrounding	Undergrounding can add 4-14x costs for relevant sections	Highly site specific	Cost uplift for SPAs	
Opex expenditure for environmental management	Opex related to managing habitats underneath or in the vicinity of lines	Up to 16% of operational costs	Already included within operational costs? Some overlap with compliance costs	Exclude to avoid double counting	Amprion
Residual costs					
Damage to ecosystems e.g.: - Habitat damage during construction - Habitat fragmentation - Bird collisions during operation	- Natural capital assessment - Ecosystem services - Hedonic pricing or willingness to pay for nature protection - Tourism impacts - Biodiversity offsetting	Impacts are site specific but can be significant	Damages should first be limited through compliance with international, EU and national laws; then through SESA, then through EIA. There are residual impacts that may not be fully addressed; these should be included in BCA where possible.	Cost uplift for SPAs	Natural Capital Initiative

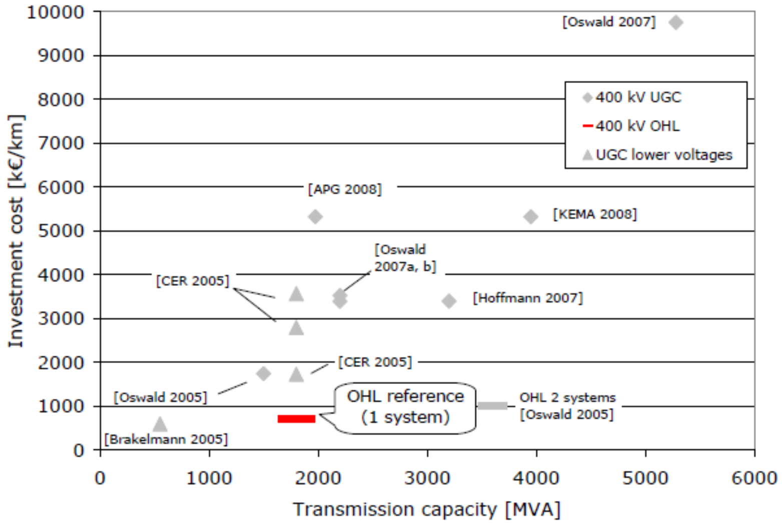
Loss of landscape visual amenity	Willingness to pay Hedonic valuation (e.g. property prices)	Large range: from €0.0005 per km per year per household to €4 per km per household	Considerably higher in national parks, areas of outstanding natural beauty and similar designations Variations not only between studies but also within studies between regions, social class etc.	Cost uplift for SPAs	Ofgem
Benefits					
Habitat creation in the vicinity of route corridors	- Natural capital assessment - Ecosystem services - Hedonic pricing or willingness to pay for nature protection - Tourism impacts	Unknown	Examples include Elia, REE Difficult to quantify value and separate costs.	Exclude	Elia, REE, RSPB
Biodiversity and landscape benefits from avoided electricity generation	- Externalities associated with different forms of electricity generation and associated supply chains (e.g. coal mining)	Unknown	Scenarios include fixed values for generation mix; therefore hard to include directly. Overlap with Renewables benefits, CO_2.	Exclude (as generation scenarios fixed)	Extern-E, other sources?

Biodiversity benefits from avoided investments in storage and other infrastructure	- Externalities associated with storage	Unknown	Scenarios include fixed values for generation mix; therefore hard to include.	Exclude (as generation and storage scenarios fixed)	

Tab. A2-2 – Transmission highways: assessment of impacts on health and wellbeing

Effect	**How we can calculate that effect**	**Types of approaches**	**Cost of these approaches**
Health concerns and negative visual impacts associated with overhead lines Health concerns over EMF levels Noise pollution	Proximity to sensitive areas/areas of high population density	Implementation of mitigation measures (2) by TSOs to reduce health and noise concerns – however, this is dependent on having knowledge of the exact route:	The cost could be assumed to exist in sensitive areas. A few TSOs mention mitigation measures, but do not give actual cost figures. The costs incurred by implementing mitigation measures may lead to future savings due to a decrease in public opposition and resulting time delays.
		1) Minimising the use of overhead transmission lines near areas of high	The literature and TSO interviews reveal that overhead lines are the cheapest option, with underground cables being more expensive and cable tunnels being the most expensive option.

Effect	How we can calculate that effect	Types of approaches	Cost of these approaches
concerns		population density. 2) Using underground or cable tunnels to house transmission lines as opposed to overhead lines. This reduces the health risk and visual impact associated with overhead lines.	The National Grid (2001) estimated that the cost of an overhead line was between €1.88 to €2.11 million/km, the cost of an underground cable was between €21.11 to €25.81 million/km and the cost of a cable tunnel was between €30.50 to €52.78 million/km. [55] found that underground cable cost approximately €1.54 million more and were 2.5 times more expensive overhead lines. The underground capital cost is more, relative to transmission capacity, than overhead lines, and is also more expensive with increased voltages (See graph; [52]). However, the finding by [68] that there is no risk to health if the cables are underground may justify the additional costs. There is public concern on the health risks of new transmission lines, with one report finding that 474 out of 522 people cited health risk concerns with new transmission lines [62]. The costs also vary depending on the maintenance strip surrounding the lines. It was estimated to cost €800,000 for 1km of overhead line with a maintenance strip of 70m (35m each side) in Poland (Lubicki et al., 2008).

Effect	**How we can calculate that effect**	**Types of approaches**	**Cost of these approaches**
			 Capital costs for various UGC projects (◇ 400 kV, Δ lower voltages) in k€ per km depending on design transmission capacity and in comparison with common OHL investment levels (–)
Health concerns over EMF levels Noise pollution concerns	Instances of illness near to grid infrastructure and overhead lines Noise volume from	Implementation of monitoring systems (2) to avoid negative health and wellbeing impacts: 1) Monitoring of EMF levels	Energy grid infrastructure has to meet European guidelines for safe EMF levels. Some Member States adhere to national guidelines that are lower than these European guidelines. Svenska Kraftnaet (TSO) reported that if EMF values are too high they offer to buy the house. There are also costs associated with monitoring EMF levels (Terna, TSO). The costs are likely to be known by the TSOs and will be requested from

Effect	**How we can calculate that effect**	**Types of approaches**	**Cost of these approaches**
	different types of grid infrastructure and overhead lines	2) Monitoring of noise levels from transformers	them. If noise levels are too high, then noise reduction measures such as switchgear housings are taken, in Germany (Amprion, TSO). The costs are likely to be known by the TSOs and will be requested from them.
Negative visual impact of overhead lines results in decrease in wellbeing of affected population	Km of transmission line that passes through sensitive areas (especially landscapes of concern such as World Heritage sites)	Avoiding the situation in the planning stage Implementation of mitigation measures (2) by TSOs to reduce visual impact concerns – such as land compensation[37] – however, this is dependent on having knowledge of the exact route: 1) Offer to buy the house at	The TSO responses indicate that they generally seek to avoid these situations at the start. However, if the development is likely to have a negative visual impact, perhaps from overhead lines, then they may offer compensation (Svenska Kraftnaet, TSO). Elia (TSO) reported that they may offer compensation for visual impact before the realisation of the project. [69] use compensation/mitigation measures in response to any visual damage that their developments cause. The second option is for RTE to refund the difference between the selling price of the property (providing it's clearly not underestimated) and the market value of the property before the construction of the line.

[37] Note: There is a lack of clarity over the reasons behind land compensation. If the land compensation is for activities foregone, then it belongs in Section 4.2, however, if it is for disruptions to health and wellbeing, or to compensate for ill feeling towards the energy grid development, then it belongs in Sections 4.4 or 4.5

Effect	How we can calculate that effect	Types of approaches	Cost of these approaches
		market value 2) Offer to financially compensate the land owner for the loss of property value resulting from the addition of overhead lines/energy grid infrastructure	
Loss of landscapes that bring psychological and spiritual benefits		Hedonic pricing for aesthetic views or proximity to recreational spaces	
Decreases in economic wellbeing due to decrease in home values because of new energy grid infrastructure developments	Finding estimated property values near to transmission lines and then working out the % decrease in their property prices – for compensation	Compensating members of the public who experience decreases in their property values due to the new developments – according to national legislation	Estimation that overhead pylons can lead to a decrease of 1-10% in property prices. This is from a US study, which also found that this was only for properties within 200 feet of the new pylons [66]. Compensation/mitigation measures for visual damage, second option is for RTE to refund the difference between the selling price of the property (providing it's clearly not underestimated) and the market value of the property before the construction of the line [69] Taxation commission (Denmark) estimates the loss of value on houses close to the new lines (Energinet, TSO)

Effect	**How we can calculate that effect**	**Types of approaches**	**Cost of these approaches**
Cultural and historical assets destroyed or damaged due to new developments	Asking TSOs how much they pay for archaeological and paleontological surveys – then multiplying this by length of line in sensitive areas as defined by landscape (and not population density) – perhaps finding an average figure	Implementation of monitoring systems (1) to avoid negative health and wellbeing impacts: (1) Carrying out archaeological and paleontological surveys to detect and identify cultural and historical assets	Cost for archaeological and paleontological surveys. Whilst the cost of the *surveys* is not identical to the cost of *damages* to cultural and historical assets, it is the cost of avoiding the destruction or damage of these assets by identifying them through surveying and then adjusting development plans to avoid such assets. The cost of destroying or damaging cultural and historical assets cannot be calculated or generalized across Europe as there is a wide variety in such assets and as the costing of the health and wellbeing benefits (through psychological and spiritual benefits) is impossible There is an awareness of the requirement for European Member States to identify and account for cultural and historical assets under the Environmental Impact Assessment directive. This European requirement means that the damage and destruction of cultural and historical assets is considered during the planning stages.

Tab. A2-3 – Transmission highways: assessment of impacts on public attitudes and actions

Effect	How we can calculate that effect	Types of approaches	Cost of these approaches
Public opposition to proposed transmission lines/ energy grid infrastructure and appeals against decisions (time delays)	Estimating the need for public events – perhaps as a function of population density	Reducing public opposition (1) to the new grid infrastructure: 1) Early and effective engagement processes: holding public engagement/consultation events and information disclosure events	The cost of these communication and engagement approaches can be estimated through data requests to TSOs. Swissgrid provided such information and estimated that it cost €121,619 for public consultation events and €81,080 for information disclosure event. Several TSOs have identified general relationships between transmission and costs. Longer lines cover more regions and may need more events; areas of high population density may have many land owners with small properties and have greater engagement costs as a result (Swissgrid; Svenska Krafnaet)
	Gathering information on the duration of previous time delays	Identifying costs from time delays through (1): (1) Delays in realising 'project benefits' – loss of potential financial benefits	National legislation dictates set periods of time to be set aside for each step of the process. Public consultation may last up to 45 days, permitting procedures up to 190 days (IPTO). Information regarding time delays and the scale of the project (national, regional, local) is needed. There will also be a cost from a 'lack of project benefits' (Terna), which will be a function of financial project benefits and length of delay in completion. Time delays may result from public protests. These time delays and associated costs will vary across Europe. We will request data for disruptiond to energy grid projects caused by protestors,

Effect	How we can calculate that effect	Types of approaches	Cost of these approaches
			specifically the length of delay and the cost incurred.
	Using national legislation to find levels of compensation needed to be paid and under what circumstances	Mitigation measures, such as land compensation: Providing financial compensation to landowners and municipalities to benefit areas affected	It is unclear as to what this land compensation is for, and whether it is for health and wellbeing or as a response to reduce public opposition. In Germany, municipalities will be able to receive up to €400,000 / grid km crossing their land [70]. [69] is also paying €1 million/year in pylon taxes for 300 pylons in France.
	Looking at existing flood risk maps and the areas covered – construction in these areas may incur additional costs relating to flood risk reduction (km of transmission line in these areas?) The number of roads that transmission lines will cover?	Mitigation measures such as minimising landscape degradation during the construction process and by undertaking landscape restoration work after construction:- REE report the use of cranes in order to minimise landscape damage and of reducing newly created flood risk from construction work, and of restoring roads that have been damaged during construction	Annual reports from TSOs show that costs are incurred to reduce flood risk caused by the construction of new transmission lines and substations. The reports also note that construction can negatively affect roads and lead to the need to recover and recondition them. Additional costs can also be incurred for hanging transmission lines by helicopters and cranes, in order to reduce damage to cropland and roads. No costs are recorded in the TSO reports, but we will request such costs from TSOs.

Annex 3

11. Ownership

11.1. Overview

The ‘ownership’ subtask WP6.4.1 investigates different ownership aspects that impact the financial and regulatory indicators. There are four ownership aspects considered:

1) System owner (SO) collaboration: multiple national SO/regional SO/ single European SO
2) Investment type: public/private investment
3) System owner/operator framework type: TSO/ITO/ISO&TO
4) Asset ownership structure

11.2. System owner (SO) collaboration

A single European SO: the whole volume of European transmission network investment is performed by the European SO as if the interconnected grid is a single zone. The objective of grid investment is to maximize total net welfare, which is the total benefit minus total cost [98].

Multiple national SO: the network planning and investment is performed in the national level by the corresponding system owner(s). Objectives are maximal “zonal” welfare.

The system owner collaboration has a profound effect on cost benefit analysis.

The objective of the BCA when considering the single European SO is to maximize the SO welfare (which should indirectly maximize total net welfare for the system), so it will keep on investing until the marginal benefit of network expansion equals the marginal cost. However, the individual welfare in different zones might be conflicting. The gain in a certain zone might cause a loss in other zones. In contrast, the objective of the multiple national SO is to maximize the welfare of each national SO. In other words, the multiple national SO scheme pursues optimal result in each subsystem. The single European SO pursues optimal result at system level, but for individual subsystem, the result is not guaranteed to be optimal, and needs to be accounted for in the BCA analysis.

11.3. Investment type

There are two types of investment type considered: ‘Public investment’ refers to the investment performed by public sector or publicly owned companies; ‘Private investment’ refers to investment committed by private sector.

The impact of public and private investment on transmission network is discussed from the investor and social benefit respectively.

Public investment, generally, is usually perceived by the market as having sovereign guarantees and seen as secure investment. A lower rate of turn is required for this type of investment. Public investment has the role of providing infrastructure for the public good. However, public investment might be constrained by the government budget and may lead to gold-plating as the capital costs could be recovered by taxation.

Private sector involvement could be more incentivised to improve productivity, thus allocate the risk more efficiently. Private sector investors are primarily interested in their own benefits rather than the social welfare. Provision of infrastructure by private sector could lead to social suboptimal and often result in low levels of investment.

From market investor perspective, investment by private sector is more risky as the risks allocated to private sector are borne by investors. So a risk premium is charged by the market investors.

In the methodology proposed by this document, the risk transfer between public and private sector determines the cost of capital for specific project.

11.4. System owner/operator framework type

There are three main types of system owner/operator framework options that we take into consideration: ISO/TO, TSO and ITO, where:

- 'TO' is a transmission network owner;
- 'ISO' is a fully unbundled system operator without the grid assets;
- 'TSO' is a transmission system operator that owns the system assets, and ownership of the grid is fully unbundled from generation;
- 'ITO' is a transmission system operator owning the assets and belonging to a vertically integrated company.
- 'SO' is a system owner of any type (note that SO is sometimes also used to identify a system operator).

At this moment, the most common owner/operator framework in Europe is TSO model. However, different models exist (within Europe and outside). The manner in which the unbundling has been implemented has a significant impact on the transmission investment patterns and needs to be taken into account.

Compared with the national TSO model, a single independent system operator has the potential to manage the network of multiple transmission owners in a larger region, which could accelerate regional market integration. Hence, they are more interested in increasing interconnection capacity, if it has overall social welfare benefits, however, the actual investments are done by the system owner (In some cases, third parties are allowed to finance the network expansion approved by regulators. if the owner does not support the investment.) Depending on the regulatory framework and the manner in which incentives are given for new investments, actual decisions are taken and the owner objectives might not align with the operator objectives. –Note that the ISO concept does not need to overreach multiple zones, also the possibility of an ISO and TO on the same geographical surface might exist.

ITOs are in favour of the interconnection investment that increases export and/or security [99]. In case the transmission expansion is expected to create additional imports, under-investment or postponements of the investment are more likely to occur as ITOs may have the incentives to favour their affiliated generation company.

From the financial perspective, increased level of unbundling may reduce the cost of capital if the transmission projects can access cheaper capital market. But the possibility of increased cost of capital also exists if more stringent regulations for transmission investment or more regulatory uncertainties are perceived by the market [100].

In the following section, the implications of TSO model and ISO/TO model are discussed in detail. Since the investment consideration of ITO involves generation assets, which is outside the scope of grid architecture evaluation, no quantitative analysis is given.

11.5. Asset ownership structure

Two types of asset ownership structure are defined: regulated assets and non-regulated assets.

Regulated assets are subject to traditional pricing regulations defined in subtask 6.4.2 such as cost of service, pricing/revenue cap, sliding scale and yardstick.

'Non-regulated' assets refer to the assets that do not follow the above mentioned traditional pricing regulations. Merchant investments are a typical example of this type of assets.

Non-regulated assets are subject to different regulatory and financial risks compared with the regulated assets. It has been well elaborated in the literature that non-regulated asset investment such as merchant investment may cause an under-investment problem. As the revenue of merchant lines depends on price differences of the interconnected zones, the merchant line developers are incentivized to develop a system with a capacity that maximizes their own revenue instead of maximizing social welfare. Other study suggests that if the merchant line is owned by an unbundled SO, or has ownership link with generation companies, it can be subject to helping generation companies to exert their market power and earn at the cost of others.

11.6. Methodology

11.6.1. Characteristics about public investment and private investment

It is widely accepted that public sector investments can attract capital at a lower cost compared to a private investor. Specifically speaking, it is assumed in our analysis that public investment is indifferent to uncertainties or risks. As such, a risk free rate can be used for public spending. Two reasons support this view. First, it is assumed that government or its agencies invest in a large number of projects and are able themselves to pool the risk through asset diversification. Secondly, the private investors may require higher rates of return to hedge the risk against fraudulent market behaviour or unstable policy they associate. This type of risk is usually not an issue for public investment. Therefore, it is not priced into required return on capital for public investment [101].

As demonstrated by Figure 1, for the private investment, market demands a higher rate of return to compensate the perceived project risks.

Fig. 63 and Tab. 80 depict the relationship between risk allocation, risk free rate, project rate and systematic risk premium. Risk free rate is used to discount cash flows for projects invested by public sector, and it usually adopts the government bond rate as proxy. Project rate refers to the required rate of return from projects in which all systematic risks are exposed to private sector. It is applied to private investment with a systematic risk premium adding up to the risk free rate [93].

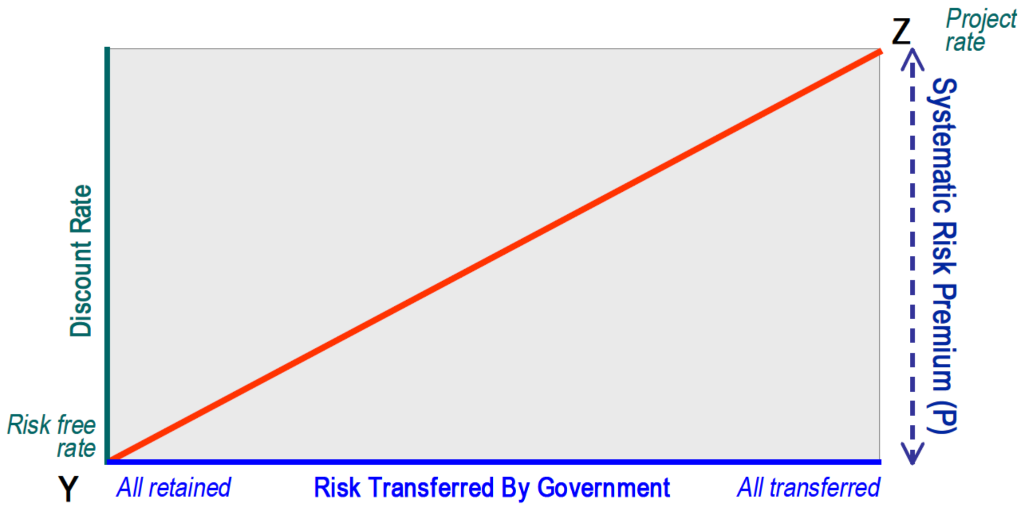


Fig. 63 – Relation between risk-free rate and project rate [93]

Fig. can also be used to interpret capital cost in the public and private project financing. Systematic risk can be shared by investor, users and tax payers. The latter two referring to more or less the same group in network industry, and risks are borne by users directly and by tax payers indirectly. In this document, we do not differentiate the risk borne by users and tax payers and see them as risk borne by public sector.

The eventual discount rate applied to a transmission investment project is evaluated by the risk transfer. The asset beta value, which reflects the non-diversifiable systematic risk covariance to the average market return, is linear to the risk allocation from public to private sector.

An example is provided below in Tab. 80 to demonstrate this relation and the discount rate calculation methodology.

Tab. 80 – Example of risk sharing and cost of capital

	Risk free rate	Market risk premium	Asset Beta	Discount rate
All risk with public sector	4%	-	-	4%
All risk with private sector	4%	5%	0.6	7%
60% risk transferred	4%	5%	0.6*0.6	5.8%

In the risk indicator evaluation process, this risk allocation between public and private sector is implicitly applied. Under different regulation designs, we focus on risk exposure to investor in each category and calculate its corresponding asset beta. It is important to realize the other parts of risk are borne the users and tax payers.

11.6.2. System operator type

In current social political context at the European level, the preferred owner/operator framework is TSO model. However, the manner in which unbundling has been implemented has a significant impact on the transmission investment patterns.

Compared with the national TSO model, a single independent system operator over larger regions has the potential to manage the network of multiple transmission owners in a larger region, which could accelerate regional market integration. Hence, an ISO is more interested in increasing interconnection capacity, if it has overall social welfare benefits, however, the actual investments are done by the system owner. This might lead to conflicting interests. Furthermore in some cases, third parties are allowed to finance network expansions approved by regulators. if the owner does not support the investment. Depending on the regulatory framework and the manner in which incentives are given for new investments, actual decisions are taken. For this analysis of financial implication of ISO/TO arrangement, we take the typical division of network functions between transmission owner (TO) and ISO such that transmission owners are responsible for transmission capital management and the responsibility for Independent system operators falls on network operation.

As its responsibilities suggest, major part of the expenditure of TO goes into CAPEX for network investment, whereas dominant expenditure for ISO is the OPEX for system operation. TO and ISO are perceived by the market with different exposure of risks since the nature of their activities differs and so do their corporate financial profiles. Naturally, discount rate used for the CAPEX and OPEX in LCC calculation could be two sets.

	$ASSEX_i$	$DF_{ASSEX}(\hat{t})$	$OPEX_{ij,TOTAL}$	$DF_{OPEX,TOTAL}$
TO	X	x		
ISO			x	x

The TSO is responsible for both network investment and operation. Under cost service, CAPEX and OPEX are passed through with a regulated rate of return. Then the discount rates for CAPEX and OPEX are equal.

	$\mathrm{ASSEX_i}$	$\mathrm{DF_{ASSEX}}(\hat{t})$	$\mathrm{OPEX_{ij,TOTAL}}$	$\mathrm{DF_{OPEX,TOTAL}}$
TSO	X	x	x	x

11.6.3. Regulated VS Merchant investment

Merchant transmission is an appealing type of investment adding up to regulated business, in particular for capital intensive programs, since it provides alternative means to gain access to capital market.

Fig. 64 - Two interconnected zones by merchant line

$$\boldsymbol{Congestion\ Revenue} = \int_{t_{Sev}}^{t_{End\ Life}} |P_A - P_B|\, P_f$$

Where

P_A is the price in zone A

P_B is the price in zone B

P_f is the power flow on the merchant interconnector, usually it equals the capacity

As the congestion revenue formula indicates, merchant transmission revenue relies on the price difference of the interconnected zones which varies greatly with the generation and demand

pattern. This risk exposure to future generation and demand changes, which lies in the investor side, is translated into higher cost of capital.
Since merchant transmission investors are not necessarily from the zones which the line interconnects, our argument follows intuitively that for social welfare analysis considering merchant investment, the term of merchant surplus should not be included in the zonal social welfare calculation as opposed to that of the regulated investment demonstrated in WP6.1.1. We define social welfare for merchant investment as the sum of consumer surplus and producer surplus. For DC merchant transmission investment, the grid externalities are not relevant so the calculation for zonal social welfare change is more straightforward [102]. Merchant investor benefit is defined as the congestion revenue in the analysis below.

It can be observed by comparing social benefit and investor benefit formulas that the optimal interconnection capacity that maximizes social benefit is twice the size compared with the optimal capacity that maximizes investor benefit, as demonstrated in Fig. 65.

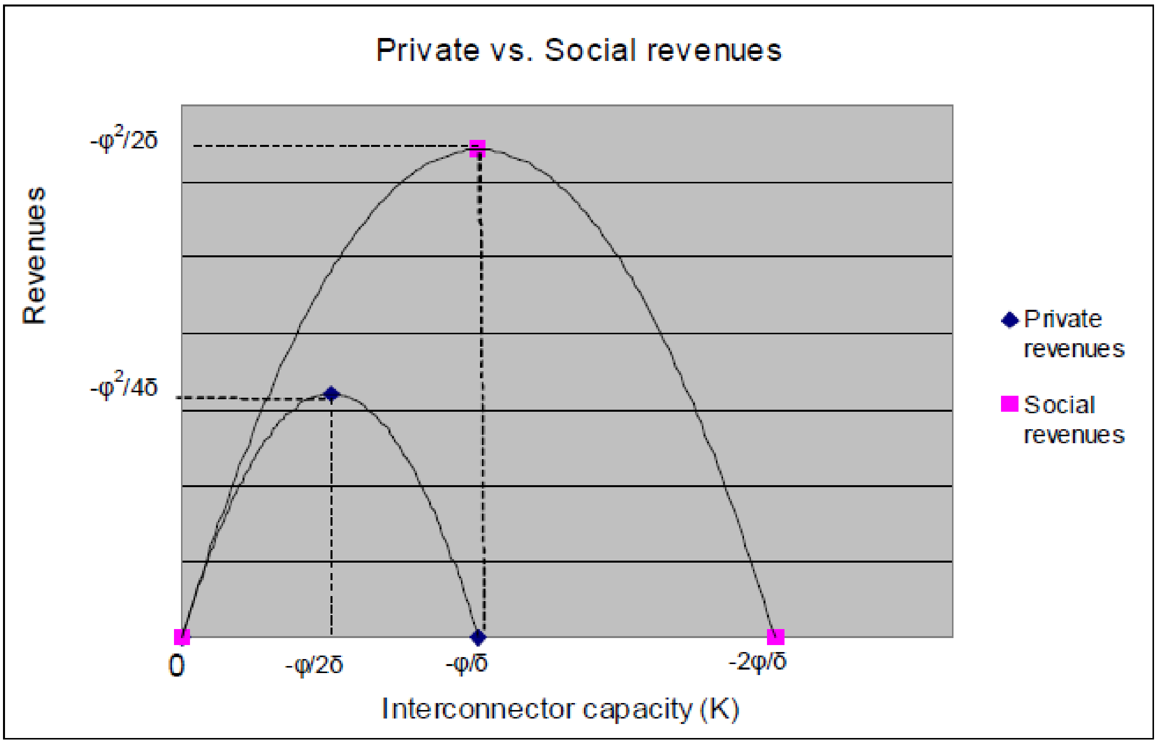


Fig. 65 - Optimal interconnector capacity for regulated investment and merchant investment [102]

11.6.4. SO collaboration

SO collaboration schemes fundamentally impact the cost benefit analysis by presenting different means to formulate objective functions.

Under the single European SO scheme, the cost benefit analysis should be performed for the overall system. Demand and supply curves should be aggregated. Overall social welfare could be calculated using the area of aggregated demand curve minus generation cost in the whole system. Merchant surplus is already included in the result, so it does not have to be calculated explicitly [98].

The objective of the multiple (national) SO is to maximize the individual welfare of the zone each national SO is responsible of. However, social welfare optimization in different zones might lead to conflicting incentives. The gain in a certain zone might cause a loss in other zones. As a result, the planner under multiple national SO scheme pursues optimal social welfare in its system under the constraints imposed by planning outcomes of other systems. To sum up, the cost benefit analysis should be performed at zonal level. It can be noted that in the current approach, SO already collaborate towards higher social welfare, also cross border, beyond the sole optimization of the local objectives. Nevertheless, it is still not a system wide approach.

In the case of regional SOs, the supply and demand curve should be aggregated at regional level, while the merchant surplus should apply to congestion rent from interregional interconnections.

12. Pricing Regulation

12.1. Typology of Regulatory Schemes

In general, electricity transmission is considered a non-contestable natural monopoly, i.e. markets are not deemed able to deliver a desirable outcome concerning price and quality in the provision of this infrastructure from a welfare economic perspective. Thus, transmission (both system operations and the assets) is usually subject to regulation, i.e.: a monopoly is awarded, but a regulator applies instruments to reach a desired output regarding quality and quantity to minimal costs. Thereby, the regulator can focus either on welfare economic or a consumer perspective. In contrast to the latter, the welfare economic perspective does not distinguish between producer and consumer surplus. If regulatory regimes are judged by these points of views, the results are often the same. However, there can be also trade-offs [106].

Armstrong and Sappington [104] propose four dimensions to characterise practical regulatory policies: (i) the extent of price flexibility given to the regulated firm, (ii) the manner in which regulatory policy is implemented and revised over time (i.e. up-dated), (iii) the degree to which regulated prices are linked to actual cost, and (iv) the discretion that regulators have, when they decide on their policy.

This taxonomy can be used to illustrate the differences between different regulatory schemes, and we will do so by first taking the (stylized) examples of a price/revenue cap regulation and a rate-of-return regulation, following Armstrong and Sappington [104].

12.1.1. Cost-based regulation

Under cost based regulation, the regulator grants the regulated firm a fixed rate of return on the capital invested. Prices are therefore closely linked to actual cost and incentives for the reduction of the firm's cost are low as compared to the price-/revenue cap approach.

$$R_t = C_t + D_t + T_t + RAB_t * r_t$$

Where

R_t is required revenue in year t

C_t is operating cost in year t

D_t is depreciation in year t

T_t is taxes in year t

RAB_t is regulated asset base in year t

r_t is allowed rate of return in year t

According to the scientific literature, cost-based regulation in its pure form is characterized by fixing the remuneration level on the basis of observed costs, i.e. the costs are completely passed through to the consumers. Consequently, the regulated firm has no incentive to reduce costs. In contrast, the firm will even tend to overinvest. This is true for both types of cost-based regulation: cost-plus as well as rate-of-return regulation, which guarantees a rate of return on the total expenditures respective the capital employed. In addition, rate-of-return regulation encourages the firm to adopt inefficiently high capital-labour ratios [105]. However, since the firm does not bear any (cost or demand) risk as long as cost changes lead to instant price changes, the costs of capital are low. This is especially true since the regulatory risk is also low. The regulator can credibly commit to assure an adequate remuneration of the investments in long-living specific assets, because for example courts can easily verify whether the regulator behaved opportunistically.

In praxis, the ideal-typical cost-based regulation with full cost pass-through is often modified by monitoring the costs; thus, the costs are examined ex post in terms of efficiency. An example is the used-and-useful criterion, which is part of the rate-of-return regulation in the USA. Furthermore, ex ante rules for cost allowances and cost controls for not standardised, valuable investment projects are usually implemented. In sum, the requested interest rate increases compared to the ideal-typical case due to a higher uncertainty for the firm, but the firm is also more incentivized to produce cost efficiently.

12.1.2. Performance based regulation

Price-/Revenue-Cap Regulation

Under a price-/revenue cap-based regulation, the regulator basically sets a cap on prices/revenues. This leads to a situation where strong incentives for cost-minimization of the firm are in place as the firm is allowed to keep the excess revenues. However, especially depending on stability of the regulatory commitments, a (shorter-term) cost-minimization is often not encouraging large infrastructure investments.

Benchmarking

If there are multiple firms of a similar kind, there is a way to "to harness competitive forces to discipline a monopoly provider" [104]: The idea of Yardstick competition is to apply efficiency observed at different firms to one firm, such as to implement a mechanism where firms have incentives to "compete" for efficiency. For that, different econometric methods, such as data envelope analysis (DEA) and stochastic frontier analysis (SFA) are applied.

An ideal-typical incentive regulation sets incentives for a cost efficient production of a certain output. The transfer of cost risk to the firm results from fixing a price or revenue cap for a regulatory period, often about five years, and the allowance to keep the resulting profits as well as the losses. The two options, price- or revenue-cap, are just different designs of an incentive regulation and differ primarily in the allocation of the demand risk, which is transferred to the firm in case of a price-cap. In order to set incentives, a determination of the remuneration level independently of the individual observed costs is essential. The remuneration level should reflect the efficient costs for producing the desired output concerning quality and quantity. Regarding the ideal text book case, the remuneration level is determined independently from the observed individual costs of the regulated firm. The efficient costs can be estimated more or less either by analytical cost models or by benchmarking of the costs of several (to a large extent homogenous) firms. In case of the latter, this is often called yardstick regulation.

The major advantage of an incentive regulation consists – at least in theory – in the incentive for (long-term) cost reductions, which includes an optimization across the interface between capital and operating expenditures if the total expenditures (TOTEX) are considered. However, an incentive regulation often leads to a short-term oriented investment strategy and therefore a deterioration of the condition of the assets and higher long-term costs, particularly if the regulator focuses on the total expenditures. This is due to the difficulty for the regulator to commit credibly that on the one hand the long-living, specific assets will be remunerated over a depreciation period of e.g. 40 years and on the other hand that long-term losses have to be borne by the firm. Compared to a cost-based regulation, a credible commitment is hard to deliver because the remuneration level depends solely on the (partly questionable) validity of the methods for estimating the efficient costs (and not the individual costs of the firm) and the comprehensibility of the methods for third persons like courts. The uncertainty whether the investments are remunerated adequately or whether the regulator will behave opportunistic and cut the remuneration ex post increases the regulatory risk and thereby the costs of risk taking. Further disadvantages are amongst others high security premiums, which are added on the estimated efficient costs due to methodical inaccuracies (and should be judged negatively from a consumer perspective), and a time lag for the remuneration of investments during the regulatory period. See Beckers et al., 2013 [106] for further explanations.

For reducing some of these problems, in praxis the cost risk is usually only partially transferred to the firm, i.e. cost-based elements are implemented. First, exogenous costs can be passed through via indexation like inflation or variations of the risk-free interest rate. Second, the regulator can take into account individual costs of the firm while determining the remuneration level, for example by reducing the inefficient costs over time instead of directly from the beginning of the regulatory period or by introducing profit sharing mechanisms (e.g. sliding scales). Besides reducing some of the above mentioned problems of an ideal-typical incentive regulation, such strategies can result in lower incentives to reduce costs or further disadvantages like the ratchet effect.

Finally, in praxis, cost-based and incentive regulation often resembles each other since ideal-typical forms are never applied. Therefore regulations officially declared as cost-plus or rate-of-return regulation may set incentives for cost reductions to the same extent as incentive regulation frameworks with strong cost-based elements. Individual and detailed examinations of the regulatory regime as well as the institutional framework (regarding for example public or private ownership) are essential in order to evaluate the (investment) effects of a regulatory regime.

12.2. Impact on cost benefit analysis

12.2.1. Stylized example: Price Cap vs. Rate of Return

In their contribution, Armstrong and Sappington [104] provide an example on how two (simplified and extreme) designs of a price cap and rate of return scheme could be classified with the help of the four categories devised earlier. The result is shown in Tab. 81.

Tab. 81 - Price cap vs. rate-of-return regulation, taken from Armstrong and Sappington [104]

Price cap versus rate-of-return regulation

	Price cap	Rate-of-return
Firm's flexibility over relative prices	Yes	No
Regulatory lag	Long	Short
Sensitivity of prices to realized costs	Low	High
Regulatory discretion	Substantial	Limited
Incentives for cost reduction	Strong	Limited
Incentives for durable sunk investment	Limited	Strong

As set out in section 12.1, regulatory schemes can be broadly split into cost-based schemes and incentive regulation schemes. The basic message was that, generally, cost of capital will be lower in a cost-based regime as regulatory commitments are stronger. However, economic theory suggests that this regime might lead to inefficiencies and higher expenditures when the firm has some discretion about their actions/choices, e.g. in technically complex fields. Based on these considerations, we assigned either +, 0 or – to each cell of Tab. 82 and Tab. 83. In Tab. 82, the choices +,0,- indicate that under the given regulatory scheme, the cost may be supposed to be relatively higher (+), unchanged (0) or lower (-). The methodology for either giving (+,-) pairs vs. giving (0,0) stems from the consideration whether the regulated firm may have a potential to lower the costs. Then, under incentive regulation, the costs may be lower than under the cost-based regulation. We propose to consider this for authorization and operations as they might not be mainly depending on 'price tags' and could be lowered by efficient processes. On the other hand, we assume, that for the assets themselves, the installation works, the decommissioning and disposal activities, there are less possibilities to reduce the cost of these activities.

Tab. 82 – Implications of regulatory options on expenditures (~EX)

	$AUTEX_{ij}$	$ASSEX_{i}$	$INSTEX_{ij}$	$OPEX_{ij,TOTAL}$	$DECOMMEX_{ij}$	$DISPEX_{i}$
cost-based regulation	+	0	0	+	0	0
incentive regulation	-	0	0	-	0	0

For the discount factors, we refer to the consideration that regulatory risk is higher under incentive regulation than under cost-based regulation as the rules are more complex in the former case. This is documented in Tab. 83, where we indicate that discount factors are generally likely to be higher under incentive regulation than under cost-based regulation.

Tab. 83 - Implications of regulatory options on discounting factors (DF~)

	DF_{AUTEX}	DF_{ASSEX}	DF_{INSTEX}	DF_{OPEX}	$DF_{DECOMMEX}$	DF_{DISPEX}
cost-based regulation	-	-	-	-	-	-
incentive regulation	+	+	+	+	+	+

12.3. Methodology

12.3.1. Evaluation of pricing regulation

From questionnaire feedback, parameter setting in each regulation scheme is essential to the amount of regulatory and financial risk borne by investors. The envisaged interlink between pricing regulation, financing and risk subtask is to propose a family of typical regulation scenarios with a variety of important parameter settings to reflect different degree of risks the investors could be exposed to. The next step is then to translate parameter settings in each regulation scenario into risk band selection, while considering different level of exogenous risks. Afterwards, the overall risk score of all the typical regulation scenarios could be obtained (see financing and risk subtask). In the end, their respective cost of capital could be calculated and compared.

Fig. 66 – Pricing regulation general methodology

Inspired by the preliminary questionnaire results, an example of regulation scenario tree is provided by Fig. 67. A pricing regulation scheme could be applied to TOTEX, which is the sum of investment cost CAPEX and operational cost OPEX. Alternatively, OPEX and CAPEX could be subject to different regulations. In the example, incentive based regulation is applied to OPEX and cost based regulation is applied to CAPEX.

For incentive based regulation, the parameter that significantly impacts risk exposure of investors is the revenue/price cap formulation. From the first feedback from the questionnaire, an important difference is whether to include productivity growth factor into the cap. With a productivity growth factor imposed by the regulator, the investor is faced with operational efficiency risk.

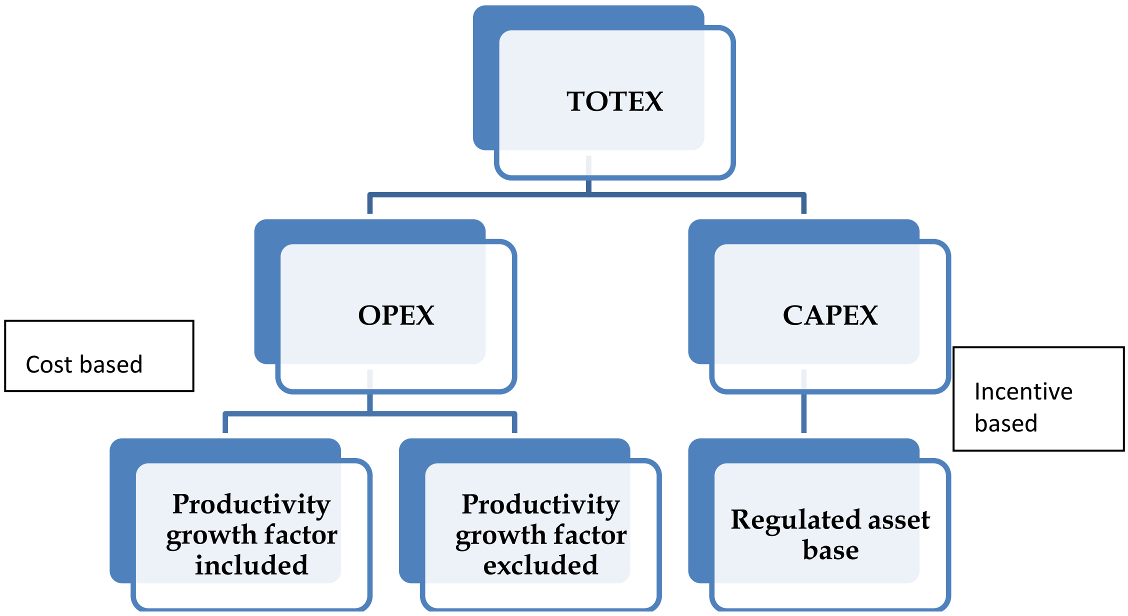


Fig. 67 – Example of regulation scenario tree

13. Financing indicators

13.1. Overview

This subtask consists of three topics or aspects:

- Investment feasibility

- Cost of capital calculation
- Financeability

Section 13.2 is a review of the three financing aspects. Section 13.3 analyzes the components of these financing aspects in detail and identifies the impact on BCA of transmission investment.

13.2. Financing aspect description

The aim of this section is a review of contents included in the subtask in order to assess whether all relevant aspects are considered.

Investment feasibility refers to different measures of economic profitability for transmission investment project. The indicators of this category are used to assess grid investment decisions. Three project investment evaluation indices are provided for initial investigation: NPV (net present value), IRR (internal rate of return) and Pay-back time.

The cost of capital is the average rate of return that is required on capital expenditures (CAPEX) by either TSOs or merchant investors. Regulators are aiming for a cost of capital level that on the one hand adequately remunerates grid investors for the risks they face so they can perform their investments, but on the other hand does not lead to costs for consumers that are higher than necessary i.e. efficient. Here is an important interaction with the subtask on risk assessment as risks effect the required rate of return on equity and debt on investments by TSOs and merchant investors, and therefore the required cost of capital.

An important question is which cost of capital or discount rate needs to be used. Since the e-highway 2050 research is performed for the European Commission one would expect that a social cost benefit analysis is performed from an overall social welfare perspective for Europe as whole. For such a social BCA usually a discount rate is applied that is equal to the discount rate for public investments.

At the same time, the E-Highway 2050 WP6.4 research aims at analyzing the need for investments for realising electricity highways up to 2050 by grid investors. Grid investors do not pay the government discount rate, but a higher corporate discount rate that reflects the higher risks of investors in private sector.

The question of which discount rate to adopt is answered by analysis on the systematic transfer between public and private sector. If all the systematic risks are borne by the public sector, then risk free rate is applied by private bid. Since no systematic risk is perceived for project investment in such case, no risk premium is required by the investor. If some part or all systematic risks are borne by private sector, a risk premium will be charged by the market investor and project rate will be applied.

Financeability ratios are used to assess the financial position of network operators, either TSOs or merchant investors. Network operators need to generate sufficient cash flow to cover capital expenditures and payments to debt holders, otherwise a financeability problem may develop [107].

13.3. Financing aspect impact on investment

This step aims to analyze the effect of the important aspects identified in previous section on transmission investment as part of the BCA. To that aim the following two questions need to be answered:

1. What factors contribute to different outcomes of the important aspects in your subtask?
2. How do these factors impact the outcome of the important aspects?

In section 3.2 three important aspects have been identified:

- Investment feasibility
- Cost of capital
- Financeability

Investment feasibility

In e-Highway 2050 project, the 2050 grid architecture is first proposed and later the intermediate grids of 2030 and 2040 will be developed. Due to this schedule, the input parameters to calculate investment feasibility such as annual investment cost are not available at this stage. So the investment feasibility analysis will not be performed in WP6.4. However, it is important to note that usually for investment feasibility several basic and important criteria need to be satisfied: NPV being positive, profitability index greater than 1 and internal rate of return larger than cost of capital.

Cost of capital

The cost of capital is usually calculated as a weighted average of the cost of debt and the cost of equity and hence denoted as Weighted Average Cost of Capital (WACC).

Depending on the regulatory regime at hand the WACC must be calculated after or before taxation:

$$WACC\ after\ tax = g * r_d * (1 - T) + (1 - g) * r_e$$
$$WACC\ pre\ tax = g * r_d + (1 - g) * r_e / (1 - T)$$

Where

g is gearing, proportion of debt in total assets (debt + equity)

r_d is cost of debt

r_e is cost of equity

T is corporate tax rate

Cost of debt:

$$r_d = r_f + r_p$$

Where

r_f is risk free interest rate depending on the overall economic conditions, not influenced by any company specific factors

r_p is debt premium, additional return expected by investors to invest in corporate debt compared to government debt to compensate for the higher default risk of the former

Cost of equity:

$$r_e = r_f + \left(r_m - r_f\right) * \beta_e$$

Where

r_m is expected rate of return on the market. The difference between the market return and the risk-free interest rate is equal to the equity risk premium

β_e is equity beta, the non-diversifiable or systematic risk as part of the total risk of the company and that is related to the market

Asset beta

$$\beta_a = (1 - g) * \beta_e$$

Where

β_a is the unlevered asset beta, which measures how return on this investment co-varies with market portfolio;

Concerning the first question, three groups of factors that influence the WACC can be distinguished:

1. Factors that influence the overall WACC but cannot directly be related to one of its specific parameters
    a. Regulatory regime: Choice for cost-of-service or one of the variants of price or revenue cap regulation (i.e. sliding scale or yardstick competition) i.e. extent to which cost-pass through of actual costs is allowed
    b. Type of investment: regulated versus merchant
    c. Utilization of the actual WACC of a network operator or of a notional WACC for an efficient financed network operator
    d. New regulatory period: extent to which the WACC is calculated using predictions that are either based upon realizations in recent years or estimations of changes due to new developments/trends
    e. Pre-tax or after-tax WACC
    f. Treatment of inflation: real or nominal WACC (nominal WACC includes inflation)
    g. Network companies are often not quoted. In this case, comparison with peer group of comparable companies for allowed rate of return on equity.
2. Factors that influence specifically the cost of debt

   a. Nominal risk free rate:
      - Maturity of debt
      - Nationality of debt
      - Reference period: current rates or long-term averages
   b. Debt premium:
      - Additional risk of corporate debt compared to government debt is reflected in the credit rating
      - Network companies are often not quoted. In this case, comparison with peer group of comparable companies for calculation of debt premium (e.g. national or EU energy companies)
      - No allowance for transaction costs associated with issuing debt in case of comparison with other companies; hence, specific allowance for transaction costs to be made
3. Factors that influence specifically the cost of equity
   a. Selected asset pricing models; Capital Asset Pricing Model (CAPM), Arbitrage Pricing Theory (APT) and Dividend Growth Model (DGM)
   b. Equity risk premium (ERP), see definition above
      - Historic ERP and/or ERP expectations (modeling or survey evidence)
      - Arithmetic or geometric mean
   c. Equity beta, see definition above
      - Network companies are often not quoted. In this case, calculation based on betas of comparable quoted companies i.e. the ‘peer group’
      - Choice of peer group (size and type)
      - Choice of estimation method
         - Data frequency (daily, weekly, monthly, yearly betas)
         - Reference period: e.g. data over one year, several years, decade etc.
         - Market index (national, EU-wide, worldwide)
         - Correction of raw Beta estimates (Vasicek or Blume corrections)
         - Conversion of equity to asset beta and the other way around (Modigliani-Miller, Miller, Miles-Ezzel methods)
         - Range of beta values to be taken into account

The next question is then: How do these factors impact the outcome of the important aspects? This depends on the factor considered. It is proposed to describe the impact for the first group of factors in detail, and only on high level for the second and third groups. The reason is that it makes no sense to describe in detail current country-specific assumptions, since the future cost of debt and cost of equity will depend on circumstances in 2030 or 2040.

Financeability

In case a network operator is quoted, it is likely that financeability metrics are used to assess the financial health of the operator, resulting in the credit rating. These metrics are necessary since even when the cost of capital is estimated correctly it does not mean there cannot be financeability issues. The reason is that the timing of cash flows can have consequences for the cost of capital and gearing capacity of a company. Since compensation of network investment costs is in several countries (at least partly) ex-post based upon realized CAPEX, cash inflows tend to be (partly) later in time than cash outflows. Combined with the fact that high investment levels are needed to allow for the transition to a sustainable and fully integrated European energy system, thresholds for financeability metrics can be breached [98]. Consequently, financeability ratios are necessary as a complement to the cost of capital.

14. Risks

14.1. Overview

This subtask focuses on the different categories of risks that will impact the financial and regulatory indices developed under WP 6.4 as well as the costs and benefits of specific grid lines and grid architectures in general. Section 14 is organised as follows:

- Identify and describe the dimensions to take into account for risk assessment =>Section 14.2;
- Identify and describe main risks along 4 categories: regulatory risks, financial risks, risk on scenarios and other risks ==>Section 14.3;
- Propose indicators to represent the impact of the most relevant risks, and methodologies for the quantification of these indicators ==>Section 14.5;
- Identify how these risks impact BCA results by evaluating the consequences on investors and electricity users along the different dimensions. Rank these risks according to their severity, in order to select the most relevant ones and assign weight . In the end, the overall investor risk score is obtained and translated into cost of capital ==>Section 14.5;

Research approach – The information collected is supported by the e-Highway project partners' expertise in the field of electricity networks, a literature review and public case studies, as well as interviews and a questionnaire answered by selected investors and European TSOs.

14.2. Dimension

The risks involved in developing and financing interconnections (be them new lines, expansions, or retrofits) largely depend on the regulatory regime selected for the interconnection, what phase the project is in, and which party (investor or user) is considered.

Project phases – As for any engineering project, the development of grid lines can be split between planning & permitting, construction, operation and decommissioning. The risks involved vary greatly according to which phase of the project is considered.

During planning & permitting, the main uncertainties are whether the project will be permitted, how long the procedure will take and how much it will cost.

During construction, the main uncertainties lie in the costs of the project: cost of equipment, contractors, financing, which can be all exacerbated by delays.

During operation, the main uncertainty relates to the project revenues.

During decommissioning, the main uncertainty relates to the change of financial rules concerning the end life of the asset (i.e. amortization rule) European regulatory framework for interconnector investment - Under existing EU legislation, the default approach to developing new interconnections is through regulated investments; exemptions are granted in some circumstances to allow for merchant projects. Although one can expect the regulatory framework to evolve to 2050, understanding the existing EU legislation is helpful in highlighting what risks lie in the European regulatory process.

Regulated interconnectors: European interconnectors are generally developed by the national transmission system operators. TSOs recover their costs through transmission tariffs agreed by the regulators, according to a methodology and parameters also agreed by the regulators. The costs are then passed onto consumers. In return, their revenues must be used for the following purposes [108]:

(a) Guaranteeing the actual availability of the allocated capacity; and/or

(b) Maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.

If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) of the first subparagraph, they may be used, subject to approval by the regulatory authorities of the Member States concerned, up to a maximum amount to be decided by those regulatory authorities, as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs.

Merchant lines: Interconnectors can be developed as merchant projects, outside of the regulated transmission business. Under this model, the developer is free to decide how to use their revenues, and how to charge for the use of capacity. It is however bearing the investment risk as it is fully exposed to the market demand and the price set for the capacity, both relatively uncertain. For this type of investment to be allowed, developers seek exemptions from their regulators for one or several legal requirements. The Commission reserves the right to veto or amend exemptions granted by regulators; conditions were for instance added to the BritNed exemption.

Other approaches – Regulators, TSOs and developers are considering compromise solutions between regulated and commercial investments. For instance, Ofgem and CREG have proposed a new regulated regime under which returns within a certain range depend on auction revenues but returns above the cap or below the floor are respectively returned to or supplemented from customers.

Stakeholder – The risks emerging from regulatory and financing conditions will often impact investors/TSOs and electricity users differently. For instance, increased construction costs will be passed onto consumers for a regulated line, thus financially impacting end-users more than it impacts TSOs and investors.

Conclusions for risk assessment – We will thus consider these different dimensions when identifying and quantifying relevant BCA indicators; planning / construction / operation of the project; regulated versus merchant lines; investors versus consumers.

14.3. Risk Description

14.3.1. Regulatory risks

- For all: Uncertainty about European or national regulatory regime creates uncertainty around likelihood of project, length of the approval procedure, planning costs. Most of those risks can be monetised (find case studies).

- For regulated investments, agreed methodology and parameters key in getting costs & revenues calculated
  - Regulations can provide long-term clarity and streamlined processes, or on the contrary unclear, long and costly procedures increasing planning costs further.
  - Cost liability (on investor or consumer) depends of eligibility of planning and permitting costs in overall compensation methodology.
  - Parameters for revenue caps / grid charges calculations, directly impacting user charges.
  - In questionnaire: Change of allowed rate of return / Change of allowed revenue cap

- For merchant lines, or any line seeking exemption from EU regulation
  - Exemption seeking process is a long process leading to extra costs and delay of income, and extra uncertainty regarding the viability of the project.
  - Most of the risk then exposed to commercial viability of the line. The impact of changes in policy frameworks on both sides of the interconnection is addressed in the scenario risks section (mainly determines energy mix on both sides).
- Actual revenues addressed in WP6.1. Actual pricing parameters in the pricing section. Mainly focusing on extra costs due to uncertainty.

14.3.2. Financial risks

Financial risk comprises of two types. The first type of risks stem from uncertainties in the macroeconomics and capital market. Inflation and interest rate movement are included in the first type. The second type of risk considers the competition of peer companies to attract capital.

14.3.3. Risk on scenarios

- For all: uncertainty about load and generation profile creates uncertainty around the results of the BCA of the projects.

- For regulated investments, the risks on scenarios are present mainly during:

  - Planning and construction phase when a change of main assumptions could deeply influence the results of the BCA of the project. As a consequence, the project could not be approved by regulators and the eligibility of planning costs and construction costs is not guaranteed. This risk is supported by both investors and users.
  - Operation phase when a change of main assumptions could deeply influence the results of the BCA. The expected benefits (SoS, RES integration, flexibility,…) could maybe not compensate the raise of the tariffs due to this new investment. This risk is mainly supported by users.
  - In questionnaire: Change of scenarios (load and generation profile)

- For merchant lines, the risks on scenarios are present mainly during :
  - Planning and construction phase where a change in assumptions on scenarios could deeply influence BCA. In case of a negative BCA this could lead to a “no go” in project construction with the risks to lose all planning and construction costs. This risk is supported by investors only.
  - Operation phase where a change in assumptions on scenarios could deeply influence BCA. The use of the assets could not be viable anymore based on project revenues. This risk is supported by investors. Users support the risk that the project will not be realised and they cannot benefit from other benefits of the project (SoS, RES integration, flexibility,…)
  - In questionnaire: Change of scenarios (load and generation profile)

14.3.4. Other risks

Other risks can be described by a common consequence, being delay in realization of the project: project overrun, planning & permitting delays, construction delays,...

14.4. Risk Impact

The table below illustrates the impact of the identified risk on investors and electricity users by describing the consequences and severity, taking into account the dimensions of project phase and regulated vs. merchant lines.

There are two main consequences

- Project execution is delayed / benefits outlook change==> can eventually lead to project being stopped
    - Impact on investor: longer payback period, more uncertainty on eventual benefits realization, reconsideration of project continuation in long end
    - Impact on user depends on urgency of project realization in terms of other project benefits (SoS, price convergence, RES integration,…)
- Project is not executed / being stopped
    - Impact on investor in terms of recuperation of costs made
    - Impact on user in terms of "who pays costs made" and missed added value in terms of other project benefits (SoS, price convergence, RES integration,…)

Project phase	***Risk type***	***Risk***	***Regulated line***				***Merchant line***			
			Investor (others but TSOs : banks, private funds,...)		***User***		***Investor (TSOs , banks, private funds,...)***		***User***	
			Consequences	Severity	Consequences	Severity	Consequences	Severity	Consequences	Severity
Planning/ construction	Regulatory	Change of regulatory rules (e.g. remuneration of investors)	project less attractive for investors→ project stopped → planning/partial construction cost are lost	+ (if investors must pay a share of planning/construction costs)	project not done due to lack of financial ressources	++	/	/	/	/
		Stringency/Length approval process (regulated)/exemption process (merchant)	Additionnal costs and delay in project revenues	+	Additionnal costs and delay in project revenues	+	Additionnal costs and delay in project revenues	+	delay in the benefits given by the project	+
	Financial	Change of TSOs's gearing ratio	/	/	higher costs of capital through higher tariffs	++	/	/	higher costs of capital through higher tariffs	++
		Change interest rate ...	project less attractive for investors --> project stopped	+ (if investors must pay a share of planning/construction costs)	project not done due to lack of financial ressources	++	project less attractive for investors --> project stopped	++	project not done due to lack of financial ressources	++
	Scenario	Change of basic assumptions on load and generation profile	project CBA may become negative --> project not approved by regulator	+ (if investors must pay a share of planning/construction costs)	project CBA may become negative --> project not approved by regulator	+ (if users must pay a share of planning/construction costs)	project NPV could be lower than expected --> project stopped --> no way to recover costs	++	project not done as not viable for investors --> users cannot benefit from the project	++
	Other	Uncertainty around construction delays, supply chain, etc.	Delay in project revenues	+	delay in the benefits given by the project	+	Delay in project revenues	+	delay in the benefits given by the project	+
Operation	Regulatory	Methodology / All parameters	project could be less attractive	++	change of methodology could alter tariffs	-	/	/	/	/
	Financial	Change of TSOs's gearing ratio	/	/	higher costs of capital through higher tariffs	++	/	/	higher costs of capital through higher tariffs	++
		Change interest rate ...	/	-	/	-	/	-	/	-
	Scenario	Uncertainty around energy mix / energy flows /	/	/	project CBA may become negative	+	project revenues could be lower than expected	+++	project not done as not viable for investors --> users cannot benefit from the project	+
Decommissioning	Regulatory	Liability for decom costs ?	additionnal costs	-	additionnal costs	-	additionnal costs	-	/	/
	Financial	change of financial rules (e.g. amortization)	additionnal costs	-	additionnal costs	-	additionnal costs	-	/	/

14.5. Three alternative risk quantification methods

In literature, a number of methodologies are used to integrate risk into financial analysis. The 3 most prominent ones are value at risk, option theory (real option and mini max regret. None of these methods have been used in the analysis. Nevertheless it is of interest to cover them in this part of the deliverable.

14.5.1. Value at risk

Value at risk measures the expected maximum loss over a target horizon with a given confidence level.

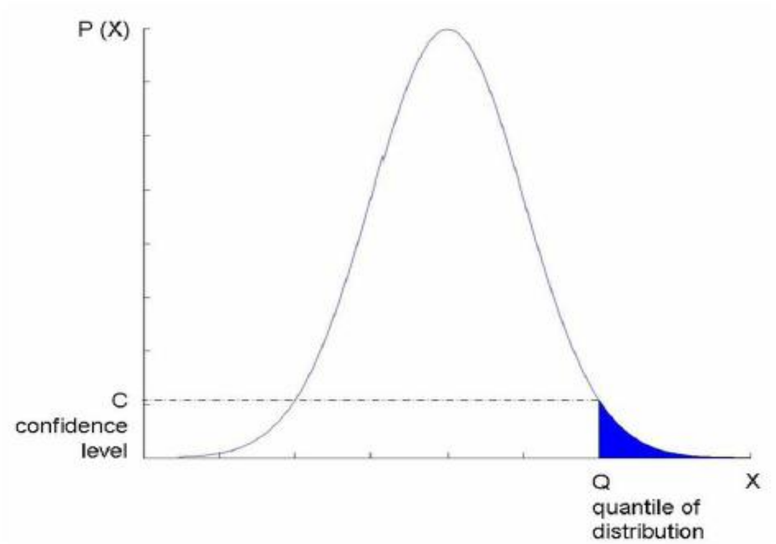


Fig. 68 – Value at Risk as quartile of normal density function [108]

Value at Risk can be visualized by Fig. 68, which gives the worst possible loss realization Q at the confidence C in the given time frame.

$$C = \int_Q^{\infty} f(w)dw$$

The portfolio loss is calculated by:

$$L^1 = p^0 - p^1$$

Where L^1 is portfolio loss at the end of time horizon;

p^0 is the asset market value at the beginning of the time horizon;

p^1 is the asset market value at the end of time horizon;

The market value at the end of time horizon p^1 could be formulated as a function of the variables R which can be used to value the assets.

Potential data requirement

- Function of market value P in relation to key factor R
- key factor R probability distribution at the end of time horizon

In WP6.4, the degree of systematic risk exposure is identified to be the risk factor that influences the cost of capital. Probability distribution of such risk factor is not obtainable for data of 2050.

14.5.2. Real option

Real option analysis assesses the value of flexibility to undertake certain business actions, such as deferring, abandoning, expanding or contracting a capital investment project.

Data requirement for real option [96]:

- Value of the constructed transmission line discounted for the construction lag
- Volatility of the value of the constructed transmission line
- Initial construction cost
- Years to expiration date of construction permit
- Risk-free interest rate
- Net revenue of operation less depreciation

The volatility of transmission construction value can only be assessed by probability distribution, which is not available for data for 2050.

14.5.3. Mini max regret

The mini max regret approach aims to minimize the worst-case regret. The criterion generated by mini max regret method for risk analysis is the regret. To assess grid investment decisions, the benefit or value of different network expansions under different future scenarios should be available.

Within WP6.4, an integrated approach to evaluate the ownership, regulatory impact on cost of capital is proposed for a one-time off investment decision. In other words, from investor perspective, the benefit implied by less risk exposure is represented by lower cost of capital. However, cost of capital is not a result of different future generation load scenarios, so the mini max regret method does not apply here.

14.5.4. Conclusion

To summarize, in order to measure market risk in an asset portfolio using value-at-risk, significantly more data is required. In particular, a certain accuracy of the data is needed, together with the probability distribution of the asset portfolio’s market value. Within e-Highway 2050 project, the availability of accurate forecasts of financial data is very limited, and the probability distribution of the market value of grid architecture in 2050 is not obtainable.

Real option and mini max regret are used to assess investment decision against future uncertainties. Therefore both methods are forward looking. In e-Highway 2050 project, the grid architecture of 2050 is proposed first and grid architectures of 2030 and 2040 are developed later. From the sequence of grid development, these two methods do not suit for grid evaluation in D6.1.

15. Summary of questionnaire result e-Highway WP6 Task 6.4

OWNERSHIP

TSO collaboration (multinational TSO, regional TSO and a single European TSO)	
Country 1	Multiple national TSO in 2020 and 2030. Regional TSOs will appear in 2030, 2040 and 2050 with a Single European TSO is also foreseen to appear in 2050. Single European TSO only for Overlay/Supergrid level. Influence on cross border transmission investments will rather be positive, since coordination efforts will decrease.
Country 2	N/A
Country 3	Multiple national TSO will continue all the way to 2050. Regional TSOs will emerge in 2040 and 2050. Regional TSO to be understood in the form of increased cooperation companies like Coreso (i.e a cooperation of independent companies) or a more in depth integration like M&As.
Country 4	Multiple national TSOs foreseen from 2020 to 2050. It empowers the investment in each country in order to increase or adjust the NTC to market needs.
Country 5	Multiple national TSOs foreseen from 2020 to 2050.
Country 6	Multiple national TSOs foreseen from 2020 to 2050.
Country 7	Multiple national TSOs foreseen from 2020 to 2050. Regional TSO emerge from 2030 to 2050.
Country 8	Both multiple national TSOs and regional TSOs are expect to collaborate from 2020 to 2050. A single European TSO will emerge only in 2050.
Country 9	N/A

Ownership of TSO (state owned TSO, privately owned TSO)	
Country 1	A mix of ownership of “state-owned TSO” and “privately-owned TSO” in 2020 and 2030. Any guesses on ownership after 2030 are not reasonable (depending too much on political directions which cannot be influenced). Mix of ownership is likely according to current discussion. Impact on transmission investments rather depending on economic conditions than on ownership structure
Country 2	N/A
Country 3	A mix ownership of state-owned TSO and Privately owned TSO in 2020 and 2030. If any convergence would occur, it is more likely to shift towards more privately owned TSOs in 2040 and 2050.

Country 4	State-owned TSOs and privately owned-TSOs will coexist from 2020 to 2050.
Country 5	State-owned TSOs and privately owned-TSOs will coexist from 2020 to 2050.
Country 6	State-owned TSO for 2020 and 2030. A mix of state-owned and privately-owned is foreseen for 2040 and 2050.
Country 7	State-owned and privately-owned TSOs will co-exist in 2020 and 2030. In 2040 and 2050 privately-owned TSO are foreseen as the type of TSO suggested.
Country 8	Privately-owned TSOs are foreseen as the most likely form of TSO ownership from 2020 to 2050.
Country 9	N/A

System operator type (TSO, ISO and ITO)	
Country 1	TSO is the preferred model from 2020 to 2050.
Country 2	Country 2
Country 3	TSO is the preferred model from 2020 to 2050.
Country 4	TSO is the preferred model from 2020 to 2050.
Country 5	TSO is the preferred model from 2020 to 2050.
Country 6	TSO is the preferred model from 2020 to 2050.
Country 7	TSO is the preferred model from 2020 to 2050.
Country 8	TSO is the preferred model from 2020 to 2050.
Country 9	N/A

Asset ownership structure (Non-regulated investment/ (non-regulated investment + regulated investment)	
Super grid	
Country 1	Regulated lines are dominant from 2030 to 2050. In 2020, there will be only regulated lines. They depend on the achievable RoE rather than on ownership structure.
Country 2	N/A
Country 3	For very capital intensive investments, new financing mechanisms where potentially merchant aspects are present are more and more likely.
Country 4	Regulated lines will be the only assets in 2020 and 2030. Regulated lines are estimated to be dominant in 2040 and 2050.
Country 5	Regulated lines are dominant in 2020 and 2030. Non-regulated lines will become dominant in 2040 and 2050.
Country 6	Regulated lines will remain dominant from 2020 to 2050.
Country 7	Regulated lines will be the only assets in 2020. From 2030 to 2040 regulated lines are estimated to remain dominant and in 2050 non-regulated lines will become dominant.

Country 8	Regulated lines foreseen as the only assets for 2020. Regulated lines will remain dominant from 2030 to 2050.
Country 9	N/A
Upgrade on existing system	
Country 1	Only regulated lines foreseen in 2020 and 2030.Regulated lines are dominant in 2040 and 2050. They depend on the achievable RoE rather than on ownership structure.
Country 2	N/A
Country 3	Regulated lines are dominant from 2020 to 2050.
Country 4	Regulated lines will be the only form of assets from 2020 to 2050.
Country 5	Regulated lines will remain dominant from 2020 to 2050.
Country 6	Regulated lines will be the only form of assets for 2020 and 2030. They will remain dominant in 2040 and 2050.
Country 7	Regulated lines remain dominant in 2020 and 2030. In 2040 and 2050 non-regulated lines will become dominant.
Country 8	Regulated lines foreseen as the only assets for 2020. Regulated lines will remain dominant from 2030 to 2050.
Country 9	N/A
Grid in between	
Country 1	Regulated assets will have a high share all throughout 2050.
Country 2	N/A
Country 3	Similar to the super-grid, for very capital intensive investments, new financing mechanisms where potentially merchant aspects are present, are more and more likely.
Country 4	Regulated lines will be the only form of assets from 2020 to 2040. They will remain dominant in 2050 but it is possible that non-regulated lines will also emerge.
Country 5	Regulated lines will remain dominant from 2020 to 2050.
Country 6	Regulated lines will be the only form of assets for 2020 and 2030. They will remain dominant in 2040 and 2050.
Country 7	Regulated lines will remain dominant from 2020 to 2040. Non-regulated assets are estimated to emerge only in 2050.
Country 8	Regulated lines are foreseen as the only assets in 2020. They will remain dominant from 2030 to 2050.
Country 9	N/A

PRICING REGULATION

Currently implemented pricing regulation	
Country 1	Revenue cap
Country 2	Cost of service
Country 3	A mix of cost of service, revenue cap and sliding scale.
Country 4	Cost of service and revenue cap
Country 5	Revenue cap
Country 6	Cost of service
Country 7	Cost of service
Country 8	-
Country 9	Cost of service
Recommended pricing regulation for super grid	
Country 1	N/A
Country 2	N/A
Country 3	Cost of service, revenue cap, sliding scale
Country 4	Cost of service and revenue cap
Country 5	Revenue cap
Country 6	N/A
Country 7	Mix of price cap and revenue cap.
Country 8	-
Country 9	N/A
Recommended pricing regulation for upgrade on existing grid	
Country 1	N/A
Country 2	N/A
Country 3	Cost of service, revenue cap, sliding scale
Country 4	Cost of service and revenue cap
Country 5	Revenue cap
Country 6	N/A
Country 7	Cost of service
Country 8	-
Country 9	N/A
Recommended pricing regulation for grid in between	
Country 1	N/A
Country 2	N/A
Country 3	Cost of service, revenue cap, sliding scale
Country 4	Cost of service and revenue cap
Country 5	Revenue cap

Country 6	N/A
Country 7	Price cap and revenue cap
Country 8	-
Country 9	N/A

Pricing regulation parameter assessment
Country 1
The currently implemented revenue cap in country 1 include following elements in its calculation: operation and maintenance costs and return on invested capital. The terms included in the revenue cap setting formula are inflation factor, productivity growth X-factor. The formula used to calculate the revenue cap with the terms mentioned is also given. There is A sector-wide X factor is applicable.
Country 2
N/A
Country 3
In country 2, cost of service, revenue cap and sliding scale regulation is applied. For RAB evaluation, historic cost is used and it is assessed ex-post. Investment, depreciation, asset disposal and change of working capital are the terms included in RAB calculation. Operation and maintenance cost, depreciation and return on invested capital are included in the initial revenue cap. Inflation factor, load growth and productivity growth X-factor are used in formula to set revenue cap. X-factor is not sector wide applicable and regulation period is 4 years. Information about sliding scale is not available. The recommended parameter assessment methodology is the same as current practice except for regulation period. A regulatory period between 4 and 6 years is advised.
Country 4
Country 4 adopts cost of service and revenue cap regulation currently. Historic cost is used to evaluate regulated asset base (RAB), and the TSO recommends indexed historic cost methods for e-Highway 2050 project. Ex-ante assessment is employed now and suggested for e-Highway 2050 project. To calculate RAB, investment and depreciation are taken into account now, but only investment is recommended to use. Current regulation period is 3 years and more than 5 years period is suggested. In country 1, operation and maintenance cost is subject to initial revenue cap. In the cap formula, inflation factor and productivity growth X factor are used included and IPC-X formula is used. Moreover, the X factor is sector wide and regulation is 3 years. For e-Highway 2050, the suggestion for revenue cap stays exactly the same as the current situation except for regulatory period. More than 5 years of regulatory period is recommended.
Country 5
Operation and maintenance costs, depreciation, return on invested capital and costs associated with energy loss are included in the initial revenue cap. Inflation factor, losses and productivity growth X-factor are used in formula to set the revenue cap. The X-factor is sector-wide applicable and the regulation period for five year. All the items are recommended for both the current situation and for e-Highway2050.
Country 6
The indexed historic cost is included in the regulated asset base evaluation methodology. The assessment timing of regulated asset base is ex-ante. Investment and depreciation are included to calculate the regulated asset base. The regulation period happens on an annual basis in BA and MK; and is 3 years in ME. No recommendations are available for e-Highway2050.
Country 7
Historic cost is used to evaluate the regulated asset base and the TSO recommends replacement cost method for e-Highway2050. The current assessment timing of regulated asset base is ex-ante and it is also recommended for e-Highway2050. Investment, depreciation, asset disposal, change of working and change of capital contribution are included to calculate the regulated asset base. These terms are also recommended for e-Highway2050. The tariffs are adjusted every year which has a cost-based regulation. The recommendation suggests a rolling five years as a possibility, otherwise yearly. The price cap pricing regulation recommended for a possible 2050 super grid could be based on benchmarks of other TSOs. A sector-wide X factor is not applicable now but it is suggested for the e-Highway2050 super grid. Again, the regulation period could roll for five years, otherwise could be yearly. Similar, the revenue cap recommended for the 2050 super grid include O&M, depreciation, return on invested capital and costs associated with energy loss in its calculation. Inflation factor and losses are included in the revenue cap setting formula and there is a recommendation for a sector-wide X factor in 2050.

Country 8
No information given.
Country 9
Discounted cash flow asset base evaluation methodology is used. Both ex-ante and ex-post regulated asset base assessment are performed. Investment and depreciation are included to calculate the regulated asset base. The regulation period is four years. No recommendations are available for e-Highway 2050.

Q9. Financing Indicator

Financial indicators		**WACC**	
Country 1		**Country 1**	
Indicator for grid investment	**Priority**	No information is given.	
Internal rate of return	N/A		
Return on shareholder’s equity	N/A		
Return on total assets	N/A		
FFO(*3)/Net Debt	N/A		
Interest coverage(*4)	**N/A**		
Country 3		**Country 3**	
Indicator for grid investment	**Priority**	**Regulation type in your country**	--
Return on shareholder's equity		**nominal risk free rate**	National government 10 year obligation
Assuming proper unbundling: the main threshold is whether the investment is social welfare increasing. If the regulator accepts the investment (In principle, it is justified from a social welfare perspective), TSO in principle have no reason for not realizing the investment as the investment can be included in the regulated asset base. In a simplified view, it is possible to separate the financing problem from this kind of indicators, as in the end regulatory (tariff) treatment will be the main decision factor. For E-Highway the suggested threshold should be based on social welfare increase.		**debt premium**	0,70%
		equity market risk premium	3,50%
		asset beta	0,17
		equity beta	It depends on historical track records of the company share compared to the benchmark stock market index.
		gearing (gearing: debt/(debt+equity))	regulatory incentive to keep this at 1/3 Equity and 2/3 Debt

Financial indicators		WACC
Country 4		**Country 4**
Indicator for grid investment	**Priority**	No information is given
Internal Rate of Return	1	
Return on Shareholders' equity	1	
Return on total assets	1	
FFO (Funds from Operations) Net Debt	1	
Interest coverage	1	
Payback time	2	
Net present value	3	
Country 6		**Country 6**
Indicator for grid investment	**Priority**	No information available on the WACC
Net present value	1	
Internal rate of return	1	
Payback time	3	
Profitability index	4	
Country 7		**Country 7**
Indicator for grid investment	**Priority**	No information available on the WACC
Net present value	1	
Profitability index	3	
A positive net present value along with robust risk analysis is used as the value to determine grid investment and suggested for the e-Highway2050 calculation. Due to regulation, financeability is not an issue if the investment analysis is sufficient with positive NPV and robust risk analysis. Money is being supplied by the National Bank and afterwards paid by electricity consumers.		

Country 5	Country 5	
No information is given on indicator for grid investment.	**WACC rate**	8.52%
	WACC type (real pre-tax)	Real pre-tax
	nominal risk free rate	6%

		Debt premium	2%
		equity market risk premium	6%
		asset beta	βe = βat [1+(1-t) Debt/Equity]
		equity beta	0.94
		gearing (gearing: debt/(debt+equity))	40%
		cost of debt	8%
		Cost of equity	11.65%
		Tax rate	16 5
		Projected inflation rate	2.5%
Country 9		**Country 9**	
Indicator for grid investment	**Priority**	**Regulation type in your country**	Cost of service
Pay-back time	1	**nominal risk free rate**	4%
Net present value	10	**debt premium**	0.6%
Gearing	1	**equity market risk premium**	5.0%
FFO/Net Debt	2	**asset beta**	0.33
The pay-back time threshold is 10 years and net present value threshold from collective point of view positive.		**equity beta**	0.66
		gearing (gearing: debt/(debt+equity))	60%
		Cost of debt	4.6%
		Cost of equity	11.2%
		Tax rate	34.43%
		WACC rate	7.25%
		WACC type	(real pre-tax)

Risk

Regulated investment			Merchant investment
Country 1			**Country 1**
Risk	**Phase**	**Ranking**	No risk ranking is given for merchant investment
Regulatory risk			
Change of regulatory rules	Planning/construction	N/A	
Stringency/Length approval process	Planning/construction	N/A	
Stringency/Length exemption process	-	N/A	
Eligibility of planning costs	Planning/construction	N/A	
Liability for decommissioning cost	Planning/construction/ operation/decommission	N/A	
Financial risk			
Interest rate change	Planning/construction	N/A	
Change/decrease of regulatory assured RoE	Planning/construction	N/A	
Scenario risk			
Modelling uncertainty around load profile	planning	N/A	
Modelling uncertainty around generation mix	planning	N/A	
Uncertainty about effectiveness of interconnector capacity allocation	planning	N/A	
Other risks			
Project overrun	planning/construction	N/A	
Delivery risk	construction	N/A	
Planning and permitting delays	planning/construction	N/A	
Supply chain risks	construction	N/A	
Construction delay	construction	N/A	
The risks predominantly impact the investor/user.			

Country 3	Country 3
Regulatory risk is seen as the main risk, as the regulatory framework determines how risks are taken into account and divided between investors and users. . In a regulated case, the acceptance of costs by the regulator is always a risk. Also the stability of regulatory regime is important. If for instance tariff methodologies would change over time, this could create a risk. Note that regulatory periods are much shorter than typical asset life time. For other elements (e.g. lengthy approval or NIMBY effects) it depends on how the costs are covered. If the costs during approval period are already covered via tariffs, there is no risk for the regulated company. If those costs have to be pre-financed, there is a risk.	Regulatory risk is seen as the main risk, as the regulatory framework determines how risks are taken into account and divided between investors and users. . For merchant investors, regulatory certainty on exemption rules is important. Additionally, for merchant investment, the risk of a wrong scenario could be more difficult to bear than for regulated assets as it will always be the merchant investor bearing the risk.
In general, in order to incentivize investments, risks and rewards should be aligned. This means that projects with higher risks should have a proportionate return. Market design and other developments in the market have been identified as a scenario risk.	

Country 4			
Regulated investment			Merchant investment
Risk	**Phase**	**Ranking**	
Stringency/Length approval process	Planning/construction	1	No risk ranking is given for merchant investment
Change of Leverage (FFO/Net Debt)	Operation	1	
Project overrun	Construction	1	
Change of regulatory rules	Operation	2	
Change of gearing limit	Operation	2	
Delivery risk	Construction	2	
Planning and permitting delays	Planning	2	
Interest rate change	Operation	3	
Construction delay	Construction	3	

	Country 5		
Regulated investment			
Type of risk	**Phase**	**Priority**	No risk ranking is given for merchant investment
Regulatory risks			
Change of regulatory rules	operation	**1**	
Stringency/Length approval process	planning	2	
Cessation of the investment cost recovery process	operation	1	
Slow recovery of cash invested in transmission assets (see above)	operation	2	
Uncertainty around the recovery of investment cost overruns (see above)	operation	1	
Financial risks			
Interest rate change	construction/operation	1	
Foreign exchange risk	construction/operation	1	
Scenario risks			
Modelling uncertainty around load profile	planning		
Modelling uncertainty around generation mix	planning		
Other risks			
Project overrun	construction	1	
Planning and permitting delays	planning	2	
Supply chain risks	construction	2	
Construction delay	construction	2	

	Country 6		
Regulated investment			
Type of risk	**Phase**	**Priority**	No risk ranking is given for merchant investment
Regulatory risks			
Change of regulatory rules	construction/operation	1	
Stringency/Length approval	planning/construction	3	

process			
Stringency/lengthy exemption process	planning/construction	3	
Eligibility of planning cost	planning/construction	3	
Liability for decommissioning cost	decommission	4	
Financial risk			
Interest rate change	construction/operation	1	
Change of gearing permit	planning/construction/ operation	3	
Scenario risk			
Modelling uncertainty around load profile	planning	2	
Modelling uncertainty around generation mix	planning	1	
Uncertainty about effectiveness of interconnector capacity allocation	planning/operation	2	
Other risks			
Planning and permitting delays	Planning/construction	1	
Project overrun	Construction/operation	3	
Delivery risk	Construction	3	
Supply chain risks	Planning/construction	3	
Construction delay	Construction	3	
Country 7		**Country 7**	
Regulated investment			**Merchant investment**
Type of risk	**Phase**	**Priority**	**Priority**
Regulatory risk			
Change of regulatory rules	Operation	3	3
Liability for decommission cost	Operation/decommission	5	8
Stringency/Length approval process	Planning/construction	7	7
Stringency/Length exemption process	Planning/construction/ operation/decommission	7	7
Eligibility of planning cost	Planning	9	9

Financial risk			
Interest rate change	Planning/construction/ operation	2	2
Scenario risk			
Modelling uncertainty around generation mix	Planning/operation	1	1
Modelling uncertainty around load profile	Planning/operation	8	8
Other risks			
Project overrun	Planning/construction	2	2
Delivery risk	Planning/construction	4	4
Planning and permitting delays	Planning/construction	3	3
Supply chain risks	Planning/construction	3	3
Construction delays	Planning/construction	4	4
Country 9			
Regulated investment			
Type of risk	**Phase**	**Priority**	No risk ranking is given for merchant investment
Regulatory risks			
Change of regulatory rules	Planning/construction/ operation/decommissi on	5	
Stringency/Length approval process	Planning	5	
Financial risks			
Interest rate change	Planning		
Change of gearing limit	Planning/construction/ operation/decommissi on	5	
Scenario risks			
Uncertainty about effectiveness of interconnector capacity allocation	planning	3	
Modelling uncertainty around load profile	planning	5	
Modelling uncertainty around generation mix	planning	10	
Other risks			
Project overrun	planning/construction		
Delivery risk	operation		

Planning and permitting delays	planning/construction/ operation/decommissi on		
Supply chain risk	planning/construction/ operation/decommissi on		
Construction delay	planning/construction/ operation/decommissi on		

16. Analysis of questionnaire

The analysis of the WP6 questionnaire is based on responses from eight TSOs across Europe and one regional consultancy firm. Note that not all respondents gave feedback on all aspects. We will mention the number of actual respondents during the analysis.

16.1. Ownership[38]

16.1.1. Type of TSO collaboration

Overall, most European TSOs see a continuation of multiple national TSOs from 2020 to 2050. 3 out of 7[39] respondents see a role for a multiple national TSOs only structure as best fostering investment in each country.

Yet 4 out of 7 respondents think that the type of TSO collaboration towards 2050 will consists of collaboration between several system operators within a country. Of these, the opinions are divided. Two predict that there will be a mix between multiple national TSOs with regional TSOs only emerging at varying timeframes.

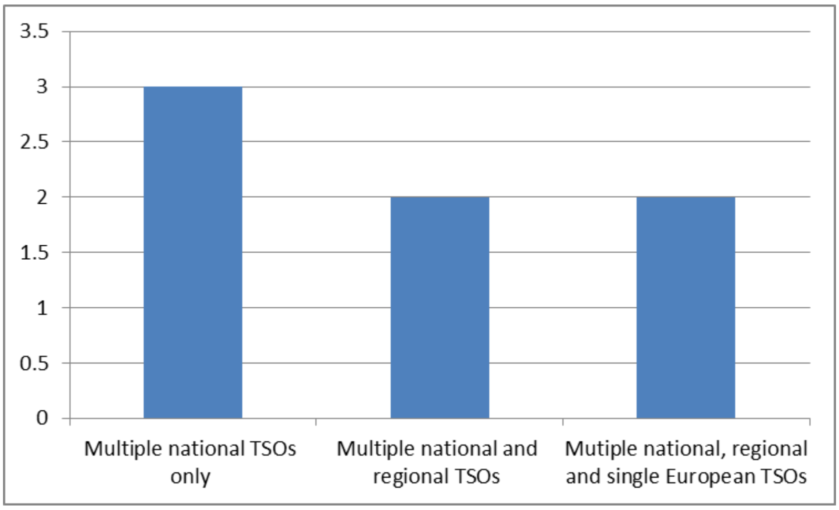
The other two also foresee an additional role for a single European TSO in 2050 as it is likely that a multi-national TSO collaboration will lead to larger investments in transmission works or a single European TSO is only necessary for an overlay/supergrid structure.

One respondent in favour of multi-national collaboration mentioned that regional TSOs and potentially a single European TSO will most likely invest in more transmission projects that multiple national TSOs because they have aligned incentives. Another replied that regional TSOs

[38] Note that the responses on this section need to be seen in the light of the respondents. Only TSOs responded to the questionnaire, which might result in a biased outcome.

[39] Note that not all respondents gave feedback on all aspects. We will mention the number of actual respondents during the analysis.

should be understood in the broad sense as there might be further cooperation like Coreso (i.e a cooperation of independent companies) or more in-depth integration like M&As.



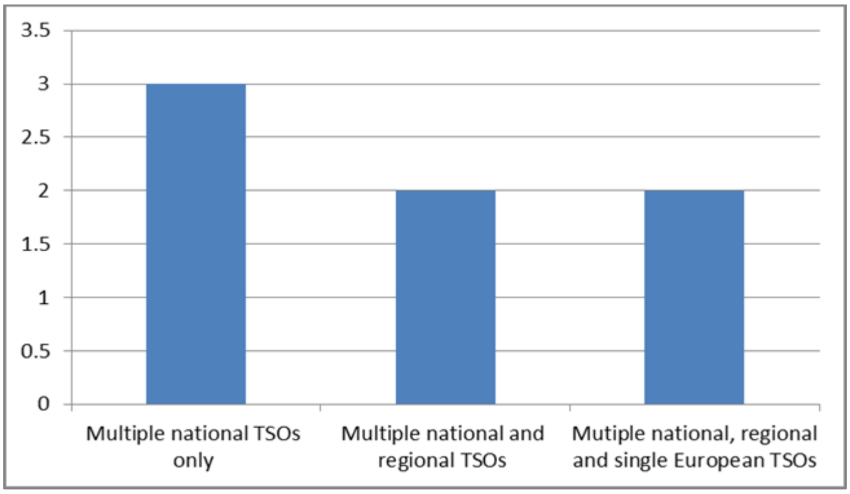
16.1.2. Ownership of TSO

Overall, a majority of countries estimated that state-owned TSOs and privately-owned TSOs will co-exist in the coming decades to varying timeframes. Two TSOs foresee a mix of the two all the way throughout 2020 and 2050 yet either the state-owned TSO or privately-owned TSOs must obey to concession contract and regulatory obligations, therefore the contract subject matters and regulations are the relevant items. So in its content should be expressed, amongst other, the public service efficiently provided and security and continuity of supply obligations.

Other TSOs mentioned that it is difficult to assess the type of ownership given the long time frame. One mentioned that any estimates on ownership after 2030 would not be reasonable as it depends too much on unpredictable political directions. Also, the impact on transmission investments rather depends on the economic situations rather than ownership structure.

Another mentioned that it is difficult to assess being state-owned or private could be advantageous or limit, it depends on the actual case. This question seems less relevant for e-Highway2050. If any convergence would occur, it is more likely towards more privately-owned TSOs. Moreover, there can always be a mixed form of shareholders involving both state ownership and private equity holders. The combination of both private and state-owned companies within a single grid might sometimes be conflicting, as both types have different objectives (profit-driven versus national-driven).

Only one country estimated that privately-owned TSOs are foreseen as the most likely form of ownership from 2020 to 2050 as transmission investment will be mainly driven by the desired internal rate of return.



16.1.3. System operator (TSO, ISO, ITO)

Supergrid

Most TSOs agreed that regulated lines will remain dominant up to 2050. 4 out 7 respondents of estimated that regulated lines will be the only assets in 2020. And two respondents predicted the emergence of non-regulated lines in the long-term horizon: one for both 2040 and 2050 and the other only in 2050. One respondent mentioned that for very capital –intensive investments new financing mechanisms where potentially merchant aspects are present are more and more likely to emerge.

Upgrade on existing system

Similar, on the upgrade of existing systems, a majority of TSOs foresee regulated lines to remain dominant up to 2050. One respondent estimated that regulated lines will be the only type of assets all throughout 2050. And only one TSO saw an emergence of non-regulated lines in 2040 and 2050.

Grid architecture in between

As in the previous two cases, a majority of TSOs agreed that regulated lines will remain dominant up to 2050 for the grid architecture in between. Yet they also saw a greater role for regulated lines only than in the previous two scenarios.

Only one TSO saw merchant lines emerging in 2050. Another respondent mentioned that for very capital-intensive investments, new financing mechanisms where potentially merchant aspects are present are more and more likely to emerge yet to a lesser extent than in a super-grid scenario.

16.2. Pricing regulation

16.2.1. Type of regulation

The most commonly implemented type of regulation in the surveyed countries is the cost of service (4 out of 8 respondents). Two countries have revenue cap as current regulation and two have a mix of either cost of service and revenue cap or cost of service, revenue cap and sliding scale.

Currently implemented typing regulation	Country
Cost of service	4
Revenue cap	2
Cost of service and revenue cap	1
Cost of service and revenue cap and sliding scale	1

There seems to be no agreement as to the recommended pricing regulation for super grid. Five countries did not provide answers.

Recommended pricing regulation for super grid	Country
Price cap, revenue cap	1
Revenue cap	1
Cost of service and revenue cap	1
Cost of service, revenue cap and sliding scale	1

There seems to be no agreement as to the recommended pricing regulation for update on existing grid. Five countries did not provide answers.

Recommended pricing regulation for upgrade on existing grid	Country
Cost of service	1
Revenue cap	1
Cost of service and revenue cap	1
Cost of service, revenue cap and sliding scale	1

There seems to be no agreement as to the recommended pricing regulation for grid in between. Five countries did not provide answers.

Recommended pricing regulation for upgrade on existing grid	Country
Revenue cap	1
Price cap and revenue cap	1
Cost of service and revenue cap	1
Cost of service, revenue cap and sliding scale	1

16.2.2. Cost-based regulation

Four countries have a cost of service regulation in place. The analysis is based on two countries only as one did not provide explanations (Country 2).

- **Regulated-asset base evaluation methodology**

Current situation	Country
Historic cost	1
Indexed historic cost	1
Replacement cost	-
Market value	-
Discounted cash flow	1
Deprival value	-

The country that uses the historic cost to evaluate the regulated asset base is mentioned that the market value could also be an option but there is no competitive market for electric grids in specific countries. Similarly, they did not see a role for market value for e-Highway2050.

Recommendation for e-Highway2050	Country
Historic cost	-
Indexed historic cost	-
Replacement cost	1
Market value	-
Discounted cash flow	-
Deprival value	-
Market value	-

Only one country provided recommendations for e-Highway2050. Replacement cost is suggested to evaluate regulated asset base.

- **Assessment timing of regulated asset base**

Current situation	Country
Ex-ante	3
Ex-post	1

Two countries use an ex-ante RAB assessment and one country uses ex-ante RAB assessment for tariff setting and ex-post assessment for correction.

Recommendation for e-Highway2050	Country
Ex-ante	1
Ex-post	-

Only one country provided recommendations for e-Highway2050.

- **Elements in the regulated asset base formula**

Current situation	Country
Investment	3
Depreciation	3
Asset disposal	1
Change of working	1
Change of capital contribution	1

Two countries use only investment and depreciation to calculate the regulated asset base. Another country uses them all.

Recommendation for e-Highway2050	Country
Investment	1
Depreciation	1
Asset disposal	1
Change of working	1
Change of capital contribution	1

Only one country provided recommendations for e-Highway2050, which is to use all elements for RAB assessment.

- **Regulation period**

Regulation period (number of years)	Annual/three years
Regulatory delay information (how the construction cost is compensated by the regulator)	-

16.2.3. Incentive-based regulation

Four countries use a revenue cap either as standalone or in combination with other pricing regulations.

- **Terms included to calculate the initial revenue cap**

Current situation	Country
O&M	4
Depreciation	2
Return on invested capital	3
Costs associated with energy loss	1

All countries that use a revenue cap include the O&M costs in their calculation of the initial revenue cap. Three use return on invested capital, two depreciation and one costs associated with energy loss.

- **Terms included in the revenue cap setting formula**

Current situation	Country
Inflation factor	4
Load growth	1
Losses	1
Productivity growth X-factor	4

All four countries include both the inflation factor and the productivity growth factor in the revenue cap setting formula. Only two countries consider load growth and losses.

- **Formula used to calculate revenue cap**

Country 1	EOt = KAdnb,t + (KAvnb,0 + (1 – Vt) · KAb,0) · (VPIt /VPI0 – PFt) · EFt + (VKt – VK0).
Country 3	-
Country 4	IPC – X
Country 5	-

Only two countries provided formulas for calculation of the revenue cap.

- **X-factor setting**

Country 1	X-factor applicable; no formula
Country 3	X-factor is not applicable
Country 4	X-factor applicable; no formula
Country 5	X-factor applicable Formula: 0.8 x actual average annual productivity achieved over a 5-yr regulatory period. Subject to a minimum of 1%.

16.3. Financing

16.3.1. Financing indicators

Six out of the nine interviewed countries provided responses on financing indicators. All of them use investment feasibility indicators to determine if certain grid investments are feasible or not. Only three of these also use additional financeability ratio indicators to assess the financeability of investments.

In country 3, assessing the indicators for grid investment depends on whether the investment is social welfare increase. If the regulator accepts the investment from a social welfare perspective, the TSOs would have no reason for not realising the investment as the investment can be included in the regulated asset base. To simplify, it is possible to separate the financing problem from this kind of indicator, as in the end the regulatory (tariff) treatment will be the main decision factor. The TSO suggests a threshold for e-Highway2050 based on social welfare increase.

In country 9, the threshold value for their most important investment feasibility indicator- payback time- is identified to be 10 years. And the net present value which is given less priority is considered from collective point of view, whose threshold is set to be positive.

Other TSOs use additional indicators in their companies. One TSO pointed out that for investments to be done; a fair return on investment is required. Therefore, there should be a balance between risks and returns. If projects entail higher risks the return should be proportionate. ENTSO-E[40] recently proposed a mechanism of priority premiums as a possible solution to tackle this issue. It is important to realise that such mechanism would mean to differentiate returns over projects, whereas until today the return is mostly determined for the entire asset base at once. Another two respondents use the FFO/ Net Debt and interest coverage as additional financial indicators to investment feasibility and finance ability.

In country 7, financeability does not represent a main concern if the investment analysis is sufficient with positive NPV and robust risk analysis. The capital is supplied by the National Bank which is afterwards passed on to electricity consumers.

Concerning the investment feasibility, the most used indicators for grid investments are the net present value and the internal rate of return (IRR). Two countries chose the internal rate of return as the second priority indicator used.

Ranking	Number of countries
Net present value as 1st priority indicator	2
Internal rate of return (IRR) as 1st priority indicator	2
Payback time as 2nd priority indicator	2
Payback time as 1st priority indicator	1

Two out of three TSOs that use a financeability ratio ranked the return on shareholders' equity as the most important indicator. The return on total assets and the interest coverage came out to be important indicators as well, ranking first for each TSO respectively. Another TSO ranked gearing as the most important indicator, followed by FFO/Net debt.

Ranking	**Number of countries**
Return on shareholders' equity as 1st priority	2
Return on total assets as 1st priority	1
Interest coverage as 1st priority	1

40 https://www.entsoe.eu/fileadmin/user_upload/_library/position_papers/130523__Incentivising_European_Investments_in_Transmission_Networks_Final.pdf

16.3.2. Cost of capital

Only three TSOs provided information on the WACC calculation.

	Country 3	Country 5	Country 7	Country 9
Regulation type	Cost of service/revenue cap/sliding scale	Revenue cap	Cost of service	Cost of service
WACC %	-	8.52% real pre-tax	4% real after tax	
Risk free rate in the country %	10 year obligation	6%	-	
Debt premium	0.7%	2%	-	
Equity market risk premium	3.5%	6%	-	
Equity beta	Depends on historical track records	0.94	-	
Gearing level	regulatory incentive to keep this at 1/3Equity and 2/3Debt	40%	-	

The TSO in Country 5 mentioned that the WACC for Merchant transmission will very much depend on the potential standardisation of the risks attached to such transmission framework. While the possibility of total standardisation (resulting in a one-size-fits-all WACC) for merchant transmission is limited, financing mechanisms like project bonds with EC/EIB supporting good solid ratings through guarantees and/or subordinated debt injections could provide some degree of risk standardisation across merchant lines operating in different European regions. In the absence of such risk equalization mechanisms, there will be no single one-size-fits-all WACC as required returns will have to reflect project-specific risks.

16.4. Risk

Overall, five out of eight TSOs provided information on risks. The analysis in this section is not as obvious as some respondents ranked indices per type of risks whereas other ranked them globally. The analysis below excluded the TSO that provided a global ranking.

Most respondents provided ranking for regulatory risks, with only two giving information on indices for merchant investments.

16.4.1. Regulatory risks

Concerning regulatory risks for regulated investments, the **change of regulatory rules** and the **stringency/length approval process** were seen as the main regulatory risks.

Ranking risks	Number of countries
Change of regulatory rules ranking 1st	4
Change of regulatory rules ranking 2nd	1
Stringency/length approval process ranking 1st	2
Stringency/length approval process ranking 2nd	2

Additionally, one TSO place the cessation of the investment cost recovery process before completion and the uncertainty around the recovery of investment cost overrun as very important risks. The regulator can cease the investment cost recovery process before completion (as by taking assets out of the RAB before they are fully depreciated) following ex-post analysis of the actual efficiency of previously approved transmission projects. Regulatory bias towards overly extended depreciation schedules (slow recovery of cash invested in transmission assets although the cash flow profile is theoretically NPV neutral). Uncertainty around the recovery of cost overruns associated with new complex projects undertaken by the TSO with little or no past experience in the cost budgeting of such investments. Lack of CAPEX flexibility within a regulatory period (5 year) is perceived as risk. Additions to the pre-approved CAPEX plan are added to the RAB at the beginning of the next regulatory period on a net-of-accumulated depreciation basis (time lag and investment cost not fully recoverable).

Another TSO stated that the acceptance of costs by the regulator is always a risk in addition to the stability of the regulatory regime. If for instance tariff methodologies would change over time, this could create a risk. Note that regulatory periods are much shorter than typical asset life time. For other elements (.e.g. lengthy approval or NIMBY effects) it depends on how the costs are covered. If the costs during approval period are already covered via tariffs, there is no risk for the regulated company. If those costs have to be pre-financed, there is a risk.

16.4.2. Financial risks

Three out of the six respondents agreed that the **interest rate change** represents the main financial risk for grid investments. In addition, two TSOs also saw **the foreign exchange risk** as ranking first and second respectively. Besides, one country list change of gearing limit as the main financial risk.

Ranking risks	Number of countries
Interest rate change as ranking 1st	4

Foreign exchange risk ranking 1st	1
Foreign exchange risk ranking 2nd	1
Change of leverage ranking 1st	1
Change of gearing limit 1st	1

The TSO active in country 5 stated that as the regulated rate of return remains constant throughout the 5-year regulatory period with no possibility for interim reviews/updates, upward changes in interest rates increase the cost of the TSO's index-linked debt resulting in a deterioration of both credit and equity metrics. Currency mismatch between equipment purchase currency (mainly Euro) and tariff currency (national currency, country 5 is in the non-euro zone). The funds needed to purchase equipment are borrowed and repaid in Euro while cost recovery is made in local currency. Adverse developments in FX rates (appreciation of the Euro against the tariff currency) have a negative impact on operating cash flows. Hedging options and effectiveness are limited.

16.4.3. **Scenario risks and other risks**

1. Country 1 – NA
2. Country 2 – NA
3. Country 3 - the main risk is the REGUALTORY RISK
4. Country 4 – Other risks: project overrun (1), delivery risk (2), planning and permitting delays (2).
5. Country 5- NA
6. Country 6– NA
7. Country 7– Scenario risks: modeling uncertainty around generation mix (1), project overrun (2), planning and permitting delays (3).
8. Country 8 – NA
9. Country 9 – Scenario risks: Uncertainty about effectiveness of interconnector capacity allocation (1), modelling uncertainty around load profile (2), modelling uncertainty around generation mix (3) ; Other risks: project overrun, delivery risk, planning and permitting delays, supply chain risks and construction delay.

It seems that the main risks are **project overrun**, modeling uncertainty around generation mix and planning and permitting delays.

Country 9 gives an extensive answer on the scenario risks and other risk. The most important scenario risk is identified as uncertainty about effectiveness of interconnector capacity allocation, followed by uncertainty around load profile and uncertainty around generation mix. Scenario risk quantification is performed by evaluating scenario possible scenarios at 2030 and examining generation adequacy report. As for quantifying project overrun risk, technical and environmental feasibility studies are developed to establish cost at +/- 15%. Delivery risk is evaluated by strong technical knowledge, specific qualifying test for materials and well defined tender for subcontractors. Planning and permitting delays are taken into account by starting studies well in advance. Supply chain risks are dealt with by self -purchase service with long term contract and/or spot contract. Construction delay is quantified in both technical and environmental feasibility studies.