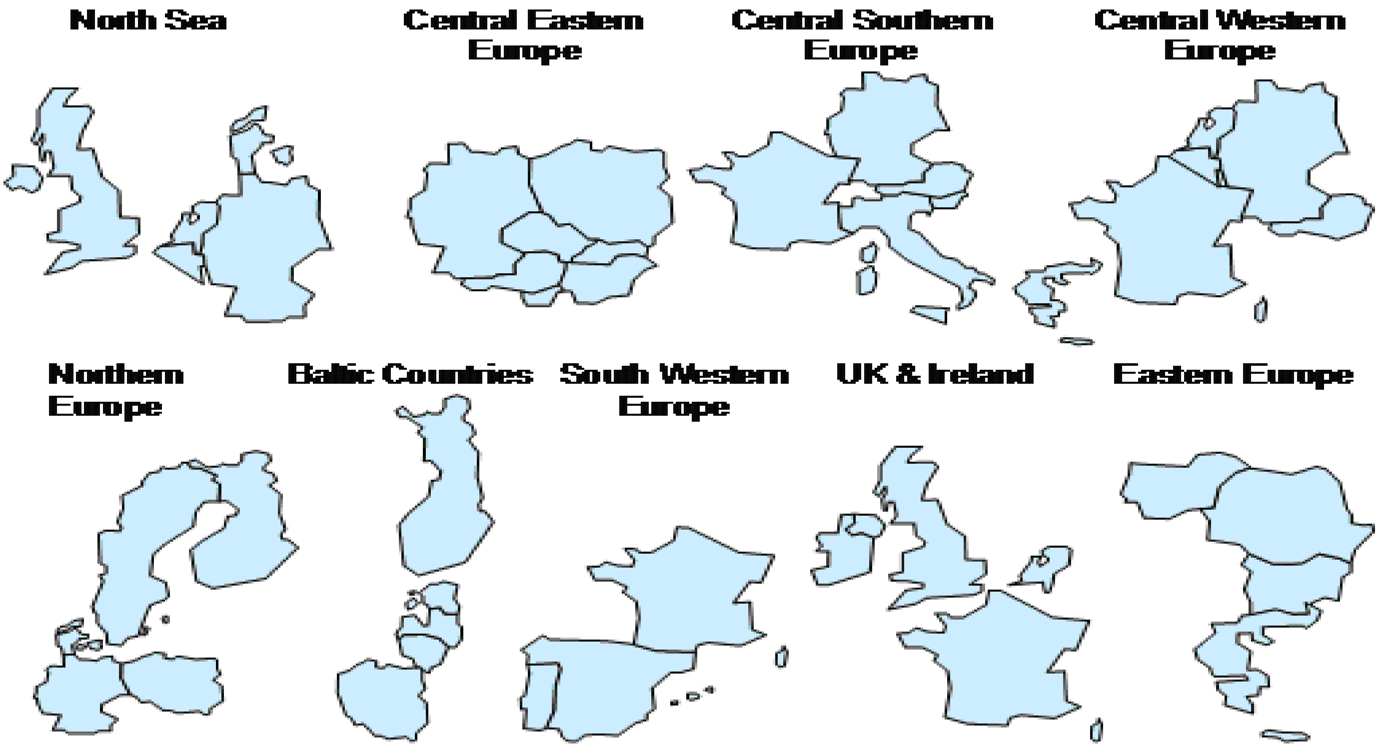

Prepared for the European Commission

T E N - ENERGY Priority Corridors for Energy Transmission

Part Two: Electricity

November 2008

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1. Executive summary

Concerning the electricity sector, the objective of this methodology is the provision of an adequate instrument at regional level in order to select and implement electricity interconnection projects of European interest up to the year 2020. To this aim a number of regions at the European level have been defined that fully cover supply and demand needs regarding the new electricity interconnection axes. Secondly, two different methodological approaches are proposed so as to select electricity corridors in the EU, with the subsequent analysis and recommendations on the pros and cons of using each one. The selection of one of the two approaches heavily relies on the role that plays involved stakeholders so that the co-ordination and co-operation is essential for the proper designation of projects of European interest in the electricity sector. Therefore, an open and transparent assessment of transmission needs at regional level depends on all stakeholders, including the organisations for electricity, regulators, national authorities, private companies and any other organisation. All these aspects should be carefully treated in the following TEN-E guidelines in conjunction with other measures that are relevant for the declaration of electricity priority corridors.

As a result, the proposed methodology cover three phases, namely the selection of the regions together with the relevant stakeholders and description of their role, the instrument to select electricity interconnection projects and finally the proposals for the review of the existing guidelines. In addition, recommendations on the timely authorisation, implementation and construction of electricity projects are also drafted. Finally, the assessment of the needs of the transmission infrastructure in every country and in every defined region is presented in accordance to one of the proposed methodological approaches as an example of how this methodology works in the declaration of projects of European interest. Further, the other approach is also presented by illustrating the Spanish-French interconnection needs as the alternative methodology. In all the process particular emphasis is placed on investments in renewable energy sources as well as carbon-free electricity generation and their integration into the Trans-European energy networks, always in line with the security of supply requirements and the increase of competition with the aim of creating a single electricity European market.

Selection of suitable regions

To select suitable regions which cover the priority axes the existing regions selected for similar purposes are analysed in-depth so as to better understand the manner in which regions are formed. In this regard, experiences from ERGEG, Trande Wind and ENTSO are reviewed and the main conclusion arisen from these experiences is that regions are defined in accordance to target set for every single objective. Therefore, from the perspective of the declaration of projects of European interest supply and demand features are analysed in order to decide the best regional formation, but also taking into account the existing regions that may facilitate the integration of involved stakeholders into existing institutions.

Thus, supply concerns show that the supply necessities in terms of transmission corridors depends on the sources location. The majority of sources are widely available at European level or are constrained to be constructed for geographical or political reasons. The only exception is wind power which is the only technology that may require specific transmission needs and it will be expanded in the following years across Europe. Therefore, transmission interconnection needs at regional level are taken into account for future wind power expansion plans. On the other hand, demand is the main aspect that determines electricity interconnection needs since it is specifically located. To comply with demand requirements, a number of measures are analysed in order to select the most appropriate regions. These measures are as follows:

- Transmission capacities in the interconnection between countries.
- Coordination level of cross border trading resulting in relevant cross-border exchanges among countries.
- Other variables:
    - Planning investments
    - Regulatory harmonisation
    - Reliability in transmission investments
    - Co-ordination and co-operation of the regulatory bodies among countries included in the regions.

Under the former supply and demand analysis nine regions are proposed in the first phase:

- North Sea: Belgium, Denmark, Germany, the UK, the Netherlands and (Norway). This region tries to coordinate the supply requirements (wind power) on transmission needs. Sweden and Finland might also be included since the interconnection in these countries is quite good, but in order to avoid excessive number of actors involved in the designation of corridors the number of countries is decreased.
- Central Eastern Europe: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia. Although the interconnection capacity among new Member States is generally adequate, certain degree of harmonisation and coordination is required before joining a larger region (through the CEE alternative).

- Central Southern Europe: Austria, France, Germany, Greece, Italy, Slovenia, (Switzerland). This region is the axe that must connect Greece and Italy with the central western countries of the EU.

- Central Western Europe: Austria, Belgium, France, Germany, Luxembourg, the Netherlands and (Switzerland). The creation of the TLC market favours the definition of this region, which must be enlarged with other regions once the conditions are favourable.

- Northern Europe: Denmark, Finland, Germany, Norway, Poland, Sweden. Nordpool and the well interconnected areas favour the definition of this region that must be enlarged with other regions once the conditions are appropriate. In addition, this region is also proposed for fostering the integration of the wind power plans into the electricity market.

- Baltic countries: Latvia, Estonia, Lithuania, Finland and Poland. The proposed interconnection projects of the Baltic countries with Finland and Poland must integrate the Baltic countries with the neighbouring areas once the regulatory harmonisation allows for that.

- South Western Europe: France, Portugal, Spain. The creation of MIBEL ensures regulatory harmonisation, but the low interconnection capacity with France reduces the possibilities of interconnecting the Iberian Peninsula with Europe in spite of the transmission projects that are already planned.

- UK and Ireland: France, Ireland, the UK and the Netherlands. The isolation of the two islands reduces the possibility of designating transmission corridors. Belgium could be included in the regions, but following the same criterion as above (avoid excessive number of actors) it is excluded.

- Eastern Europe: Greece, Hungary, Romania and Bulgaria. The two new member states are also included. Their interconnection capacity is weak and Greece and Hungary need to be included in order to accommodate the transmission capacity to the creation of a single European electricity market.

This is considered the first phase since regions are supposed to be an intermediate stage in the formation of a single electricity European market. From now to 2020 the regions should tend to be integrated in bigger areas before being a solely region.

It can be observed the central Europe is better interconnected than those areas places at the border limits. This is so because of the electricity networks idiosyncrasy, so that special attention is required for the limiting countries, especially in the South area of the EU.

The role of stakeholders

Once the regions have been defined, a list of all stakeholders concerned and their functions is also presented, which consists of regulators and authorities, TSOs and private companies. The role of each stakeholder is crucial for the sake of selecting priority corridors in the electricity sector. Special attention has to be paid to the TSOs role, since the selection and implementation of electricity corridors is part of their functions. Therefore, current proposals made by regional TSOs are analysed and evaluated with the aim of providing a sound methodological approach in the prioritization of projects of European interest. The most relevant recommendations on their proposals are as follows:

- TSO cooperation on regional, inter-regional and European level: in order to identify candidate projects to be declared of European interest, this measure is essential referring to the regions definition.

- Modelling tools:

    - A common methodology including a modelling tool would ensure consistency of selected projects and would facilitate agreements and negotiations. In this regard, it is not necessary to use the same models, but the same methodology.

    - However, a common model would facilitate the selection process. Regarding the use of common data bases for evaluating new interconnection plans, this is critical so as to provide adequate results. If the use of a common methodological framework enables the appropriate assessment, the use of common databases is essential to ensure the recommendations of the methodology. In addition, the use of a common tool would also facilitate the common understanding and the accessibility and simplicity of the process.

    - A common approach to simplify the modelling of weakly connected neighbouring countries would facilitate negotiations and agreements.

    - At the regional level common databases are required to enable adequate modelling.

    - Multi-area simulation tools already in use within NORDEL seem to be a promising approach for the selection of project to be prioritized. However a least cost expansion model should also be considered as an appropriate alternative that fully complies with the requirements to invest in new interconnection capacity in terms of those aspects included in the TEN-E guidelines.

- Implementation of the projects:

Even though the proposed procedures improve the coordination between TSOs, ensure the quality of the assessment and commitment of the TSOs, the implementation of the projects is still subject to a long and complex process which involves many other entities apart from the TSOs. The essential elements for implementing additional transmission network infrastructure are:

- Building and construction authorisations and permissions:
  - To reduce times for project approval from 7 to 5 years.
  - A clear political support.
  - An independent view of a project's wider benefits for the Internal European Market can be helpful for the promotion of the project during the consultation phase.
- Role of regulators :
  - EU and other concerned regulators should be given some form of collective duty and competence to oversee and promote (cross border) transmission network investments and approve cost allocation of cross border elements as appropriate, possibly through the Agency for the Cooperation of Energy Regulators (as proposed in 3rd package)
  - Competences of regulators and of the procedures used to deliver cost approval should be harmonized in order to avoid potential additional obstacles for the time schedule of the implementation.
  - In the consultation phase changes in the technical design of the project leading to additional costs can be necessary in order to get agreements with local authorities. TSOs should ensure that these extra-costs regulators would be accepted by the regulators.

The selection criteria

To specify selection criteria for the most important links needed the declaration of European interest should be granted only for links that specify clearly the quality description, which in turn has to be accepted by all stakeholders. Of particular interest are:

- The in-depth planning is initialised to which all stakeholders contribute in the appropriate manner.

- Specification of appropriate project and quality description. This allows a first cost estimate.

Regarding the cost estimate, the proposed methodology must comply with those aspects included in the regulation, more precisely the appropriate measurement of any project must:

- have a significant impact on increasing competition and/or

- strengthen security of energy supply and/or

- result in an increase in the use of renewable energies.

Hence, the two methodological approaches presented in this report provide the analysis of the possibility to develop a common measurement of each project's contribution to all above criteria through an objective ranking, or alternatively the use of a multi-criteria decision-making methodology, which implies assigning a weight to each individual criterion. This is in fact a trade-off between simplicity and accuracy for assessing and ranking the projects.

As a result, two methodologies are proposed, Alternative #1 that is based on the use of modelling tools presenting an objective ranking and Alternative #2 that lies on the use of multi-criteria analysis. The two approaches can be summarised as described below.

Alternative #1

1. Impact on increasing competition in the internal market: benefits arising from increased trading can be measured based on market simulations of the clearing process. In fact, optimal expansion models as described below include an estimation of clearing costs, so these benefits form automatically part of the planning process.

   Furthermore, as cross border interconnections usually allow reducing the market's concentration, it is expected that market power potential will be reduced as well. This can be assessed in two ways: (1) including market power exercise in the planning model, or (2) describing the impact of each expansion on market concentration indicators, typically HHI and pivotal.

2. Strengthen security of energy supply in the EU: this can be included in the planning models through the cost of non-supplied energy. Alternatively, a constraint may be imposed, typically the non-supplied energy should be lower than a pre-specified threshold targeted in the regulation or set as an objective. Typically, planning in developed economies aims to non-supplied energy being lower than 10-4 times the energy demand. A suitable indicator is the expected non-supplied energy in the whole EU or the defined suitable regions.

3. Increase in the use of renewable energies: as far as the planning expansion model considers intermittent renewable generation as a stochastic variable, the size of corridors to allow optimal management of these resources results optimised. So, no special considerations are necessary.

   The volume of renewable generation is based on the existing plants and the new projects informed by investors. Typically the new projects are informed for a period no longer than the initial 5 years.

   Planning models provide indicators for the optimal expansion plan as a whole, but not for individual projects.

In order to obtain the selected indicators for individual projects two alternatives are available:

- After obtaining an optimal expansion plan, to analyse a new plan without considering as candidate the project that is being assessed (with-without). Although effective, this process is slow if used for several projects. Furthermore, the marginal impact of the project is assessed.

- Through sensitivity analysis provided by the mathematical solvers, which analyses the impact of marginal changes in one variable (the indicator) due to changes in other variable (the project).

Once the list of candidate projects is provided by the model expansion optimization results, it is previously required to define priority corridors concept (i.e., the list of candidate projects that allow some level of increase in the indicators described above) in the sense that it also fulfils the condition of having a positive impact on social welfare.

Alternative #2

The results provided by the MCDM analysis for the selection criteria are based on indicators. This alternative may provide better results in all these cases where the optimal amount of interconnection capacity is difficult to be assessed since it requires extended data modelling, taking into account (at least) the geographic distribution of generation, existing network capacities and generation cost information.

Apart from the present more detailed modeling efforts, this alternative provides some first ideas on the development of an ‘Electricity Interconnection Indicator’ which provides a first-order insight into the need for additional interconnection capacity for each country (or system). This indicator should be able to generate a rough indication on the need for additional interconnection capacity.

An advantage of this type of indicator is that it may be calculated quickly from easily accessible information. Nevertheless, it should always be taken into account that it is far from perfect, so it needs to be applied with cautiousness.

In this regard, the suggested Electricity Interconnection Indicator (E _ I) is being calculated per country (or market zone) and is derived from four sub-indicators:

- An indication of the competitive structure of the electricity market: M
- An indication of the security of supply: S
- An indication of the amount of flow-based renewable power generation: R
- And optionally: an indication of the price level of a country: P.

The E _ I will be calculated as a function of these four sub-indicators:

$$E\_I = f(M, S, R, P)$$

This four subindicators are based on the relevant information of each one, so that finally a weighted indicator is built.

Revision of the TEN-E guidelines

Finally, to provide the necessary input for a revision of the TEN-E guidelines the objectives must be:

- Enable authorisation and construction of selected projects declared to be of European interest in a maximum time span of five years.
- Proposing to the Commission priority energy transmission corridors together with projects of European interest as a result of the regional priorities.

Hence, the guidelines must be focused on facing all the mentioned issues so as to allow the proposed methodology the necessary degree of success. The main points are the following:

- The definition of a European grid seems to be appropriate from the efficient point of view, although it is much more challenging.
- Since electricity flows in meshed networks are a complex issue, a co-ordinated planning approach is necessary. A regional planning process can identify cost-saving opportunities and facilitate the construction of new transmission to support robust wholesale markets and improved reliability.
- A much more difficult issue is to provide guidance on how the economic value of a new interconnection may be assessed. Although it is presently not clear whether a harmonized framework can be established at all, if such a procedure can be developed the advantages will be significant. From the economic perspective investment decisions based on congestion is not efficient since it may introduce incentives to unnecessary investments. The

efficient criteria is to allocate resources to reinforcements based on its economic convenience (those projects that lead to positive benefits for the whole system, which is measure to the social welfare increase), but not through the distort criterion of allocating congestion revenues. A sound and fair practice is to use congestion revenues to reduce internal transmission tariffs.

- An additional area where guidelines might be developed relates to the regulatory treatment of new interconnections, especially with respect to the elimination of regulatory impediments and the provision of regulatory certainty, particularly with respect to attractive returns, incentives, cost allocation and cost recovery, in order to raise the necessary capital to construct the required, cost-effective transmission facilities.

Conclusions

In summation, the conclusions drafted from this proposed methodology for the sake of electricity transmission projects of European interest are as follows:

- Interconnection Projects - Rights of Way: obtaining the rights of way seems to be the most critical component of a transmission project.

- Planning Methodology: a sustainable identification of projects should go through an initial filtering, that is to increase the social (measured through the social welfare concept, i.e. the sum of the consumer's surplus plus producer's surplus). So, any methodology should ensure that the increase in benefits and the project costs should be properly identified. Further to increase in net benefits, in order to be nominated as a project of priority interest, the project should contribute to the fulfilment of some of the EU policies regarding competition, security of supply and penetration of renewables.

  Simple analysis based on short term benefits or only on technical considerations should be avoided, as it may lead to waste of valuable resources. And it is important to remark that given the increased trend of overhead lines being rejected by the population located near the electricity transmission routes, presently, further to the project's direct cost, it is necessary to account with the enormous effort to obtain the acceptation of the project. It would not have sense to waste this effort in projects that do not increase the social welfare.

  The final recommended alternative to identifying projects of priority interest is based on the use of a cascade of models: (1) long term planning model; (2) market simulation; (3) and power system analysis. This methodology was labelled as Alternative #1. A simple alternative methodology was evaluated (Alternative #2), but this should only be used as a tool to diagnose zones with some needs (security of supply, difficulties to transmit renewable energy or high market concentration), which can be mitigated through cross border interconnections.

- Projects Review: the economic evaluation of projects of European interest is based on some cost estimations. Therefore, it would be good to know in each case which is the maximum cost of the interconnection that preserves the condition that the social welfare increases.

- Congestion fees: a common but flawed practice is to evaluate the benefits of a project based on the congestion rents to be collected. This approach has several conceptual errors that have to be avoided.

- Congestion management: the use of implicit and explicit auctions to allocate such capacity substantially improved the efficiency in the use of the existing transmission capacity. However, this can be further improved with the introduction of point to point transmission rights.

2. TEN-Energy Priority Corridors for Energy Transmission

The priorities for trans-European electricity networks stem from the creation of a more open and competitive market as a result of the implementation of Directive 2003/54/EC. These priorities are part of the conclusions of the 2001 Stockholm European Council referring to the development of electricity infrastructure and the increased use of renewables.

The need for a strengthened policy to facilitate the completion of priority infrastructure projects was underlined by the EU Heads of State and Government at Hampton Court in October 2005. Then, the European Council of March 2006 called for the adoption of a Priority Interconnection Plan, as part of the Strategic European Energy Review. The European Council of June 2006 asked to give full support to external energy infrastructure projects aimed at enhancing security of supplies.

To this aim, the construction and maintenance of the electricity infrastructure must be based on economic principles by paying special attention on whether the increase of interconnection capacity benefits the internal competition, provides security of supply and facilitates the use of renewables.

In this sense, Decision 1363/2006/EC setting out guidelines for trans-European energy networks attempts to move forward the electricity interconnection capacity level set at the 2002 Barcelona European Council in order to improve the security of supply and to increase the internal market's functioning by increasing interconnection capacity at a minimum of 10% between Member States. Therefore, the European Union formulated a number of policies with the aim of promoting an adequate European infrastructure that consisted of identifying projects of common interest, the EU introduced specific rules to ensure an appropriate level of electricity interconnection between Member States, the European Council asked to give full support to infrastructure projects compatible with environmental considerations with a view to diversifying energy imports, and finally the European Council highlighted the importance of the good functioning of the internal energy market.

Therefore, once these principles are widely accepted, the declaration of priority interest for European projects regarding electricity infrastructure must be prioritized by all the stakeholders involved in the declaration process. The coordination between the parties involved in terms of regular information exchange, organisation and flexibility is essential for the completion of the project of interest in a timeline of less than five years.

The procedure for identifying projects of European interest is formed on two different levels; the first one establishes a restricted number of criteria for the identification of such projects, while the second stage consists of describing the projects in detail. This study basically deals with the identification stage in which an open and transparent methodology has to be implemented, also regarding that the increase of operational and economic efficiency are crucial for declaring a project of highest priority. Nevertheless, the proposed methodology must be used as the baseline for the specification of priority interest projects.

In addition to this Decision, the Energy Package, released by the European Commission in 2007, emphasised the necessity of European electricity networks to create a single electricity market by introducing targets to set minimum levels of priority interconnections based on coordinating planning at regional level, and aiming at streamlining the authorisation procedures to maximum five years. The Decision also envisages for some procedures to encourage investment development in case of delays, once the specifications are already defined.

As a result, a European network investment plan is envisaged to be elaborated biannually by the TSOs. Furthermore, the TSOs' cooperation body "European Network for Transmission System Operators" (ENTSO) will propose a procedure that enables coordinating electricity network planning at regional and European level, leading to a common approach for the selection of the projects of European interest.

The methodology developed in this study is in line with the requirements of the Decision and with the procedure that is being developed by the ENTSO. In this regard, the methodological proposal enables the selection of electricity interconnection capacity between countries at a regional level by using economic principles in order to facilitate the specifications of projects of European interest by the TSOs. Furthermore, this study also deals with other important aspects that are necessary for implementing a common methodological framework, such as the role of the stakeholders involved in the process for the declaration of projects of European interest.

The following chapters of this section focus on the electricity part of Tasks 1-3 of the Terms of Reference. These tasks mainly consist of the selection of suitable regions to identify priority corridors at regional level, the methodology for the in-depth planning and the specification of appropriate project and quality description and the necessary input for a review of the TEN-E guidelines.

3. Suitable regions

The transition which will be faced by the EU's electricity market in the coming years presents a massive challenge to all parties and stakeholders involved in it. From the perspective of the EU objectives, where the main purpose regarding energy networks is the creation of a single, efficient and competitive electricity market, the optimal solution is to plan at the EU-wide level in order to reach all Member States' integration into a common market.

However, the electricity networks' planning process is, in many occasions, not as easily reachable as desirable with respect to the integration of a common European network, in the sense that many factors impede a common view due to the different necessities of the transmission networks forming the EU. These needs arise from a number of specific issues that affect the regulation of electricity markets in the transition from regulated markets to liberalised ones, but also taking into account other concerns such as the security of supply or the implementation of renewable energy sources that are of special attention for the transmission activity, as resulting from the latest regulatory decisions at the European level.

Thus, due, but not limited, to the cited complexities, the objective of unifying the energy networks requires simplifications, so as to create a single electricity market. In this regard, the large number of Member States and disparities of issues and priorities of the involved countries, support the idea of splitting the priority corridors' designation in regions, as a reasonable measure to accelerate the process of unifying the planning, construction and operational criteria. This purpose implies a phased implementation of the unified electricity market, starting from a "regional" market, and at a second stage, unifying regions that will finally form a single electricity market. From the operational point of view, such an arrangement is already working in several parts of the EU. In any case, the main purposes of defining suitable regions rather than a solely EU one in the process of fostering common initiatives must be based on the same principles as those pursued by a unique common framework.

In addition, the Energy Package released by the EC is fostering the coordination procedures among Member States in order to provide a regular European investment plan. To this aim, the ENTSO is developing coordinating network planning at a regional European level. Therefore, the split of the European market for the declaration of projects of European interest would enable complying with the objectives set in the TEN-E guidelines and in the Energy Package, through the use of a common methodological framework. To this end, this chapter focuses on the most adequate definition of suitable regions that would allow for the creation of a single European electricity market by developing planning investment plans at regional level.

However, the definition of electricity suitable Regions within the EU must be considered as an intermediate step in the pursuing of the European electricity market' full integration, and also in the designation of transmission corridors that provide an adequate solution for the required integration.

It has to be pointed out that the selection of Regions aims to solve other problems more efficiently than they would be solved at the EU-wide level. The challenges to be considered in the formation of Regions for this purpose include the following, among others:

- Reduce the isolation of electricity regions within the EU: this is one of the underlying principles in the creation of a single electricity market. Isolation is of special attention as a result of the new European policies that aim to foster the electricity production from renewable energy sources, which tend to be geographically located in remote areas or highly intermittent ones (e.g., off-shore wind).

- Increasing the security of supply is an important concern for the majority of the EU countries, and obviously within the EU. The new energy policies passed by the EU, and which will be implemented by the Member States, include an important increase in the production of electricity from renewable sources which introduces additional complexities to the security of supply.

- Solidarity is required among countries in order to create a single market. For this purpose, the definition of Regions does not substantially reinforce the solidarity among countries; however, the integration among countries will require progressively a major degree of solidarity among them since geographical and socio-economic conditions tend to be similar within regions. Therefore, solidarity will be applied more efficiently once the electricity market tends to be unified. On the other hand, the creation of Regions is not an obstacle to the increased electricity trading across the whole EU, which is mainly limited from the available cross border capacity. As far as the regional approach to planning succeeds, this limitation will become apparent.

- Increasing efficiency at the European level is another target of special importance in the creation of a single market. The use of the available resources in an efficient manner is achievable through a single European market. The proper development of interconnectors in the transmission system is therefore crucial for increasing efficiency. In this sense, global efficiency may be reached through regional initiatives, but these must be adopted through the use of general planning procedures involving all the countries influenced by the decision in order to properly estimate costs and benefits of such an initiative, independently of their inclusion or not into the affected region. Otherwise, regional initiatives may lead to inefficient decisions.

- Increased competition within the European electricity market is one of the main concerns at the European level. The definition of Regions is just an intermediate stage in this process since competition at the regional level may lead to competition at the single electricity market.

Hence, the designation of transmission corridors through the definition of suitable Regions must be in line with the above challenges rather that trying to foster the single electricity market in the EU.

Tackling these challenges should be done in smaller regions in order to be handled in the most efficient manner. In this case, the challenges must be matched by obtaining further benefits from defining such strategy for the designation of transmission corridors at the European level. Benefits have to be linked to the challenges commented previously, in comparison with an alternative strategy. In this sense, the regions' alternative must be superior in order to be justified in the process of creating a single electricity market at the European level, and regarding the purpose of this section, the provision of a methodology for the designation of electricity transmission corridors.

As a result, the most relevant benefits identified for defining Regions in pursuing an efficient designation of transmission corridors in comparison with the alternative of considering the whole EU-system are as follows:

- The definition of Regions may be more effective in removing the regulatory problems that cannot be solved by considering a single European region. In the recent years, a number of proposals have been made in order to harmonise several aspects of the European regulation, such as cross-border transmission tariffs (Inter-TSO Compensation), interconnection capacity and some others that are likely to be better managed through regional initiatives rather than European ones. In some of them overall consensus is required, but in many others the agreement is easily reachable by few agents as an intermediate stage in the creation of a single market.

- Local planning necessities are of primary interest in order to reduce isolation, which is one of the most crucial pursues of the European authorities and national governments. In this sense, local planning may be also better managed by regional initiatives rather than global ones, then facilitating the process of integrating isolated regions within a European market. This is especially relevant regarding the transmission corridors that are initially managed as local necessities rather than European ones.

- Another benefit is the reduction of transaction costs between stakeholders (i.e., commitments between +27 countries are not easily achievable). This is of special concern in planning procedures since the countries' necessities may differ across Europe. Thus, the less parties involved in the determination of regional planning the more likely to be successful. The required coordination among parties is more effective with fewer participants, and this is more easily manageable where regional necessities in regulatory or technical terms are similar.

- Competition increases may also be fostered through regional initiatives although the final objective is the full competition at the European level. However, regional initiatives may also facilitate at an intermediate stage the promotion of competition in those areas where competition is at its initial stages. In this sense, transmission initiatives at regional level may also be positive.

- Since one of the main barriers in the European transmission policy is the treatment of environmental damages, the regional initiatives may deal with this concern in more detail by analysing alternatives more carefully. In general however, this concern is always treated cautiously since environmental concerns are of special interest at both the national and the European level.

- The integration of renewable energy generation affects mainly regional transmission needs, and so an analysis from this perspective seems more appropriate . The designation of transmission corridors through regional initiatives may therefore be assessed with special concern.

- Harmonisation in the national regulatory implementation is complex and the implementation of global measures requires a high degree of flexibility due to the differences that exist among the countries' regulatory frameworks. It is therefore necessary to implement different measures that might be addressed through the use of regional initiatives that better fit the countries' local problems. Once the homogeneity of regulation is achieved at the regional level, the following step is the integration of all Member States so as to properly guarantee the functioning of the electricity single market.

Hence, it seems that the introduction of Regions as an intermediate stage for designating transmission corridors at the European level seems to be at least an attractive solution compared to the alternative of making global decisions. However, it has to be stressed that regional initiatives do not hamper the global planning necessities. This implies that planning at EU level is necessary regarding transmission corridors, as it was commented above by mentioning the "European Grid". Thus, the definition of suitable Regions does not imply that only local solutions will be implemented, but that such solutions must take into account the necessities of the entire European Grid. Chapter 3 develops an approach to planning that considers two levels of planning: regional and inter-regional.

However, all the potential benefits described above may be reduced, or even not be secured, if there is no appropriate methodology for defining Regions. Therefore, in order to provide the best solution, it is necessary to define suitable Regions in connection with the designation of electricity transmission corridors. Otherwise, the result may not be valid and result in the subsequent inconvenience and distortion of the objectives set in the electricity sector.

ERGEG's suitable regions

Regions are already a well known concept in the EU electricity market as the approach is already familiar from the ERGEG Regional Initiatives. Thus, the definition of suitable Regions by the European regulators' group, ERGEG[1], identified four areas of work for the integration of electricity markets:

- availability of transmission capacity
- availability and control of information
- co-operation between network operators
- compatibility of wholesale market arrangements

ERGEG has been working with relevant stakeholders to integrate electricity markets. Finally, ERGEG proposes regional initiatives for the priority issues to be addressed.

ERGEG's definition of regional markets is based on the following four conditions:

- sufficient transmission capacity exists between the markets within the region
- no distortions that might significantly affect the functioning of the regional market exist within the local markets
- an appropriate legal and regulatory framework is in place allowing for action across a regional market
- national institutions within the regional market coordinate and cooperate closely.

However, there is a lack of dynamic view in the definition of suitable regions if these criteria must be followed for the definition of suitable regions for designating electricity priority corridors.

Nevertheless, in order to define suitable regions based on the above cited conditions, ERGEG also identifies obstacles to trade that hamper the establishment of the single electricity market. Therefore, the creation of regional electricity markets as a milestone to a single electricity market has to comply with the four cited conditions by means of avoiding a number of obstacles to trade. These obstacles are divided into three different categories that are summarised as follows:

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[1] "The Creation of Regional Energy Markets. An ERGEG Conclusions Paper" 8 February 2008 ERGEG

- Network operations: the TSO's responsibility for the transmission network is essential for achieving a single electricity market. Among the TSO companies' key functions that must ease the trade of electricity agents, are the coordination and cooperation in the next requirements:

    - Network capacity and investment. Cross-border infrastructures may be impeded since regulatory or technical conditions are not always clear.

    - Network access. Transmission rights allocation might introduce excessive transmission capacity.

    - Transmission charges. Harmonising the transmission charging principles is desirable to avoid distortions.

    - Network operation. Balancing mechanisms should be transparent.

    - Network maintenance. Technical standards in security and reliability must be harmonised.

    - Provision of information. Information asymmetries provoke distortions.

- Wholesale market arrangements: market designs distort trade between national markets. A certain degree of market integration is therefore desirable. To this end, the following must be analysed:

    - Transparency. Access to information is essential.

    - Market structure. Lack of concentration or degree of liberalisation is crucial in this regard.

- Regulation across regional markets: The Regulator's responsibilities to ensure that competition is feasible in the cross-border are crucial for the creation of regional markets.

Hence, regional initiatives must avoid the above issues with the aim of integrating national markets into regions, in a manner which will allow the full integration of the European electricity markets. All involved stakeholders have their role in the process of creating a single electricity market.

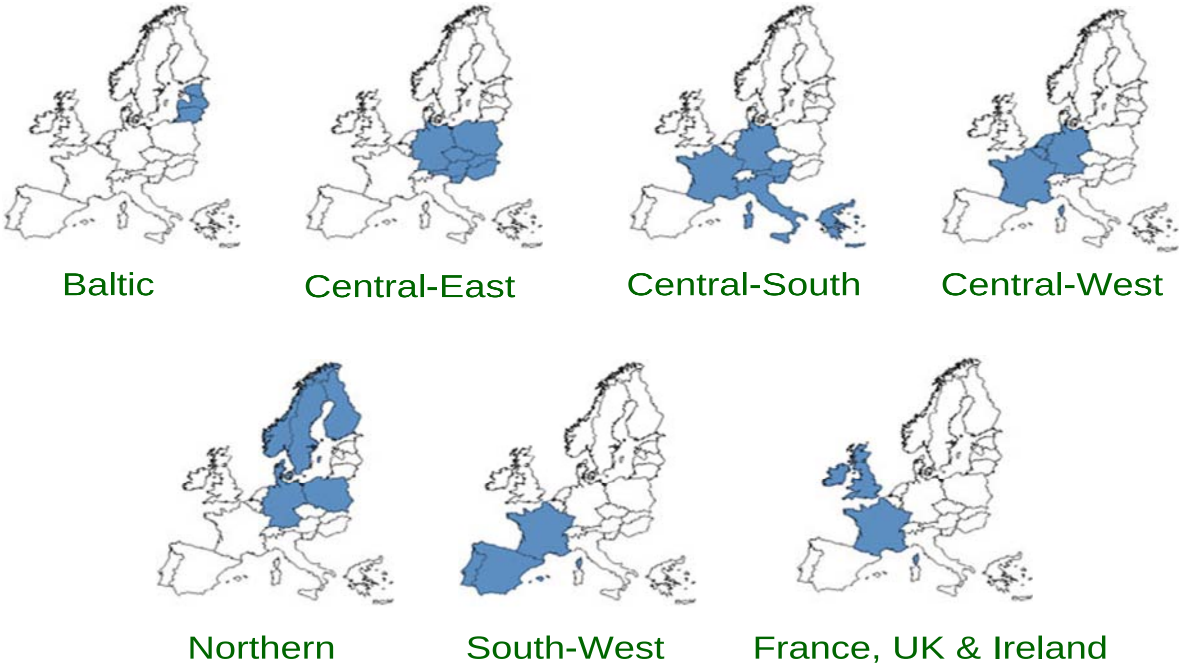
The first proposal for the composition of regional markets was formed by 7 different regions:

- Baltic States: Estonia, Latvia, Lithuania

- Central Eastern Europe: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia
- Central Southern Europe: Austria, France, Germany, Greece, Italy, Slovenia, (Switzerland)
- Central Western Europe: Belgium, France, Germany, Luxembourg, The Netherlands
- Northern Europe: Denmark, Finland, Germany, Norway, Poland, Sweden
- South Western Europe: France, Portugal, Spain
- UK and Ireland: France, Ireland, the UK

The following figure shows the regions:

Figure 1 - Alternative Definitions of Electricity Transmission Corridors



TRADE WIND's suitable regions

ERGEG is not the sole body involved in defining Regions at the European level. In this regard, Trade Wind has also defined an alternative European electricity market with the objective of wide market access for wind power. The definition of regions is based on the initial findings of ERGEG, however, due to different objectives the final selection of regions varies from the one provided by ERGEG. Therefore, the countries selected for every region are complementary to ERGEG's vision because they pay special attention to the wind power necessities.

With this view, wind power market regions are the following:

- North Sea: Belgium, Denmark, Germany, the UK, the Netherlands and Norway

- Central Eastern Europe: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia

- Central Southern Europe: Austria, France, Germany, Greece, Italy, Slovenia, (Switzerland)

- Central Western Europe: Austria, Belgium, France, Germany, Luxembourg, the Netherlands and (Switzerland)

- Northern Europe: Denmark, Finland, Germany, Norway, Poland, Sweden

- South Western Europe: France, Portugal, Spain

- UK and Ireland: France, Ireland, the UK and the Netherlands

The main differences with ERGEG's definition consist in the following: i) Austria is included in the Central Western areas due to the lack of congestion; ii) it also takes into account the transmission interconnection plans of the UK with the Netherlands and Norway; iii) the Baltic countries are not included in the study; iv) and the off-shore wind power envisaged in the North Sea is considered as a specific matter of the wind power. This is due to the fact that Trade Wind is looking for regional planning procedures for the connection of wind power to the main transmission network. This implies that the off-shore wind projects of the North Sea region require special attention because of the complexities these projects create with respect to the large amount of capacity to be connected to the main network, as well as the transmission network extensions and reinforcements to enable this wind capacity the energy withdrawal to the transmission grid.

ENTSO's suitable regions

The TSO cooperation body for planning transmission investment needs is formed by a number of European TSO Associations that attempt to map the existing regional planning procedures, methods and tools used in the assessment of future transmission planning. The existing TSO associations are UCTE, BALTSO, NORDEL and UKTSO & ATSOI, which are basically the synchronous areas currently operating in Europe. Within each association the TSOs carry out and coordinate studies for network development that is made at the association level (i.e., regional).

However, the UCTE opted to divide its region into five smaller ones in order to ease the coordination. Therefore, the regional planning groups are the following:

- Central West: Belgium, France, Germany, the Netherlands and Luxemburg
- Central East: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia and Slovenia
- Central South: Austria, France, Germany, Italy, Slovenia and Switzerland
- South West: France, Spain and Portugal
- South East: Bosnia and Herzegovina, Bulgaria, Croatia, FYROM, Hungary, Italy, Greece, Montenegro, Romania, Serbia and Slovenia
- Baltso: Latvia, Estonia and Lithuania
- Nordel: Denmark, Finland, Norway and Sweden
- ATSOI: Northern Ireland and Ireland
- UKTSO: the UK

A regional master plan is envisaged to be developed within these organisations, which will provide a list of candidate projects to be declared of European interest. Furthermore, there is also inter-regional coordination for the defined regions in order to plan the necessary interconnections between regions.

Conclusions

Hence, as it has already been shown, the definition of Regions relies heavily on the challenges. Thus, from the regulatory point of view the definition of regions is different from the wind power necessities, so that in setting a methodology for the designation of transmission corridors, the definition of regions might be different from the ones already defined with other challenges. Different challenges lead to different regions and a certain degree of flexibility is required in order to provide suitable solutions that better fit with the objectives set by the authorities.

Therefore, the definition of regions for the designation of transmission corridors needs to carefully analyse the conditions that are of special attention for this purpose. However, the initial findings of ERGEG will be adopted since the majority of agents involved in the electricity sector seem to be comfortable with this definition.

For the purpose of defining Regions three different cases have been presented as organisations that have opted to use regional areas for the internal electricity market's functioning: ERGEG, Trade Wind and ENTSO. Regions proposed by ERGEG are basically defined for regulatory purposes, while the Trade Wind's regional definition is focused on the implementation of off-shore and on-shore wind projects across Europe, and the ENTSO's regional split is based on the existing transmission synchronous networks in Europe, which also include other countries apart from the EU Member States. Thus, this indicates that the use of regional areas is commonly accepted by different associations that pursue the implementation of the single European electricity market. Nevertheless, as it was stated before, different purposes lead to the definition of different Regions, so the development of a sound methodology with the declaration of projects of European interest may be different in defining suitable Regions. Therefore, further analysis is required in order to define the most adequate Regions that fit with the selection of electricity transmission corridors.

3.1 Key aspects for defining Regions

For the gas proposed regions, the challenges are better faced within regions that connect supply and demand, and where market conditions are the most alike. As it was cited above, gas supply sources are really concentrated so that any selection of regions dealing with gas transmissions should take into consideration the issue of supply and demand.

On the contrary, in the electricity sector, the supply sources are broadly available, and the only exception might be wind power, which was analysed earlier in the Trade Wind association's definition of regions. The future off-shore wind power plants are already included in the definition of regions provided by this association. Therefore, the priority corridors are basically required by demand needs rather than supply sources, although the definition of the Trade Wind association will also be taken into account for the definition of regions.

However, supply necessities will be taken into account in order to accommodate transmission needs to supply sources (wind power) regarding the transmission investment plans identified below. This measure evaluates supply areas with respect to transmission needs.

3.1.1 Supply areas

The number of approved projects within a region implies that the interest of being integrated within this specific region is a matter of security of supply, commercial interest, reduction of the degree of isolation or solidarity or a combination of the above.

Projects planned by the TSOs basically include the major ones identified by internal TSO plans, although they may also include some others not considered in the TSOs' plans but by any other stakeholders such as TEN-E funds, other EC funds or any other interested party. Therefore, a list of projects is required in order to facilitate the regions' definition, which is essential to accommodate transmission necessities to demand requirements.

Approved projects also provide additional information on the dynamism of the electricity transmission system within a region. Significant investments in transmission corridors are basically focused on the necessity to reinforce the lack of transmission capacity for a functioning day-ahead or intra-day spot market. However, an additional type of investment is currently being prioritised by incumbent authorities, and this is the connection of isolated wind power facilities to the main transmission system. This necessity is being included in the transmission capacity expansion plans in order to promote market integration, which also includes the interconnection transmission facilities between countries. The increase of transmission capacity between countries in the mid-term must be taken into account so as to properly define the suitable regions.[2]

In this regard, Trade Wind provides a list of significant interconnectors for wind power exchange between countries, which identifies necessities of corridors for wind power integration. Interconnection projects coincide with the priority axes defined in the TEN-E guidelines. This is essential for defining regions, so a list of interconnection projects with the current net transfer capacity (NTC) and the expected development at the border, with the schedule for the expected development is provided. But, it has to be stressed that a number of the following projects is likely to be delayed.

[2] This was taken into account by Wind Trade, as already shown.

Table 1 Priority Interconnection Plans until 2020

Interconnection	NTC (MW)	Schedule
Belgium-France	1100 / 2700	Between 2010-2015
Germany-Denmark West	950 / 1500	Completed in 2012
Denmark West-Norway	950 / 1000	Scheduled for 2012
Finland-Sweden	1600 / 2000	Scheduled for 2010
Poland-Germany	1200 / 800	Scheduled for 2010 and 2013
Ireland- Great Britain	170 / 330	Scheduled for 2012
Great Britain – Netherlands	600	Scheduled for 2010
Austria – Italy	200 / 70	Between 2013 and 2018
Slovenia – Italy	330 / 120	Scheduled for 2010
Austria – Slovenia	350 /1000	Scheduled for 2009
France – Italy	2400 / 870	Not defined yet
Greece – Italy	500 / 500	Not defined yet
Spain – France	500 / 1200	Scheduled for 2010
Poland – Germany	1200 / 800	Scheduled for 2010
Czech Rep. – Germany	100 / 800	Not scheduled
Poland – Czech Rep.	1700 / 800	Not scheduled
Poland – Slovakia	450 / 450	Not scheduled
Czech Rep. – Slovakia	1050 / 950	Not scheduled
Czech Rep. – Austria	350 / 600	Scheduled for 2009
Hungary – Austria	200 / 500	Not scheduled
Hungary – Slovakia	600 / 1100	Scheduled for 2017
Austria – Slovakia	0	Scheduled for 2015
Austria – Slovenia	350 / 1000	Scheduled for 2009
Norway – Netherlands	700	Scheduled for 2008
Great Britain – Netherlands	1320	Scheduled for 2010
Germany – Great Britain	n/a	Not scheduled
Germany – Denmark West	n/a	Not scheduled
Norway – Great Britain	n/a	Not scheduled

Source: Trade Wind

The above list of transmission corridors identifies the supply sources' necessities in terms of transmission corridors for the most relevant source of supply depending on the location. Other supply sources also comply with this necessity, but the wind power construction plans are by far the most representative in Europe for the coming years.

As it can be observed, the majority of corridors may be included in one of the regions defined by ERGEG, with the exception of those corridors that connect the region referred to as North Sea by Trade Wind.

3.1.2 Demand areas

Demand areas are evaluated in perspective to the transmission necessities through each route to consumption. The idea behind the definition of suitable regions is based on the following set of rules:

- A suitable region must have enough transmission capacity within its borders. This is the necessary condition since the transmission corridors are developed to provide adequate transmission capacity. This implies that these well interconnected areas that form a Region will initially develop their own interconnection capacity more easily than those areas requiring further capacity increases with the subsequent problems that arise from this type of works, as shown by the recent European experience. However, it is obvious that several countries will form part of several Regions in order to connect the isolated countries with the remaining ones.

- A suitable region must have more cross-border trade within its borders than with the remaining countries located in other regions. This criterion shows a certain degree of isolation which is necessary to conclude that the selected countries form a region.

- Countries forming a suitable region must have a higher degree of integration in regulatory terms than the neighbour countries of other regions. It is recommended that the integration be formed by a set of common projects in transmission investments, regulatory developments and regulatory initiatives to solve differences among countries. An existing high level of coordination is an appropriate proxy to regulatory harmonization, so existing associations that include a number of countries is a strong selection criterion.

The set of rules developed above must be translated into some simple measures that may help in the definition of suitable regions. The proxy variables identified as the most appropriate to be measured in the selection of regions are the following:

- Transmission capacities in the interconnection between countries.

- Coordination level of cross border trading resulting in relevant cross-border exchanges among countries.

- Other variables:

    - Planning investments

    - Regulatory harmonisation

    - Reliability in transmission investments

    - Co-ordination and co-operation of the regulatory bodies among countries included in the regions.

Transmission Capacity

The estimation of the transmission capacity in the interconnection within a region is the most crucial aspect that must be taken into account when defining suitable regions.

Transmission capacity must be enough to provide right signals to electricity markets in order to avoid distortions within a selected region. A 10% margin is widely used, calculated as the transmission capacity over the total installed capacity which is the measure that introduces an adequate interconnection capacity. Therefore, at the beginning it would be desirable to have a minimum 10% margin to define a suitable region, which is also in line with the security of supply requirements, another objective that is included in the formation of a single electricity market.

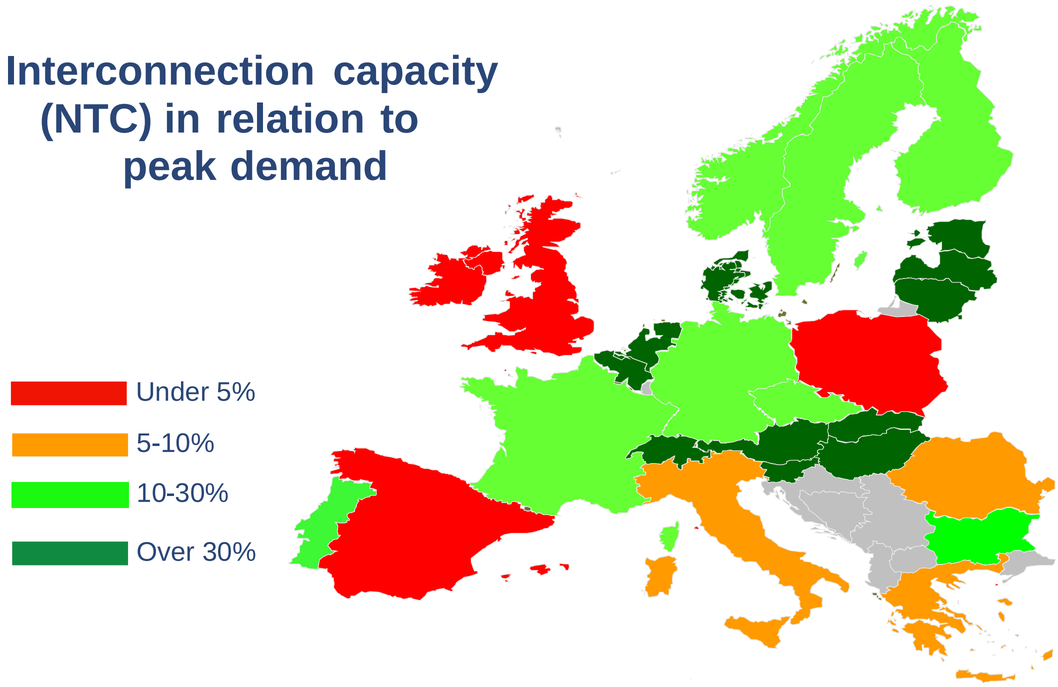
However, this percentage does not necessarily mean that 10% is the required interconnection capacity to guarantee the reliability of the transmission interconnection between two countries. From this perspective, the size of the neighbouring countries is important since the interconnection capacity of countries of similar size may be adequate with a 10% capacity, but it might be insufficient for countries with huge differences in the total electricity consumption. Therefore, this has to be taken into account.

In addition, the transmission capacity is not well defined as the actual capacity because it may depend on the system's operational mode. Furthermore, some of the available capacity may be used as reserve power. Therefore, some different measures for transmission capacity might be provided in order to properly assess the priority corridors' designation. In this sense, the most standard measure is the interconnection capacity in net terms (NTC).

Below follow an analysis of the generating capacity in the EU Member States and some other countries, and of how these countries' current state in terms of interconnection capacity. The generation capacity measure must be carefully selected so as to properly define the interconnection capacity. Thus, the appropriate measure to use is the peak demand rather than the total installed capacity or the maximum generating capacity. The former measure is more realistic under the present necessities, and so it is considered as more adequate for the operational transmission requirements. This measure is also supported by the TSO companies, which in fact consider that proper transmission planning and operations are related to the peak demand.

As a result, the interconnection capacity in terms of peak demand is shown in the following figure:

Figure 2 - Interconnection capacity



Source: ETSO and own calculation

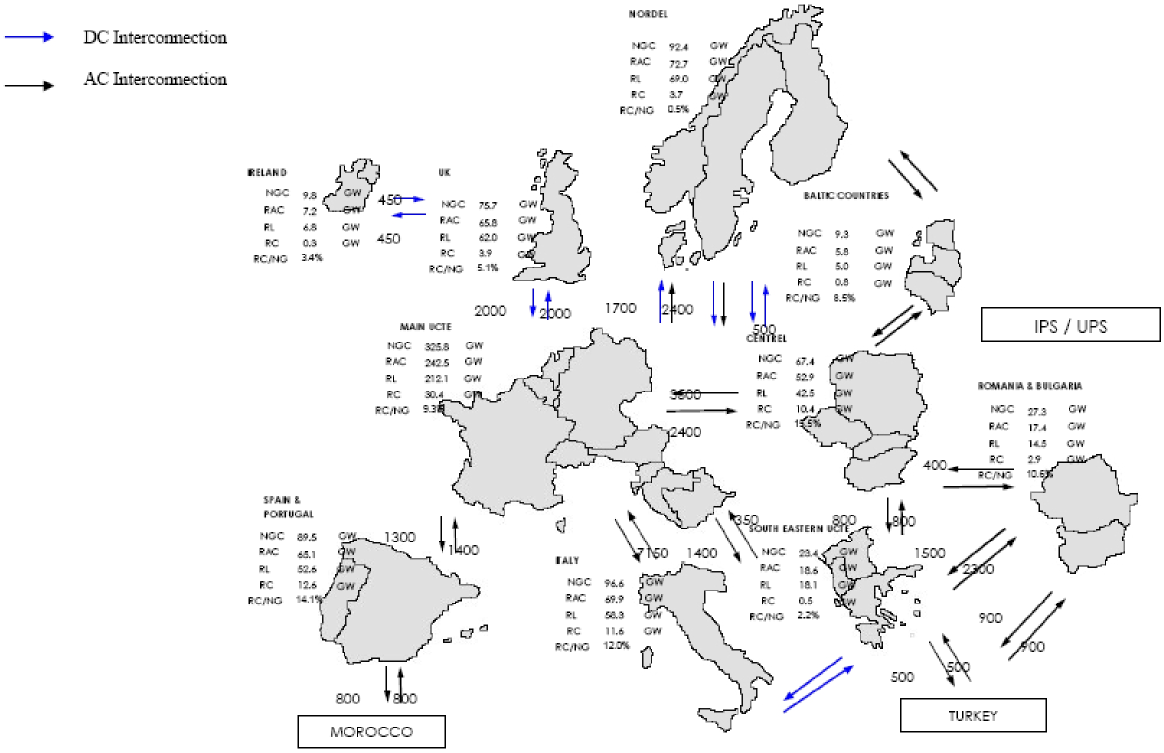
As shown above, the majority of the EU Member States have over 10% of installed capacity with the exception of the UK, Ireland, Spain, Italy, Greece and Poland. The case of Greece is ambiguous since the interconnection capacity is measured with respect to the EU Member States so that its real interconnection capacity is higher than the one shown above. However, Greece is to form part of a Region within the EU, so its transmission constraints are measured according to this criterion. In any case, Italy and Greece are not the countries with lower interconnection capacity. Regarding Bulgaria and Romania, the absence of adequate transmission capacity in Romania also characterises their interconnection capacity, although Bulgaria is not in the same situation.

The above results imply that the remaining countries are in principle in a condition to form suitable regions. However, some drawbacks show inconsistencies in the definition of large regions, as it will be commented below.

In addition, the transmission adequacy for the creation of a single electricity market is constantly changing, so a dynamic component is necessary for the definition of suitable regions. The evolution of the transmission needs is therefore required as a matter of integration of the countries into a region.

Below are some figures illustrating the transmission necessities and the generating load evolution for all European countries that are affected by the designation of transmission corridors for different years, grouped by transmission systems.

Figure 3 - Transmission System Adequacy in 2008[3]



Source: ETSO

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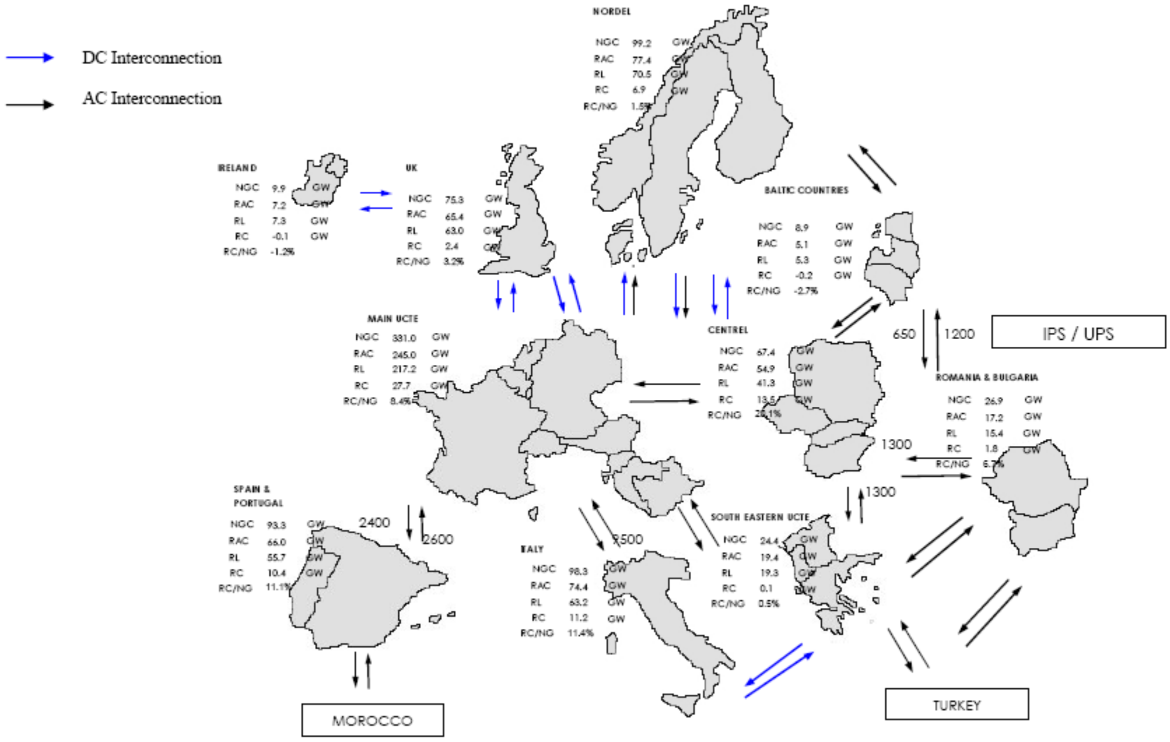
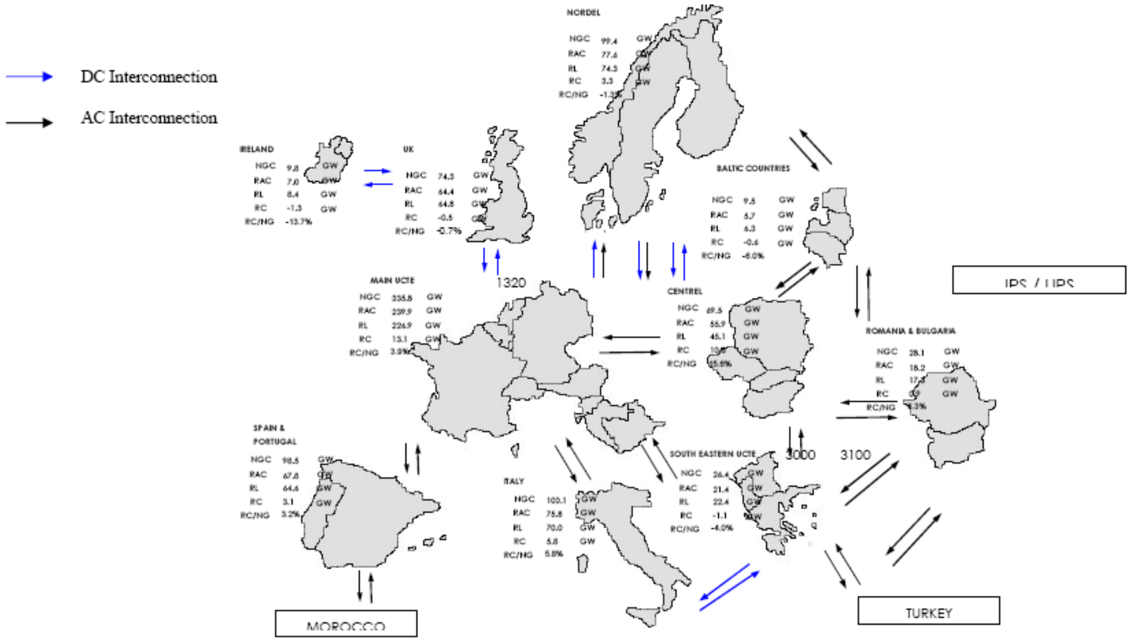
[3] "Generation Adequacy. An assessment of the interconnected European power systems 2008-2015" ETSO (May 2006) (pp 39-42)

Figure 4 - Transmission System Adequacy in 2010



Source: ETSO

Figure 5 - Transmission System Adequacy in 2015



Source: ETSO

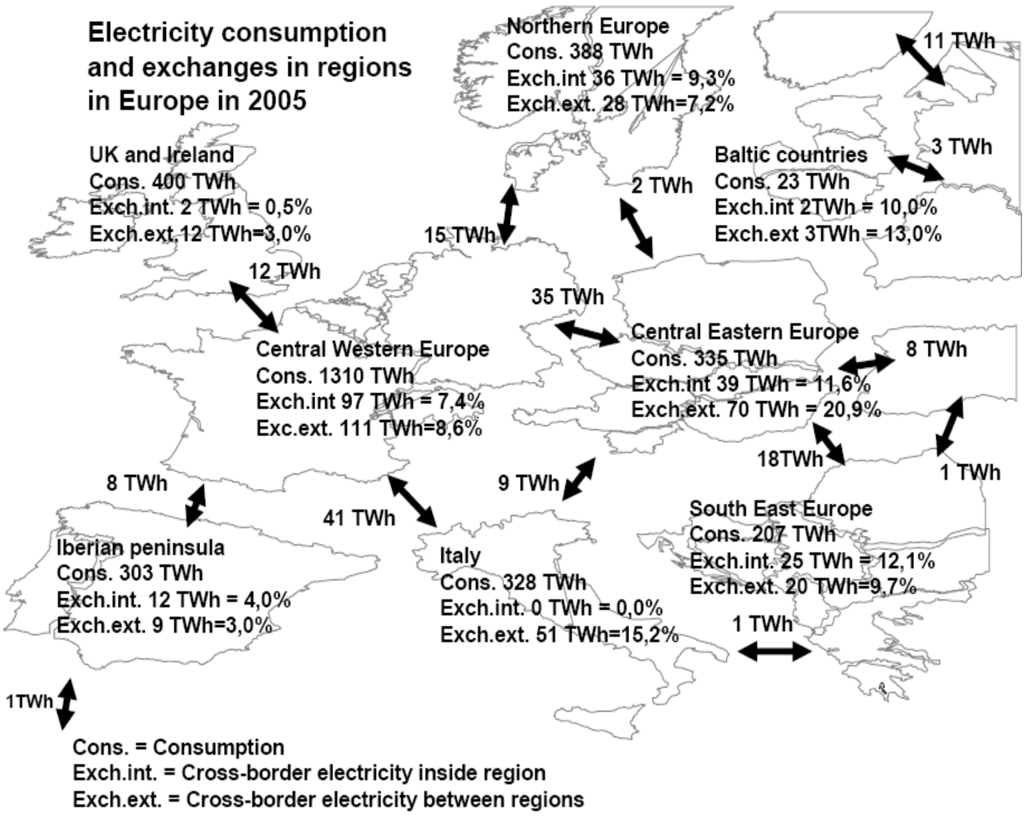
The previous figures show a preliminary view of the interconnection capacity among different transmission systems across Europe with respect to the installed capacity and the load for 2008, 2010 and 2015, in accordance to data provided by the ETSO. It can be observed how the transmission necessities increase over time all around Europe because of the demand increase. Thus, the formation of Regions is a dynamic matter and the Regions will not necessarily be the same as years go by, but a unified sole Region is the final target. In this sense, in spite of many countries having enough interconnection capacity at present, it is appropriate to consider that the reinforcement of current and future interconnections at regional level is crucial just to foster the integration of countries into regions and finally these regions into a sole region.

Cross-border Exchanges

The degree of integration between regions is characterised by the cross-border exchanges within a region, but also in comparison with other regions. Therefore, according to the following figure, the EC shows the cross-border exchanges within and among regions. The higher percentage of cross-border interchange among countries indicates a higher degree of integration and co-ordination. Therefore, these countries with lower interconnection requirements are suitable to form a suitable region. However, this does not imply that interconnection reinforcements are not necessary to improve the interconnection capacity between countries involved in the same region.

In addition, a lower percentage of cross-border exchanges between regions indicates a certain degree of isolation and lack of coordination, which limit the possibilities of grouping the involved countries within the same region. When this percentage is under 5%, the interconnection necessities are likely to be essential so as to form part of the single European electricity market. Therefore, the cross-border exchanges must provide enough information on the countries' degree of isolation and coordination within the EU. The figure below shows a set of regions presented by the EC, with cross-border flows within a number of regions that formerly comprised the historic transmission systems in Europe.

Figure 6 - Cross-border flows



Source: The European Commission

As it was shown above, the areas located at the EU borders have a lower degree of cross-border exchanges, as expected. Therefore, these areas are more likely to be defined as regions because of their isolation. In addition, exchanges also provide results referring to the level of coordination between countries, which also favours the inclusion of those countries with large amount of exchanges within the same region. As it can be observed, many of the countries are grouped according to the definition provided by the ENTSO, which are basically the different systems and the UCTE region divided into different sub-regions. This is also in line with the definition provided by ERGEG. Therefore, it seems that the regional definition provided by these organizations tends to differentiate regions by following cross-border exchanges.

Other Variables

There are other variables that need to be taken into account for the definition of regions in the designation of electricity transmission corridors. These aspects are difficult to measure, but they can provide a reliable assessment on the current status of the electricity markets' integration across Europe.

The considered variables are mainly related to the future initiatives regarding regulatory harmonisation and coordination among countries.

Regulatory Harmonisation

The regulatory harmonisation among countries is crucial for allowing the definition of a suitable region. Even though the transmission capacity is enough to guarantee the integration of two countries, the existence of regulatory harmonisation is also essential in order to avoid distortions in market prices between two countries. In this sense, the following aspects are the most important ones:

- Cross-border trading methods to address congestion. The existence of different methods applied in both sides of the borders does not provide the best signals for trading. Although this is not common in the EU, some examples exist in several countries. In this sense, significant progress has been made in integrating day-ahead markets at a regional level. The following tables depict the current situation:

Table 2 Regional Day-Ahead Markets

NAME	REGION	TYPE	METHOD	CAPACITY MODEL
Nordic market	Sweden, Finland, Denmark, Norway	Intraregional price setting	Market splitting	NTC
Mibel	Spain, Portugal	Intraregional price setting	Market splitting	NTC
TLC	France, Belgium, The Netherlands	Intraregional price setting	Market coupling (price based)	NTC
CEE	Czech Rep., Poland, Germany, Slovakia	Explicit	Explicit coordinated auction based on technical profiles	NTC

Source: ETSO and EuroPEX[4]

[4] "Development and implementation of a coordinated model for regional and inter-regional congestion management. Interim Report" ETSO and EuroPEX (April 2008) (p. 13)

Table 3 Inter-regional Day-Ahead Proposals

NAME	REGION	TYPE	STATUS	METHOD	CAPACITY MODEL
EMCC	Sweden, Finland, Norway, Germany	Interregional flow setting	Planned 2008	Market coupling (tight volume based)	NTC
CWE	France, Belgium, Germany, the Netherlands	Intraregional price setting	Planned 2009	Market coupling (price based)	Flow based

Source: ETSO and EuroPEX

- The emerging situation at present is of discrete regional day-ahead arrangements with capacity between market regions allocated using explicit auctions. On the basis that implicit auctions are generally superior to explicit auctions in terms of outcomes, the key issue is how to establish an integrated European market using implicit auctions. Following, three options are described.

    - Intra-day congestion methods and balancing also offer a greater degree of integration among countries within a region. The Nordic countries, the Iberian market and the French interconnections offer this possibility. There is a number of design options that allow for this possibility that minimises the balancing actions required in real time.

    - Tariff methodology for access to the interconnection. Different countries applied different methodologies for tariffs, so that consumers may be supporting other items not directly related to the electricity sector, such as the nuclear moratoria or subsidies to coal. Alternatively these electricity markets may be subject to costs, such as the stranded costs of liberalised markets that might provide wrong signals for the economic incentives of integrating countries within a region. Other aspects, such as the inter-TSO compensation are also being analysed by regulators. All these aspects must be taken into account as well.

    - Locational signals. These signals influence the generation dispatch, so that distortions may arise in the market. In addition, the existence of different nodal or zonal prices may also distort the functioning of the markets, thus decreasing the degree of integration.

The divergence among the above mentioned regulatory aspects may distort the proper market mechanisms functioning across countries, which reduces the possibility of defining regions for the designation of transmission corridors.

As it can be observed, the regional initiatives are still under implementation; however a certain degree of integration is being reached. In this sense, the regional initiatives for regulatory harmonisation basically match with the regional definition proposed by the associations mentioned before.

Co-ordination and Co-operation of the Regulatory Bodies

At present, seven different regions have been defined by ERGEG, which implies that some coordination within each defined region is being developed. Therefore, a certain degree of cooperation and coordination at this stage is envisaged for these regions. Each region has also identified its priorities in terms of convergence and a calendar for integrating countries within regions is also scheduled.

In addition, the European Commission and several stakeholders are also involved in the development of these regions. Priorities so far have been focused on the following ideas:

- Congestion management methods. Most of the work is being carried out in this area. As it was shown above, the congestion is widely spread across the EU countries with few exceptions.

- Transparency. The legal framework of every single electricity market is crucial for the coordination of regions.

- Balancing. The integration of countries within a region relies heavily on the balancing services. These initiatives require a big effort in terms of coordination and cooperation.

- Regulatory issues. Avoiding gaps and different market designs hamper the integration of regional markets.

These initiatives are well-known within regions, so that it is likely that other initiatives will be launched from these working groups.

3.2 Proposed Regions

Coupling demand and supply in single regions will allow stakeholders within each region to optimize on an appropriate socio-economic optimal level. Furthermore, it will allow for all the affected parties in each project to get involved in the process.

Priority projects should be analysed economically, taking itno consideration economical aspects and implications in the whole of the regions, because changing supply is bound top affect all stakeholders between the initial supply point and the end demand point.

Regions need to be defined in accordance with the aspects described above, once the selected criteria for the designation of transmission corridors in the EU have been decided..

The previous chapter of this electricity section showed the relevant aspects for the regional definition process. It has also been shown how associations have defined their regions and the underlying reasons for this proposal. Thus, a number of conclusions may be drafted from the previous analysis for selecting electricity priority corridors.

The initial criterion stems from ERGEG's findings, however further analysis regarding suitable regions has been carried out in order to comply with the designation of electricity transmission corridors. As it was mentioned above, some differences arise regarding the ERGEG's purposes in the definition of regions that do not fully comply with the needs of electricity transmission corridors. This is due to the fact that a number of aspects differentiate the purpose for defining regions:

- ERGEG's regions comply with a certain degree of harmonisation, coordination and cooperation regarding regions development. However, regional selection does not take into account the supply concerns, especially from the perspective of renewables use.
- Central Europe is reasonably well interconnected at present, but some regulatory divergences impede the definition of a sole region.
- The supply areas must also be taken into account. In this regard, the Trade Wind's definition of regions is positive.
- A number of transmission projects are currently launched for the following years (with different degree of accomplishment), which indicates a certain degree of cooperation and coordination.
- New Member States must be also included in the definition of regions.

Hence, following the key aspects described above, the following may be concluded:

- Three different associations have made their own regional definition with different purposes. However, these three associations are involved in the creation of a single European electricity market. In this regard, the regional definition is quite similar in terms of number of regions and countries involved in them. Minor differences have arisen from this perspective so the regional definition for the declaration of projects of European interest for electricity can not differ significantly from this point of view.
- Regarding the supply areas' analysis, it may be concluded that due to wind power necessities currently arising at the European level the Trade Wind regional definition is the one that better fits with the purpose of declaring projects of European interest. Furthermore, the additional region defined by the same organisation, compared to ERGEG's one, has to do with the large number of interconnection projects that are likely to be developed for the connection of new wind power capacity. This is relevant since the

coordination of all these new projects is encouraged by the latest technological approach that comprises the off-shore wind projects and their electricity injection into the main network. To this end, the regional coordination of the main region involved in that purpose, the North Sea region, might be extremely helpful.

- Regarding the demand areas' analysis, three different approaches were used in order to evaluate the best regional definition for matching electricity demand by using new interconnection capacity. From this perspective, the transmission capacity analysis showed that current electricity interconnection capacity is good enough in many EU countries, where the main lack of interconnection capacity is located in the EU bordering countries, more specifically islands and Southern countries. Therefore, it seems that many EU countries could be grouped into a single region with the exception of those countries with inadequate interconnection capacity. Nevertheless, the increase of demand necessities has to be taken into account because of the additional interconnection necessities that will take place in Europe in the following ten years.

- Also, regarding the demand areas' analysis, it can be concluded that from the point of view of cross border exchanges many countries interchange less than 5% of their electricity with other regions. In this sense, the ENTSO's definition is the one that better fits with the cross-border exchanges.

- Finally, with respect to the latest variables analyzed to comply with demand needs in the declaration of projects of European interest, the regulatory harmonisation and the co-ordination and co-operation of regulatory bodies show that the regional definition that better fits with these two purposes is the one provided by ERGEG.

Thus, once the supply and demand necessities have been analyzed, it is concluded that the three different regional definitions provided by Trade Wind, ERGEG and ENTSO are in line with the key aspects that comprise the regional definition. However, while Trade Wind better fits with the supply requirements, ERGEG and ENTSO are more in line with demand requirements. This implies that ERGEG's regional definition is to be considered as the basis for regional definition; however the large number of new interconnection projects envisaged for the following years regarding the off-shore wind project, a new region is added for the North Sea region. In addition, the last two Member States have also been included into a new region. Furthermore, because of the large number of interconnection projects within Austria, this country is included into three different regions, the Baltic countries also include their neighbour countries (i.e., Poland and Finland), while the UK & Ireland region also includes the Netherlands because of sea projects planned at present and in the future.

As a result of the above comments, the following nine regions are proposed in the first phase:

- North Sea: Belgium, Denmark, Germany, the UK, the Netherlands and (Norway). This region tries to coordinate the supply requirements (wind power) on transmission needs. Sweden and Finland might also be included since the interconnection in these countries is quite good, but in order to avoid excessive number of actors involved in the designation of corridors the number of countries is decreased.[5]

- Central Eastern Europe: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia. Although the interconnection capacity among new Member States is generally adequate, certain degree of harmonisation and coordination is required before joining a larger region (through the CEE alternative).

- Central Southern Europe: Austria, France, Germany, Greece, Italy, Slovenia, (Switzerland). This region is the axe that must connect Greece and Italy with the central western countries of the EU.

- Central Western Europe: Austria, Belgium, France, Germany, Luxembourg, the Netherlands and (Switzerland). The creation of the TLC market favours the definition of this region, which must be enlarged with other regions once the conditions are favourable.

- Northern Europe: Denmark, Finland, Germany, Norway, Poland, Sweden. Nordpool and the well interconnected areas favour the definition of this region that must be enlarged with other regions once the conditions are appropriate. In addition, this region is also proposed for fostering the integration of the wind power plans into the electricity market.

- Baltic countries: Latvia, Estonia, Lithuania, Finland and Poland. The proposed interconnection projects of the Baltic countries with Finland and Poland must integrate the Baltic countries with the neighbouring areas once the regulatory harmonisation allows for that.

- South Western Europe: France, Portugal, Spain. The creation of MIBEL ensures regulatory harmonisation, but the low interconnection capacity with France reduces the possibilities of interconnecting the Iberian Peninsula with Europe in spite of the transmission projects that are already planned.

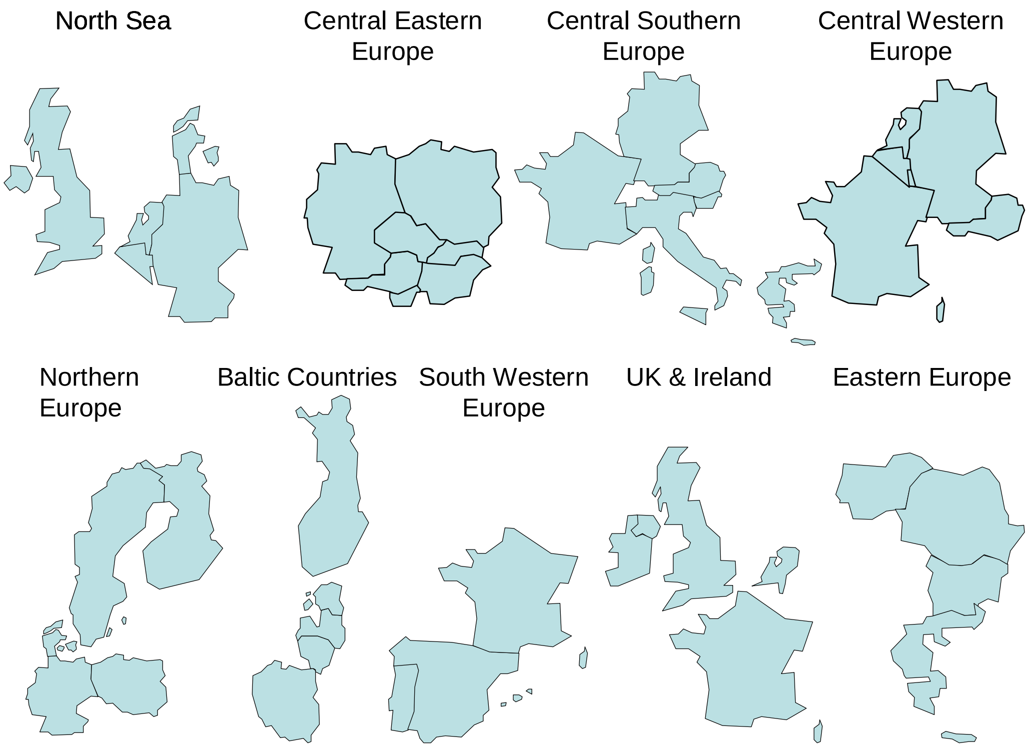
- UK and Ireland: France, Ireland, the UK and the Netherlands. The isolation of the two islands reduces the possibility of designating transmission corridors. Belgium could be included in the regions, but following the same criterion as above (avoid excessive number of actors) it is excluded.

[5] However, through their own region's proposals, these countries might also translate their own concerns on transmission needs regarding supply areas evolution.

- Eastern Europe: Greece, Hungary, Romania and Bulgaria. The two new member states are also included. Their interconnection capacity is weak and Greece and Hungary need to be included in order to accommodate the transmission capacity to the creation of a single European electricity market.

The next figure illustrates how the regions would be formed:

Figure 7 - Proposed regions



In a second stage, after the first interconnections have been developed and a certain degree of regulatory harmonisation is reached in order to couple supply and demand across different countries, the suitable regions are likely to be the following:[6]

- Central Eastern Europe: Austria, Czech Republic, Denmark, Finland, Germany, Norway, Hungary, Latvia, Estonia, Lithuania, Poland, Slovakia, Sweden. Although the interconnection capacity among new Member States is generally adequate, certain degree of harmonisation and coordination is required before joining a larger region (through the CEE alternative).

- Central Western Europe: Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Italy, Slovenia, (Switzerland). This region is the axe that must connect Greece and Italy with EU's central western countries.

[6] This should happen around 2014

- South Western Europe: France, Portugal, Spain. The low interconnection capacity with France reduces the possibilities of interconnecting the Iberian Peninsula with Europe in spite of the adequate market integration. Therefore, additional interconnection capacity is likely to be necessary.

- UK and Ireland: France, Ireland, the UK and the Netherlands. The isolation of the two islands reduces its possibility for the designation of transmission corridors, but a more active role of the stakeholders must allow the countries to form an integrated market.

- Eastern Europe: Greece, Hungary, Romania and Bulgaria. Their interconnection capacity is weak and the necessary development of liberalisation and market functioning takes time. Thus, further measures are necessary to foster the integration of these regions in the integration of the whole countries.

The suitable regions will be formed by two main blocks comprising the Eastern and Western European countries and the isolated regions that consist of the latest member states.

By 2020, all countries should be integrated into a common system in order to designate projects of European interest to form a single electricity market. In this sense, the regulatory harmonisation will play an important role so as to facilitate the integration of the European electricity system.

3.3 Proposed stakeholders to be involved in the regions

However, the authorities are not the only stakeholders that play an important role in the designation of transmission corridors, but transmission system operators and market participants are also active in this process. Thus, before defining suitable regions there is a preliminary stage in which the role of the agents needs to be analysed so as to accommodate their role to the final purposes.

A number of agents are involved in the construction of electricity transmission corridors. All these agents have different roles in the designation of electricity transmission corridors through suitable regions, so that the objectives of the involved agents may differ significantly across countries by applying different mechanisms of influence in the decision-making process. The agents are as follows:

- National governments

- Energy regulators

- Transmission system operators

- Electricity market participants

As mentioned in the previous section, a number of obstacles hamper the integration of electricity markets, and therefore all involved stakeholders have their role in removing these potential barriers. In order to comply with the designation of corridors in suitable regional markets, every involved party in any specific regional market has to address a series of problems that are presented below for every stakeholder category.

Transmission System Operators (TSO)

TSO companies are among the most relevant stakeholders involved in the designation of electricity transmission corridors as a primary step to the integration of electricity markets. The TSOs' main tasks are those related to the planning and system operation activities for the electricity transmission system, some of them being directly involved in all these aspects that affect the regional market integration. Their tasks are the following:

- Congestion Management. Includes e.g., congestion management methods, capacity calculation methods and models applied, coordination issues, transparency, congestion income issues.

- Balancing Market. Includes e.g., technical requirements for balancing power, balancing mechanism (balancing and settlement), integration of balancing markets, interaction with automatic reserves and intra-day markets.

- Common Market Rules. Includes e.g., market design, interaction between different markets (e.g., day-ahead, intra-day, balancing), power exchanges.

- Inter-TSO Compensation. Includes e.g., definition of cost base (existing and future grid, losses), method to calculate compensations and payments.

- Tarification. Includes e.g., harmonisation of tarification, tarification of generation and load, tarification structure.

- Operational Security. Includes e.g., operational planning; planning tools, data exchange, security criteria; transmission capacity calculation; network operation (reserve requirements, maintenance, frequency, voltage, real-time data exchange, disturbance handling, remedial actions); cooperation, coordination and communication between TSOs; restoration (plans, testing); training; roles and responsibilities.

- Connection. Includes e.g., general connection requirements for generation (including distributed generation), consumers and DSOs (technical compatibility), voltage and frequency quality.

- Grid Planning. Includes e.g., requirements for joint planning, scenarios for planning, timeframe, information exchange between TSOs, planning criteria, security criteria, planning tools and models, update of investment programme.

- Information Management and Transparency. Includes e.g., information on load, grid, generation, balancing market, power exchanges, OTC market and retail market.

Only few of the above functions are directly related to the designation of transmission corridors because the remaining activities are more focused on the the transmission system's day-to-day activities. Hence, for this purpose only those activities related to planning are relevant for the designation of transmission corridors at the EU level. It is therefore crucial to take into account only those activities that affect the designation of transmission corridors in order to avoid distortions in the process, and to implement the necessary mechanisms that allow for that.

In this regard, the planning activities, and therefore the planning departments of the TSO companies, are the ones involved in the designation of the transmission planning and the of transmission corridors.

National Governments and Regulators

National regulators, both governments and regulatory bodies, need to develop compatible and complementary competences in order to integrate the European electricity markets, first at regional level and then into a single market. Therefore, legal conditions may be enhanced with the aim of facilitating the market integration, especially regarding cross-border regulation.

Different powers are envisaged for governmental and regulatory agencies across countries that at minimum are required to implement the EU legislation. Effectively, the regulatory bodies are required to be independent from the industry's interest, which does not imply that the regulatory functions will be separate from the existing government structures. In general, the regulators are in charge of ensuring non-discrimination and monitoring competition and network regulation. Regarding the interconnection, main roles are monitoring of management and allocation of interconnection capacity, interconnection operation and maintenance, information provision, competition, transparency and system operation.

The European Directive 2003/54/EC and Regulation 1228/2003 on electricity set that the regulatory bodies must:

- Establish the total transfer capacity

- Decide on exemption to normal access rules for new investments

- Ensure compliance with binding regulation

- Cooperate to meet regulatory requirements
- Decide on cross-border disputes

However, some regulatory gaps may arise as a result of the differences in competences between two different countries and the authorities involved in any cited process. Therefore, these gaps may impede regional electricity integration through the designation of electricity transmission corridors. So, it will be desirable that regulatory decisions also take into account the interests of electricity agents located at the other side of the border. To do that, information exchange is also required so as to take appropriate decisions.

Hence, the regulators must comply with the following competences in order to provide a good framework for the European corridors' construction:

- Include foreign interests in the designation of European corridors concerning transmission investments and infrastructure.
- Cooperate and coordinate the transmission interconnection decisions by means of information exchange, joint technical and economical analyses and effective decision process.

But, the disparities regarding the national regulatory bodies' powers across the EU cannot be avoided, which reduce the role of many independent regulatory bodies just to provide opinion on many of the concerns related to the designation of transmission corridors. Moreover, national governments are in many cases in charge of the designation of final transmission routes, which endanger the viability of any project in the terms required by the EU because of the inclusion of political interests in the final decision process.

The latest regulatory package launched by the EU envisaged the creation of a regulatory body to assess these investments that may play an important role in the designation of transmission corridors. However, at the end of the day the major part of the responsibility in this regard lies on the local/national authorities so that open and transparent mechanisms are required in order to properly comply with the creation of a single electricity market. In this sense, the regional initiatives may be positive for improving coordination and developing regulation in the interconnection activity across countries.

Electricity Market Participants

The interest of the electricity market participants in the designation of European Corridors is twofold: economic objectives for electricity agents (i.e., generators) and supply and route concerns for electricity customers. Therefore, electricity market participants affected by the expansion of new interconnection capacity are in favour of the new infrastructure only if this is profitable for their interests (in terms of generation or consumption), which does not necessarily mean that the projects are viable from the interests for the creation of a single electricity market. On the contrary, customers might be against the expansion of new interconnection capacity although it could be appropriate for the creation of a single electricity market.

In this sense, priority corridors are fostered to increase trading among electricity agents by means of increasing the interconnection capacity. However, some obstacles may hinder the proper functioning of the electricity agents' commercial interests. These obstacles may be related to the regulatory measures adopted by the regulatory agents or regulatory procedures followed by the agent in charge of the interconnection, which may hamper the proper functioning of the market. The type of measures is related to the existence of implicit/explicit auctions, the balancing market rules, the tariff methodology, etc.

However, some additional market failures may impede the functioning of priority corridors, so that electricity market agents may have anti-competitive behaviour which might hamper the region's appropriate design. This type of behaviour might be strictly observed by the regulatory bodies.

Additionally, many electricity market participants may be involved in more than one regions, since the electricity players tend to be globally located across European countries. This is important because many players will have a wider view of the problems that may arise in connecting countries or regions. Therefore, their experience is highly valuable for the sake of the single electricity market at the EU level. It is therefore recommended not to avoid the participation of these agents in the decision-making process for transmission corridors.

Regarding electricity customers, it is important to include their needs in terms of electricity supply, but it is also relevant to consider their capacity to block the construction of eligible transmission corridors.

Conclusions

In summary, it is crucial that all involved stakeholders in the designation of electricity transmission corridors through suitable regions play a role in order to avoid issues once the EC designates an electricity corridor. The next chapter provides further details on more specific aspects related to stakeholders.

4. Electricity Stakeholders

As it was already mentioned, in order to provide for a better planning and subsequent quicker implementation of priority energy projects, it is necessary to conduct a stakeholder analysis to, first of all, identify and, consequently, assess the influence of the different stakeholder groups with an interest in the project.

The primary objective of the stakeholders' analysis is to identify and compile relevant information on the groups and organisations that have an interest or stake in a given project/policy. This information can be used to provide input for other analyses; to develop action plans; to increase support for a project; and to guide a participatory, consensus-building process.

Four major attributes are mentioned as relevant for Stakeholder Analysis: the stakeholders' position on the project, the level of influence (power) they hold, the level of interest they have in the specific project, and the group/coalition to which they belong or can reasonably be associated with. These attributes are used to provide a detailed list of stages in which electricity stakeholders take part.

The project's life cycle for electricity priority corridors is the same as those already analysed for the gas projects. Therefore, this chapter mainly deals with the presentation of the main stakeholders involved in priority projects, their functioning, and finally a stage list of the role of the actors in order to assess how the process could be improved.

4.1 Presentation of diff. stakeholder groups and their function during the diff. project stages

In the tables below the main stakeholders are grouped and their functions are provided. As illustrated in the complexities of the electricity sector regarding stakeholders is at the same level as in the gas sector.

Table 4 - Presentation of Main Stakeholder Groups for Electricity Projects

Stakeholder Group	Definition	List of Possible Stakeholders (Examples)
Supra-Nationals	An international organisation, or union, whereby member states transcend national boundaries or interests to share in the decision-making and vote on issues pertaining to the wider grouping	• United Nations (UNECE) • NATO • IEA • OECD • EU

Associations	An organised body of people/entities who have an interest, activity, or purpose in common	• UCTE • European Energy Forum • ETSO • CIGRE • CENTREL • NORDEL • EUROPEX • EURELECTRIC • Pentalateral Energy Forum
Regulators	A body or agency, which ensures compliance with laws, regulations, and established rules	• EU (ERGEG, CEER) • National (Energy agencies etc.)
Authorities	A public agency or corporation with administrative powers in a specified field	• Legal authorities • Ministries of Environment and Climate • Ministries of Transport and Energy • Ministries of Trade and Industry • Ministries of Foreign Affairs • Financial institutions in Member States and Candidate Countries • Donors (EIB, EBRD, EU etc.) • Governmental Institutions/Regional Authorities
Public/Private Enterprises		• Transmission System Operators (TSOs) • Distribution System Operators (DSOs)

		• Electricity companies
Others		• NGOs (environmentalists) • Non-profit organisations • Local Communities/Municipalities/ Residents • End users/consumers

Table 5 – Main stakeholder functions

Stage	Stakeholder Group	Stakeholder Function
Policy	Supranationals Authorities Regulators Associations	Provide policy guidelines Implement policy guidelines Supervise the implementation Make proposals
(De) regulation	Authorities Regulators Public/Private Enterprises	Approval Make proposals / approval Make proposals
Decision-Making	Supranationals Authorities Regulators Public/Private Enterprises	Provide guidelines Approval Make proposals Make proposals
Planning	Authorities Regulators Public/Private Enterprises	Approval Make proposals / approval Make proposals
Permitting	Authorities Others	Approval Approval
Construction	Public/Private Enterprises	Financing

	Authorities Others	Supervising Financing
Operation	Regulators Public/Private Enterprises	Supervision Operation
De-Commissioning	Authorities Public/Private Enterprises	Approval Operation

The stakeholders' role has already been analyzed in the gas stakeholder's analysis through an example of the Nord Stream Case Study. The main conclusions that arise from the study show the importance of the role of stakeholders involved in the decision-making process in the designation and construction of an energy priority corridor. The issues of the electricity sector can be extrapolated in general to those presented in the gas case study.

4.2 Sub-conclusion – Stakeholder Map

The gas stakeholder analysis provided stakeholder categories with a number of attributes that also included a number of stakeholder maps for different phases in which stakeholders have an important role. These phases, i.e., planning, permitting and construction, were divided into power and interest, showing the degree of influence that stakeholders may have in the decision-making process.

As a result, the participation of stakeholders must be organized not only for regulatory bodies but also for TSOs and market participants. The active role and coordination of all those involved parties is crucial for the proper functioning of the designation process of eligible transmission corridors.

In this regard, the three phases involved different actors that must participate in the process. For the electricity sector more specific mapping of the stakeholders' role is considered. Therefore, it is proposed that in the whole project selection process the agents involved participate in the different stages. This participation could be divided into six stages:

- Stage 1: preparatory. During this stage stakeholders (not only regulators, but also consumers or generators) of each defined suitable region should:

    - Provide candidate projects, with information calculated with a common methodology

    - Provide relevant information in order to obtain a first assessment.

    - Discuss constraints, especially regading transmission permissions and environmental impact assessment.

- Stage 2: once an agreement is reached on the above issues, the planning process should be developed by technicians. During this process other projects could be identified. This planning process will be developed in two steps:

    - Regional level

    - EU wide

  The methodology to establish how these two geographical scopes will interact is the one proposed previously.

- Stage 3: discussion of results by stakeholders and technicians. Decision on the projects that will be developed at feasibility level. In this stage, a multi-criteria analysis (MCDM) can be used in order to include other aspects that may be considered of relevance that could not be included in the planning process stage. Under this approach, further factors (other than those in monetary terms) may be weighted so as to take them into consideration.

- Stage 4: feasibility studies of the selected projects will be carried out by the Evaluation Committee in compliance with the regulatory bodies and the TSOs.

- Stage 5: decision on the projects to be developed. If some projects are considered unfeasible, the planning process should be repeated, and then stages from 1 to 4 will be repeated as well.

- Stage 6: based on benefits and geographical scope, some projects are nominated as “EU priority corridors” (or of “European Interest”).

After stages 2 and 5, a technical record of each selected project would be developed, as the necessary output to coordinate the whole process.

A report will finally describe the impact on the whole EU and the defined suitable regions of the selected projects.

It must be pointed out that the key player among stakeholders in the declaration of electricity priority corridors is the TSO, although all stakeholders are relevant and necessary for this process. The TSO’s role in prioritizing investments is crucial since it is usually involved in all the stages already defined. Therefore, in order to provide more detailed analyses on the role of the TSO the following sections elaborate what the TSO’s contribution for declaring projects of priority interest has to be in terms of planning, use of methodology and elaboration of feasible studies. Furthermore, the role of other stakeholders is also analyzed so as to provide a global vision of the priority projects process.

4.3 TSO's contribution to priority projects

As a result of the report titled "TSO's contribution to a procedure for prioritized European grid investments"[7] (ENTSO report hereinafter), which proposes a procedure oriented to enable coordinated electricity network planning at regional and European levels and leads to a common approach for the selection of the projects of European Interest, first between TSOs and then with the other involved parties (regulators, national administrations, EC), it is necessary to have an in-depth look regarding the TSOs' role in all the stages previously defined for the declaration of a project of European interest in electricity transmission.

Particularly, the ENTSO report compares the methods and procedures described in the TSOs' documents against the recommendations of the Priority Corridors studies.

4.3.1 Scope of Planning

The European power system is described as a combination of electrically synchronous regions that are asynchronously interconnected with the continental Europe. The existing regional TSO associations cover the synchronous regions as follows:

- UCTE: The synchronous area(s) covering the majority of Central, Western and Eastern member state networks in the continental Europe and also several non-member state networks. UCTE includes the following sub-regions:
    - Central West : Belgium (BE) - France (FR) - Germany (DE) (NL) – Luxemburg (LU) - The Netherlands (NL)
    - Central East : Austria (AT) – Czech Republic (CZ) – Germany (DE) – Hungary (HU) - Poland (PL) – Slovakia (SK) – Slovenia (SL)
    - Central South : Austria (AT) - France (FR) – Germany (DE) - Italy (IT) – Slovenia (SL) - Switzerland (CH)
    - South West : France (FR) – Portugal (PT) – Spain (ES)
    - South East : Bosnia and Herzegovina (BA) – Bulgaria (BG) - Croatia (HR) – FYROM (MK) – Hungary (HU) – Italy (IT) - Greece (GR) – Montenegro (ME) – Romania (RO) – Serbia (RS) - Slovenia (SL)
- BALTSO: The synchronous area(s) covering the Baltic state networks. Asynchronous connection with the Nordic networks.

[7] ENTSO, July 2008

- NORDEL: The synchronous area(s) covering the Nordic state networks (including Norway). Both synchronous (Western Denmark) and asynchronous connections to continental Europe.

- UKTSOA & ATSOI: The two synchronous areas (asynchronous to mainland Europe and to each other) formed by the UK and Ireland.

The TSOs propose a two-level approach to planning. The first level is performed by each of these regional organisations. A regional master plan is being worked out and a list of candidate projects for European interest is identified.

The second level would be the inter-regional coordination, i.e. coordination at the borders of the associations. The inter-regional coordination would be organized by having inter-regional meetings of the associations or the neighbouring TSOs.

The outcome of the regional and interregional TSO procedures will be finally coordinated within the ETSO (in the future ENTSO). Coordination at European level aims at ensuring consistent planning quality and logic of the regional and interregional procedures and identification of the added values from the European perspective.

This approach is consistent with the proposed methodology developed in this study in this section, mainly the regional approach to allow working with smaller regions that was previously discussed, and then to coordinate the results of all the regions in order to identify the EU priority corridors.

In this respect, the conclusions included in this section establish that the coordination procedure should be systematised, in order to allow obtaining the optimal alternatives at EU level with (almost) the same degree of accuracy as at regional level.

A second issue to be considered is the feedback of the projects selected at the EU level to correct the regional master plans.

4.3.2 Methods and tools used in the regional processes

The methods and tools that are currently being planned in the regional processes for the identification of priority projects are described in the following paragraphs by analyzing the different alternatives used by the ENTSO members.

Nordel

Description of the Methodology

Grid investment assessments are conducted using a common multi-area simulation model available for all Nordic TSOs.

The national input data are delivered by the TSOs based on estimated changes for the generation park and the demand. The planning period is normally about 10 years ahead. The ongoing study covers the years 2020-2025.

The simulation model integrates the electricity market simulation with load-flow analyses. The model is especially developed for a hydro-dominated power system, using the water value concept. The Nordic power system is divided into 17 areas and transmission capacities between these areas are included in the model. The neighbouring markets are also included in the simulations using more simplified models. Market simulations are based on water value calculations and an assumption that the generators are activated in merit order.

The assessment criteria when comparing different investment projects can be grouped into three categories:

- The technical criteria based on security standards according to the Nordel Planning Code; N-1 dimensioning rule being one of the key indicators. The technical criteria are a check rule. The criteria have to be fulfilled in all cases.

- The impact on the market's functioning i.e., on the congested hours, congestion fees or the possibility to exercise market power. The impact on the market is calculated as congestion fees. TSOs consider that it is very difficult to make a quantitative analysis on how grid reinforcements impact the possibility of exercising market power. A potential market power problem cannot be solved by grid investments only.

- The socio-economic benefit of new transmission reinforcements including reductions in CO_2-emissions. Nordel has identified several indicators for an analysis of the socio-economic benefits due to transmission capacity expansions. The analysis is made at the Nordic level utilising a common simulation tool and a common data base previously described.

    - Reductions of the marginal generation costs and changes in consumer benefits including the effect on CO_2-emissions and changes in congestion rents

    - Reduction of transmission losses

    - Reduced risk of power shortage

    - Reduced risk for energy rationing

    - Reduced costs for regulating power and ancillary services

The first two socio-economic indicators are assessed as a result of two simulations; with and without reinforcement. The remaining indicators are assessed separately using other tools.

Comments

The approach using a simulation model is consistent with what it is so-called in the following chapter steps 2 (simulation) and 3 (power system studies) in the Alternative 1.

However, this methodology is only useful for assessing a few projects, mainly using the "with and without" approach. When there are several candidate projects, some of them exclusive (i.e., the development of a project makes unfeasible the other) or supplementary (the benefits of a project depend on the development of another project), the use of simulations becomes impossible due to the large number of cases that would need further analysis.

Therefore, in the general case a least cost planning model becomes crucial to identify the optimal alternatives. The simulation model in conjunction with power system studies (load flows, stability, etc.) should be used to analyse the detailed functioning of the optimal solution. Furthermore, an expansion plan that allows identifying the benefits of a project during its entire life is beyond the horizon for which the generation expansion is known due to expansion models also provide a suitable expansion for the generation.

A second comment refers to the objective function. It would be desirable that the selection criteria be the increase in the social welfare, or, if demand is considered inelastic, to minimise the incremental costs to meet the forecasted demand. These costs should include the social costs produced by the expected unsupplied energy. Under this approach the objective function will include most of the evaluation items described above: reduction in generation costs, losses, congestion, risks of power shortages and reduction of CO2 and pollutants emissions (this may be a model constraint). An appropriate estimation of the social welfare or cost to meet the demand requires a probabilistic approach, taking into consideration the relevant uncertainties of the value of some relevant variables: fuel prices, CO2 prices, success of policies (e.g. 20/20/20), etc.

The calculation of the benefits linked to increased security (risk of power or energy rationing) requires and estimation of the Value of Lost Load (VoLL) i.e., the social cost of the unsupplied energy. Although this parameter is both conceptually and practically very difficult to estimate, its use, even with the mentioned limitations, improves the understanding of the complex interrelations between transmission expansions and social welfare, and allows deeming at what extent the technical and economic criteria are consistently used. Therefore, even inaccurate VoLL values would produce better results than the use of only technical indicators (like LOLE, LOLP, etc).

Congestion fees should not be considered for project assessment, as it is only a transference of revenue among the market players, but it is not a measure of the potential benefits of new investments (the reduction of congestion fees could be considered as a proxy of the social welfare increase, but the fee itself does not have any relation with the social welfare).

One of the benefits of the interconnection would be to reduce the potential market power in a specific region. Common simulation models are not able to asses how much an interconnection may reduce the potential market power. The main difficulty derives from the fact that each market player that exercises market power has its own "style", which means a proper methodology to influence the setting of electricity prices. From an academic analysis perspective several styles have been defined, for instance the Cournot, Bertrand, or Supply Functions strategies. But in the real world each player may use one of this equilibrium models or any other strategy. Therefore, a model to assess potential market power mitigation has a structural difficulty to deal with, since multiple strategies can be used by any market player.

However, it would be possible to use some of these stylised methods to assess the potential market power reduction. The economic literature describes several possible models to assess this issue, the most commons assuming a Nash equilibrium among players that exercise market power with a Cournot strategy. Although, the results are not conclusive, they may be an appropriate tool to compare the impact of different project alternatives on potential market power.

Project assessment within UCTE

Description of the methodology

The UCTE system models include a complete description of the involved TSOs' network and the immediately surrounding areas, therefore the remaining European systems have weak influence on the flows in the concerned area under analysis. This reduction aims to limit the computation time and to allow examining more base cases and scenarios, or to apply probabilistic methods. This model aims at performing DC/AC load flow calculations. These calculations are made for some typical base cases (the so-called "deterministic approach"):

- winter peak load
- in some cases summer peak, winter and summer off-peak
- with typical or contrasted scenarios on the generation schedule

The criteria used to assess the projects are similar to the ones used in NORDEL.

- a technical assessment consisting in checking the compliance with security rules (N-1) and in some cases assessing on stability problems,
- a quantification of the expected increase of interconnection capacity in each of the considered base cases,

- the comparison of the different options' feasibility, in particular the environmental and social acceptance, the timeframe and the total costs.

However, a new methodology is being developed, basically consisting of the following five steps:

- Step 1: Identification of the prices and volume sales of electricity within each of the adjacent grid areas before an increase in cross border capacity.

- Step 2: Calculation of the increase in cross border capacity and estimation of the resulting prices for electricity within each of the two adjacent grid areas.

- Step 3: Determination of the benefits RCB for the consumers due to additional cross border capacity applying the results of step 1 and step 2.

- Step 4: Calculation of the costs for additional cross border capacity CCB.

- Step 5: Determination of the economic feasibility of project development based on whether its benefits are higher or equal to its costs.

Additional benefits provided by the projects should be included in the cost benefit assessment, like the following:

- promotion of Security of Supply (evaluated by the Loss of Load Expectation - LOLE),

- reduction of transmission losses, and

- reduction of re-dispatched generation and associated costs and effects on CO_2 emissions.

Comments

All the comments to Nordel methodology are applicable to the UCTE case. According to the description, only after the implementation of the new methodology the UCTE would be at the same level as Nordel.

Planning in BALTSO

Description of the methodology

Development expansion plans for BALTSO transmission system are based on common grid simulation model available for Baltic countries. These models include detailed information on high voltage (110 kV and higher) grid of the BALTSO region and surrounding IPS/UPS power systems – all Belarus, part of Russia (North – West region) and part of Ukraine. The input data provided by Baltic TSOs are based on estimated grid changes in a time horizon from 10 to 30 years ahead.

The criteria used for assessing investment projects are very similar to the criteria used in both Nordel and UCTE.:

- technical assessment – investigation of compliance with criteria n-1 (for winter season) and n-2 (for summer period), and technical losses;
- impact to transfer capacities and power system stability (steady state stability, voltage stability and dynamic stability);
- socio-economic assessment and environmental impact assessment; and
- project feasibility.

Improvements are mainly focussed on dynamic model updating in accordance to new available data, WAMS and the creation of a tool for electricity market modelling the region (possible together with Nordel by adding the Baltic market area).

<u>Comments</u>

All the comments to Nordel methodology are applicable to the BALTSO case. Furthermore, presently only power system models are used, so the next step should be to start using simulation models like in Nordel.

4.3.3 Comments and recommendations

Once the models used for planning are analyzed and new electricity transmission investments are evaluated, the next step is to analyze the TSOs' final recommendations, which are then commented for the sake of using an appropriate methodology in prioritizing new electricity transmission investments.

The ENTSO's recommendations together with the comments are as follows:

- <u>TSO cooperation on regional, inter-regional and European level:</u>

  Following the ERGEG regional initiative, the Europe-wide network planning could be based on regional coordination carried out within and across the proposed eight regions, namely five regional fora in the UCTE area, plus UKTSOA & ATSOI , BALTSO and NORDEL.

  From the perspective of setting a common regional approach to identify candidate projects to be declared of European interest, this view is agreed referring to the scheme and regions definition, although the regional proposal is slightly different for the reasons provided in the previous chapter.

- <u>Modelling tools:</u>

  - One common modelling tool for the entire Europe is not the preferred option. In fact, tools and system modelling should be adapted for the problem to be solved.

A common methodology including a modelling tool would ensure consistency of selected projects and would facilitate agreements and negotiations. In this regard, it is not necessary to use the same models, but the same methodology. On the contrary, different methodologies may lead to different results discouraging new investments because of the different measures provided. This is crucial in the selection of new priority investments, especially in those sensible cases that require strong analysis.

- The individual regions may use different models, but the basic data should be consistent and validated by the same procedure and the deliverables of any modelling should be compatible throughout all European regions.

  In general, this conclusion complies with the methodological requirements; however, a common model would facilitate this aim. Regarding the use of common data bases for evaluating new interconnection plans, this is critical so as to provide adequate results. If the use of a common methodological framework enables the appropriate assessment, the use of common databases is essential to ensure the recommendations of the methodology. In addition, the use of a common tool would also facilitate the common understanding and the accessibility and simplicity of the process. The use of different models may lead to different conclusions, although it is true that it may be used as a test to check whether the new investments should be declared of priority interest.

- This is especially important for weakly interconnected regions. It is emphasised that neighbouring regions can be modelled in a simplified way in each of the possible different regional models.

  This is in line with the methodological proposal included in the following chapter. A common approach to simplify the modelling of weakly connected neighbouring countries would facilitate negotiations and agreements. This argument reinforces the idea of having different regions as it was concluded in the previous chapter.

- At the regional level common databases are required to enable adequate modelling.

  Again, this is the basis for providing good assessment on the necessities of corridors. This is fully in line with the methodological approach that is developed in the following chapter.

- Multi-area simulation tools already in use within NORDEL seem to be a promising approach for that purpose. These tools are developed by different TSOs within UCTE and also considered by BALTSO (possibly together with Nordel by adding the Baltic market area).

This recommendation may be accepted, however a least cost expansion model should also be considered as an appropriate alternative that fully complies with the requirements to invest in new interconnection capacity in terms of those aspects included in the TEN-E guidelines.

- Implementation of the projects:

  Even though the proposed procedures improve the coordination between TSOs, ensure the quality of the assessment and commitment of the TSOs, the implementation of the projects is still subject to a long and complex process which involves many other entities apart from the TSOs. The implementation problem is still more complex when cross-border infrastructure is concerned (e.g., the use of high speed train tunnels for constructing new interconnection capacity between two countries). The essential elements for implementing additional transmission network infrastructure are:

  - Building and construction authorisations and permissions:

    - To reduce times for project approval from 7 to 5 years.

      This is in line with EU policy strategy.

    - A clear political support is needed to raise difficulties arising from the differences in the permitting procedures on both sides of the borders.

      This would facilitate the process.

    - It is more difficult to convince local people of the benefits of cross border projects. An independent view of a project’s wider benefits for the Internal European Market can be helpful for the promotion of the project during the consultation phase.

      It is completely necessary. Additionally, the possible difficulties to convince people should be taken into consideration in the planning phase, identifying transmission lines located, when it is possible, far from sensible zones. In the event that sensible areas are included in any selected route, an alternative route must be provided and analyzed in order to avoid construction delays.

- Role of regulators :

  - § EU and other concerned regulators should be given some form of collective duty and competence to oversee and promote (cross border) transmission network investments and approve cost allocation of cross border elements as appropriate, possibly through the Agency for the Cooperation of Energy Regulators (as proposed in 3rd package).

    This is in line with the methodological proposal that is supported in the following chapter.

  - § Competences of regulators and of the procedures used to deliver cost approval should be harmonized in order to avoid potential additional obstacles for the time schedule of the implementation.

    This is also necessary for the proper methodological functioning.

  - § In the consultation phase changes in the technical design of the project leading to additional costs can be necessary in order to get agreements with local authorities. TSOs should ensure that these extra-costs regulators would be accepted by the regulators.

    This is necessary for the time reduction in the selection and construction of new electricity transmission investment. But some rules should be defined to abandon or review projects when extra-cost leads to a negative increase of social welfare.

5. Selection of projects of European interest

5.1 Selection criteria

This chapter develops what the selection criteria for the potential projects of European interest for electricity transmission corridors should be, in cooperation with the concerned TSOs and regulators, as well as other specified stakeholders. The final selected criteria aim to establish that only those transmission corridors complying with the whole process described below can be declared of European interest. This process has to be accepted by all stakeholders as part of the requirements that have to be fulfilled. In order to define appropriate criteria for designating electricity transmission corridors of European interest the following aspects are treated with due concern:

- An in-depth planning is initialised to which all stakeholders, including authorities granting the construction permit, regulators and experts from academic, the finance sector and other areas, contribute in the appropriate manner. This has been already discussed in the previous chapter with a number of suggestions that are taken into account in the methodological section of this chapter.

- Specification of appropriate project and quality description is essential to guarantee the designation of any transmission corridor. The quality description takes into account congestion and connectivity throughout the region, including the area's level of isolation and the intensity of renewable energy sources use. Project description should include a first cost estimate together with a choice of the required financing instruments. Thus, the regulators can suggest the transmission fees' level. The project and quality description should include, at least, the following key issues:

    - Description of interconnection, region and countries involved.

    - Detailed description of link and local reinforcement and its benefits, including reduction of congestion, contribution to security of supply and technology utilised, and status.

    - Impact on power flows, trading and on system reliability in the region and possible interaction with other connections.

    - Investment costs, financing scheme including self-financing and other possible sources of funding.

    - Milestones for streamlining the planning and authorisation phase.

    - Specific proposals for European grid operation and regulatory constancy.

- o Preliminary assessment of potential conflicts related with the rights of way and alternative rights of way.

Therefore, the process for selecting criteria to declare projects of European interest is based on the two main aspects cited before: first, the planning process for the electricity transmission corridor and, second, the estimation of the costs and benefits obtained from the selected projects. The determination of the project's benefits and their sharing among the involved parties will finally determine the appropriateness to carry out the EU declaration to support the electricity transmission initiative since it not only seeks to increase global welfare but also to distribute this increased welfare among citizens. All the discussion of this section will therefore be focused on these two aspects as the baseline for designing the appropriate methodology. However, it should be noted that this approach implies some methodological challenges: (1) how to properly quantify benefits, (2) to consider the string interactions between electricity transmission projects, that lead to the issue that a project's benefits can be strongly influenced by the development or not of tier competitive or complementary projects, (3) how to take into regard uncertainties on generation developments, which are based on decentralised decision of multiple market participants.

The selection criteria must be developed following this rationale, although some other aspects must be analysed first, in order to properly assess the preferred option for the designation of transmission corridors of European interest. In this sense, the EU policy and its regulatory framework provide a number of measures for electricity transmission that must be taken into account before defining any methodological approach for corridors. In addition, it is necessary to properly address which is the meaning of an electricity transmission corridor, and its physical and financial requirements.

Before analysing what selection criteria should be applied when considering future projects, the evaluation of the electricity projects already selected as priority ones will be described in order to determine whether any lessons can be learned from the electricity priority corridors' set-up as it has worked so far.

5.2 Status of existing selection criteria

5.2.1 EU regulatory framework

The European Directive 2003/54/EC for the creation of a more open and competitive internal energy market set priorities regarding the development of the needed infrastructure for the operation of the energy market. In this sense, the priorities for trans-European energy networks are established to foster the creation of the European single electricity market.

In addition, the EU enlargement to include 27 countries has substantially increased the necessities of laying down a number of guidelines for trans-European energy networks in order to integrate all the countries.

Current European necessities regarding priority corridors are the result of the following Councils' decisions:

- Stockholm European Council of 23 and 24 March 2001, which concluded that the development of infrastructure was necessary to efficiently operate the energy market.

- Barcelona European Council of 15 and 16 March 2002, fosters the interconnection among countries with the aim of increasing security of supply and network integration to create a more open and competitive market.

As a result, the latest regulatory "decision" (Decision No 1364/2006/EC) of the European Parliament regarding trans-European energy network establishes that the energy infrastructure must be subject to market principles, operational efficiency and operative coordination among countries so as to increase the security of supply and the diversification of sources.

For these purposes, the "decision" defines guidelines to identify projects of common interest and priority projects for the trans-European energy networks with the aim of increasing the degree of integration among countries. This is achieved by means of ensuring the operability of transmission networks between countries and the connection of renewable energy production to the common network.

Projects of common interest are those that basically provide an economic viability, while priority projects are those mainly related to cross-border interconnections that are characterised by the following[8]:

- Significant impact on the integration of the transmission network.

- Significant contribution to guarantee the security of supply.

- Promote the use of renewable energy production.

In addition, as a component of the 10 January 2007 Energy Package, the Priority Interconnection Plan has been launched formulating a series of policies (actions) aimed at supporting the development of an effective energy infrastructure in Europe:

- Action 1: Identification of the most important infrastructure encountering significant difficulties.

- Action 2: Designation of European Coordinators to facilitate the completion of four specific projects.

- Action 3: Establishment of a strengthened framework for TSOs responsible for coordinated network planning.

[8] These projects may include those labelled as projects of common interest

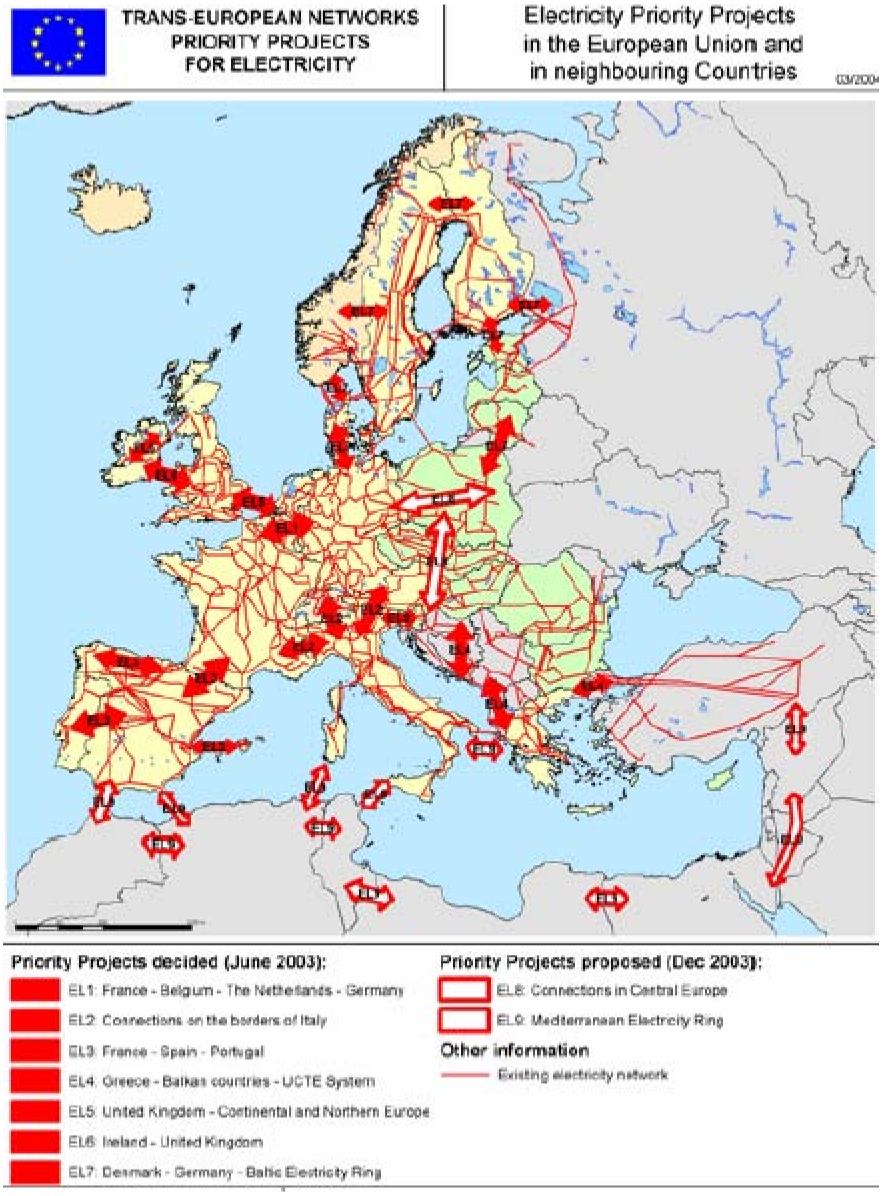
- Action 4: Streamlining of authorisation procedures with a view to requiring the Member States, with due regard to the subsidiarity principle, to set up national procedures under which planning and approval processes for projects of European interest should be completed in a maximum time span of five years.
- Action 5: Review of the financial perspectives on whether increased EU funding for TEN-E networks is necessary.

However, all these measures do not guarantee the designation of electricity transmission corridors since some aspects are not included, and so barriers arise in the proper development of these projects. Thus, in order to complete the regulatory framework a number of measures could be considered for both the selection criteria and the global regulatory framework. This can be observed in the amount of European interest projects that have been carried out so far.

5.2.2 Realised electricity transmission projects in recent years

The number of projects designated as of European interest totalled 32, as it can be observed in the following figure.

Figure 8 Projects of European interest in electricity

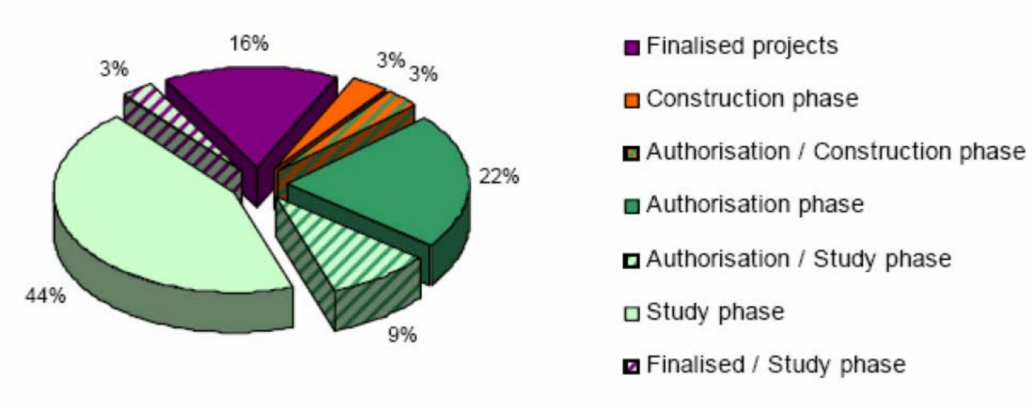


Source: European Commission – DG Energy and Transport

The above set of projects was initially proposed in June 2003 and updated later in December 2003.

The figure below illustrates the electricity projects of European interest that have been realized in Europe in the recent years, giving further evidence to the fact that the realisation of electricity projects is quite difficult and complex, contrary to natural gas projects that have been more successful in the past.

Figure 9 Implementation of projects of European interest in electricity



Source: European Commission – DG Energy and Transport

Thus, the activity level regarding investments in electricity transmission projects has been relatively low when evaluating the level of prioritized projects. Furthermore, almost three quarters of the 32 electricity projects have not obtained the necessary permits for construction, and only 16% of them are already finalized. This indicates that, at least in terms of electricity projects, the priority corridors and TEN-E guidelines have been unsatisfactory as the time span of five years, since their designation as projects of European interest, has expired.

The unsatisfactory level of investments on electricity transmission indicates that perhaps a new and different set of criteria could be more appropriate. It is however important to analyze the developments faced by the EU in terms of electricity, specifically security of supply, Climate change and Energy policy, and market developments.

5.3 Updating the criteria

5.3.1 Regulatory guidelines

The EU policy aims at creating a regulatory framework for the establishment of a European single electricity market, and so EU corridors are essential for ths purpose. To achieve this goal it is necessary to propose a number of objectives of European interest, to be set in the regulation. With this aim, the new policies should contain the following:[9]

- The regulation must be based on technical standards.

- The regulation must provide a common basis for the implementation of the European interest objectives across the countries.

[9] These actions will be analyzed in the following chapter.

- European interest objectives must be based on security of supply targets and justified by cost-benefit analysis.[10]

The process of selecting priorities for the trans-European networks must be open and transparent. These requirements are aligned with the purpose of designating priority corridors to fully integrate the former 15 Member States and the new accession countries. In any case, the selection of priority projects of European interest is required to be decided under consensus of all the parties involved in the development of the European grid. However, the consensus criterion must always lie on the following four principles regarding European priorities:

- Security of supply needs must be always prioritized in the designation of corridors of European interest. In addition, there is also a necessity for network stability, which is of special concern when electricity production from intermittent renewable energy sources is expected to increase in the following years, as a result of the European policies (20/20/20) recently approved to foster the reduction of CO_2 emissions. This type of production leads to uncertainty in production due to its unstable conditions which makes more crucial the increase of the interconnection capacity in the transmission network, so as to inject clean energy when possible or to import energy from third countries when this type of production is limited due to atmospheric conditions.

- The sake of the single European electricity market is also a priority so that all these selected projects must be in line with this legislative purpose.

- Energy efficiency must be taken into account since it is comprehensive that the designation of priority corridors improves the dispatch of the most efficient generation plants.

- The integration of isolated regions is also prioritized by the EC as a matter of the Treaty. The main reason behind this principle is the fact that isolated regions are likely to be affected by power outages. In addition, these regions must comprise both consumption and generation areas, so that special attention is required for the electricity produced from renewable sources for the above cited reasons.

The above priorities in the designation of priority corridors must be based on the principle of solidarity among countries, which underlies in the integration of the electricity system in conjunction with the creation of a single, open and competitive market.

Moreover, due to the environmental and population concerns that have arisen in both the EC and in the countries forming the EU, the reduction of environmental

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[10] However, it would be desirable that the European interest objectives be based on maximising social welfare with the constraints given by security of supply and environmental targets.

damages is crucial within the context of the designation of priority corridors regarding the new priorities of the EU legislation. Although this is not a principle by itself it may however be considered as an important aspect of the new regulatory framework of the EC in the electricity sector. On the other hand, an inappropriate consideration of this issue may lead to delays in the approval and building of the corridors, which jeopardises the EU targets with respect to the prompt development of these corridors.

Therefore, the EC has envisaged a number of regulatory measures in order to meet the above priorities through the harmonization and the reinforcement of both the independence and the powers of the national regulators. Then, regulators should have all the power and independence they need for monitoring the market and for regulating third party access, thus ensuring the grids' neutral management. Nevertheless, regulators should be accountable for assuring compliance with internal market rules on the basis of transparent, objective and verifiable criteria. In addition, the establishment of a European agency for the cooperation of energy regulators is proposed, but only to complement at European level the regulatory tasks performed at national level. This agency may assess the EC in non-binding proposals.

With these tools, the EC attempts to foster the priorities already defined. Therefore, it is expected that the policies implemented by the Commission will tend to promote measures that will be in line with the completion of these priorities. However, it is also interesting to have a look into other regulatory experiences in the designation of electricity transmission corridors, the most recent and relevant being the case of the US.

5.3.2 International Experiences in Corridors: The US National Corridors

The US Department of Energy (DOE) has recently implemented the development of national interest electricity transmission corridors (National Corridors) for those customers that are being negatively affected by transmission capacity constraints or congestion. This was considered as a matter of national importance so that national bodies may exercise its right to designate a National Corridor.

With these designations, the DOE takes into account demand and generation at both national and local level. However, the designation of a National Corridor does not imply that specific transmission facilities are required to be built. This means that the national government does not require the States or local governments to solve issues related to transmission capacity.

Therefore, the designation of a National Corridor covers a broad area to facilitate the access to generation plants located in the congested areas. Thus, local governments and electricity agents decide whether or not the selected range of routes is of potential interest.

In the designation of National Corridors, the DOE does not take into account environmental sensitive areas, local communities or land ownership, although these areas may be reviewed. Therefore, DOE just provides a range of alternatives for potential transmission projects, leaving the determination of the best route to the incumbent bodies, which are supposed to be better positioned for making such decisions. National Corridors however have specific boundaries by which involved parties may easily identify potentially affected areas.

A relevant issue for designating a prioritary corridor is congestion, which is a sound criterion. Other objectives such as security of supply, facilitation of renewables penetration or competition are properly measured by congestion. This approach should be considered for the EU as a sound indicator of the benefits provided by a corridor.

The designed National Corridor must stand for a minimum period of time, due to the construction time. A common practice is to set an initial period of 12 years for the whole corridor, but extensions or renewals are allowed.

The designation of a National Corridor is a first step in providing incumbent agents the necessity of building new transmission facilities. In case that any specific route is rejected for any reason, alternative routes may be proposed. Nevertheless, a consensus agreement among all parties involved is necessary before constructing transmission facilities. Therefore, the situation is similar to the priority corridors proposed by the EC, with the main difference that the latter designates specific routes rather than proposed corridors.

The main advantage of the US system is that it provides flexibility in the designation of final routes, and then it leaves the entire responsibility of developing the final selected routes to the involved parties. On the contrary, the main drawback is that delays are likely to be frequent in those conflictive areas mainly due to environmental concerns and the local communities' project rejection. In addition, the social welfare is completely left to the incumbent authorities, so that benefits derived to other areas may be ignored. It must be taken into account that the designation of corridors just provides solutions for congestion, while the European priority corridors also seek for the single electricity markets and some other purposes that are not necessarily covered by this definition.

In any case, the procedure is interesting in the sense that the same issues also arise in the US, so that they opted to solve the construction of transmission facilities by means of leaving to the involved parties the power to sort it out.

5.3.3 TEN-E guidelines

The latest revision of the TEN-E guidelines, Decision No 1364/2006/EC article 7, sets out the existing criteria to be used for the selection of priority projects, as follows:

> The criteria used for selection of links are that projects must be in line with sustainable development and meet the following criteria:

a) they shall have a significant impact on increasing competition in the internal market and/or

b) they shall strengthen security of energy supply in the EU and/or

c) they shall result in an increase in the use of renewable energies

In order to attain status of a priority project, the project must fulfil one or more of the above criteria.

In this chapter the following issues are addressed regarding the definition of appropriate criteria for selecting priority corridors:

1. The appropriate measurement of each criterion in order to promote and develop projects that will:
    a. have a significant impact on increasing competition and/or
    b. strengthen security of energy supply and/or
    c. result in an increase in the use of renewable energies
2. Analysis of the possibility to develop a common measurement of each project’s contribution to all above criteria, which would enable an objective ranking, or
3. Alternatively the need to use a multi-criteria decision-making methodology (MCDM), which implies assigning a weight to each individual criterion
4. Addressing the trade-off between simplicity and accuracy of any approach for assessing and ranking the projects.

As it is stated in the latter point, there is a conflict of interest on the most adequate methodology in the designation of transmission links. In any case, the declaration of European interest should be granted only for those transmission corridor projects that clearly fulfil the principles underlying the EU priorities, which in turn has to be accepted by all stakeholders. It is feasible that both aspects can properly fulfil the above requirements, but one of them can be more appropriate, or a mixture of both might also be selected as a feasible solution.

In the following sections the four points cited above are analyzed in order to provide the best alternative for updating the selection criteria. Sections 5.4 to 5.7 address the appropriate measurement to promote and develop projects, while Sections 5.8 to 5.10 provide the discussion for the availability of methodology approaches.

5.4 Market integration and development

By enabling the optimization of the generation resources, cross border transmission expansion facilitates cost reduction in meeting demand. If appropriate transmission capacity is available, the most economical resources available in each country can be used in each moment to meet the regional demand, which leads in turn to minimisation of fuel costs.

The economic theory establishes that each corridor's optimal capacity would equal the marginal benefit (measured as marginal reduction of costs to meet the load) of one additional MW of capacity with the unit cost to build that additional capacity. However, this simple approach does not translate to appropriate results due to the electricity sector's nature that is characterised by the following range of key issues that introduce distortions in the electricity markets' functioning:

- Typically the cost of transmission is discrete i.e., the line capacity for a given voltage level is rather fixed.

- Prices in electricity markets with high concentration of generation ownership do not necessarily reflect variable costs, since dominant generators can exercise market power and raise prices above the socially optimal levels.

- In many cases cross border corridors contribute to mitigating market power potential, as they produce the effect of reducing generation ownership concentration.

In liberalized electricity markets it may be socially beneficial to invest more in cross border expansion than it would be in a centrally planned system, given the effect of interconnections to reduce market concentration, and therefore pushing prices to competitive levels. In this case the additional cross border capacity may induce generators to bid variable costs and therefore create a more competitive market. The larger the cross border capacity, the less likely it is that generators can exercise market power. Thus, increased cross border capacity can increase social welfare by reducing market power. But, in any case, the increase of the cross-border capacity leads to improved efficiency of the electricity system since the merit-order dispatching system is better allocated with the increase of the generating power capacity that supplies the electricity system.

Quantifying the corridors' contribution to increased social welfare is complex but necessary; it requires considering discrete costs of transmission facilities and increases in trading benefits, simultaneously with the social benefits of a potential reduction of market power. Only with the use of simulation and planning models it is possible to appropriately measure such benefits.

A suitable measure of the impact on increasing competition in the internal market is the increase of social welfare. But as mentioned above this calculation is complex. In this regard, some indexes could be added in order to ease the results provided by these models.

5.5 The security of supply situation

5.5.1 Defining Security of Supply

Changes in the regulation of the electric power industry worldwide have modified the traditional approaches to reliability. In the vertically integrated utility, under cost-of-service regulation, reliability was achieved by centralised utility planning and operation, at all levels: generation, transmission and distribution. In the market approach, where investments in generation are not centrally decided, the new regulation must ensure that the appropriate economic incentives exist for each segment so that service reliability is maintained at socially optimal levels.

The “security of supply” (SoS) concept (also called quality of service or supply reliability), encompasses two main attributes of the power system:

- Operational security, which describes the system’s ability to withstand sudden disturbances, and

- Adequacy, which represents the system’s ability to meet the aggregated power and energy requirements of all consumers at all times. In the EU, adequacy has at least two dimensions:

    - Generation adequacy: enough generation capacity to meet the aggregated demand, taking into consideration the reliability of generation units and transmission facilities, as well as the availability of plants that used intermittent primary resources such as water or wind.

    - Adequacy of primary sources: the system’s ability to meet aggregated demand of all fuels, either for final consumption in power generation or in other transformation industries.

In simple terms, adequacy deals with planning, capacity and investment, while operational security deals with short-term operations. The latter are normally addressed under regulatory Grid Codes and performance standards, which are out of the scope of this report.

The concept of adequacy represents the system’s ability to meet demand on a longer time scale considering the inherent uncertainty in demand and supply, the non-storability of power and the long lead-time for capacity expansion. Generation adequacy is measured in terms of the system’s reserves and, more accurately, the corresponding probability of not meeting the demand.

Adequacy includes not only enough generation to meet the load, but also sufficient transmission capacity for the connection of generation to load, as well as sufficient reserve capacity to allow the system to withstand major facility outages, extremely dry[11] periods or a credible lack of fossil fuel availability.

Operational security and adequacy are closely related notions but are not the same. Without operational security the output of the generation resources, no matter how abundant, cannot be delivered to customers. Correspondingly, a high degree of security is of little value if there are insufficient generation or transmission resources to meet customer needs.

Adequacy is also linked to the existence of an appropriate transmission system. Enough installed capacity cannot provide adequacy if the generation plants are not properly connected to the load. This issue is becoming more and more relevant with the high penetration of renewable generation, as these types of plants should be located where the primary resource is available (often far from load centres), and thus reliable transmission is crucial to achieve supply adequacy.

A sound approach to SoS is through congestion. The operative security criteria, performance standards and Grid Codes establish how the TSO should operate transmission facilities, which in turn leads to limited power exchanges. The consequence is that congestion increases when security criteria are used. The possibility of not fulfilling the security criteria maybe considered only in the event that a region needs to import energy to meet the load. But the latter situation is not common in Europe. It can be concluded that security constrained operation leads to congestion, which becomes a sound indicator of the need to increase a corridor's capacity.

5.5.2 Measuring Security of Supply

Adequacy is a probabilistic concept, as a result of the fact that both generation availability and demand are probabilistic concepts; therefore, a natural measure of adequacy is the probability that a system can meet the load during a certain time interval. A common measure of adequacy[12] is the Loss of Load Probability (LOLP) or the expected number of years between events when the load cannot be met[13]. For instance, RTOs in the United States plan system reserves to achieve an adequacy level of one day of failure in every 10 years. Furthermore, it is impossible to design a system that never fails to meet the load. So any measure of SoS should consider probabilities.

In addition to LOLP, there are several indices that measure the SoS; the most common ones are SAIDI and SAIFI. A more economically-related measure is the expected un-served energy (EUE). This index estimates the mathematical expectation of the energy that will not be served during a year.

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[11] In this report the term "dry" is used to refer to lack of all types of primary renewable resources such as water, wind, sun, etc.

[12] Although with relevant limitations.

[13] Both indices are related by the relationship NY=365*LOLP

A proper estimation of any of these indices is complex, as failures to meet the load can be linked to the outages of a major component[14] of the system, or more likely to a combination of events. The classical N-1/N-2 criterion is not appropriate when failures to meet the load can occur through a combination of events, for instance if a line goes out of order at the same time with a lack of wind to power a major wind farm. Such modern realities require more powerful tools to measure security of supply and develop expansion plans suited to achieving specific targets on this issue.

Consequently, any attempt to properly measure the contribution of a specific corridor to the EU security of supply requires the appropriate (and consequently complex) methodologies. Furthermore, the contribution that a specific corridor makes to SoS depends on the entire system's expansion (i.e., of all the corridors that are developed). In this scenario the exclusive use of simulation tools may not be enough, since these types of models require knowing the expected system expansion, which in turn depends on each corridor's appropriateness. In such a case the only solution is the use of optimal expansion models. Simulation can only indicate the benefits of a corridor, assuming all other expansion as fixed and this for the whole life of the corridor.

Section 5.9 provides a possible approach to this issue, based on the use of models that optimize system expansion and then assessing operation of the optimal solution with simulation models. In addition, an alternative approach is also provided in this section based on the use of indicators that provide a simple form for estimating the security of supply.

5.6 Climate change and the climate package

As it was previously analysed in the gas section, the focus on climate change has increased significantly worldwide, and particularly in the EU. Therefore, the selection criteria must take this into account regarding the designation of electricity transmission corridors.

5.6.1 Increasing amounts of renewable energy

Prior to the policies oriented to mitigate climate change, most of the generation expansion in the EU was based on thermal generation located near the demand, which produced less stress on the transmission system. But presently, with the 20/20/20 policy oriented to a dramatic penetration of renewable generation new challenges have arisen:[15]

- Most of the generation based on renewable resources (wind, hydro, solar etc.) should be located at the site where the resource is available. Because these sites are often located far from load centres, the need to expand the transmission network to connect the renewable generation to the grid is growing dramatically.

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[14] Presently a common design criterion is the so-called N-1, which means that load must be met, even in the absence of any single component. In some cases the N-2 criterion is used.
[15] The contents were already discussed in the gas section.

- A significant part of renewable-based plant generation availability is intermittent, particularly wind generation. An appropriate transmission system should allow for power imports when wind is scarce and for exports during periods of maximum generation. Only with an appropriate transmission system it would be possible to increase the firm capacity of wind power.

These issues of distance and intermittent availability are intrinsically stochastic, and complicate the identification of the corridors that allow optimizing the expansion of renewable energy sources. A simple and deterministic approach cannot properly identify the benefits of a corridor in relation to renewable energy sources penetration.

It is also necessary to define indices able to reflect the contribution of a particular corridor to the increased use of renewable energy.

5.6.2 The impact of using renewable energy

A possible approach can be based on the contribution of a corridor (or set of corridors) to the reduction of the necessary costs to fulfil the renewable penetration targets. Using appropriate models, it would be possible to measure the extent to which certain corridors allow for increasing the energy production and firm capacity of wind farms, and the resulting economic benefits.

Again congestion is an appropriate variable to measure excess or deficit of renewable generation. When a region has a temporary excess of renewable generation prices go down, exports are recommended but it is limited by the available transmission capacity. When renewable generation is low or zero, price increases and imports are appropriate, but are in turn limited by transmission capacity. So, released congestion in these cases constitutes a direct measure of the benefits produced by a corridor to renewable generation.

5.7 An all-energy integrated market

The main lesson to be learned from the above discussion on the appropriate measurement in order to promote projects that comply with market integration, security of supply and renewable energy and their impact on selection criteria is that all these issues are creating an energy market that requires increased geographical integration of the electricity sector. Thus, when analysing projects and estimating whether a project is optimal from a socio-economic point of view it is important that the investments are evaluated within the appropriate scope, both in terms of the proper geographical market and against all relevant projects.

This is of special concern in the electricity sector since the use of simulation models requires the estimation of not only the affected geographical regions but also of entire countries. On the contrary, the use of optimal expansion models requires more detailed action on regional markets in order to properly analyze regional constraints and necessities.

In the same sense, the use of indicators may be used either country by country or by taking into account a number of countries.

5.8 Practical and economical issues

Alongside political issues such as Security of Supply Climate change and renewables and market integration, there is a range of issues that are of a more technical, regulatory and methodological nature. Thus, before analyzing the possibility of developing a common measurement, these issues need to be identified. These constraints must be taken into account before defining any methodology because they can reduce the success of the selection criteria. Basically, these are related to transmission interconnections, regulation and issues in the implementability of projects.

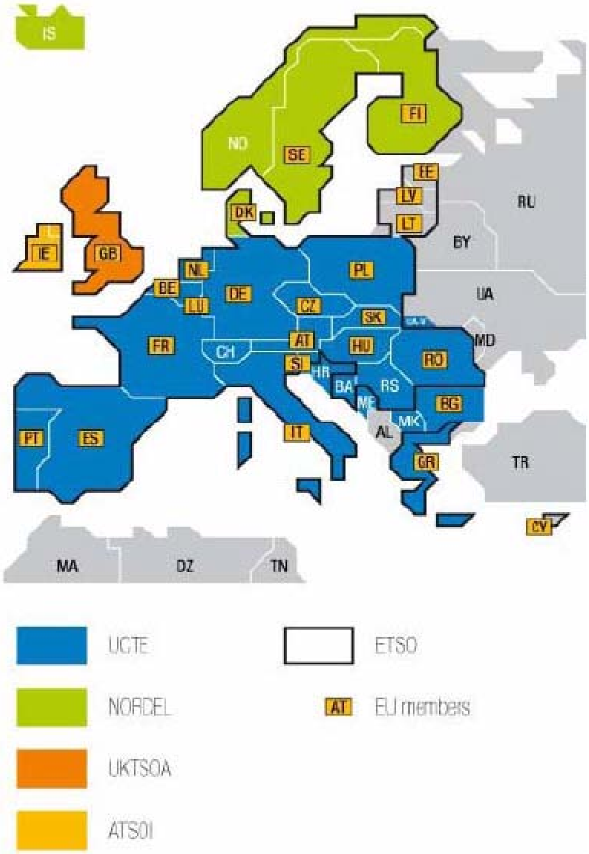
5.8.1 Transmission interconnections

Electricity transmission comprises the Extra High Voltage levels, which vary across European countries. EU corridors are those electricity transmission assets that connect the EU Member States. Therefore, neither international corridors (those interconnections linking EU Member States and foreign countries) nor national ones (those transmission infrastructures within a country) are considered for this purpose. Thus, from the perspective of this document, the regarded transmission interconnections are constrained to those interconnections linking the EU Member States in order to develop the EU single market[16].

In addition, the transmission assets that form the EU corridors may be constructed through two different technologies from the technical point of view: AC lines and DC lines. The necessary condition for an AC corridor is that electricity systems between EU Member States must be synchronous. The figure below presents the different synchronous systems of the EU.

[16] However, it is necessary to take into regard that some EU corridors may need reinforcement from the countries' internal networks. Any methodology to identify EU corridors should take this issue into serious consideration.

Figure 10 Synchronous systems in the EU



Source: UCTE

On the contrary, the DC lines do not require synchronous systems, and so the main advantage of this technology is that is able to connect two non-synchronous systems.

Links between non-synchronous systems are then better characterised by DC lines, which implies that the transmission corridors defined between these systems are preferably constrained to this type of technology. This type of interconnections across Europe was illustrated in the previous section.

5.8.2 Merchant investments

A second aspect relates to merchant investments as an alternative to centrally planned investments regarding interconnection capacity, which is allowed under EU legislation.[17] This implies that the investment is not made under a regulated tariff regime but under market conditions for financing and cost recovery.

[17] Regulation EC 1228/2003 on conditions for access to the network for cross-border exchanges in electricity, 26 June 2003, article 7.

A number of differences may be found between the two alternatives for financing transmission facilities. Although both mechanisms usually require the approval of the regulatory authority, merchant investments also require a notification to the European Commission. Regarding revenues, regulated investments recover their invested costs through the regulated tariff or through congestion revenues. Merchant investments are regulatory allowed to obtain the congestion revenues, but typically these are not enough to obtain the necessary revenues for recovering the incurred costs. Thus, in most of the cases other non-regulated sources of funding are necessary.

This issue leads the merchant investments to incur in other type of regulation such as the priority reservation for the capacity in front of the regulation that fosters the European Commission of full availability to any market participant. But this reservation is only possible for DC links or connected AC radial lines[18]. Therefore, in some cases the interconnection of merchant lines is not included in the transmission network, but is separated from the rest of the transmission lines. However, in some cases it is envisaged the implementation of an exemption limited to a specific period. This is mainly due to the risk faced by the agents involved in transmission investments, so that the financing partners of the merchant lines are not covered by the regulated tariff; so, when possible, some exemptions are necessary in order to promote necessary investments.

At present, the regulatory criteria for approving a merchant interconnector are not very transparent. Furthermore, the incentives for private parties to invest in an interconnection may clearly deviate from common public interests, which may lead to lock-in effects and long-term inefficiencies. Finally, it must be noted that presently no real merchant investments in transmission have been realized in Europe. The two available examples are the realized Estlink and the proposed BritNed interconnections, but these projects involve the participation of the TSO's holding companies.[19] A different orientation should be necessary, i.e. to orient merchant investment to connect remote generation facilities to the main network. This should substantially improve the efficiency of generation decisions and release the TSO from the duty to connect any generation facility regardless of the efficiency of the location[20].

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[18] This is because an exclusivity right granted to a merchant AC line would affect the flow in all the lines that directly on indirectly close a loop with the merchant line. These "externalities" turn impossible granting transmission rights to an AC line in a meshed network.
[19] For an extensive discussion of the issue of merchant interconnection, see R.A. Hakvoort and H.M. de Jong, Pushing European power transmission: private investment in priority interconnections? European Review of Energy Markets, vol.2 (1), 2007, p.109-139.
[20] In this direction it is very interesting to observe the US regulation that envisages RTOs to plan transmission expansions used to supply demand or improve security, but lines to connect generators should be developed by the plants owners. This criterion issues signals for optimal location of plants, and simultaneously save the consumers from paying the cost of inappropriate locations.

The present document only considers regulated network investments, i.e. investments in international transmission links undertaken by TSOs or other transmission companies, who will be remunerated either from already collected congestion rents and/or from the regulated transmission tariffs. This assumption is more realistic under the current regulatory framework since merchant investments are likely to be fostered between EU Member States and third countries, which are out of the scope of the proposals included in this report. Nevertheless, the selected criterion can be feasibly applied to this type of investments by taking into account its specific characteristics in the decision process. In this sense, some specific references to the merchant investment alternatives are commented for the construction phase of priority corridors.

5.8.3 Project "Implementability"

Regarding interconnections, the electricity sector is strongly limited to the planning permissions, which is likely to be the major concern in this respect. In this sense, it is widely recognised and emphasised that difficulties in obtaining these permissions are a major obstacle to necessary infrastructure investment. It is important to note that regulators do not have any direct competences in this area but might be able to help by, for example, coordinating with each other and other relevant authorities where permissions are needed on both sides of a border. Thus, the next issues must be carefully treated before designating an energy corridor:

- Who is the responsible stakeholder for planning? And more specifically, who is responsible for technical decisions? Who is responsible for political decisions?

- How is implementing the contract process? Addressing this issue may be appropriate for providing a general assessment regarding international best practices.

- How are rights of way treated across each piece of public or private property along the selected route?

Another relevant aspect of planning permissions is the definition of the boundaries for the priority corridors. The most appropriate means for determining a general area should be the one complying with the physical properties of the electricity transmission network. But additional issues arise from this definition:

- What are the boundaries/limits (e.g. municipal, regional or national)? This requires further investigation since different countries might apply different approaches.

- How should environmentally, historically or culturally sensitive potential areas be treated? Should these aspects be excluded from energy corridors assessment so as to ease the project's designation?

- Who is eligible to file a request for re-assessing any feasible energy corridor?

All the above information requirements are essential to facilitate the proper functioning of the methodological approach regarding all the planning permissions constraints that may affect the designation of an electricity transmission corridor. Among others, the set of information necessities might include more specific aspects in relation with the following main key issues:

- Decision-making process across countries and regions.
- Planning timing.
- Expansions responsibility in terms of both responsibilities and timing.
- Rights-of-way.

All these issues are analysed in the next chapter as most of them are more related to the regulatory concerns rather than the selection criteria itself. However, their appropriate treatment is crucial for the adequate implementation of the selection criteria.

5.9 Alternatives for the selection criteria

Therefore, once the above constraints regarding the designation of priority corridors are analyzed, any methodology used to identify priority corridors should at least be in line with the following:

- Verify that the approved projects increase the social welfare, which requires the estimation of marginal cost curves in Europe.
- Verify that the project is globally part of the least cost solution to meet electricity demand in the EU scope.
- Estimate its contribution to the EU policies, through appropriate indices. Tentatively these indices can be:
    - Competition through expected reduction in costs to meet the forecasted load. Optimization and simulation models can provide this information.
    - Security of supply through expected reduction of non-supplied energy valued at the VoLL. Optimization and simulation models can provide this information. Alternatively through released congestion, which also requires simulation and/or optimization models.
    - Renewables through reduction in cost to fulfil the 20% penetration targets. Dual variables of optimization models can provide this information. Alternatively through released congestion, which also requires simulation and/or optimization models.

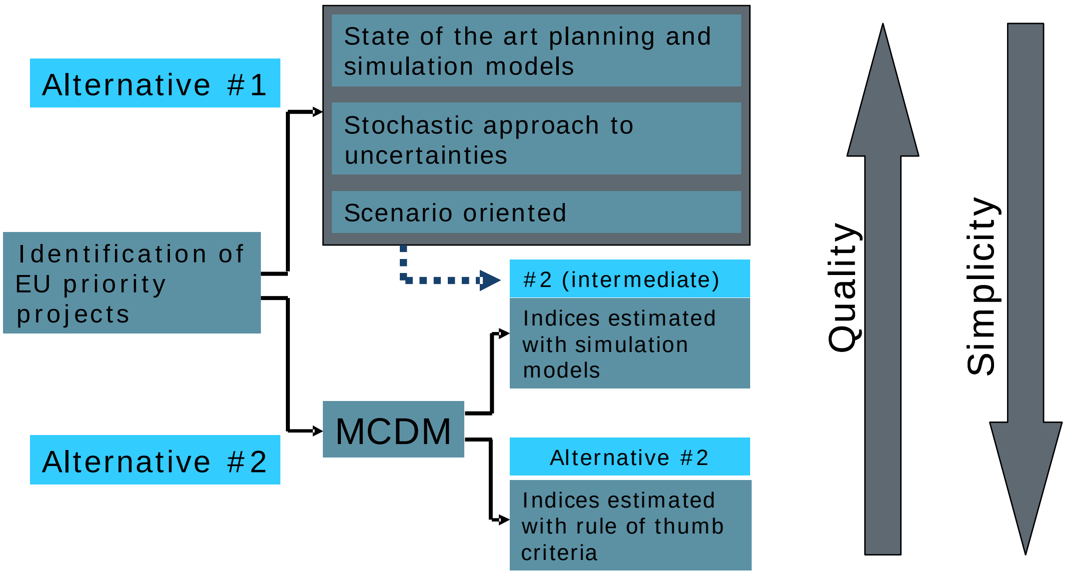
All these indices measure contributions to fulfil EU policies in monetary terms.

- A project ranking to establish the condition of EU priority could be established based on the sum of the indicators' values, as a weighted average or using some MCDM methodology. However, as all indices are measured in monetary terms, the direct sum should be the less arbitrary criterion, but at the same time robust and simple.

Following the above methodological steps the selection criteria must provide results for the designation of electricity transmission corridors, which finally provides results in monetary terms as an objective measure to rank costs and benefits of the interconnection expansion projects. The main issue is to decide whether the use of complex mechanisms is better than those results provided by the use of simple approaches (Alternative #1 vs Alternative #2).

These alternatives are compared in the next figure:

Figure 11 Methodological alternatives



As it can be observed in the above figure, Alternative #2 is divided into two different approaches; one of them is called "intermediate" and is the combination of both Alternatives, as it will be described below.

Therefore, in order to define the benefits of electricity transmission links, although these benefits are at EU level and consistent with EU policies and objectives, the selection criteria finally arise from a standard set of benefits linked to transmission facilities. These are as follows:

1. Ensure the supply to end consumers by connecting sources with demand.

2. Reduce the costs to meet the load by allowing optimization of primary resources. Cross border trading allows optimizing the use of existing resources when a country's market participant (regional market) with lower marginal cost sells to a participant of another country (regional market) with higher marginal costs. A reduction of unwished emissions is expectable as a result of this rationale.

3. Allow the development of projects whose scale requires a bigger market than the project's influence area. This issue will play a crucial role with the strong increase of development of large scale renewable electricity projects, which require exporting the excess of energy that can be safely consumed near the plants.

4. To increase the competitiveness of the electricity markets by allowing a reduction of the concentration of generation ownership. Market power potential is directly connected to the concentration of generation ownership. Due to the high inelasticity of electricity demand in real time, market power potential is exacerbated. While a storable commodities market is considered competitive when HHI is lower than 1,800, in electricity markets values lower than 1,000 are necessary.[21]

5. Improve the quality and reliability (security) of supply by allowing sharing reserves among the market's members.

6. Security of supply is by nature probabilistic; therefore, it should be addressed as a stochastic issue. Usually failure to meet demand arises from random failures of major facilities (generation, transmission), lack of intermittent primary resources (wind, hydro), demand higher than the forecasted, or combination of these factors. Valuing the expected non-supplied energy at the VoLL allows economical evaluation of the system's security. An issue that should be included as a source of supply risk is gas availability, either because of problems with pipelines or due to political reasons.

7. To enable the diversification of primary resources' supply increasing their adequacy.

5.9.1 Alternative #1

Regarding the results provided by mathematical models optimization for the selection criteria, the most important electricity transmission projects require a set of

[21] In the electricity sector, because of the necessity to match demand and supply at every moment, the possibility of exercising market power is easier in off-peak hours than in other markets. Therefore, HHI values between 800 and 1,000 are usually considered optimal in order to avoid market power concerns.

prior definitions so as to properly address the outcome requirements that fully comply with the necessities of the transmission expansion network. The main aspect in this regard is the one related to the definition of the benefits to be provided by the methodological approach.

Compliance with the regulatory requirements is essential in the definition of any methodology's selection in the planning process for designating priority corridors. In this regard, the criteria used for selecting priority corridors are that projects must be in line with sustainable development and meet the following requirements previously defined:

- they shall have a significant impact on increasing competition in the internal market and/or
- they shall strengthen security of energy supply in the EU and/or
- they shall result in an increase in the use of renewable energies.

In order to attain status of a priority corridor project, the project must fulfil one or more of the above criteria.

All these criteria are applicable for projects that are socially and economically appropriate for setting a single electricity market complying with all the necessary requirements defined previously. On the contrary, a large number of projects may be eligible to fulfil the above criteria. So, the introduction of the socio-economical appropriateness as a filtering criterion is crucial for the adequacy of any corridor's proposal.

As all TEN-E criteria are susceptible of a socio-economic assessment, it is possible to define project ranking based on the contribution of each of the projects to the fulfilment of the above targets, based on a common measure, their impact on social welfare.

All these criteria are susceptible of quantification, and the most adequate planning tool for selecting priority corridors based on the general principles provided in the regulation is the use of expansion models optimization. The results that provide this type of models in compliance with the EU policies are as follows:

1. Impact on increasing competition in the internal market: benefits arising from increased trading can be measured based on market simulations of the clearing process. In fact, optimal expansion models as described below include an estimation of clearing costs, so these benefits form automatically part of the planning process.

   Furthermore, as cross border interconnections usually allow reducing the market's concentration, it is expected that market power potential will be reduced as well. This can be assessed in two ways: (1) including market power exercise in the planning model, or (2) describing the impact of each expansion on market concentration indicators, typically HHI and pivotal.

2. Strengthen security of energy supply in the EU: this can be included in the planning models through the cost of unserved energy. Alternatively, a constraint may be imposed, typically the non-supplied energy should be lower than a pre-specified threshold targeted in the regulation or set as an objective. Typically, planning in developed economies aims to non-supplied energy being lower than 10-4 times the energy demand. A suitable indicator is the expected non-supplied energy in the whole EU or the defined suitable regions.

3. Increase in the use of renewable energies: as far as the planning expansion model considers intermittent renewable generation as a stochastic variable, the size of corridors to allow optimal management of these resources results optimised. So, no special considerations are necessary.

   The volume of renewable generation is based on the existing plants and the new projects informed by investors. Typically the new projects are informed for a period no longer than the initial 5 years.

   As the planning horizon exceeds this initial period, the expansion model should include assumptions on how expansion will occur in the years for which no new generation is informed. In this case the natural assumptions should be based on that countries will fulfil their obligations related to EU targets (the 20/20/20), as well as in the rational behaviour of investors.

   Therefore, the planning model should define the expected expansion of electricity generated from renewable energy sources, taking into consideration the new EU directives[22]. Particularly the new directive allows (with limitations) the trading of Guaranty of Origin (GoO) certificates. This means that a country is allowed to partially fulfil its obligations on renewables by buying GoO to agents of other countries. The planning model is an appropriate tool to analyse how GoO trading will impact on the development of cross border interconnections.

   Planning models provide indicators for the optimal expansion plan as a whole, but not for individual projects.

[22] On January 23rd, 2008, the European Commission published a proposal for a new Directive on the promotion of the use of renewable energy sources (the “Directive proposal”). The Directive proposal aims at introducing a new EU-wide, market-based system for the promotion of the use of renewable energy sources (the “community system”). Under the community system, Member States are assigned individual targets for the share of renewable energy sources in final energy consumption in 2020. An indicative trajectory for achieving the 2020 target, starting from the actual penetration level in 2005, is also indicated.

In order to obtain the selected indicators for individual projects two alternatives are available:

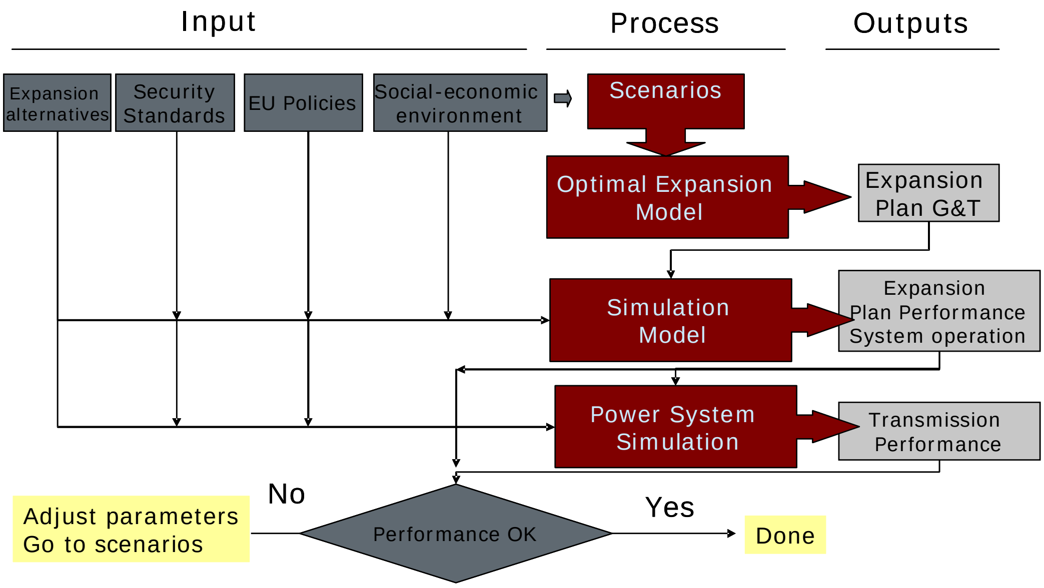
- After obtaining an optimal expansion plan, to analyse a new plan without considering as candidate the project that is being assessed (with-without). Although effective, this process is slow if used for several projects. Furthermore, the marginal impact of the project is assessed.

- Through sensitivity analysis provided by the mathematical solvers, which analyses the impact of marginal changes in one variable (the indicator) due to changes in other variable (the project).

Once the list of candidate projects is provided by the model expansion optimization results, it is previously required to define priority corridors concept (i.e., the list of candidate projects that allow some level of increase in the indicators described above) in the sense that it also fulfils the condition of having a positive impact on benefits for electricity customers (with mathematically is measured through the social welfare increase).

The whole process can be summarized in the following figure that illustrates the functioning of Alternative #1.

Figure 12 Alternative # 1 scheme



This approach is consistent with the EU vision. For instance in the document "Priority Axes and TEN-E Projects" it is stated that:

> "In view of European added value of interconnections with the objective to creating a European-wide internal energy market, it appears necessary to focus the Community support on projects with particular high European significance. This leads us to establish - prior to specification of executable projects – the main corridors called "priority axes" and, further, additional generic criteria".

Our assumption is that the European significance is given for the level benefits from a list consistent with the EU objectives and values, and for the number of countries benefited by the project.

Estimation of benefits and costs

The final target of the planning process can be stated as follows:

> 'how to allocate resources so as to maximise the social, environmental and economic welfare of society'

As a result of the necessities concerning the estimation of benefits (i.e. social, environmental and economic welfare) and the fulfilment of the EU policy requirements, the selection criteria identification methodology to define the priority corridors is forced to comply with the abilities cited below. The methodology outcome is therefore characterised by the following outcome:

- The objective function of the planning process is to maximise the social welfare increase, i.e. the sum of the consumer's surplus's plus the producer's surplus. However, in many case demand is assumed as inelastic, and therefore social welfare maximization becomes equal to minimisation of the total incremental costs necessary to incur the meet a previously forecasted demand. This is the criteria used in most of the standard planning software.[23]

- Estimate the benefits of a project out of a set of projects, based for instance on the indicators defined above, and on the criterion of positive impact on social welfare in monetary units.

- Taking into consideration the different types of constraints (physical, economic, financial, policy, environmental) that limit the optimization of each project.

- To convert the political/policy issues in constraints or costs. This would allow minimizing the subjectivity when political/policy issues do influence the decisions.

[23] To describe the proposed methodology, it is used this approach, therefore hereinafter it will indistinctly use the terms "least cost minimisation" or social benefits (social welfare) maximisation.

- Identify how the project's benefits spread among the EU countries.
- The decision about the development of new projects requires successive steps, starting with an initial or draft idea, which is assessed in consecutive stages, each with a higher level of accuracy and a narrower scope. Typical steps of this process are:
  - Step 1 – Project Identification: requires a preliminary estimation of benefits, environmental impact and costs. This step should be oriented exclusively to checking whether the project's potential deserves to include it as a candidate for the next step, the planning process. In order to apply this step a number of questions need to be addressed so as to identify the corridors:
    - What are the short- and long-term corridor needs of TSOs?
    - Given the corridor needs identified by TSOs, what are the appropriate priorities assigned to the identified corridors?
    - What are the major institutional and regulatory issues and government decisions necessary to address the issues associated with the identified corridors?
    - Which local agents are key participants in identifying environmental and land use issues associated with the identified corridors?
  - Step 2 – Planning: the project is included in the planning process as a candidate. After obtaining the results of the planning process, it would be possible to identify it as a "priority corridor".

    It should be noted that the planning activity can be defined as the selection of the most appropriate candidate projects that allow fulfilling some objectives subject to a set of constraints:
    - Maximizing the social benefits (measured to social welfare) increase, or, equivalent under some assumptions, meeting the load with minimum cost
    - Constraints are related to physical issues (Kirchoff's laws, primary sources availability, etc.), political, environmental (emission limits), financial (availability of resources to finance the expansion), etc.
    - Projects should be selected from the list of "candidates". It is necessary to identify candidates through some previous identification methodology.

        - Expansion of generation can be an input data for short term planning, or be selected as part of the planning process.

    - Step 3 – Project feasibility Assessment: if the project is part of the optimal solution in the planning process, it is studied with more detail in a feasibility study, which includes refinements in the cost calculation, environmental impact, definition of the rights of way and benefit estimation. Because the involvement of multiple stakeholders is crucial, an assessment is made by a Group of experts formed by representative stakeholders to assist in the final route by providing inputs regarding physical and institutional issues that may arise in the feasibility assessment. As mentioned above, an Evaluation Commission is also envisaged to follow up the project's identification process.

    - After the feasibility study (which may have several phases), a final decision can be taken regarding its development. Additionally, an explicit expiration date on a priority energy corridor designation should also be defined.

Therefore, the planning methodology named Alternative #1 for identification and designation of corridors may be summarised as follows:

1. Assess state-wide transmission needs for reliability and economic projects as well as those necessary to achieve state-wide policy goals included in the EU regulation;

2. Approve beneficial transmission infrastructure investments that can move into permitting; and

3. Examine transmission alternatives early in the planning phase, so that the environmental review in the permitting phase can more appropriately focus on routing alternatives and mitigation measures.

Security Criteria

Security (reliability) criteria are defined and measured in terms of performance of a system under various contingencies. Prediction of performance is based on simulation. These criteria are based on the fundamental assumption that system integrity will be maintained for the more probable and less probable contingencies and that there is no loss of load for the common more probable contingencies.

Security criteria may be predefined (for instance to deterministic criteria as N-1 or LOLE[24] targets), or can be a result of the planning process. In this case the social and economical cost of unserved energy (measured through Value of Loss Load – VoLL) plus the cost of the measures to reduce unserved energy is minimised. Although this methodology is economically sound, as effectively ensures the maximization of the social welfare, its use is not common, basically because reluctancy of energy policy makers and planners to accept the security of supply as a result of the planning process, rather than an input. Furthermore methodologies for VoLL estimation requires of further improvement.

For the above reasons, the security criteria is usually a constrain of the optimization process. Typical ways to consider security during the planning process are:

- N-1 criteria[25]: although it is standard to verify the fulfilment of this criteria using simulation models (Optimal Load Flow – OLF) and power systems analysis tools, it is more difficult to include this criteria in the Optimal Expansion Model. Although there is an extensive list of academic references to optimal expansion models that includes the N-1 criteria[26], the available models requires too big number of variables that makes practically impossible to plan the system for a long time horizon. Furthermore, these models typically concentrate in transmission development and simplify the generation system, ignoring for instance the competition between local generation and transmission. This problem can be considered as deterministic, as all the possible N-1 contingencies can be identified and taken into consideration in the planning process.

- LOLE criteria: in this case the probability that load cannot be met is the planning constrain. This is a probabilistic criterion, therefore models that use this criteria needs of simulation to identify all the possible contingencies, and their probability of occurrence. So there are not available optimal transmission planning models that use these criteria. The solution is to use a deterministic transmission planning to identify an economically sound solution, to verify the LOLE using simulation tools, and then if necessary to introduce additional constrains[27] in the planning model until achieving a

[24] Loss of Load Expectation, that estimates the expected interval between events when available capacity to meet the load in the whole power system or is some nodes is lower than the demand.
[25] More complex criteria as overlapping single contingency and generator outage (N-G-1) and trip - maintenance (N-1-1) disturbances are also used.
[26] See for example MULTI-STAGE TRANSMISSION EXPANSION PLANNING CONSIDERING MULTIPLE DISPATCHES AND CONTINGENCY CRITERIO GERSON C. OLIVEIRA, SILVIO BINATO, MARIO V. PEREIRA, LUIZ M. THOME or MULTI-AREA REGIONAL INTERCONNECTION PLANNING UNDER UNCERTAINTY, J.C. Enamorado, T. Gómez y A. Ramos Instituto de Investigación Tecnológica - Universidad Pontificia Comillas.
[27] For instance requiring double circuits in some lines, or increasing the reserve in zones with potential deficit.

solution that meets the LOLE criteria. This iterative methodology is shown in the figure 12.

- Maximum expected unserved energy: In this case it is constrained the maximum unserved energy. As the LOLE criteria, this method requires of simulations to identify all the possible contingencies and their probability. It is also necessary an iterative procedure between optimal expansion and simulations models.

As a conclusion, security criteria can be included in the planning process, although the most suited solutions requires of iterations between an optimal expansion model and detailed simulations aimed to the accurate estimation of the probability of events conducting to unserved energy.

5.9.2 Alternative #2

The results provided by the MCDM analysis for the selection criteria are based on indicators. This alternative may provide better results in all these cases where the optimal amount of interconnection capacity is difficult to be assessed since it requires extended data modelling, taking into account (at least) the geographic distribution of generation, existing network capacities and generation cost information.

Apart from the present more detailed modeling efforts, this section provides some first ideas on the development of an 'Electricity Interconnection Indicator' (hereafter denoted as 'E _ I') which provides a first-order insight into the need for additional interconnection capacity for each country (or system). Obviously, such a 'quick and dirty' indicator is not very advanced in the sense that it provides the exact economic optimum for new investments. Nevertheless, it should be able to generate a rough indication on the need for additional interconnection capacity (irrespective of whether this can be materialized by new investments in international tie lines, upgrading of the existing lines or reinforcements in the national network which impact interconnection capacities).

An advantage of the E _ I is that it may be calculated quickly from easily accessible information. Nevertheless, it should always be taken into account that it is far from perfect, so it needs to be applied with cautiousness.

Sub-indicators

The suggested Electricity Interconnection Indicator E _ I is being calculated per country (or market zone) and is derived from four sub-indicators:

- An indication of the competitive structure of the electricity market: M
- An indication of the security of supply: S
- An indication of the amount of flow-based renewable power generation: R

- And optionally: an indication of the price level of a country: P.

The E_I will be calculated as a function of these four sub-indicators:

$$E\_I = f(M, S, R, P) \qquad (1)$$

This function heavily depends on the weights provided to each of these four sub-indicators that are based on the multi-criteria assessment.[28] Therefore, the weights of the sub-indicators are crucial in the aim of providing accuracy of results. In this regard, the role of policy makers, in consultation with the stakeholders, in order to decide on the most appropriate values would contribute to the success of using this alternative. Even, weights values may differ in each country/region, although homogeneity is more adequate so as to avoid biases. Thus, feasibility of using this alternative basically lies on the general agreement among affected stakeholders concerning the importance of sub-indicators.

Requirements for the sub-indicators

There are several requirements for each of the sub-indicators:

- The sub-indicator needs to be applicable to the entire system for which the interconnection indicator is assessed.

- The sub-indicator should be derived from simple and easy-to-assess numbers, without the need to perform complex calculations.

- The sub-indicators must have a comparable format and range, in order to be able to be merged to a single indicator, the E_I.

- Optionally, each sub-indicator might contain a threshold, below which the sub-indicator results in 0, as an indication that no need for additional interconnection capacity exists given the national system's flexibility.

Relevance of the electricity interconnection indicator

The idea is that the electricity interconnection indicator E_I can be used to estimate the 'optimal' amount of interconnection capacity by multiplying it with the system's capacity (C):

$$\text{optimal interconnection capacity} = E\_I \times C \qquad (2)$$

The outcome of formula (2) represents the need for interconnection capacity (in MW) of a certain country or system. A comparison with the present amount of interconnection capacity will then show whether new investments are needed.

Calculation of the sub-indicators

The four sub-indicators to the electricity interconnection indicator will be defined as follows:

- the sub-indicator for the competitive structure of the electricity market: M,
- the sub-indicator for the security of supply: S,
- the sub-indicator for the amount of flow-based renewable power generation: R, and
- optionally: the sub-indicator for the price level of a country: P.

Sub-indicator for the competitive structure of the electricity market (M)

- Objective: The sub-indicator for the competitive structure of the electricity market is an indicator for the level of competition in a country's electricity market. Since it is very difficult to change the market structure, import competition is often one of the most effective ways to improve a market's competitiveness. The present sub-indicator offers a measure for the amount of additional import capacity needed to make the market more or less competitive.

- Definition: There are several indicators for the competitiveness of the electricity markets. Structural indicators include market share, the HHI index and the residual supply index. For the present application, we suggest using the HHI-index. Although recent research has shown that this indicator is far from obvious to apply to the electricity market, it is nevertheless rather easy to calculate based on general market data. Additionally, it does not seem to exist many straightforward alternatives.

  Although one has to be careful not to draw too hasty conclusions on the precise height of the index, the HHI gives an indication on the market's competitiveness based on its structure, i.e. the relative shares of its participants. For the present purpose, we use the HHI based on the generators' market shares in the country for which the interconnection index needs to be calculated without taking into account imports (since the objective is to calculate the need for additional imported competition).

- Formula: For each country, the sub-indicator for the competitiveness of the electricity market (M) is calculated as follows:

  $$\text{IF } [\ (\bullet(HHI)/100 \bullet M_t] > 0 \ \text{ then } \quad M = (\bullet(HHI) \ / \ 100 \bullet M_t)$$

  $$\text{OTHERWISE:} \quad M = 0 \qquad (3)$$

[28] For the examples provided in this study it is assumed that all sub-indicators weight the same.

In detail: The M-indicator represents the difference between the square root of a system's HHI (represented as a percentage of the maximum value for the square root of HHI, i.e. •(10,000) = 100) and the threshold for competitive markets (M_t). The sub-indicator is (more or less) a measure for the amount of additional supply (from foreign suppliers) which is needed to make the competitive structure of the electricity market 'acceptable'.

- Threshold: In accordance with the common application of the HHI, the threshold above which the HHI index indicates possible structural competition problems is set to 1,800. Above this value the market is being considered heavily concentrated.[29] Therefore, we suggest setting the threshold M_t:

$$M_t = \bullet(1800)/100 = 0.42 \qquad (4)$$

An alternative could be to derive the threshold from an HHI value of 1000, below which the market is considered unconcentrated, or a value in between.

- Examples: As an example, for countries with an HHI of 1,000, 2,000, 3,000 or 4,000 and based on a threshold M_t of 0.42, the sub-indicator for the competitive structure of the electricity market (M) amounts to:

HHI = 1,000	M = 0 %
HHI = 2,000	M = 2 %
HHI = 3,000	M = 12 %
HHI = 4,000	M = 21 %

Sub-indicator for the security of supply (S)

- Objective: The sub-indicator for the security of supply provides an indication of the amount of imported capacity which is needed to guarantee a system's security of supply. When the difference between peak capacity and demand is too small, imports are needed (although often only in exceptional situations) to keep the lights on. The objective is to provide a measure for the necessary imported capacity in order to guarantee security of supply.

- Definition: Security of supply refers to the ability of the power system to supply all load. This implies that the installed generation capacity should be

[29] This threshold is applied by the US Department of Justice for merger evaluation. See http://www.usdoj.gov/atr/public/testimony/hhi.htm.

sufficient to meet the peak load, even in the situation of maintenance and failure of (some) generators.

Security of supply is generally measured by a reserve factor, which is the ratio of the available generation capacity and peak demand. This reserve factor needs to be higher than 1, in order to allow for maintenance and occasional generator unavailability.

- Formula: For a given year, the security of supply sub-indicator is derived from the shortage of generation capacity with respect to the necessary reserve factor, taking into account:

  - the addition of all generation capacity which has been commissioned and is available for the market,
  - no subtraction of generation capacity which is unavailable due to repair and maintenance,
  - no addition of generation capacity which is still under construction (0%),
  - and adding a correction for electricity generation from renewable resources, such as wind and sun, by incorporating this capacity only to a limited amount (since these generators are only available when wind or sunlight is available).
  - A question arises with respect to the so-called 'moth-balled' plant. These facilities may or may not be included in the sub-indicator (probably depending on the time needed to make them operational again).

Presented as a formula, the sub-indicator for security of supply (S) can be set to:

$$\text{IF } [\ (PG \cdot RenCorr)/PD < S_t\ ] \text{ THEN } \quad S = S_t \cdot (PG \cdot RenCorr)/PD$$

$$\text{OTHERWISE:} \quad S = 0 \qquad (5)$$

Where:

PG: Peak generation capacity (MW)

PD: Peak demand (MW)

RenCorr: Correction for the limited contribution of installed renewable electricity generation capacity

S_t: Threshold for the security of supply sub-indicator (see below)

The correction for the limited contribution of renewable electricity to the security of supply (RenCorr) equals:

$$RenCorr = (1 \bullet RenCont) \times PG \qquad (6)$$

Where:

RenCont: Effective contribution of renewable electricity generation to security of supply

The latter component compensates for the availability of wind and solar installations. Since the wind speed and solar influx are not constant, the annual energy production of wind and solar energy generators is never as much as the sum of the generator's nameplate ratings multiplied by the total hours in a year. The ratio of actual productivity in a year to this theoretical maximum is called the "capacity factor".

Because of this, wind and solar installations will never contribute to the security of supply for their total (nameplate) capacity. A reduction is applied, which is defined as RenCont, the effective contribution of renewable energy generation to security of supply. Note that this parameter may be different from the capacity factor. Its value needs to be defined, preferably on an EU-wide basis, although an assessment on a country-by-country basis is also possible. In general, RenCont may have a value between 0 and 0.3, resulting in a reduction of the generation capacity contributing to the security of supply indicator of 0.7 to 1.0 times the peak generation capacity.

- Threshold: Imports are only needed to safeguard security of supply in case the net available generation capacity (PG • RenCorr in formula (5)) is less than the threshold S_t. The latter is defined as:

$$S_t = PD \times RF \qquad (7)$$

Where:

RF: Minimum reserve factor

In practice, the minimum reserve factor should take into account the average availability of power generators. The reserve factor (RF) is established in the range between 1.1 and 1.25.[30]

[30] UCTE uses the so-called 'Adequacy Reference Margin' which accounts for unexpected events affecting load and generation. This value is calculated for each country. See UCTE, System

- Examples: As an example, we calculate the security of supply sub-indicator for a country with a peak demand of 10,000 MW, peak capacity of 11,000 MW and 12,000 MW respectively, and a share of renewable energy (wind and sun) of 0 % and 10 %. The calculations are based on an effective contribution of renewable electricity generation to security of supply (RenCont) of 0.25 and a reserve factor (RF) of 1.15.

	0 % renewable energy	10 % renewable energy
Peak demand of 11,000 MW	S = 5 %	S = 13 %
Peak demand of 12,000 MW	S = 0 %	S = 4 %

Sub-indicator for the amount of flow-based renewable power generation (R)

- Objective: The sub-indicator for the amount of (flow-based) renewable power generation reflects the amount of renewable generation based on wind and solar energy. As the availability of these sources is dependent on weather conditions, the output of these generators may vary. The system needs to be able to adapt to (especially) sudden changes in output. When significant wind and solar power generation units are installed, a system may become (partly) dependent on imports for its system balancing. The present sub-indicator aims to provide a measure for this import need.

- Definition: There are two effects that might need to be taken into account:

    1. The significant network flows that large-scale renewable generation may induce as in the example of Northern Germany. Depending on the network's layout, this may yield different flow patterns across borders, for which interconnection capacity needs to be available.

    2. The additional balancing requirement in the case of sudden (exceptional) changes in the output of the wind turbines or solar energy panels.

    Especially the second effect may lead to an additional need for interconnection capacity. In general, it might be assumed that the larger the share of wind and solar energy, the larger the need for interconnection capacity. The sub-indicator for the amount of flow-based renewables represents the effect on the need for interconnection capacity.

Adequacy Forecast 2008-2020, http://www.ucte.org/_library/systemadequacy/saf/UCTE_SAF_2008-2020.pdf.

- Formula: For each country, the sub-indicator for the amount of flow-based renewables (R) is calculated as follows:

$$\text{IF } [\text{RenShare} \bullet \text{Rt}] > 0 \quad \text{THEN} \quad R = (\text{RenShare} \bullet \text{Rt}) \times \text{RenInt}$$

$$\text{OTHERWISE:} \quad R = 0 \tag{8}$$

Where:

RenShare:	The fraction of installed wind and solar energy capacity (as a percentage of peak generation capacity)
RenInt:	The impact of wind and solar energy power generation on necessary available international transport capacity
R_t:	Threshold for the renewable generation sub-indicator (see below)

In detail: The sub-indicator assumes that from a certain threshold, international assistance may be needed for a fraction of the installed wind and solar power (RenInt) to be able to balance sudden fluctuations in generator output.

The value of the variable RenInt depends on each country's ability to balance the system. For larger systems, there might be less need for international assistance to balance the system in exceptional situations, than for smaller countries. To facilitate the formula's application, a single value to be applied for all countries may be preferable. Such a value might be derived from calculations on the impact of renewable power generation on import needs in several European electricity systems.

- Threshold: It may be assumed that each system will be able to compensate for fluctuations in wind and solar energy power generation when installed capacities are small. Therefore, it seems reasonable to assume a threshold R_t, which may be established at some low value, e.g.:

$$R_t = 5\ \% \tag{9}$$

- Examples: As an example, we calculate the renewable energy sub-indicator for a country with a peak capacity of 10,000 MW and a share of renewable energy (wind and sun) of 5 %, 10 % and 15 %. The calculations are based on a value of 80 % for the impact of wind and solar energy power generation on available international transport capacity and a threshold of 5 %.

RenShare = 5 %	R = 0 %
RenShare = 10 %	R = 4 %
RenShare = 15 %	R = 8 %

Sub-indicator for the price level of a country (P)

- Objective: Until now, with respect to market development only an indication for the market structure has been included, which reflects the possibility for competition. However, this does not guarantee electricity supply at the lowest price. The latter depends on the system's cost structure of generation. In case of a high price area, depending on the marginal cost curve, market demand for imports may be high, possibly restricted foremost by the availability of import capacity. Lowest-cost dispatch of generators across borders would lead to additional welfare.

  Therefore, one might consider adding a fourth indicator reflecting the price level in a country. The underlying idea is that it may be desirable to let high-price areas be open to imports in order to be benefited by the internal European market for electricity. However, depending on the specific market situation (and the historic cost structure of the power generation industry), this might lead to a large additional demand for interconnection capacity.

  In a longer term, it is difficult to see why the cost structure for generation based on a specific fuel should not (at least to a large extent) gradually converge within Europe. Therefore, it is questionable whether investments in interconnection capacity are advisable from this perspective.

  Nevertheless, some indication for the price levels might be taken into account, which should then reflect the price level in one country's electricity market in relation to the average European price level.

- Formula: For each country, the sub-indicator for the price level (P) might be calculated as follows:

$$\text{IF } [\ (MP \bullet MP_{Eur}\ ] > 0 \text{ THEN} \quad P = (MP \bullet MP_{Eur}) \times MInt / MP_{Eur}$$

$$\text{OTHERWISE:} \quad P = 0 \qquad (10)$$

  Where:

MP	(Some) average electricity market price in a specific country for a given year (to be further defined!)
MP_{Eur}	(Some) average electricity market price for Europe for a given year (to be further defined!)

MInt: Market interconnection impact factor, which represents the desirability of additional interconnection capacity given a certain market price markup.

In detail, when in a specific country the market price is higher than the average for Europe, the relative surplus (as a percentage of the average market European price) is multiplied by the market interconnection impact factor to obtain the sub-indicator for the price level.

- Examples: Since all components of formula (10) are open to debate, it is not very easy to decide on proper market price definitions or the market interconnection impact factor. For the market prices, possibly some annual average of spot prices would be fine. Nevertheless, an average European electricity market prices index does not seem to exist. One might consider applying the average market price (derived from spot markets) in surrounding countries instead (although this makes the value of MP_{Eur} counter dependent). In addition, the market interconnection impact factor needs to be set, probably more by a political decision than based on some technical argument.

  For these reasons, the market price sub-indicator will not be taken into account in the remainder of this section.

Application of the E_I indicator

The European Interconnection Indicator E_I can be calculated for each country or system. However, since the input data will change over time, care has to be taken when calculating the indicator for a specific year or time period.

The same holds for the situation when the European Interconnection Indicator is being calculated for a year in the future for which the need for interconnection capacity needs to be assessed. This implies that reasonable estimates need to be made for sub-indicators M, S and R for the respective year. Given that commissioning and decommissioning of generator plant affects the value of the sub-indicators, estimates for the sub-indicators might not be easy to make. As a substitute, a best guess extrapolated from the present conditions may be used.

For this reason, it should be noted that the indicator cannot be used as a target value beyond any discussion. Nevertheless, it may be expected to provide a good guess of the desirable interconnection capacity for some year in the future, at least not worse than any alternative approach applied so far.

Furthermore, the European Interconnection Indicator provides information on a specific system’s need for interconnection. It does not specify which additional links need to be constructed. At best, it indicates which countries need additional capacity and which links will bring the highest benefit to these systems.

The European Interconnection Indicator is based on technical characteristics only. It does not include cost data nor provides a cost-benefit analysis for a specific link. After a calculation of the E_I indicator, it may be concluded that additional interconnection capacity should be welcome given a reasonable cost-benefit balance, which probably needs to be assessed by applying more detailed models.

Finally, the interconnection indicator can be applied both to a single country as well as to an integrated market. This is up to the decision makers.

5.9.3 Alternative #2 Intermediate

As mentioned above, a third alternative is presented as a combination of the two previously cited. This third approach attempts to include the detailed analysis of Alternative #1 and the simplicity of Alternative #2. Under this approach, the outcome should be a mixture of the results provided by the two alternatives.

In this regard, the use of optimization models would provide the numbers for the indicators that compose Alternative #2. To this aim, the results provided by the use of optimization and simulations tools, can be used for the calculation of the sub-indicators concerning increase of competition, use of renewables and security of supply. It could also provide price results since the models are oriented to the marginal cost's estimation in order to determine the least-cost expansion plan and the optimal dispatch of existing and new plants.

As the use of optimization models enables the provision of prices, optimal use of renewables, increase of existing capacity and increase of available interconnection, the parameters needed for the estimation of sub-indicators can be better constructed and the accuracy of the numbers forming the indicator can assess more properly the new interconnection capacity necessities from the perspective of the optimal use of existing resources and the entry in operation of additional ones. This is of special interest when analyzing future events, since the indicators are not able to provide a good assessment in future years because of the lack of available reliable information.

In this sense, as Alternative #2 is quite flexible it can properly accommodate the necessities resulting from the optimization model results in a specific area.

However, the use of this approach is not sustainable in the long term because a proper methodology must be implemented in the mid-term. Thus, it can be a feasible alternative before a sound methodology becomes fully available for the declaration of projects of European interest. Nevertheless, its use can be acceptable also as a valid testing tool in the definition of priority projects before any final methodology is fully agreed by all involved stakeholders.

5.9.4 Conclusions

Hence, the identification of priority corridors based on the fulfilment of EU policies is complex, due to the following issues:

- Priority corridors must be selected from a broad catalogue of candidate projects, with strong linkages between new projects and existing facilities.
- Projects should be considered as discrete, and it should be necessary to take into consideration that in some cases electricity projects could be exclusive.
- First selection criteria should prioritize projects that are part of the least cost solution (i.e. increase social welfare).
- Subsequently, it is necessary to assess how selected projects contribute to the fulfillment of EU policies.
- Declaration of priority corridors should aim to achieve these EU policies and objectives.

Given the complexity of this identification process, simple approaches are not likely to fulfil the principles underlying the selection of priority corridors in electricity transmission. Therefore, a detailed modelling methodology seems to be the only effective solution to the identification of robust, socially beneficial priority corridors in the long term.

The validity of the tool in the long term is a different requirement that should be met for avoiding delays in the decision-making process since priority corridors usually last for several years. The use of short-term indexes is likely to be more criticised by involved stakeholders dur to the subsequent delays that this type of investments brings in electricity transmission.

In any case, the use of any of the proposed alternatives in measuring each project's contribution to the development of the European interconnection system may be valid depending on the process to select priority corridors. Even the use of both methodologies may be viable in order to compare results and allow for discussion in the selection process. The use of a combination of both alternatives may be acceptable before a final methodology is fully supported by those agents involved in the declaration of electricity priority projects.

5.10 Proposal of selection criteria

Once the methodology for the selection criteria has been set for providing results that are in line with the requirements of the principles underlying the designation of electricity transmission corridors, the whole process has to be defined, from identification to construction.

5.10.1 The entire process

The set of processes that conclude to the commissioning of EU priority corridor needs is composed of four phases, each one divisible in turn in several activities:

1. Identification of candidate transmission projects that, in a first assessment, seem to provide benefits at regional level. These are the

candidate projects. An important issue is that, in many cases the benefits arising from candidate projects are independent. In some cases the development of one project reduces the benefits of others. This is the case of competitive projects. In others cases, the benefits of a project increase when another one is built. In this case candidate projects are supplementary.

2. Overall assessment of projects and ranking. Require a planning process suitable to select the most appropriate projects from the candidates' list. However, taking into consideration that the candidates' list will contain competitive and supplementary projects, a simple screening process is not enough. This is more relevant in electricity, since the building of a transmission facility modifies flows (and consequently benefits) of other facilities (new and existent). Therefore, no simple screening methodologies are appropriate for project ranking. This ranking methodology should be able not only to assess the projects from a socio-economic perspective, but also from the scope of their contribution to the EU policies. A simplified but doubtfully robust criterion is to measure the individual benefits of a particular project, assuming that all remaining expansion is known and fixed.

3. Decision Process. Each project encompasses a considerable number of stakeholders. Therefore, after developing an appropriate ranking, it is necessary to check the attitude of stakeholders against proposed projects. Most of the transmission projects in electricity markets produce winners and losers. This is unavoidable. For instance in the case of cross border transmission line dedicated to export energy from country A to B, generators of B and loads from A are the losers, while generators of A and B are the winners. If the overall socio-economic benefit is positive, the decision process should impede the losers from blocking the projects. However, most resistance to the projects does not come from market participants. In particular, two groups have frequently exerted big influence on decisions: (1) population affected by the construction of a transmission line and stakeholder of the exported country that is affected by the price increase; (2) the second group includes politicians that do not see convenient increase prices to consumers. So the project decision should obtain the consensus of stakeholders that are actually affected by the construction of the selected facilities, but avoid to be influenced for undue parties.

4. Construction Process. Presently the process of electricity transmission facilities development is one of the reasons of the big delays in the commissioning of new facilities, including of course those labelled as priority ones. The steps from the decision to build a project until its commissioning are the following:

a. Facilities design

b. Final environmental studies and approval

c. Other authorizations

d. Freed of rights of way

e. Construction contracting

f. Construction

Once freed the rights of way, which is the only (in some cases) complex issue, the construction should not require more than 2 years for electricity transmission lines. This requires of suited contracting and building methodologies. Therefore, to obtain an appropriate reduction of times, improvements should primarily be oriented to expedite activities b, c and e.

In order to follow the process and make intermediate decisions, the European Commission should appoint a department/commission/working-group (the Evaluation Commission) with clear responsibility and attributions to make decisions on intermediate steps, as explained below. The final decision of declaring a project as EU-Priority, and consequently receive some specific benefits, should be taken by the European Commission.

Based on these comments the rest of the chapter is devoted to presenting sound ideas and recommendations about how to improve the present process. The resulting recommendations will aim to allow European Commission to identify the best alternative for designating priority corridors and to considerably reduce the time for making decisions and building the facilities.

Identification of Candidate Projects

Candidate projects can be identified for any stakeholder. However most of them will be identified by the TSOs and market participants. However, in the future the European Commission should be a relevant source of candidate projects, mainly those oriented to fulfil the EU policies.

In this regard, it is crucial that each stakeholder (the Project Sponsor) have the right to present candidate projects to the entity responsible for carrying out the planning process (the Planning Entity).

It would be necessary that sponsors of each candidate project present some basic information on each project:

- Expected benefits of the project.
- Expected investment costs and operation and maintenance expenses.

- How the investment will be recovered, although TSO project costs are recovered through transmission tariffs.

- Preliminarily environmental assessment. This assessment should be able to identify any issue that may impede or substantially increase the cost of the project.

- Alternative project rights of way.

- Identification of potential problems with the rights of way. In case conflictive zones are identified, alternative rights of ways should be specified. The main issue is to prevent delays in the construction and the need to use extremely expensive alternatives like underground cables that can multiply by 5-6 times the total cost of overhead transmission lines. This solution is likely to be adopted in many electricity transmission corridors where the population is against the project (i.e., the Spanish-French interconnection).

The Evaluation Commission should approve the condition of any candidate project presented by a stakeholder, based on the above listed information. However, rejection should be based on the non-fulfilment of the principles underlying the designation of electricity transmission corridors.

A preliminary screening may be necessary if the number of candidate projects becomes too large and difficult to manage by the planning process. However, this screening should avoid eliminating arbitrarily any projects.

Planning for Developing Electricity Transmission Corridors

This activity aims to select the appropriate projects from the list of candidates ones, and to identify those than can be considered as EU Priority.

Here there are important differences between the methodology for gas and electricity. Two issues differentiate the planning methodologies for the two markets:

- All electricity transmission corridors interact strongly, so an individual project analysis cannot produce appropriate results, and

- The number of candidate projects is substantially greater in electricity.

Therefore, this phase requires of a sound methodology for the designation of priority corridors in electricity. This is due to transmission planning facing relevant conceptual and methodological difficulties, some of them exclusive for electricity. The following list includes these differences:

1. Transmission connects sources (generation, gas fields) with sinks (demand). But, because of the liberalization processes, sources have been independently defined by Market Participants. So, at the time of

elaborating the planning process there are relevant uncertainties on where the sources will be located since these are private decisions. On the other hand, demand can be forecasted with lower error, but substantially greater than zero.

2. Transmission planning requires a long term horizon (typically 25-30 years), compatible with the projects' life cycle. However, the horizon of investments in generation is much lower, usually no more than five years. Therefore, the planning methodology should be able to make reasonable assumptions on investments in new sources for the whole planning horizon. A sound solution is that the optimal expansion planning model identifies the most convenient expansion of generation beyond the time for which new projects are known. For instance if the list of ongoing or decided new generation projects covers the demand in a horizon of five years, the model can select the generation expansion for year six onwards.

3. In electricity, due to the meshed design of the electricity grid, the physical load flows do not follow the economic transactions. Therefore, the entire system is affected by commercial transactions between two specific countries, resulting in transits through national grids. Although financial arrangements have been established to compensate for these transits, the network needs to be able to physically accommodate the requested flows.

4. Linked to the above issue, each new transmission facility modifies the flow patterns in lines (electrically) near the new project. Therefore, it is extremely inaccurate to individually asses the candidate projects[31]. Additionally, an integrated planning approach is mandatory.

5. Electricity is not traceable; this means that there is no scientific method to identify responsible(s) of a particular flow in a line[32]. Consequently, it is difficult to efficiently allocate investment and operation costs to the system's users. Therefore, those agents involved have no proper incentives to look for socially and economically efficient locations.

6. Typical security criteria for transmission systems (for instance N-1) hinder the planning process, since demand must be met even when a major facility is not operative.

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[31] The only exception could be a line connecting isolated systems, which is not the case in the EU projects.

[32] In many cases arbitrary criteria have been defined to identify the users of transmission systems (marginal participation, average participation, etc). But all these methods fail to provide physically and economically supported identification of usage.

7. The natural planning criteria, to select the candidate projects that minimise costs (as a way to achieve social benefits maximisation) may be not consistent with stakeholder interests. A planning based approach will ensure that an optimal outcome is identified “and not just any option that generates a net private benefit”. Furthermore a solution that minimises costs, and that is implemented by private investors will always ensure to this investments a rate of return not lower that the discount rate used in the planning process. Some of the concerns related with the coordination between global social benefits and private development of the projects are:

   a. TSO profits arise from a regulated rate of return on the developed facilities. This regulated rate may be (and usually is) different to the social discount rate. So, the TSOs’ objectives (and therefore selected projects) may differ from the general welfare targets.

   b. Market Participants make decisions on investments based on their own risk perception. Expected return on investment depends on this risk perception. In the other hand, planning requires a single discount rate arising from a single risk assessment, so inconsistencies are expectable.

   c. In some countries (e.g., Brazil or Peru) the use of competitive procedure to appoint the company responsible to develop each transmission project reduces substantially the differences between private and social discount rate. These procedures reduce some of the risks that face investors, ensuring them previously to the construction of the new facility the stream of revenues that allows achieving the expected return on the investments.

8. Security of supply can be quantitatively incorporated to the planning process using the concept of Value of Lost Load (VoLL), i.e. the (subjective or objective) value that each consumer assigns to the energy he/her could not consume because of a service interruption or lack of capacity. But, VoLL estimation requires a considerable effort.

9. Usually TSOs plan their system with the target to maximize benefits at national level. A regional or EU wide planning will attempt to maximise the overall regional-EU social welfare, which means that selected projects may be different. Regional planning should include the representation of internal transmission networks of the involved countries. Although this representation may be simplified, it should be accurate enough to identify internal congestion that may arise by combination of local and cross border transactions. An appropriate planning methodology can ensure that expected benefits in a country are

no lower than those arising from the internal's TSO planning. However, on the other hand, priority corridors are mostly cross border facilities that require a regional-EU planning.

10. Renewable energy in a specific location is mostly intermittent. When high levels of penetration are achieved, demand meeting in some countries will probably depend on the availability of these resources. However, as spatial correlation between distant renewable location is low, it is highly possible that in other zone there is enough generation to cover the lack of generation in the zone deficit. Therefore, the main objectives to promote renewable penetration is to ensure that when renewable generation is in low level, a country can be supplied by the rest of the EU countries, and when there is excess of production, this can be consumed in the rest of the countries. This means that planning should properly consider the intrinsic stochastic nature of some renewable energy sources like hydro and wind. The methodology proposed as Alternative 1 is appropriate to assess the benefits of corridors to allow a more secure (and economical) development of intermittent renewable sources as it is suited to consider the effect of different renewable generation series in each country.

Hence, as a result of the above list of issues that arise in the planning process, a set of solutions need to be addressed regarding the selection of a proper methodology for the planning process in the designation of electricity transmission corridors. The solution must comprise the following two aspects:

1. To define a methodology that can properly address the issues mentioned above, and

2. To identify the most appropriate entity to carry out the planning, taking into consideration the potential conflicts of interest identified above, as well as the need of a regional-EU wide planning aimed to maximize the global social welfare.

As a consequence of the number of issues to be treated, section 5.9 fully analysed the necessary solutions for providing reasonable results regarding the identification and the planning phase in the methodology proposal. More specifically, the section attempted to address the two main issues:

- A methodological proposal that fulfils the above identified issues.

- Some consideration on the most appropriate entity for carrying out the regional-EU wide planning.

The outcomes of the planning process will be composed of the list of candidate projects that are part of the optimal solution. With the proposed methodology that was fully developed in the cited section, all the selected candidate projects will be required to provide a marginal rate of return greater or equal to the social discount rate used for planning. For each selected project a list of indicators will assess the project's contribution to the fulfilment of the EU policies (i.e., Alternative #1 or Alternative #2 results). However, the most appropriate methodology is the one that provides only one comprehensive indicator as it was previously mentioned. Contribution to social welfare or economic value congestion released (minus building costs) can fulfil the condition of unique indicators (i.e., Alternative #1).

Those selected projects whose indicators have values above a threefold previously defined, could be declared of EU Interest by the Evaluation Commission, and therefore become candidates to receive the proposed benefits, if they are finally selected with the criteria proposed.

Decision Making Process

Once the list of EU Interest projects is available, the next step would be to obtain the comments and objections of the stakeholders. This should be done in a reasonable time interval, typically 2-4 months.

At this phase it would be advisable to identify and solve any objection that may arise in relation with the rights of way.

The comments/objection should be reviewed by the Evaluation Commission and, based on this proposal to the European Commission, the declaration of EU Priority Corridor will be made, with the subsequent right to receive the corresponding benefits included in this type of projects. The Evaluation Commission should also identify the responsible party to build and operate the project within each country. Although this role corresponds typically to the national TSOs, some alternatives might be analysed.

Whoever is the final responsible for project development, it would have to fulfil a previously defined schedule to complete and commission the new facilities, including penalization for delays.

Project Development

Although the traditional scheme is to allocate the building of new projects to TSOs, international experience shows very interesting alternatives that succeed to complete complex transmission expansions in very short time periods (e.g., the network expansion in Brazil).

In case of merchant facilities, the developing is the sponsors' responsibility. However, if the delay in the commissioning affects the benefits of other ongoing projects, the sponsors could be penalized.

Once commissioned, the operation of the new non-merchant facilities can be assigned to the company that built it, or to the respective TSO.

5.10.2 The process with Alternative #1

Once mentioned the features and abilities that the selection criteria methodology must comply with, and following the discussion on the appropriateness of having robust estimation with simple results, it is regarded that the theoretical optimal approach must make a long term optimization of the whole EU transportation networks.

However, this type of modelling also presents a number of aspects that reduce its attractiveness. This is due to the following:

1. It would be difficult to coordinate the simultaneous planning of 27+ countries and to achieve reasonable agreements timely.

2. It would be impossible to manage the huge number of variables that would require a long term planning of 27+ countries.

Hence, it is necessary to develop a methodology that can manage smaller regions, and use a temporal hierarchical approach for planning. In this sense, the identification of the suitable Regions provided in the first chapter of this section allows providing a more detailed analysis while the use of these types of models also helps in the provision of the appropriate outcome.

The spatial issue

As a result of the selection of suitable Regions, the planning phase can be performed at regional level. Then in a second phase the regions identify and assess the inter-regional connections. A number of iterations may be necessary until a solution is reached. This approach has the following advantages:

- It will be easier to achieve agreements at regional level.

- The inter-regional planning will require agreements on a smaller number of interconnection projects.

- The volumes of information are more manageable, and it will be easier to get an agreement on the basic assumptions (although some of these assumptions will require an EU wide agreement).

The temporal issue

As the life of cross border interconnections is likely to be longer than 30 years, a reasonable planning process should consider at least such an horizon. On the other hand, detailed load flow and stability studies involve a very detailed representation of networks. Therefore, it is impossible to optimize the expansion in a 30 year horizon with this level of detail.

The solution is the use of a hierarchy of planning models, each with a different time horizon and level of detail. This type of modelling is composed of the following three models that are necessary to be estimated for matching both transmission and generating planning needs:

- Model 1 – Optimal Expansion: Generation and transmission model with 30 year horizon, using a simplified modelling of the transmission system.

- Model 2 - Market Simulation: Optimal long term solution for the first 10 years is simulated with an optimal load flow model (OLF).

- Model 3 - load flow, stability, short circuit, reliability studies are performed for the optimal solution with a 3-5 year horizon, based on typical generation-demand profiles arising from model 2.

These models are run iteratively and the results of short term models are used to modify input data or assumptions of longer horizons.

Finally, those projects that pass the three stages are selected for detailed feasibility studies of Step 3 mentioned in the previous section.

It has to be stressed that the use of this type of models is commonly accepted by TSOs and planning advisory agents, so that its use is widely known. This is an additional advantage that introduces simplicity compared to other methodologies.

Results of Alternative #1

The hierarchy of planning models provides an outcome that fully complies with the selection criteria requirements and with the fulfilment of the EU policy. This is done through the benefits estimation based on the following approaches:

- Cost savings: through the use of OLF models, the benefits linked to the designation of a specific transmission corridor are estimated. The simulation model provides the best alternative for investments in electricity transmission infrastructure in monetary terms.

- Renewables development: typical planning models have the ability to identify the least cost solutions for transmission and the use of renewable energy sources for generating purposes. Benefits will result in cost savings (fuel and emissions) that are translated into monetary terms.

- Improvement in quality of supply: OLF models with Montecarlo simulation can provide estimation of number of service interruptions and unserved energy, which should be valued at Value of Lost Load (VoLL). Therefore, simulating models provide results in monetary terms.

- Inclusion of emissions policy:

    - For CO_2 through emission costs. However, as the power sector will have strong influence on credit prices (40% of emissions, high elasticity to emissions price) a more sophisticated approach should be proposed.

    - Through constrains to sector emissions.

- Reduction of market power potential: simulation models provide estimation on the increase in social welfare when competition increases through the increase of the interconnection capacity across countries.

- Congestion is easily identified when using optimal expansion and simulation models that represent the internal and cross border transmission systems. As models are able to deal with internal bottlenecks and N-1 criterion, the selection of projects of European interest may be analyzed not only from the international perspective, but also from the national one. Therefore, the planning process as proposed will identify not only the optimal cross border expansion, but also the new investments or reinforcements of the internal networks. This is of special relevance since the transmission necessary to increase of both wind power on-shore and off-shore capacity is necessary to be optimized. Windy periods are modelled in simulation models by including different scenarios, so that bottlenecks require intervention in the market in order to maintain system security (N-1 criterion). Therefore, the transmission expansion plan allows for the selection of both interconnections and internal bottlenecks as candidates for being finally declared priority corridors.

Thus, through the use of this type of modelling, the benefits are integrated in the planning methodology, and the requirements of the selection criteria are fulfilled.

In addition, it is appropriate to note that congestion reduction is not a benefit by itself; it implies greater cost to meet the load. The benefits of any electricity transmission facility that reduces congestion will be identified by planning and OLF models in the cost savings analysis.

All these aspects are treated in Annex 1 which presents the results for the Spanish – French interconnection that also includes Portugal, as it was fully affected by the increase of interconnection between these two countries and it is also part of the South Western region previously defined. In this respect, results provided by the use of this methodology are analyzed as an example of what this methodological approach can provide in the declaration of electricity priority corridors.

Issues of Alternative #1

The above models are subject to a number of difficulties related to the planning structure process that must be addressed so as to provide the best feasible assessment in the identification and designation of electricity transmission corridors.

These issues are basically the ones related to the necessary assumptions for obtaining a proper assessment on the designation of electricity transmission corridors.

The following issues are of special attention for providing reliable results for the selection criteria:

- How to plan transmission when supply (generation, gas) is only defined in the short term (the poultry problem)? A number of assumptions are necessary to represent a real situation.

- How to deal with structural uncertainties?

    - Price of fuels which are relevant to define type and location of new generation (peak oil? or new abundant supply from new producers like Brazil, development of oil sands, etc?)

    - Kyoto 2 (or post Kyoto) measures to mitigate climate change (cap and trade worldwide?, or other approaches)

    - Technology evolution: high efficiency coal plants, ICGT, CO_2 sequestration, efficiency of solar panels, cables costs, etc.

    - Policy on renewables: national or EU level?

    - Success and impact of energy efficiency measures (in which sectors will reductions occur)

- Common facilities cost for consistent planning (EU Cost Manual?)

In these areas, TSOs and regulatory bodies generally hold important and unique information regarding the state and likely state of the network and production and trading positions of each market player placed in both the liberalised and the regulated markets. Such information will be crucial for efficient price formation. Any asymmetries in the availability of information or the timing of its release could therefore distort market outcomes. It will be important therefore to ensure that TSOs manage and release information in an appropriate manner with the aim of providing appropriate information in the cost-benefit assessment. This was previously commented in the stakeholder analysis, and it was labelled as essential in the purpose of providing adequate results and allowing the methodology working adequately for the targets it is used for.

In addition to these uncertainties, a number of risks need to be examined in order to provide a proper assessment. These risks are mostly related to purely investment risks, and can be summarised as follows:

- Market risks – these are associated to the price and demand evolution once the project is developed. The following aspects have to be analysed:

  - Degree of liberalized prices (i.e., full-service tariff and access tariffs regulation).

  - Market concentration on wholesale and retail markets. The concentration degree affects the interaction between markets.

  - Harmonisation of regulatory codes and market rules in the cross-border interconnection capacity.

  - In addition, the existence of wholesale and forward markets and their liquidity also helps assessing these risks.

- Macro-economic risks – this external factor directly affects investment costs through macro-economic values, such as inflation.

- Construction risks – delays in construction may hamper investment decisions.

- Financial risks – changes in the interest rate resulting from the EC's interest rate policy directly affect the investment decision. This is not a major issue in the EU since the majority of corridors are expected to be under a regulated regime. However, the main issue might be more focused on the reinvestment policy into the network.

For these uncertainties, all parties involved must be forced to provide their best available information in order to avoid distortions in the development of the selection criteria.

In addition, in the proposed guidelines, the most relevant issues in the construction of new interconnections are analysed in more detail in the next chapter, in order to enforce further discussion on them.

Planning Models

The three stage methodological approach described in section 5.9.1 requires of three models.

The first is a least cost expansion of transmission and generation, able to work with long term horizons and several scenarios. In Annex 4 there is a general description of these type of models, which although are several alternatives commercially available, probably the magnitude of the EU planning may deserve a tailored design.

The second is a simulation model able to represent the clearing process in the EU electricity markets, but including an appropriate representation of the transmission system, and the possibility to manage renewable resources scenarios. There are appropriate models commercially available.

Finally classical power system analysis models should be used for the detailed analysis of the transmission system in selected load flow states. There are several commercial packages, and some of them are almost the standards for these type of studies. All the TSO have one or several of these packages, so no special considerations are necessary on this issue.

5.10.3 The process with Alternative #2

This section illustrates an example of the results that may be provided by using Alternative #2, when considering this approach in the selection criteria process. Under the use of this alternative simple results may be obtained, but these are likely to be less accurate than those provided by mathematical models.

An example of the results that this type of modelling could provide in the selection process is developed below.

Sample calculation for some European countries[33]

In this section, sample calculations will be made for a few European countries. These include: The Netherlands, Belgium, France, Italy, Spain, Germany and the UK, both for the present situation and for 2020.

Calculation of the sub-indicators for the competitive structure of the electricity markets (M)

First the sub-indicator for the competitive structure of the electricity market (M) will be calculated. For this purpose, values for the HHI are required.[34] For 2020, HHI values do not (yet) exist. It is assumed that these are the present values minus 25 % (thus assuming improved competition).

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[33] This is presented as an example, although a more detailed analysis is presented in Annex 2 including all EU countries and a number of recommendations concerning the declarations of projects of European interest by analyzing the results provided by this alternative. However, this does not necessarily mean that these results are optimal, but are used as an example on the use of the methodology.

[34] The value for HHI (2006) of The Netherlands has been given in: NMa, Marktmonitor, Ontwikkeling van de groothandelsmarkt voor elektriciteit in 2006, The Hague, december 2007. For the other countries, values are given in: J. Percebois, Electricity liberalization in the European Union: balancing benefits and risks, The Energy Journal, Jan, 2008, http://www.entrepreneur.com/tradejournals/article/172829795_1.html and: Structure and Performance of Six European Wholesale Electricity Markets in 2003, 2004 and 2005, February 2007, http://ec.europa.eu/comm/competition/sectors/energy/inquiry/electricity_final_part4.pdf.

	HHI 2005 or 2006	HHI 2020
The Netherlands	1,995	1,496
Belgium	8,307	6,230
France	8,592	6,444
Italy	4,150	3,113
Spain	2,790	2,093
Germany	1,914	1,436
UK	1,068	801

Calculations based on a threshold Mt of 0,42 yield the following values for the sub-indicator for the competitive structure of the electricity markets (M) today and for 2020:

	M 2005 or 2006	M 2020
The Netherlands	2 %	0 %
Belgium	49 %	37 %
France	50 %	38 %
Italy	22 %	13 %
Spain	10 %	3 %
Germany	1 %	0 %
UK	0 %	0 %

Calculation of the sub-indicators for the amount of flow-based renewables (R)

For the sub-indicator for the amount of flow-based renewables (R) information on the present and target share of renewable power generation is needed, most notably wind power in Europe. These values are:[35]

	Installed wind capacity 2006	Total installed generation capacity 2004	Share of wind power 2006	Share of wind power 2020
The Netherlands	1,558 MW	21,381 MW	7.3 %	24.7 %
Belgium	194 MW	15,751 MW	1.2 %	4.1 %
France	1,567 MW	116,850 MW	1.3 %	4.4 %
Italy	2,123 MW	81,512 MW	2.6 %	8.8 %
Spain	11,623 MW	70,304 MW	16.5 %	30 %
Germany	20,622 MW	129,123 MW	16.0 %	30 %
UK	1,962 MW	81,055 MW	2.4 %	8.1 %

The renewable energy sub-indicators for each country, omitting the contribution of solar energy and based on a value of 80 % for the impact of wind energy power generation on available international transport capacity and assuming a threshold R_t of 5 %, then become:

[35] The 2006 data on installed wind capacity is derived from: European Wind Energy Association, Wind power installed in Europe by end of 2007 (cumulative), http://www.ewea.org/fileadmin/ewea_documents/mailing/windmap-08g.pdf; The total installed generation capacity is derived from: Eurelectric, Statistics and prospects for the European electricity sector (1980-1990, 2000-2030), EURPROG 2006, December 2006; The 2020 data are derived from the 2007 data assuming an annual growth rate of 9.1 % (see European Renewable Energy Council, Renewable Energy Target for Europe, 20 % by 2020, http://www.erec-renewables.org/fileadmin/erec_docs/Documents/Publications/EREC_Targets_2020_def.pdf), i.e. an increase by a factor of 3,4 in 13 years, although capped at 30 % for each country.

	R 2006	R 2020
The Netherlands	2 %	16 %
Belgium	0 %	0 %
France	0 %	0 %
Italy	0 %	0 %
Spain	9 %	20 %
Germany	9 %	20 %
UK	0 %	0 %

Calculation of the sub-indicators for the security of supply (S)

Thirdly, we will calculate the sub-indicators for the security of supply (S) for the selected countries both at present and for 2020. For this, peak generation capacity and peak demand is needed:[36]

[36] The data on the peak generation capacity (total installed generation capacity) and peak demand are derived from: Eurelectric, Statistics and prospects for the European electricity sector (1980-1990, 2000-2030), EURPROG 2006, December 2006.

	Total installed generation capacity 2004	Total installed generation capacity 2020	Peak demand 2004	Peak demand 2020
The Netherlands	21,381 MW	26,195 MW	17,400 MW	24,200 MW
Belgium	15,751 MW	19,560 MW	13,600 MW	17,300 MW
France	116,850 MW	128,840 MW	81,400 MW	92,300 MW
Italy	81,512 MW	109,503 MW	53,600 MW	75,900 MW
Spain	70,304 MW	110,136 MW	40,200 MW	61,800 MW
Germany	129,123 MW	142,115 MW	77,200 MW	83,000 MW
UK	81,055 MW	108,111 MW	67,400 MW	82,200 MW

The sub-indicators for the security of supply then equal, based on an effective contribution of renewable electricity generation to security of supply (RenCont) of 0.25 and a reserve factor (RF) of 1.15:

	S 2004	S 2020
The Netherlands	0 %	27 %
Belgium	0 %	5 %
France	0 %	0 %
Italy	0 %	0 %
Spain	0 %	20 %
Germany	0 %	20 %
UK	0 %	0 %

Calculation of the European Interconnection Indicator (E_I)

Since all three sub-indicators have been calculated (and omitting the sub-indicator for the price level), the interconnection indicator can be calculated. This results in the following values for today:

	M	S	R	E_I
The Netherlands	2 %	0 %	2 %	3 %
Belgium	49 %	0 %	0 %	49 %
France	50 %	0 %	0 %	50 %
Italy	22 %	0 %	0 %	22 %
Spain	10 %	0 %	9 %	14 %
Germany	1 %	0 %	9 %	9 %
UK	0 %	0 %	0 %	0 %

The European Interconnection Indicator can also be calculated for 2020 (based on the data mentioned above and given all uncertainties inherent to such an estimate):

	M	S	R	E_I
The Netherlands	0 %	27 %	16 %	31 %
Belgium	37 %	5 %	0 %	49 %
France	38 %	0 %	0 %	37 %
Italy	13 %	0 %	0 %	14 %
Spain	3 %	20 %	20 %	20 %
Germany	0 %	20 %	20 %	20 %
UK	0 %	0 %	0 %	2 %

Target interconnection capacities versus existing NTC

Using the European Interconnection Indicator and applying formula (12), the target interconnection capacities can be calculated, both for today and for 2020. These can be compared with the existing NTC values[37]:

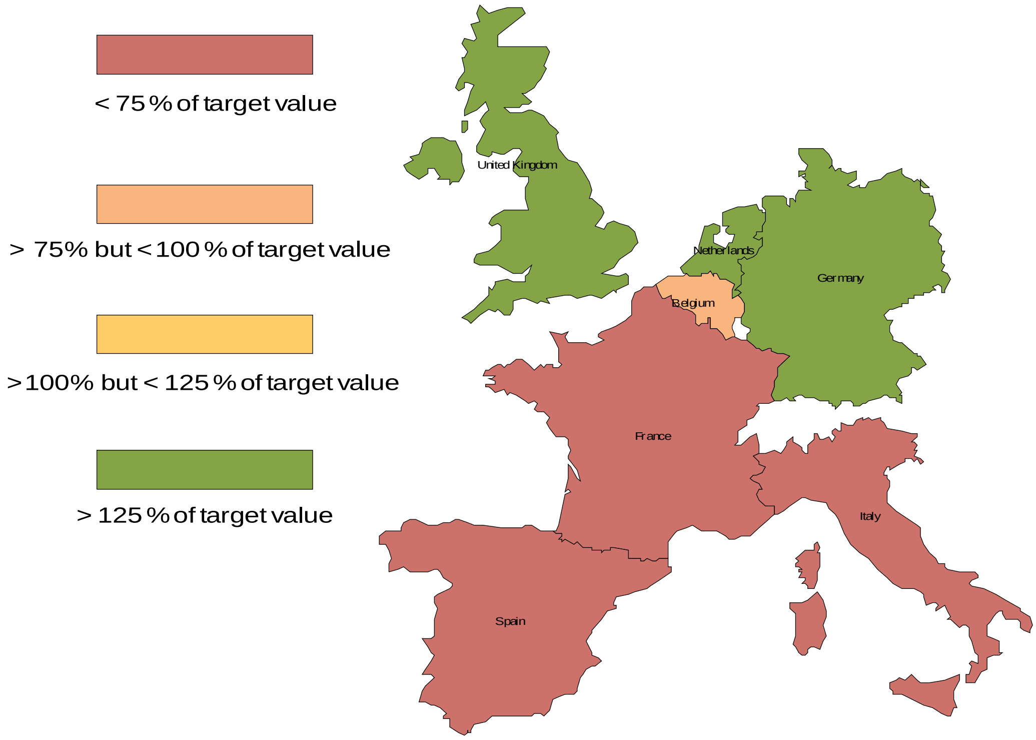
	Target IC today	Existing NTC	Capacity to be added
The Netherlands	504 MW	6,250 MW	•
Belgium	6,625 MW	5,600 MW	1,025 MW
France	40,917 MW	10,745 MW	30,172 MW
Italy	11,789 MW	7,690 MW	4,099 MW
Spain	5,580 MW	3,200 MW	2,380 MW
Germany	6,870 MW	17,700 MW	•
UK	0 MW	2,080 MW	•

	Target IC 2020	Existing NTC	Capacity to be added
The Netherlands	7,526 MW	6,250 MW	1,276 MW
Belgium	6,385 MW	5,600 MW	785 MW
France	34,934 MW	10,745 MW	24,189 MW
Italy	10,402 MW	7,690 MW	2,712 MW
Spain	12,529 MW	3,200 MW	9,329 MW
Germany	16,600 MW	17,700 MW	•
UK	2,039 MW	2,080 MW	•

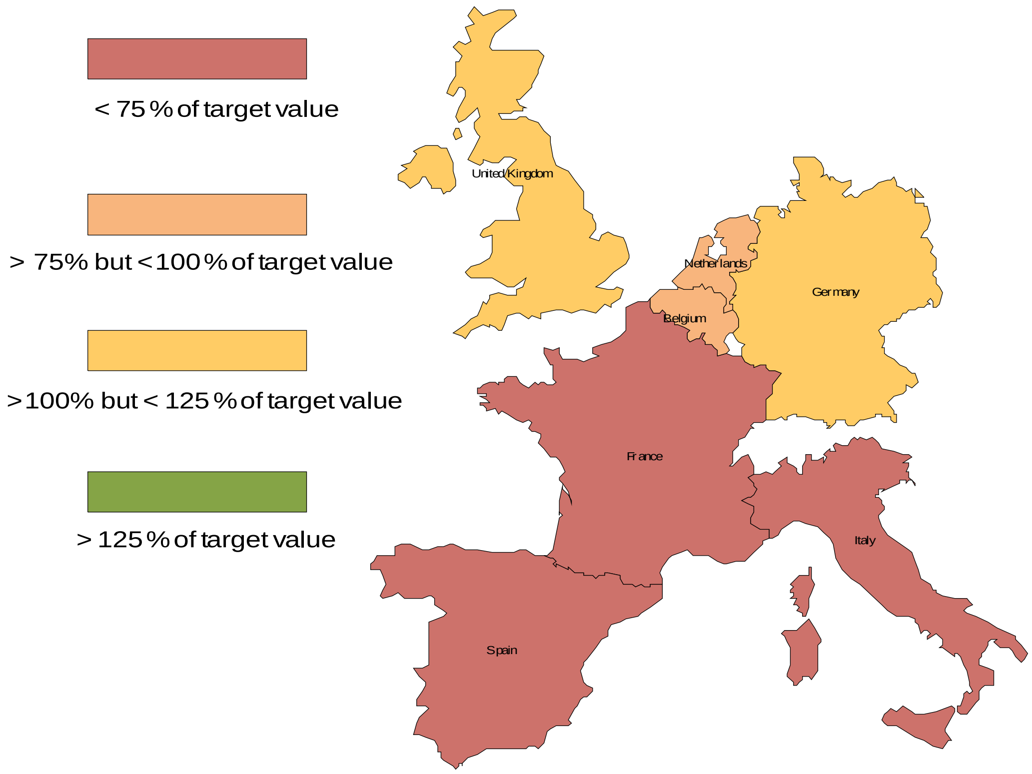
[37] NTC values are the indicative winter 2007-2008 values for the maximum import capacities for European countries as published on ETSOVista, http://www.etso-net.org/file/pdf/NTC_Matrix_Winter_2007-2008.pdf.

The need for additional interconnection capacity is country related. When these figures are depicted in a map with a color coding, the most necessary new interconnections become visible.

Below is the graph for today:



And the graph for 2020:



Balance of Alternative #2

The suggested approach to develop an interconnection indicator has the advantage of being simple and straightforward. However, its major weakness lies precisely here, since only partial information on the system and the market is taken into account. Many arguments can be found showing weakness in each of the sub-indicators. Therefore, further discussion (and also possible consultation) is needed before the European Interconnection Indicator can be applied in policy making.

Nevertheless, the simplicity of the European Interconnection Indicator E_I is appealing. When one succeeds in gauging the parameters to represent the reality in a decent way, it may offer a promising road forward. At least, one positive aspect of the European Interconnection Indicator is that the three sub-indicators reflect the basic three cornerstones of the European energy policy: competition (development of the internal market for electricity), security of supply and climate change.

5.11 Conclusions and recommendations

The main drivers for the development of a common methodological framework to select projects of European interest have been promoted by the EU. The design of a powerful planning tool is then necessary for complying with the European energy policy by allowing the selection of priority corridors taking into account competition, security of supply and increase use of renewables, with special attention to wind on-shore and off-shore capacity. The creation of a single electricity European is influenced by the connectivity between countries and regions, so that an economically based sound methodology is required. At present, interconnection decisions were basically featured by security of supply needs and very specific commercial requirements, but in the future new interconnection so as to operate the single electricity market will lead to make more decisions based on economic efficiency (e.g., new renewables integration into the system or regional interchange of hydro/thermal power to compensate for wind power variations).

Therefore, priority corridors should be able to solve this new situation and the selection of these projects must be based on the use of an appropriate tool that accounts for this framework. In this regard, Alternative #1 is able to detect arbitrage opportunities between countries[38] and / or regions, also complying with security of supply concerns. The identification of candidates is the first step to finally select a number of projects that may be labelled of European interest. This approach can offer the opportunity to design an optimal expansion transmission plan not only by underground cable investments, but also by repowering existing interconnection or construction new overhead lines through the use of different investment transmission costs. This expansion plan taken into consideration the priority dispatch of renewables energy plants, internal congestion, optimal dispatch and cross-border constraints, apart from CO_2 emission costs or technical aspects such as the N-1 criterion or the wind and hydro power flows.

In conclusion, optimization and simulation models offer the possibility to dispatching power from different technologies to different countries depending on demand to manage efficiently the European electricity network.

Finally, the type of results provided by this approach is summarized in a list of candidates that require further assessment on its viability in terms of local support or environmental impact that finally allows for ranking the list of candidates.

In this regard, the present status of priority corridors supported by a series of agents differs since any interested party use its own methodology framework with different purposes. This is not a wrong alternative but it may lead to delays or provide projects that might be unnecessary by using a common tool. As a result, there are many proposals of priority interconnection that can be observed in the following table:

EU priority corridors	TradeWind proposal	Date
Avelin (FR) — Avelgem (BE) line	Belgium-France	Between 2010-2015
Moulaine (FR) — Aubange (BE) line.		
Lienz (AT) — Cordignano (IT) line	Austria – Italy	Between 2013 and 2018
New interconnection between Italy and Slovenia		
Udine Ovest (IT) — Okroglo (SI) line	Slovenia – Italy	Scheduled for 2010
S. Fiorano (IT) — Nave (IT) — Gorlago (IT) line		

[38] Which will increase exponentially with the developments of intermittent renewable resources.

Venezia Nord (IT) — Cordignano (IT) line		
St. Peter (AT) — Tauern (AT) line		
Südburgenland (AT) — Kainachtal (AT) line		
Austria — Italy (Thaur-Brixen) interconnection through the Brenner rail tunnel.		
Sentmenat (ES) — Bescan• (ES) — Baixas (FR) line	Spain – France	Scheduled for 2010
Valdigem (PT) — Douro Internacional (PT) — Aldeadávila (ES) line and ‘Douro Internacional’ facilities.		
Philippi (EL) — Hamidabad (TR) line.		
Undersea cable to link England (UK) and the Netherlands.	Great Britain – Netherlands	Scheduled for 2010
	Great Britain – Netherlands	Scheduled for 2010
Undersea cable to link Ireland and Wales (UK).	Ireland- Great Britain	Scheduled for 2012
Kassø (DK) — Hamburg/Dollern (DE) line	Germany-Denmark West	Completed in 2012
Hamburg/Krümmel (DE) — Schwerin (DE) line		
Kassø (DK) — Revsing (DK) — Tjele (DK) line		
Vester Hassing (DK) — Trige (DK) line		
Submarine cable Skagerrak 4: between Denmark and Norway	Denmark West-Norway	Scheduled for 2012
Poland — Lithuania link	Poland-Germany	Scheduled for 2010 and 2013
Submarine cable Finland — Estonia (Estlink)		
Fennoscan submarine cable between Finland and Sweden	Finland-Sweden	Scheduled for 2010
Halle/Saale (DE) — Schweinfurt (DE).		
Neuenhagen (DE) — Vierraden (DE) — Krajnik (PL) line	Poland – Germany	Scheduled for 2010
Dürnrohr (AT) — Slav•tice (CZ) line	Czech Rep. – Austria	Scheduled for 2009
New interconnection between Germany and Poland		
Ve•ký Kapušany (SK) — Lemešany (SK) — Moldava (SK) — Sajóivánka (HU) line	Hungary – Austria	Not scheduled
	Hungary – Slovakia	Scheduled for 2017
Gab•íkovo (SK) — Vel'ký •ur (SK) line		
Stupava (SK) — south-east Vienna (AT) line.	Austria – Slovenia	Scheduled for 2009
	Austria – Slovakia	Scheduled for 2015
	Austria – Slovenia	Scheduled for 2009
	France – Italy	Not defined yet
	Greece – Italy	Not defined yet
	Czech Rep. – Germany	Not scheduled
	Poland – Czech Rep.	Not scheduled
	Poland – Slovakia	Not scheduled
	Czech Rep. – Slovakia	Not scheduled
	Norway – Netherlands	Scheduled for 2008

	Germany – Great Britain	Not scheduled
	Germany – Denmark West	Not scheduled
	Norway – Great Britain	Not scheduled

As it has been illustrated there are certain differences that are not positive for the proper development of the internal market. Alternative #1 approach is able to provide a unique list by taking into account all relevant aspects so that the final list of candidates could be better managed by involved stakeholders in further discussions and, additionally, could facilitate the designation of priority corridors by the EU. In addition, other public or private organisations, like national (e.g., DENA) or international ones (e.g., Greepeace) are providing list of interconnection needs, with the subsequent complexity for both TSOs and authorities. This fact reinforces the necessity of having a common harmonised approach, managed by involved stakeholders, transparent and coherent. Otherwise, the result may lead to several dozens of projects promoted by different agents that would lead to inefficiency process in both delays and social welfare increase.

As an example, this study provides a list of candidates in Annex 2 by using Alternative #2 and a list of candidate projects in Annex 1 and 3 regarding Alternative #2 approach in order to show how these methodologies might be used with the selection of feasible routes.

6. Revision of the TEN-E Guidelines

Since the functioning of the electricity market is, to a large extent, related to the competitive pressure felt by market parties in regional markets, the availability of sufficient interconnection capacity is very relevant. However, although there has been significant effort by the European Commission to promote interconnection expansion, actual investments seem to be lagging, which, in the end, will hamper the further development of the European electricity market.

This chapter provides recommendations on the TEN-E guidelines that may be desirable for facilitating the successful implementation of the methodology proposal developed above.

The necessary input for a revision of the TEN-E guidelines is provided by the use of the new methodological approach for identifying and designating electricity transmission corridors.

This includes the specification of the link together with its range of influence and economic impact (priority corridor). The objectives of the regional platform are:

- Enable authorisation and construction of selected projects declared to be of European interest[39] in a maximum time span of five years.

- Proposing to the Commission priority energy transmission corridors together with projects of European interest as a result of the regional priorities.

Once the entire selection process has been agreed, the appropriateness of reviewing the TEN-E guidelines will be analysed.

In principle, during the updating of the selection criteria, the methodology for assessing benefits, impact and influence area of the selected projects will be developed. This will allow identifying priority corridors on an objective basis.

The TEN-E guidelines lie on the objective to promote Europe's energy policy, sustainability, competitiveness and security of supply. In addition, renewable energy constitutes a Europe-wide challenge which exceeds the national dimension. Therefore, the proposed methodology must be in line with the aim of accelerating the implementation and construction of interconnection across European countries.

Hence, although the identification of missing links in the transmission infrastructure has already been done, further designations may be derived from the proposed

[39] It would be also convenient to define European interest objectives as those projects based on maximising social welfare with the constraints given by security of supply and environmental targets.

methodology. The new Member States of the EU enlarged will be also affected under this methodology, so that new priority corridors may be designated.

Regarding transmission corridors, in the process of contributing to drafting guidelines in defining electricity transmission corridors the assessment must be concerned on the following issues:

- Electricity corridors financial process. Despite the fact that this is not considered a major barrier since the majority of interconnection capacity is under stable regulatory frameworks, it is necessary to address this issue because of the potential savings of alternative corridors.

- Regulatory framework. The absence of harmonised regulation across countries may hamper the investment process. Thus, guidelines should promote more transparent, stable and predictable regulatory frameworks on these investments. The authorisation procedures should also be promoted to be more efficient and faster.

- Social welfare might differ from individual interests, so it should be avoided that investment decisions lie on private stakeholders.

- Market risks. These risks depend on regimes under non-regulated prices. In such cases, guidelines should be focused on different contract options, third party access or any other aspect that may delay the construction process. To this end, the removal of pricing distortions is crucial so as to ensure reliable signals for investments.

- Coordination between TSOs. The transparency of relations within regional priority corridors projects requires further mechanisms for monitoring the progress and the possible problems in the development transmission corridors.

Therefore, the proposed guidelines must try to foster the improvement of all these aspects that have hampered the proper development of electricity transmission corridors in the last years.

All the above mentioned conditions are basically impeding the development of new interconnections, as it was expected. More specifically these issues are focused on the following three major impediments, analysed below.

6.1 Impediments for New Interconnection Investments

There are three categories of major impediments for new interconnection investments that need to be addressed so far. The first relates to the underlying economics of new transmission lines, the second to the regulatory framework governing interconnection investments and the third to the lengthy planning process.

The first category may be solved with the implementation of the proposed methodology for the selection criteria. The other two require a more active role of the regulatory entities involved in these processes.

Uncertainties in the Economic Valuation

The costs of a specific transmission line are very much related to the pathway that will be allocated to it. However, for 200kV+ lines this pathway is predominantly a result of the planning process, in which not only a suitable corridor needs to be defined but also many planological hurdles are encountered (related to the crossing of urban regions, mountain passes, water crossings or natural reserves). Since the link connects systems in different countries, the decision making process on the track needs harmonization as well.

The costs for a new link are highly dependent on the length of the track for the transmission line, as well as on specific requirements for its design. In a situation where the construction of new overhead lines is getting increasingly difficult, underground cables must be considered for a part or the whole of the track at significantly higher overall costs, generally by a factor 8 to 15 higher than an overhead transmission line for the same capacity.[40,41]

Due to this uncertainty, making detailed cost estimates is often difficult until at least some guidance has been obtained on the geographic track of the link. These decisions are however often decided by other actors than the TSOs themselves. Thus, a more specific detailed plan of the involved actors is required in this respect.

In general, the major contribution to the benefit side of a cost-benefit assessment comes from benefit estimation. Thus, model simulations are needed for the European market's functioning at the moment when new interconnection becomes operational. This procedure will improve notably the results provided in the selection criteria.

Missing Regulatory Framework

Up to now, financing the new transmission line is not often a problem, due to the presence of a regulatory framework according to which financing from the tariffs (or the congestion rents) is allowed. Problems may appear only in cases at the periphery of the European financing system.

However, although the availability of sufficient financial resources is not a major issue, it does not mean that the regulatory framework is entirely clear with respect to financing international links. Several issues are not yet sufficiently resolved at

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[40] See F. Vanderberghe, Is 380 kV Underground Cable an Option, ETSO contribution to the ERGEG Electricity Infrastructure Workshop, Brussels, 13 February 2007.
[41] Although, as it was mentioned before, the latest technical studies show that costs are from 5 to 6 higher in those interconnection areas located in isolated tracks.

present. The ETSO has identified two main issues that frustrate increased interconnectivity across the EU:[42]

The first is the ever increasing difficulty to obtain planning permits for both cross border, and within member state, infrastructure. The second is the so called 'regulatory gap' where there is currently no requirement for member state regulators to consider issues outside their borders. The result is the absence of a favourable cross border legal and regulatory framework to encourage cross border investment and to ensure its financing.

The ETSO has detailed the following issues that need to be settled when designing a harmonized framework for investments in international tie lines (which will be commented on individually):[43]

- Agreements, among the regulators, on the allocation principles for the costs incurred by the TSOs for interconnection investment.

  Allocation principles are needed to provide guidelines for sharing the investment cost among the TSOs involved. Since the benefits resulting from a new line may be unevenly distributed among the systems connected by the link (e.g. the high-price area will receive different benefits from the the low-price area, or a capacity-constrained system will have more benefits than systems with ample generation capacity) it makes sense to adopt a set of principles that govern cost allocation. The same holds for situations where one TSO has to take on considerably higher costs for the interconnection, than another TSO (e.g. if the distance to the nearest network connection point is much longer in one system than the other, or in case one TSO needs to make significant costs for investing in underground cables instead of - cheaper - overhead lines.)

  However, this is not simple. Allocation of costs based on benefits seems a sound approach. However, estimating the benefits for a market participant of a particular transmission facility without considering the interactions with the rest of the expansions, require large data amounts.

  The socialization of these costs in the medium term would probably produce fairer results.

[42] ETSO, Communications from the Commission to the European Council and the European Parliament on the EC Strategic Energy Review, ETSO Response, 16 March 2007, http://www.etso-net.org/upload/documents/ETSO%20Strategic%20Energy%20Review.pdf, p.2.

[43] ETSO, Position Paper on Roles and Responsibilities of TSOs and other actors in Cross-Border Network Investment, July 19, 2006, p.4.

- Regulatory mechanisms, such as TSOs incentive payments or increased regulated return on investments in case of the development of new interconnection infrastructures.

  Although used in some cases with scarce global success, this type of incentives can create conflict of interest of moral hazard problems.

  Although, in theory, existing regulatory mechanisms should possess sufficient incentives for new investments, several situations may be envisaged when additional regulatory incentives might be needed. One such situation may arise when investments are mainly needed for accommodating transit flows, which would require including the expansion cost in the guest TSO's tariffs. But this incremental tariff should be paid by the participant that uses it for transit. Incentive-based regulatory mechanisms where the a TSO's revenues are related to the transported electricity, may provide a very limited incentive (and unnecessary risks) for investment in new interconnection. Additionally, due to future changes in network flows, it might not be guaranteed that the TSO will receive a sufficient return-on-investment, so other remuneration schemes should be considered.

- Remuneration methodologies for intra-country transmission investment that increase interconnection capacity.

  In several situations, the congestion bottleneck is not related to the capacity of the international tie lines but to capacity limitations of a domestic network. Although such investments need in principle to be recovered from national tariffs, the business case for these investments may be such that, from a national perspective, the costs are higher than the benefits, whereas from an international perspective a different business case may be presented. This may be a very complex situation to tackle, especially since the development of compensation mechanisms for such cases may induce TSOs (or regulators) to become restrictive with national investments until some costs can be allocated to other systems.

- Solutions which encompass required investment by a third country to upgrade interconnection capacity between two other countries.

  Due to the existence of load flows, an investment by a third country (e.g. Belgium) may be needed in order to enlarge the transport capacity between other countries (e.g. Germany and France). In this case the costs and benefits of a new interconnection are clearly not allocated in a balanced way.

- Arrangements which permit merchant developments and allow developers to retain congestion rents as a reward for taking the investment risk in the first instance.

Although the regulation allows for merchant investments in interconnection expansion, it is hard to tell in which situations private parties may end up with a positive business case (presumably primarily based on their exclusive use of the interconnection, which is possible in the case of DC links), whereas TSOs (based on an assessment in which many public benefits contribute to the business case and which may probably take into account lower risk premiums) cannot produce a positive business case. However, regulatory changes oriented to incentive market participants (mainly generators) to build the transmission facilities to connect their plants with the target market, may substantially increase the social benefits of merchant developments.

The following issues can be added to this list:

- Evaluative framework from which obligations for TSOs can be derived to plan and construct new links.

  Most TSOs are under the obligation to offer sufficient network capacity to domestic users[44]. However, such a framework for international transports does not exist. In case market demand for a certain transmission link (between two countries) exceeds the available capacity, TSOs are under no obligation of increasing the transmission capacity (although some incentives exist to maximize the available capacity for market parties). Merchant expansions may be the solution, however regulatory changes are required to create appropriate incentives for market participants to build transmission facilities.

- Effective regulatory supervision of international tie lines.

  International tie lines fall under the different regulatory regime of the countries connected by the link. The regulatory systems related to planning, capacity allocation and investment are not necessarily in harmony with each other. Although guidelines exist on congestion management, with respect to investments, a consistent set of guidelines on when and how to study new links is still missing. An appropriate methodology for congestion management based on short term allocation based on market splitting (in process of implementation) and long term allocation based on point to point transmission rights may allow substantially efficiency improvements on existing corridors.

- Missing framework on how to take into account the present market demand for transporting capacity when assessing the need for new interconnection.

[44] In many cases irrespective of the economical appropriateness (i.e. contribution to social welfare) of the expansion.

A specific issue which makes the TSOs' planning tasks difficult is the question of how TSOs should cope with the present market demand for international transports. Since trade patterns will be developed as well, as a result of the geographic distribution of new investments in generation among others, it is not straightforward in which manner (short-term) market demand should translate into (long-term) network availability. Although in specific cases economic assessments can be made, these may involve a large amount of subjective evaluation of present developments. Especially when the remuneration schemes for TSOs are related to the future congestion revenues, a significant risk may be incurred by the TSOs. Again, a framework on how present market demand should be taken into account for network investment decisions is presently missing.

Lengthy Planning Procedures

Once the need for a new interconnection has been decided, a formal procedure needs to be initiated in order to obtain the necessary permits and licenses for constructing and operating a new line. These procedures are national in scope and therefore need to be followed in the countries at each side of the interconnection.

The procedure in general includes the following major components:

- Request of permission at national level

  In general, before a new transmission line can be built, approval needs to be given on a national scale. Often, this involves a political decision (e.g., a declaration of public interest, as in France, or the formal inclusion in a formally (by Parliament) approved plan on the electricity infrastructure (as in the Netherlands).

- Request of permission at regional and local levels

  After a general decision on a national level, regional and local governmental bodies need to approve the transmission line, especially related to the regional and urban planning. If the project proves to be incompatible with the planning documents that define and prescribe the use of land (habitats, agriculture, industrial zones, infrastructures, etc.) a procedure must be followed to bring the project into line with these planning documents. In general, the project should meet regulatory provisions on the location, height and nature of new constructions, and secondly, it needs to be adequately integrated into the surrounding environment.

- Environmental impact assessment

  An environmental impact assessment refers to the direct and indirect impact of the transmission line on people, animals, plants, land, water, the landscape, protected areas and the cultural environment, on management of land, water as well as management of materials, raw materials and energy of the planned overhead line. The environmental impact assessment statement may include the development of options to compensate for the environmental impact of the line.

- Approval for conformity to technical standards

  Sometimes, specific approval is required for conformity of the technical design to regulations governing the safety of people and property in the neighbourhood of the line.

- Public consultation and debate

  In many procedures, consultative sessions are held to give third parties the opportunity to present their views on the plans, especially with an eye to the planning and environmental impact of the line. Often, the public debate focuses on the question whether the transmission line is really necessary and whether a cable investment may provide an acceptable alternative.

- Obtaining rights of way with property owners

  Before construction works start, the land owners need to approve the new line (or pylons) on their land. Such authorisation can be reached by amicable agreement (often also containing a financial compensation) or expropriation or easement procedures (possibly including lawsuits).

With respect to the general time period needed to pass all procedures and actually construct a new line, the ETSO notes:[45]

> As a general conclusion one could state that the total length for a project realisation is 5 years when there is no obstacle or opposition; but that is very rare. Even without major obstacles, the reality is that in the most recent cases, the timing between the first planning and its entry into operation usually is of about 10 years. Then, when there are real obstacles and opposition, projects can even lead to up to 12 or 20 years (ES-FR is an example and still not agreed) and in some cases they never see its realisation after 10 or more years discussions.

6.2 Issues in the Assessment of New Interconnections

In addition to the impediments for investing in new interconnections, there are further problems that arise when a new interconnection is planned. With the proposed methodology some of them will necessarily improve and disappear, but some of them require further attention from the regulatory and technical

[45] ETSO, Overview of the administrative procedures for constructing 110 kV to 400 kV overhead lines, 5 December 2006, p.1.

perspectives which will also benefit the results provided by the proposed methodology.

Identifying the Need for New Interconnection

The following approach is generally adopted for deciding on new interconnection:[46]

> Historically two approaches have been used as a means of identifying whether or not a transmission system is adequate i.e. a deterministic approach to comply with security criteria and a cost-benefit approach to compare costs of incremental transmission investment with benefits provided by the investment (also taking account of costs avoided e.g. constraint costs).
>
> In most countries in Europe the two approaches are used together: initially an assessment is made using the deterministic approach and then it is backed-up by using a cost-benefit approach. For the deterministic approach models and procedures exist, however the approach to evaluate the cost benefit may differ widely, and is subject to regulatory approval.
>
> In cases where interconnections already exist and are congested, the value of congestion revenues may suggest the potential need for transmission reinforcement. In cases where there is an interconnection and no congestion, there is no short-term economic case for reinforcement. However, a disparity may exist between the short-term nature of congestion as opposed to a long term decision to invest in upgrading an interconnection (involving the construction of assets with economic lives of over 40 years).

Reference network

In practice, when assessing a new connection, TSOs make load-flow calculations as well as, possibly, an estimate of short circuit current levels. In general, such calculations are done based on the UCTE's reference network, and if necessary enhanced with real network data of the transmission networks of lower voltage (100-200 kV). If applicable, all planned changes and developments in the grid are integrated in the reference network.

Generation development

The most difficult part relates to the expected generation scenario at the moment the new interconnection is commissioned. In general, several scenarios will be studied based on several evolutions of the generation portfolio. Long-term scenarios concerning the generation development may be based on a further increase in wind and other renewable power generation, as well as the continuous shut-down of

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[46] ETSO, Position Paper on Roles and Responsibilities of TSOs and other actors in Cross-Border Network Investment, July 19, 2006, p.3.

nuclear power plants. For the construction of new conventional power plants, the forecast is very difficult as it will depend on the CO_2-scenarios and the development of the European market.

Specific attention needs to be given to the development of wind capacity and its location in the grid, since the fluctuating generation pattern may have a significant impact on electricity flow patterns.

Load development

For the development of network load, the forecast is easier since, in general, extrapolation based on annual increases of a few percentages, is sufficient.

Other relevant issues

Some additional information needs to be taken into account as well. This may include experiences with current market behaviour, physical load flow behaviour, possible transit and exchange scenarios, and the system operation margin for extreme scenarios.

Analysis of new lines

Based on the above assumptions, the adequacy of the present interconnection capacity may be assessed. If this leads to the conclusion that the network will not be able to accommodate all transports, several options may be considered:

- It could be studied whether enhancing the permissible transmission capacity of existing interconnection links is possible. Such operational measures may lead to increased transmission capacity at low unit costs.

- A second option is to install load flow control elements, such as phase shifting transformer at specific nodes in the grid.

- If this does not suffice, the addition of new power lines can be studied. Specifically, the impact of new lines on the available cross-border transfer capacity and on the system security will be evaluated.

In this evaluation, not only building new overhead lines are considered but also the application of new technologies as HVDC (high-voltage direct-current) links. DC links are a highly controllable element, so that the load flow can be significantly changed based on its settings. Therefore, a DC link might give better options regarding security of supply and use of capacity. Nevertheless, the costs of DC-connections are significantly higher than for overhead lines.[47]

[47] See F. Vanderberghe, Is 380 kV Underground Cable an Option, ETSO contribution to the ERGEG Electricity Infrastructure Workshop, Brussels, 13 February 2007.

Uncertainties Related to Interconnection Planning

There are many uncertainties related to the process of evaluating whether additional transmission capacity is needed. These include:

- Due to differences in market design, tarification methodologies, subsidization of renewable power generation, etc., it is not very easy to develop deterministic market models that will provide reliable information on future transmission needs. Furthermore, the market model may be developed over time, which may additionally impact future transmission needs.

- A major uncertainty relates to the (future) geographic distribution of power generation. Although at the demand side, projections based on present consumption levels provide sufficient guidance, especially the uncertainty on location of new power plant may severely impact market price levels and, therefore, electricity flow patterns. Since the locational signals for the connection of new plant from the tariff system are rather weak (location decisions are more influenced by easy access to fuels like gas, hydro or coal, or planning considerations as for nuclear and wind power), it is a safe assumption that the grid will just need to accommodate the resulting power flows.

- Especially wind power generation involves intrinsic uncertainty due to the stochastic nature of its generation pattern:[48]

  Regions with a high density of wind generation and low electricity consumption can cause parallel flows in neighbouring grids. This situation may be worsened through mechanisms for priority dispatch for renewable generation causing flows in already congested areas of the network, forcing TSOs to reduce the tradable capacity. The problem is not the priority dispatch for renewable generation but the fact that any surplus generation in an area causes parallel or transit flows in adjacent areas for which proper allocation mechanisms have not yet been defined.

The general solution is to make network flow calculations based on several scenarios. However, the larger the differences in assumptions the larger the range of the scenarios' outcome. Especially due to different projections of new generation investment (which for instance relates on the development of the CO_2-market that may favour gas or coal fired plant, each with a different siting preference), widely diverging scenario outcomes may be obtained. The value of a new interconnection may differ accordingly.

[48] ETSO, Position Paper on Roles and Responsibilities of TSOs and other actors in Cross-Border Network Investment, July 19, 2006, p.5.

Issues Related to Licensing Procedures

Another area where major issues must be addressed is the procedure for obtaining the necessary licenses and permits for a new link.

Time-consuming licensing procedure

Although the need for new interconnection is being evaluated on a European basis, especially with an eye to market functioning and increased security of supply, authorisation procedures are often national in design. This means that planning procedures deal with a full range of issues and the impact of the project on the regional and local environment needs to be addressed extensively.

This has proven to be a very time-consuming activity. Even if a legally defined schedule is in place, the licensing procedure may in practice exceed this significantly, due to many delays and unforeseen events.

Complexity of the licensing procedure

Hundreds of parties are involved in the construction of an overhead line, both on the government side (national, regional and local governments, licensing authorities, regulators, etc.), the population (land owners, people being affected by the construction work, etc.) and lobby groups (most notably environmentalist groups), not to mention the advisors, consulting companies and lawyers involved.

Given the complexity of the licensing procedure, many resources from both TSOs and the governments are drained by a single project. For this reason, often only a limited number of 'big' projects can be dealt with at once.

Methodology for environmental impact assessment

A major problem is that there is no accepted methodology to balance the environmental impact of a project (which almost by definition is negative for any additional overhead line) with the public interest of e.g., security of supply. Since a quantitative assessment is very difficult, qualitative approaches must be applied. However, such assessments may be very prone to subjective weighing of the issues.

The absence of an accepted methodology is not observed only on a general level, but may as well exist on a detailed level. The different thresholds applied for electromagnetic fields may serve as an example. International standards may differ from national standards (if existing). If such standards are not legally defined, experts may play a role in the licensing procedure with, again, different outcomes.[49] Since such thresholds are also important from a design perspective (since they

[49] See G. Christiner, Austria – Completing the 380 kV Ring, Authorization Procedures and Major Problems, ERGEG Electricity Infrastructure Workshop, Brussels, 13 February 2007.

prescribe the minimum distance between the transmission line and urban areas), it may even impact the track for the new line.

Opposition from environmentalist groups or local organisations

In general, local population and land owners oppose new lines due to e.g., regional mentality (favouring of local renewable power generation), doubt about the benefits of market liberalisation in general as well as the lack of benefits for the local people when the major use of a line is to facilitate transits.

It is still an unsolved issue how (inter)national and regional/local issues may be integrated in a proper and balanced way in the assessment of a new interconnection. However, this issue is not limited to electricity transmission projects, but also occurs in other infrastructure projects.

Lack of political support

The political support for new transmission line projects may be limited for several reasons, including the following, among others:

- The benefits of new transmission investments (for electricity transport) are not very easily seen by politicians, especially if the current quality of supply is rather high.

- On the contrary, the benefits from the development of the European electricity market are not always visible for politicians (and the general public).

- In case of investments to be able to accommodate additional transits, the support from politicians is even lower since the direct benefits for the specific country or region is rather low.

- The above effects are even much stronger on the regional and local level than at the national level since politicians on these levels are (in general) closer to the population. Additionally, strong opposition on this level may possibly push the new line to a neighbouring region of municipality.

Due to these effects, politicians do not have much to win by speeding up licensing procedures, whereas such actions involve political risks of losing the local population’s (some) support.

In practice, due to the above and other issues, the time to build a power line will easily exceed 5 years and may even take more than 10 years.

6.3 Proposed Guidelines

Hence, as a result of the above detected issues, the guidelines must be focused on facing all the mentioned issues so as to allow the proposed methodology the necessary degree of success. In addition, some other aspects are also crucial for the designation of electricity transmission corridors.

In this sense, the next sections propose a number of guidelines in order to improve the present situation.

A Strategic Choice

Based on the dilemma presented previously, two approaches seem possible:

1. When new electricity interconnection investments are (continued to be) considered as the enforcement of links between (autonomously designed) national systems, national assessment and design processes will, by definition, continue playing a key role in the evaluation of new interconnections. Both research, planning and licensing of these links will then, by nature, be subject to national decision-making and approval processes.

2. Alternatively, if a part of the national network is (going to be) considered as component of a European grid, a set of procedures could be established to subject investment in this grid to European guidelines and regulations. However, such an approach involves 'upgrading' the present regulatory schemes, since otherwise TSOs might remain dependent on national regulatory approval processes for the remuneration of their investments.

It is clear that from a perspective of efficient interconnection investments, the second option looks more promising. However, a significant amount of changes to the present organisation of the electricity grids, as well as the regulatory framework, are needed for implementation.

Nevertheless, it seems advisable to clarify the desirable longer term development of the organisation and regulation of the European electricity transmission network.

Guidelines for Co-ordinated Planning

Since electricity flows in meshed networks are a complex issue, a co-ordinated planning approach is necessary. A regional planning process can identify cost-saving opportunities and facilitate the construction of new transmission to support robust wholesale markets and improved reliability. Especially for continental Europe, such a co-ordinated approach may facilitate the assessment of the potentially best investment alternatives.

However, developing such guidelines in a generalized way may not be that easy, especially since the outcome of a planning exercise will depend heavily on the generation (and load) scenarios applied. Such scenarios will have the highest relevance if they are designed with the specific issues of the region in mind. Therefore, any guidelines might focus predominantly on the components that need to be included in such a planning activity, and prescribe how the results might be published in a structured and transparent way.

In order to facilitate co-ordinated planning, a Europe-wide set of operational constraints related to network operation could be established as a first step. ERGEG has suggested developing a European Grid Code which includes the standards a TSO must meet when operating and investing in its transmission network:[50]

> They are the standards and rules which each TSO must follow when operating its network, and when investing in and maintaining its network (including national standards for the purely national parts of the network; and in addition EU standards where that network forms part of the integrated EU grid). Standards provide the mechanism through which TSOs can meet their higher (public interest) obligations by providing a secure, efficient and economic network at both domestic and European level. TSOs will need to bring forward new investments and to run their networks to ensure that they operate securely and efficiently and that they facilitate the efficient operation of both their national and the wider EU market. As it is the responsibility of the TSOs to develop and operate their networks to meet current and prospective demands of users (both of consumers and producers), it should be noted that the term 'security standard' therefore contains requirements relating both to security of supply and to meeting the (economically justified) needs of the market. Whilst European security standards have yet to be developed, operating standards do exist (as developed by UCTE and Nordel) which relate to regions of Europe including those which extend beyond the boundaries of the Union.

Such standards should include:[51]

- Transmission network security rules
- Transmission network standards
- Security and reliability rules and standards
- Security and quality of supply standards
- Safety and operational standards
- Planning and operational standards
- Grid Code

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[50] ERGEG, Response to the European Commission's Communication "An Energy Policy for Europe", Ref. C06-BM-09-5, 6 February 2007, p.13.
[51] ERGEG, Response to the European Commission's Communication "An Energy Policy for Europe", Ref. C06-BM-09-5, 6 February 2007, p.12.

- Operating and security standards

The existence of such an overall Grid Code may facilitate the assessment of the need for new transmission links. Nevertheless, the benefits should not be overestimated since the UCTE's Operational Handbook[52] already contains many of these issues, although they have no legal binding force.

Guidelines for the Economic Valuation of New Interconnections

A much more difficult issue is to provide guidance on how the economic value of a new interconnection may be assessed. Although it is presently not clear whether a harmonized framework can be established at all, if such a procedure can be developed the advantages will be significant. By definition, a methodology is needed that will exceed a purely economic analysis and will be able to cope with other costs and benefits which are more difficult to quantify.

Presently, the congestion management guidelines prescribe the preferred allocation of congestion rents to new interconnection investments which relieve the congestion:[53]

> The use of congestion income for investment to maintain or increase interconnection capacity shall preferably be assigned to specific predefined projects which contribute to relieving the existing associated congestion and which may also be implemented within a reasonable time, particularly as regards the authorisation process.

From the economic perspective this use is not efficient since it introduces incentives to unnecessary investments. The efficient criteria is to allocate resources to reinforcements based on its economic convenience (increase of social welfare), but not through the distort criterion of allocating congestion revenues. A sound and fair practice is to use congestion revenues to reduce internal transmission tariffs.

Guidelines for the Regulatory Treatment of New Interconnections

A third area where guidelines might be developed relates to the regulatory treatment of new interconnections, especially with respect to the elimination of regulatory impediments and the provision of regulatory certainty, particularly with respect to attractive returns, incentives, cost allocation and cost recovery, in order to raise the necessary capital to construct the required, cost-effective transmission facilities.

The following are some of the issues that may be taken into account in such a regulatory framework:[54]

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[52] See http://www.ucte.org/publications/ophandbook/.

[53] Article 6 of the 'Guidelines on the management and allocation of available transfer capacity of interconnections between national systems', Commission Decision of 9 November 2006

1. An approach in which cost recovery is guaranteed of all prudently incurred costs to design, study, pre-certify, and permit transmission facilities, including full recovery of the prudently-incurred costs of abandoned transmission projects.

2. An approach which allows utilities to include construction work in progress in the rate base, as this will encourage transmission construction through improved cash flow and greater rate stability.

3. The option to allow accelerated depreciation in ratemaking to improve financial flexibility, and promote additional transmission investment (and which should be included in the tax legislation as well).

4. In cases where Member States require purchases of renewable resources that lack siting flexibility, the regulators should allow alternative cost recovery approaches to support the building of transmission facilities, to help achieve the renewable resource goals.

5. An alternative to be analysed is the development of new facilities by "independent transmission companies". Once a project is nominated as an EU priority corridor, it is organised an auction for companies interested to build and (eventually) operate the facility. The auction is allocated to the offer that asks for ta lower annual remuneration. The construction contract should include penalties for delays in the commissioning of the project and for performance during the operation. This methodology produced outstanding results in several Latin America countries like Brazil, Argentina, Bolivia and Peru. In Brazil mode than 5000 km of 500 kV facilities have been developed during the last 10 years, practically without delays in relation with the contractual schedules and with cost substantially low (150-200 kUSD/km).

The development of a regulatory framework containing an agreed set of criteria and objectives for investment in new interconnections will greatly assist the identification and justification of new connections. According to the ETSO, the role of the relevant regulatory authorities would then be to implement a long-term stable framework, namely:[55]

- giving a long-term guarantee of rate of return on investments;

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amending the Annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity, 2006/770/EC, OJ L 312/59, 11.11.2006.

[54] Components of this section have been taken from: Edison Electric Institute, EEI Principles on Transmission Investment: Effective Wholesale Competition Needs a Robust, Reliable and Cost-Effective Transmission Infrastructure, March 17, 2005, http://www.eei.org/industry_issues/energy_infrastructure/transmission/eei_tranmission_principles_5_10.pdf?ObjectID=35619.

[55] ETSO, Position Paper on Roles and Responsibilities of TSOs and other actors in Cross-Border Network Investment, July 19, 2006, p.7.

- provide guidelines on cost allocation principles between national systems, the treatment and recovery of third party costs, revenue-recovery principles;
- implement methods to evaluate the costs and benefits of new interconnection capacities; and
- provide guidelines to potential merchant developers and ensure their compliance.

7. Final Recommendations

As a result of the issues commented in the previous chapter, a number of proposals may facilitate the declaration of projects of priority interest by using the proposed methodological framework as the most adequate tool to ensure consistency when defining new interconnection problems. Obviously, not all the issues mentioned above may be solved by the proposed methodology, since some of them require implementation of new regulation and co-ordination and co-operation among the involved stakeholders. The recommendations set in this chapter also attempt to deal with them but further analysis is required.

In this regard, this chapter summarises the recommendations oriented to improve the process for identifying EU Priority Corridors and to facilitate the constructions of those projects that are nominated as Priority Corridors. These recommendations are divided in two sections, one oriented to Priority Corridors' identification and the other one to their development.

7.1 Priority Corridors Identification

Interconnection Projects - Rights of Way

From an engineering point of view no comments are to be made on the methodologies used to design transmission lines and other related facilities. But, as currently, obtaining the rights of way seems to be the most critical component of a transmission project, a number of recommendations are prepared in order to mitigate the common problems observed on this issue, which are as follows:

- Identify potentially conflictive zones and avoid designing lines passing for these zones.

- Identify alternative rights of way, to be used when it is envisaged a strong resistance to the optimal path.

- Assess the possibility of using existing free rights of way such as existing lower voltage transmission lines, highways, rails, etc. When technically feasible, give priority to these rights of way. For instance, those projects that require longer transmission lines may be crossing unpopulated lands, being less prone to face rejection. The over-cost linked to the longer path should be assessed against the lower level of conflict that economically may be measured as the benefits linked to an earlier commissioning of the facility.

Planning Methodology

As described in the report, a sustainable identification of projects should go through an initial filtering, that is to increase the social welfare. So, any methodology should ensure that the increase in social welfare and the project costs should be properly identified. Further to social welfare increase, in order to be nominated as a project of priority interest, the project should contribute to the fulfilment of some of the EU policies regarding competition, security of supply and penetration of renewables.

It is possible to include in the social welfare measures a wide range of factors, including some related to EU policies, such as increased security of supply, improvements in the utilization of renewable energies, impact on end users prices, etc.

Simple analysis based on short term benefits or only on technical considerations should be avoided, as it may lead to waste of valuable resources. And it is important to remark that given the increased trend of overhead lines being rejected by the population located near the electricity transmission routes, presently, further to the project's direct cost, it is necessary to account with the enormous effort to obtain the acceptation of the project. It would not have sense to waste this effort in projects that do not increase the social welfare.

The final recommended alternative to identifying projects of priority interest is based on the use of a cascade of models: (1) long term planning model; (2) market simulation; (3) and power system analysis. This methodology is described in general terms in chapter 5 of this report, under the heading Alternative #1.

A simple alternative methodology was evaluated (Alternative #2), but this should only be used as a tool to diagnose zones with some needs (security of supply, difficulties to transmit renewable energy or high market concentration), which can be mitigated through cross border interconnections. The use of an intermediate alternative is also feasible by using a combination of results of the two presented approaches, although it should be only valid in the short term before a fully agreed methodology is implemented, based on the results provided by Alternative #1.

It is particularly recommended:

- A common and complete EU wide database for planning purposes. Public access to the database would facilitate the analysis and development of projects by all the sector's stakeholders.

- A common methodology, which should agree on criteria (objective function, forecasts, etc.) as well as to a common set of planning models. Although the agreement on this may require a strong initial effort, once the agreement is achieved, negotiations on selected projects would result dramatically simplified.

Projects Review

The economic evaluation of projects of European interest is based on some cost estimations. Typically the benefit/cost relationship of a transmission system is in the range 5-20%. This means that if for some reason the projects' cost increases more than 20%, this relationship may become zero or negative. Therefore, it would be good to know in each case which is the maximum cost of the interconnection that preserves the condition that the social welfare increases.

For instance, the switch from an overhead line to an underground one, may imply cost increases of 500-600% in the respective costs as it was previously stated, or even more as some sources declare on that aspect. It is difficult to assess the appropriateness of a line to this huge cost increase, so a review would ensure that the investments will contribute to increasing the social welfare.

Congestion fees

A common but flawed practice is to evaluate the benefits of a project based on the congestion rents to be collected. This approach has several conceptual errors which should lead to abandoning this criterion:

- Congestion fees means transference of wealth, not necessarily social welfare increase.
- The social benefit of a project is linked to the reduction on congestion, rather than in the remaining value.
- Congestion fees arises from using the willingness to pay, as a measure of the expected benefit linked to a transaction, which allows an efficient allocation of the available capacity. Good practices suggest that the money collected should be used to reduce the transmission tariffs of the agents that pay for the use of the transmission system. Any other destination is inefficient and unfair.

Congestion management

In the last years an essential improvement was made in the methodology used for allocation of the cross border transmission capacity. The use of implicit and explicit auctions to allocate such capacity substantially improved the efficiency in the use of the existing transmission capacity. However, this can be further improved with the introduction of point to point transmission rights[56] instead of the prevailing allocation on cross border flowgates[57].

The use of the flowgate concept (and it sconsequence the NTC concept) produces a inefficient use of the cross border (and also internal) links. This is, for example, properly reflected in the document “Congestion Management in the Nordic Region A common regulatory opinion on congestion management Report 2/2007”, referring to

[56] Point to point transmission rights entitles the holder to inject power in a node of the transmission power system and to withdrawn the same power in another node.
[57] The present methodology allocates the available (cross border) NTC to agents based on implicit or explicit auctions. Internal congestion and parallel flows are considered in the time the NTC is defined, but are not based on the actual use of the transmission system.

the current practices in NordPool (that arfe similar to those used in the rest of the EU):

> The physical interdependencies within the underlying electric network are not fully taken into account when prices, injections and withdrawals are determined in the day-ahead market. Due to the uncertainty in load and generation patterns TSOs may be obliged to deliver to the market lower transmission capacity compared to the situation where hourly load and generation patterns after day-ahead market closing are fully known. This implies that the transmission capacity of the grid may not be fully utilised in day-ahead market

The key issue is that the capacity of the flowgates depends not only on the technical limits of the cross border interconnections, but also on the internal congestion in the connected countries and parallel flows. Presently, internal congestions and loop flows are calculated based on typical load flows. The result is the Net Transfer Capacity (NTC), which then is auctioned. But the NTC calculation is very conservative, as it needs to consider all possible system conditions as well as the N-1 criteria.

As point to point rights need a detailed description of the transmission system, less assumptions are necessary, which results in increased available capacity. Probably (depending on the case) it would be possible to increase the available capacity by 20-40% with the introduction of point to point transmission rights, which is more than the capacity that all presently planned cross border projects would provide. This means that it would be possible a substantial increase of the existing cross border capacity with a very low cost, only by introducing a new regulation on transmission rights.

ANNEXES - Electricity

1 Case Study: Spanish-French electricity interconnection

The 400 kV interconnection corridor between Spain and France through the Baixas-Bescanò route, was prioritized by a European Union decision. To ensure the project was adequately promoted, Mr. Monti was appointed European coordinator in order to analyze whether the project should be carried out and, in that case, to evaluate the best route through the Pyrenees.

From December 2007, the European coordinator was balancing the project status in order to provide solutions for the interconnection, since the project was blocked in the latest years, especially after the French public debate that took place in 2003. The public debate was centred into three main aspects: the adequacy of carrying out the project (at local level), the environmental damage in the region and the long-term view of interconnection by local population. This situation led to a preliminary report with main findings on these issues.

In January 2008, both Spanish and French governments agreed the promotion of the interconnection, so a second report on the interconnection was made in order to assess the governments on the existing alternatives. Finally, a third stage is also envisaged to provide assessment to authorities to be used for the interconnection.

For the realisation of these studies, a number of agencies have been involved and two reports have been issued at present, focusing more on the technological aspects rather than on the investment's cost / benefit estimation. This type of analysis is appropriate for determining whether the interconnection must be declared of European interest, which in many cases will depend on the total investment costs of the interconnection's selected route. The key rule for declaring the interest of any transmission project is that the net benefit must be positive in order to increase the welfare of the European citizens. Otherwise, the project should not be carried out and new alternatives must be examined before prioritizing new interconnections.

In this respect, the present study aims to show how the methodology labelled as Alternative #1 may provide results for the cost/benefit analysis of the appropriateness of introducing new interconnection lines that might be of European interest. However, the results provided in this study do not try to determine whether the interconnection is necessary or not, but to illustrate how this methodology might be used in future studies. The case of the Spanish-French interconnection has be chosen since it is currently under analysis and, therefore, the proposed methodology may be tested against a project that is currently debated by both the involved stakeholders and the European Commission. Furthermore, the present project is only part of the Spanish-French electricity interconnection capacity needs, and so this study is basically focused on future necessities rather than current ones for two main reasons: i) current needs have already been satisfied; and ii) the required database for using Alternative #1 is much more detailed that the one presented in this Annex, as it will be commented in the following sections.

With the aim of fully illustrating the proposed methodology presented in the main report, the study also includes Portugal, not only because the strong interactions with the Spanish market, but also to show how the methodology deals with the regional definition presented earlier. More precisely the South Western region is analysed, so that the results include how the Portuguese electricity system should be optimized in conjunction with the Spanish and French electricity systems.

Hence, the following sections will develop the proposed methodology for the South Western region in order to analyze whether new interconnections among the three countries are economically viable until 2020. However, the analysis is not as detailed as it should be, since the purpose of this Annex is to show how the methodology works in real cases rather than providing results and, as it was referred to in the main text, all involved stakeholders must take part in the whole process of declaring projects of European interest by providing data, opinion or any other type of required analysis.

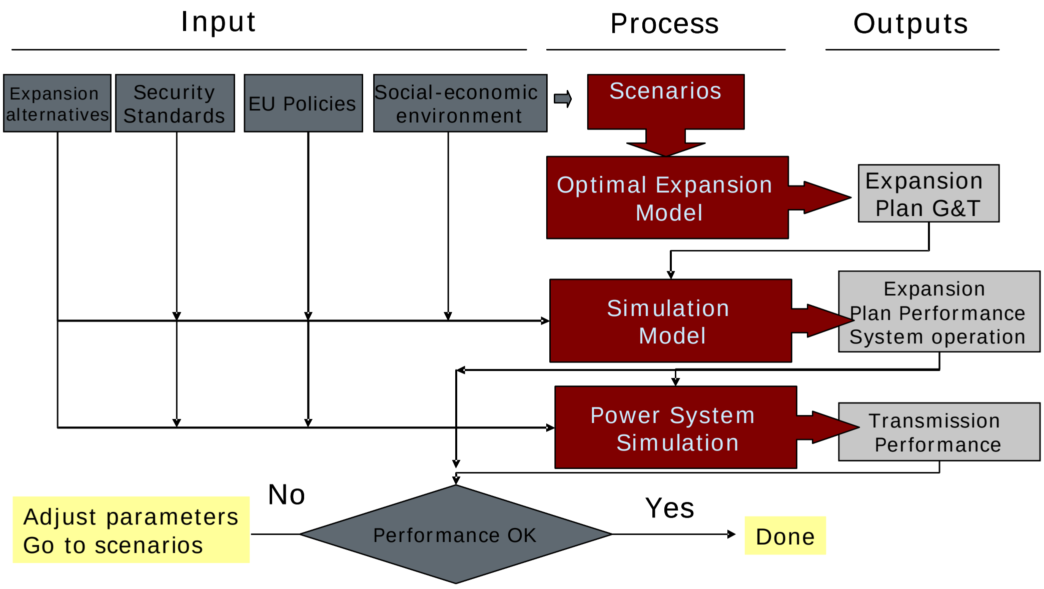
Finally, this example also tries to analyze the interconnection expansion concerning the security of supply, the use of renewables and the increase of competition. In this regard, the security of supply is treated from the perspective of avoiding non-supplied energy, the use of renewables is addressed by analyzing different scenarios for wind power implementation and the increase of competition is dealt with the optimal expansion and simulation modelling that provides competitive market prices.

The following sections summarize the methodology procedures, and then results and recommendations are presented and commented.

1.1 The whole process

Alternative #1 presented in the main text, basically consists in three phases that allow determining whether an interconnection project may be declared of European interest by the European Commission. The three phases are summarized in the next figure already presented in Chapter 5:

Figure 13 Alternative # 1 scheme



As it can be observed, the process is composed of three stages that use the data provided by different scenarios. These scenarios must be completed by all involved stakeholders, mainly the involved TSO companies, but some additional requirements in terms of regulation, security standards, environmental constraints and EU policies must also be taken into account. The three stages are as follows:

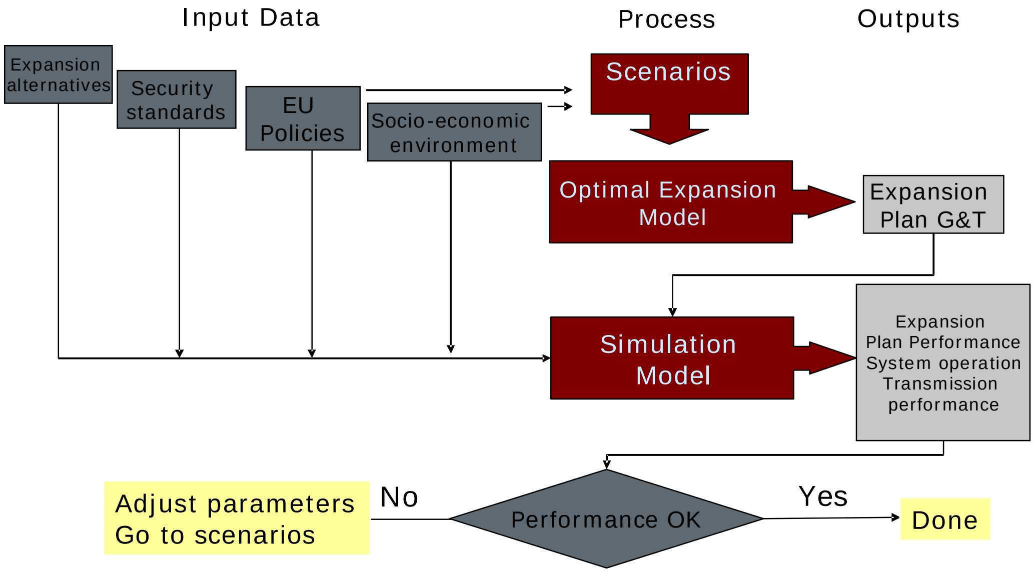
- Optimal expansion model: this stage provides the long term expansion model for both generation and transmission.
- Simulation model: this stage analyzes the expansion plan's performance for electricity system operation in the mid term.
- Power system simulation: this stage analyzes in more detailed the transmission performance in the short term.

Since the aim of the study is the provision of new interconnection needs until 2020 in terms of cost and benefits, the third stage is not presented[58]. Once these interconnections are selected, the third stage has to be modelled in order to assess on its effective feasibility. This stage is crucial in the sense that power flows need specific treatment so as to check the best alternatives from this perspective regarding the construction or upgrading of new interconnections prior to the designation of priority corridors. Under this stage, data requirements are extensive and its completeness is crucial for proper model simulation. These models are commonly available at the TSO level, and in general are widely used for transmission

[58] In fact this third stage does not differ from what TSO presently do for planning purposes.

investment decisions. In addition, at this stage other important aspects, such as the rights of way or permits, play an essential role in determining the project's feasibility. Therefore, as the aim of this study is the provision of investment needs from the economic perspective of the cost/benefit analysis, the third stage is discarded. Thus, the methodology for this example is presented in the next figure:

Figure 14 Alternative # 1 scheme for this example



Regarding the first two stages, different models are used for the estimation of results. Although different model alternatives may be used for estimating expansion needs, the key aspect is to ensure the two stages take place, so as to properly decide on the corridors that have to be simulated under the third stage. The use of optimal expansion or simulation models individually, is likely to provide inconsistent projects at some stage.

The results provided under this example use two specific models, which are described in the following sections. The software packages proposed for developing the least cost plan are ORDENA and SDDP models. However most sophisticated models should be used for planning of large systems.

1.1.1 ORDENA MODEL

The ORDENA model determines the optimal expansion (generation and transmission) required to supply the forecasted load in a multi-region or multi-country system, in long time horizons. The objective is to minimize investment cost plus the expected operation cost, composed of fuel cost plus cost of lost energy (VOLL) associated with supply reliability constraints. Supply options include hydro generation, renewables, thermal generation (coal, gas, oil, etc.), contracts and interconnections with other regions or countries. The model allows the detailed representation of hydro and renewables, and the definition of hydrological and renewables scenarios' conditions. The operation of thermal plants (for example, constraints on gas supply) and interconnections are also modelled in detail.

The ORDENA model allows an accurate representation of the demand curve, including the peak load, therefore the model's outputs are able to clearly identify the system's needs for generation suited to meet the expected load and select the alternative that optimally solves the trade-off between economy vs. reliability.

The aim of the model is to identify the expansions of generation and transmission that minimize total incremental cost to meet the countries' demand, calculated as the net present value (NPV) of capital and fixed O&M costs of new generation and transmission facilities, plus the variable costs of existing and new generation facilities. Although in this example only cross border expansions have been considered, in real world uses it would ne necessary to include the internal networks in order to identify expansions that may be necessary to allow cross border trading.

The demand is modelled as a load-duration curve that can be defined at quarter, season or yearly level. A load duration curve is necessary for each of the transmission system's nodes.

Demand can be met with existing and new generation. Alternatives for new generation can be considered as integer or continuous variables. Normally, hydro plants, transmission expansions and major thermal plants are simulated as integer variables, and small thermal and renewable plants as continuous ones.

The model allows binding of the emissions, or to assume that emissions are penalized, in order to represent environmental constraints.

1.1.2 SDDP MODEL

SDDP is a transmission-constrained production simulation model that calculates the optimal stochastic hydrothermal and renewable dispatch on a monthly or weekly basis, with representation of several load levels in each stage and detailed modelling of all system components: transmission network (linear power flow model), including losses; hydro (variation of production coefficient – MW/m3/s - with storage, spillage, filtration etc.); renewable (variation of production coefficient – MW/s); thermal (unit commitment, multiple fuels, limitations on gas supply etc.) contracts and cross-border interconnections.

The SDDP model is used on a stand-alone basis to evaluate in more detail the expansion plan produced by ORDENA.

The basic objective of hydrothermal system operation is to determine generation targets for each plant, at each stage, so as to minimize the expected operation cost along the planning period. This cost comprises the fuel costs for thermal plants, purchase costs from neighbouring systems, and penalties for interruption of load supply.

Systems with a substantial hydroelectric component can use the “free” hydro energy stored in the system’s reservoirs to meet demand, thus avoiding fuel expenses with thermal units. However, the availability of hydro energy is limited by the reservoir’s storage capacities. This creates a link between the operating decisions today and their future consequences. If the stored hydro energy is used today, and a drought occurs, it may be necessary to use expensive thermal generation in the future, or even interrupt load supply. If reservoir levels are kept high through a more intensive use of thermal generation, and high inflows occur in the future, there may be spillage, which is a waste of energy and, thus, increases operating cost. In other words, the scheduling of hydro resources is a multi-stage dynamic optimization problem, which determines the trade-off between the immediate benefit of using the stored water and the benefit of saving it for future use, measured in terms of thermal cost savings. Due to the seasonal and yearly inflow uncertainty, it is necessary to take into account many combinations of inflow scenarios (wet, dry, medium etc.) along the study period.

Systems with a substantial wind component are also modelled through a multi-stage dynamic optimization problem, which simulates the inflow uncertainty of the wind component by using different scenarios.

As a consequence, the number of variables and constraints in the hydrothermal and wind scheduling problem may be extremely high even for fairly small systems.

The SDDP model uses a solution technique called stochastic dual dynamic programming, which can solve the very large stochastic hydrothermal and wind scheduling problem in an efficient way. This technique has been successfully applied to large systems in South America, Central America, Europe, North America and New Zealand.

Despite the fact that the SDDP model may be used for the power system simulation, it is assumed that for the purpose of this study this stage is not simulated, and ideal flows are modelled for the interconnection, for the reasons mentioned above.

1.2 Modelling description

As a result of the approved interconnection investments between France and Spain, it is recommended analyze whether the new added capacity is enough to cover the interconnection necessities of the Iberian peninsula with Europe, to form part of the single European electricity market. The scope of the project attempts to set new interconnection necessities until 2020 by using the methodology cited above.

In order to determine new investment, the long run expansion plan has been developed based on two main qualities:

- The ability to state appropriate scenarios, properly reflecting the present situation and the most critical issues that influence the system’s expansion.

- A powerful optimization model, suited not only to identify least-cost solutions, but also to assess the uncertainty regarding critical variables and scenarios.

Hence, for the optimization and simulation of the South Western European region a number of assumptions have been made for the elaboration of the scenarios that are presented in the following sections with the least cost solutions.

1.2.1 ORDENA scenarios

The main assumptions for the optimization modelling are as follows:

- Planning horizon: 2008-2035.

- Generation and transmission expansions are assumed as existent in France, Spain and Portugal. The model identifies additional generation capacity and cross border interconnections needs. In this sense, the generation planned capacity for the three countries, along with the interconnection expansion plans already approved, are included in accordance with the envisaged date for entering into operation. So, the generation's installed capacity in year 2008 is as follows:

Table 6 – Total installed capacity by technology (2008)

		France	Spain	Portugal
Nuclear	MW	63.400	7.736	0
Coal	MW	6.900	10.919	1.786
CCGT	MW	1.100	21.030	2.503
OCGT	MW	7.100	4.839	1.531
Cogeneration	MW	8.350	7.264	1.364
Hydro	MW	25.300	18.463	4.582
Wind	MW	2.600	15.403	2.300
Other RES	MW	735	1.697	796
Total	MW	115.485	87.351	14.862

Source: Own estimations

The model is also adjusted for the power plants' availability, which differs from technology with the aim of replicating the 2007 dispatch in terms of use of technology. Therefore, it is assumed that nuclear power is available at 85% in Spain and 80% in France, coal at 75% and gas turbines at 90%. Wind power is also based on historical availability of figures, which is around 22%, while the remaining renewable energy sources are assumed to be available at 50%. Under this availability time framework the dispatch is replicated by ORDENA.

For the remaining period, further assumptions have been made in relation with the expansion of the generation's installed capacity until year 2020. After this year on the model selects new generation capacity from the list of available candidates regarding the most efficient solution for the system's functioning. It is important to note that although the planning is limited to the period 2008-2020, it is necessary to optimise the expansion beyond this horizon in order to asses the performance of the expansion during all (or most) of their lifes.

In year 2020 the assumed[59] generation's installed capacity is as follows:

Table 7 – Total installed capacity by technology (2020)

		France	Spain	Portugal
Nuclear	MW	63,200	7,261	0
Coal	MW	2,900	6,679	3,686
CCGT	MW	8,987	33,230	4,812
OCGT	MW	6,550	1,884	0
Cogeneration	MW	7,350	9,100	2,206
Hydro	MW	25,300	20,213	5,500
Wind	MW	5,705	26,500	6,300
Other RES	MW	2,025	4,297	1,206
Total	MW	122,017	109,165	23,710

Source: Own estimations and information form RTRE, REE, CNE and REN.

All plants are assumed to have standard availability production figures, heat rates and fixed O&M costs.

The interconnection capacity has been assumed as follows:

Table 8 – Interconnection capacity (2008)

Flows	MW
France to Spain	1,300
Spain to France	500
Portugal to Spain	1,200
Spain to Portugal	1,600

Source: TSOs

In addition, the approved added interconnection between Spain and France (1,300 MW added from 2012 onwards) and between Spain and Portugal (totaling 3,000 MW of total interconnection capacity from 2014 onwards) has been included.

- Uniform discount rate: 6% (based on WACC criterion). The calculation of this value requires further considerations since the proper discount value for the purpose of this study is the social discount rate, rather than the private one. Further discussion is necessary to determine what is the appropriate discount rate for the declaration of electricity projects of European interest.

- Candidates for generation expansion: from year 2008 onwards, the three systems are enabled to select a number of generation expansion projects

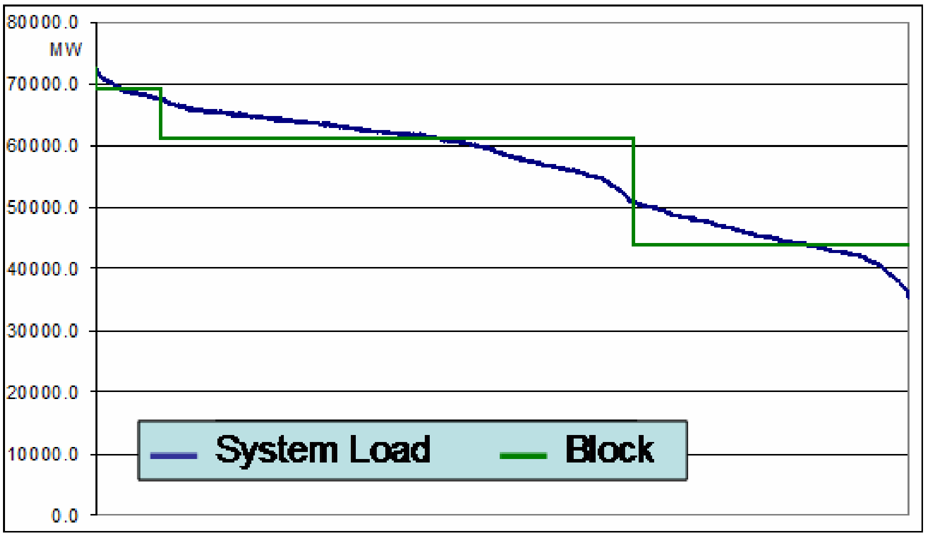
[59] Based in report from RTE, REE, CNE, REN..

from different types of technologies (i.e., CCGT, OCGT and wind power) further to the ongoing or approved expansion included in the generation installed capacity schedules of each country. This capacity is available for the event that existing generating capacity would not be enough to comply with demand requirements. Fuel and O&M costs are those included for the same installed technology, but additional annual investment standard costs are taken into account before deciding the optimal expansion plan. For instance, new CCGT capacity is valued at 700 €/kW , while OCGT is valued at 250 €/kW.[60] In addition, availability is also standardized for these new power facilities to 90%.

- Countries divided in zones. It was assumed that the Iberian and French systems do not have important internal congestion, therefore each country is considered as a unique zone. However, as the French electricity system is connected to other European countries, an additional zone is added in order to allow for international exchanges with third countries. The Spain-Morocco interconnection was considered as a fixed exportation from Spain in the border of 500MW.

- Load was modelled by region and season (winter and summer). With the aim of simplifying, only two seasons are provided. Thus, demand is modelled for every country in accordance to three different blocks in both seasons. The following figure shows how the blocks are estimated for every country season, where peak block consists of 350 hours, day block of 2,523 hours and night block of 1,507 hours.

Figure 15 Example of energy demand by blocks



[60] Wind power and nuclear expansions were also considered, but none of them was included in the optimal expansion plan as it will be shown below.

Once blocks are determined, the total demand is estimated for every country. The forecast assumes that the electricity sector of all the countries fulfils the 20% of increase of energy efficiency. The next table illustrates the demand assumptions made for the whole estimation period:

Table 9 – Demand

Country	2008	2016	2020	2025	2030	2035
Spain	270,029	344,393	376,436	415,616	458,874	506,634
France	451,675	492,009	511,986	538,103	565,552	594,400
Portugal	52,794	69,991	78,010	88,261	99,860	112,982

Source: Own estimations

In addition to the modelled variables, certain assumptions were also made for the fuel costs. The following table shows those costs included for the calculation of the marginal costs until 2020, assume then that fuel values remain constant over the whole period.

Table 10 – Fuel costs

Spain	Unit	2008	2016	2020
Exchange rate	USD/EUR	1.53	1.35	1.35
Brent	USD/bbl	101.13	69.14	72.50
Fuel Oil (1%) MED CIF	EUR/MWh	29.14	23.12	24.16
Gas-oil (distillate #2)	EUR/MWh	47.41	39.18	40.72
Coal	EUR/MWh	15.03	11.66	11.84
Gas (commodity)	EUR/MWh	23.42	19.98	20.46
Gas (transport)	EUR/MWh	0.85	0.66	0.66
Gas (retail margin)	EUR/MWh	0.66	0.66	0.66
Portugal	**Unit**	**2008**	**2016**	**2020**
Exchange rate	USD/EUR	1.53	1.35	1.35
Brent	USD/bbl	101.13	69.14	72.50
Fuel Oil (1%) MED CIF	EUR/MWh	29.14	23.12	24.16
Gasoil	EUR/MWh	47.41	39.18	40.72
Gas	EUR/MWh	27.17	21.30	21.78
Coal	EUR/MWh	15.03	11.66	11.84
France	**Unit**	**2008**	**2016**	**2020**
Exchange rate	USD/EUR	1.53	1.35	1.35
Brent	USD/bbl	101.13	69.14	72.50
Fuel Oil (1%) NWE CIF	EUR/MWh	28.14	22.56	23.53
Gas-oil	EUR/MWh	46.20	38.42	39.89
Coal	EUR/MWh	13.77	10.41	10.59
Gas (commodity)	EUR/MWh	25.71	22.24	23.05
Gas (transport)	EUR/MWh	0.47	0.47	0.47
Gas (retail margin)	EUR/MWh	0.66	0.66	0.66

Source: Own calculations based on EIA oil price forecasts

The expansion of renewable energy assumes the fulfilment of the 20/20/20 EU policy, considering that the electricity sector will install above the 20% to compensate lower penetration in otgher sectors.

Regarding the possibility of increasing the transmission through the interconnection, the transmission expansion has been considered the possibility of annual increases of 1,000 MW in the interconnection from 2016 onwards, since the approved interconnection plans were already included in the available transmission capacity in accordance with their planned entry in operation. Assuming additional interconnection capacity would be unreal. The total costs for transmission candidates are € 2 million per km, assuming the standard route length is 25 km.

Finally, it has to be stressed that the model does not restrict electricity imports among countries and no limit on the external dependence is imposed to the region's countries[61].

Regarding hydrology and the use of wind power, the optimization model provides that the amount of available water and wind and the generation pattern change dramatically from the wet season to the dry season. Therefore, it is necessary to model both seasons in this regard, although an average water year is assumed (only differentiated by season), while wind power is differentiated within the season. In order to take into account both issues, a procedure based on two steps was followed:

- identify three different kinds of years according to their annual wind energy generated (strong, average and weak), and

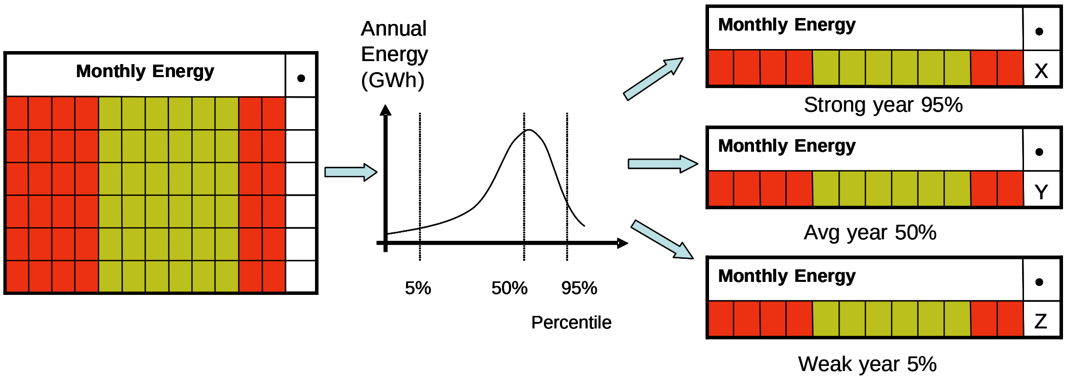
- compute the wind power generated by each country during the wet season and the dry season.

To obtain accurate wind outputs for those nine scenarios, several years of data on a monthly basis were needed.[62]

The next figure shows how the wind power is modelled:

[61] The assumption is that implicit and explicit auctions for allocating cross boder capacity are efficient, and therefore congestion rents reflects exactly the prices differencial between adjacent countries.
[62] The scenarios could increase by introducing hydro scenarios, but in order to facilitate the estimation only wind scenarios are considered. As this is an example, it just attempts to illustrate how the wind power can be modelled in accordance with the use of renewables as required in the priority corridors' methodology.

Figure 16 Wind power scenarios



As wind power does not contribute to the security of supply, it is also restricted to 5% of availability in the season peak hour, and for the rest of the season a flat electricity production is considered in each block, assuming that the historical wind power availability is around 22%[63].

The nine scenarios result from the combination of different wind scenarios for the three countries of the South Western regions, with associated probabilities for each season that are as follows:

Table 11 –Wind power scenarios (hourly production per MW installed - MWh)

France	Spain	Portugal	France	Spain	Portugal	Probability
Low	Low	Average	0.06	0.06	0.24	1%
Average	Low	Average	0.24	0.06	0.24	8%
High	Low	Average	0.49	0.06	0.24	1%
Low	Average	Average	0.06	0.24	0.24	8%
Average	Average	Average	0.24	0.24	0.24	64%
High	Average	Average	0.49	0.24	0.24	8%
Low	High	Average	0.06	0.49	0.24	1%
Average	High	Average	0.24	0.49	0.24	8%
High	High	Average	0.49	0.49	0.24	1%

As it can be observed, probability scenarios assume that Portugal is operating under average wind regime, while Spain and France vary their production in accordance to three different types of wind scenarios. These probabilities are applied to the two different seasons, so that seasonal scenarios are as follows:

[63] It is the average plant factor of each wind farm.

Table 12 –Winter wind power scenarios (hourly production per MW installed - MWh)

France	Spain	Portugal	France	Spain	Portugal	Probability
Low	Low	Average	0.08	0.08	0.28	1%
Average	Low	Average	0.28	0.08	0.28	8%
High	Low	Average	0.58	0.08	0.28	1%
Low	Average	Average	0.08	0.28	0.28	8%
Average	Average	Average	0.28	0.28	0.28	64%
High	Average	Average	0.58	0.28	0.28	8%
Low	High	Average	0.08	0.58	0.28	1%
Average	High	Average	0.28	0.58	0.28	8%
High	High	Average	0.58	0.58	0.28	1%

Table 13 –Summer wind power scenarios (hourly production per MW installed - MWh)

France	Spain	Portugal	France	Spain	Portugal	Probability
Low	Low	Average	0.06	0.06	0.21	1%
Average	Low	Average	0.21	0.06	0.21	8%
High	Low	Average	0.43	0.06	0.21	1%
Low	Average	Average	0.06	0.21	0.21	8%
Average	Average	Average	0.21	0.21	0.21	64%
High	Average	Average	0.43	0.21	0.21	8%
Low	High	Average	0.06	0.43	0.21	1%
Average	High	Average	0.21	0.43	0.21	8%
High	High	Average	0.43	0.43	0.21	1%

Hydro generation is divided in two parts: base (flat) generation, for those plants without storage capacity or with forced releases due to constrain imposed by non energetic uses of water (irrigation, domestic, navigation, environmental, etc) and plants with storage that can freely optimise the use of water.

Storage hydro plants are optimised by the model, allowing concentrating generation in peak hours. The pump units are also used for generating in peak hours. The optimal dispatch then results from optimization of the allocation of peak hydro generation in peak hours.

1.2.2 SDDP scenarios

The optimal expansion provided by the ORDENA model was then run in the SDDP in order to verify the functioning of the optimal solution with a much mode detailed model. Particularly this model allows verifying whether individual transmission capacities had been violated as a result of the transmission expansion plan, or whether there was an unacceptable level of non-supplied energy (taking into account the actual weekly demand curve of each country, hydrological and wind generation uncertainty, and other contingencies). Furthermore, consistency of dispatch of units in both models is verifies.

The main assumptions for modelling the expansion plan identified for Spain, Portugal and France by the ORDENA model with SDDP were:

- The existing planned and candidate facilities (generation units and transmission lines) decided by the ORDENA model are introduced in the SDDP model.

- Fuel pricing structure and demand data are exactly the same as considered in the ORDENA model.

- Three time periods were considered:

    - 2008 as the initial year, and

    - 2016 and 2020 as representative for the new interconnection needs in the next decade.

- Each time period comprises 52 weeks, and four demand blocks are modelled in each week.

- In 2016, two alternatives are shown: the first one considers only the cross border capacity expansion forecasted by the TSO at present, while the other one takes into account the optimal expansion plan provided by the ORDENA model (this fact means an extra expansion of 1,000 MW of interconnection capacity in both directions between Spain and France).

- In 2020, two alternatives are shown again: the first one considers only the cross border capacity expansion forecasted by the TSO at present, and the other takes into account the optimal expansion plan provided by the ORDENA model (this means an extra expansion of 1,000 MW in both directions between Spain and France). In this sense, no extra expansion is provided by ORDENA results between Spain and Portugal.

- The hydro generation output uses a stochastic characterization across 100 different series and 10 hydrological scenarios generated by the SDDP. Historical generation data or hydrological records were used to characterise the 10 scenarios. For real world use of this methodology 50-100 series should be used.

- The wind generation output uses a stochastic characterization based on historic generation. 10 wind scenarios were generated by the SDDP, which reproduces the historical pattern of generation (average and standard deviation), and assuming a Weibull[64] distribution of wind.

- The policy on water and wind used in the SDDP is the result of a stochastic description which requires a context of historical data on flows and generation that serve as a statistical sample.
- Results are summarized in three wind power cases for each country: the average between the 10 scenarios, the one with the highest wind production (percentile higher than 90%) and the one with the lowest wind production (percentile lower than 10%).

Hence, SDDP simulates the dispatching and pricing according to the above assumptions, and the results of both models are presented in the following section.

1.3 Modelling results

Once the scenarios are introduced into the models, the long term optimization model is run at first, so as to provide extension plans in both generation and transmission in the simulation model. Later, these results are used for the simulation model to check whether any inconsistency is detected in terms of security of supply, use of renewables and competition increase. Thus, results are presented by following this scheme for a better understanding of the proposed methodology.

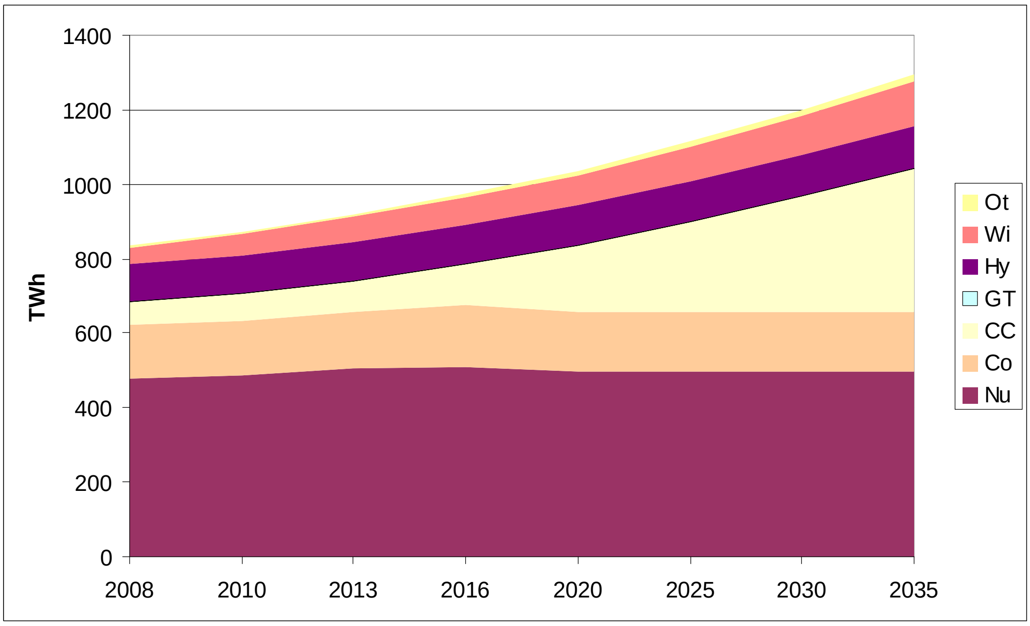
1.3.1 ORDENA results

The optimization model provides the optimal expansion plans for both generation and transmission in the South Western region according to the wind power scenarios assumed and existing generation and transmission and list of candidates units for the whole period. The model provides dispatched capacity by technology in each seasonal block and marginal costs in each seasonal block.[65]

Thus, the results provided by the ORDENA optimization model for the whole period are summarized in the next figure that illustrates the power production by technology for the entire region. These results comprise the nine scenarios to provide the weighted generation dispatch.

[64] Parameters of the Weibull distribution were estimated based on historical records.
[65] ORDENA enables the possibility of running

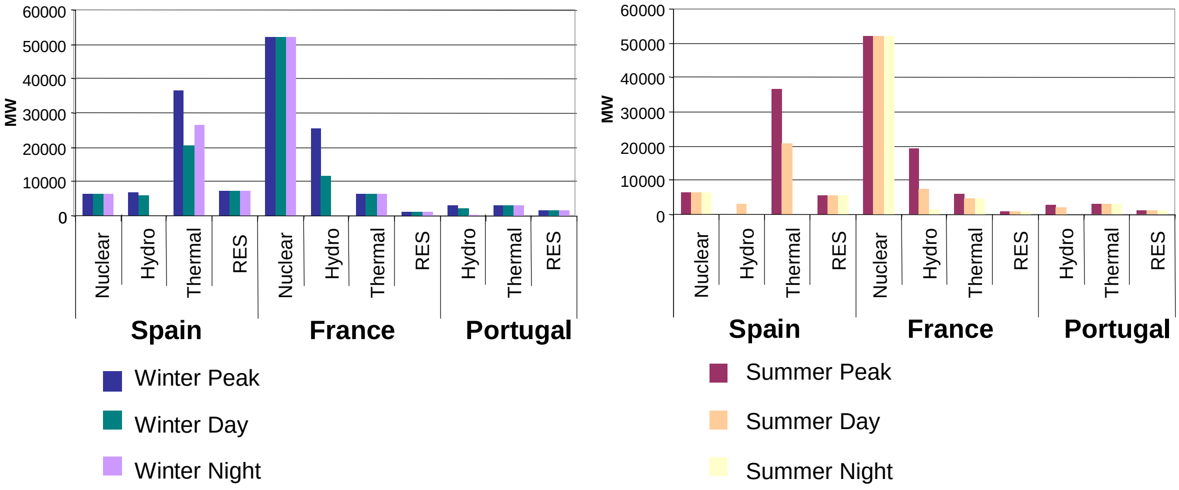
Graph 1 Power production by technology in the South Western region



As it can be observed, the main technology in the region is nuclear power (Nu), although its production tends to decrease over time, and obviously its participation is lower in percentage at the end of the period. The remaining thermal plants remain constant in terms of production (i.e., coal (Co) and OCGT (GT) with the exception of combined cycles (CC) that rapidly increase t production over time. Hydro power (Hy) also remains constant, but renewables (wind power (Wi) and other RES (Ot)) increase its production over time, especially in the case of the wind power.

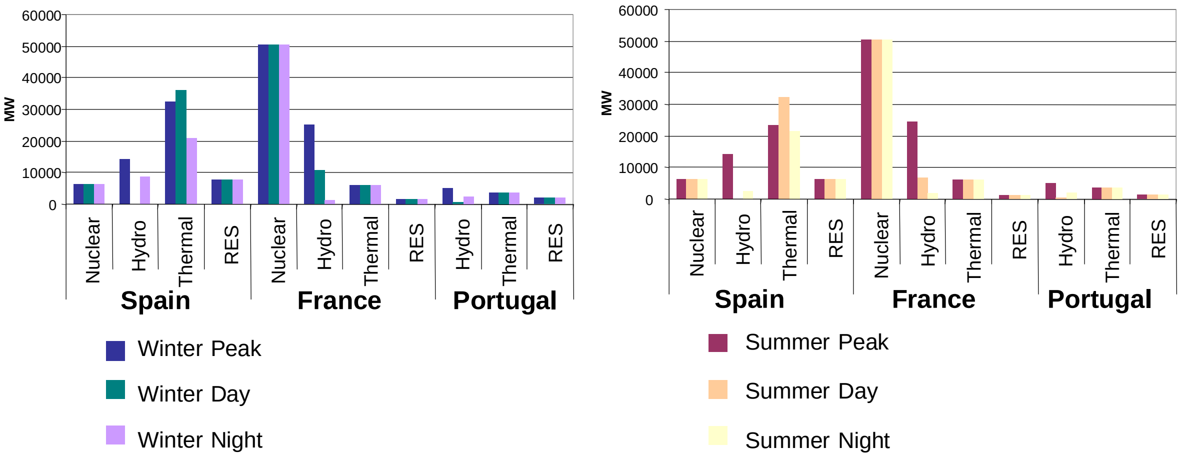
These results are aggregated for the three countries; France, Spain and Portugal. However, ORDENA provides seasonal results for each scenario for every single country. In this regard, the next figure shows the power dispatched in every country in year 2016. It also illustrates power dispatched by seasonal time periods.

Figure 17 Power dispatched in 2016 by country, season and block in the average scenario (MW)



The above figure results from the average scenario, but eight additional results are also obtained. The selected year is 2016 as representative of the next decade concerning the power dispatched in every seasonal time period. The below figure also shows results in year 2020:

Figure 18 Power dispatched in 2020 by country, season and block in the average scenario (MW)



The two figures above show that nuclear power is base dispatched in France and Spain, while in Portugal thermal power is base dispatched. Furthermore, marginal technologies are hydro in France, thermal in Spain and hydro in Portugal in winter and summer time in the three blocks. Wind and other RES are supposed to be injected in the network independently on their marginal prices, so that these technologies are base dispatched by the optimization model.

As it was referred to in the production graph, nuclear power is the most relevant type of technology, mainly because of the large amount of nuclear power installed in France, and complemented with the Spanish nuclear power. Portugal does not include nuclear power in its electricity system. Thermal power is most relevant type of production technology in both Spain and Portugal, while wind power is especially relevant in Spain, reaching almost 9,000 MW per block hour. In France and Portugal the RES is not as relevant as it is in Spain. Finally, hydro power is modelled to be dispatched to cover peak demand because of the opportunity cost value of the storage water. As a result, hydro resources are dispatched when prices are higher due to two possible reasons; high demand (i.e., peak hours) or low supply resources (i.e., short availability of existing thermal units due to planned outages, etc.), which are reflected through price signals. Therefore, hydro power tends to be dispatched in peak hours rather than in night hours.

In this sense, as demand increases over time, existing units are not enough to fully produce the required electricity power, so that the optimization model requires new installed capacity in order to avoid non-supplied energy. To this aim, depending on the power necessities, the model provides a generating expansion plan over time to better allocate new capacity into the existing one. As a result, for the considered time horizon the new installed capacity for France, Spain and Portugal provided by ORDENA is as follows:

Table 14 –New installed capacity (MW)

	2013	2016	2020	2025	2030	2035	Total
OCGT Spain	0	0	0	13,353	14,045	4,573	31,972
CCGT Spain	0	0	0	0	0	6,905	6,905
OCGT France	0	0	0	0	3,642	7,442	11,084
OCGT Portugal	0	0	0	0	0	1,328	1,328
TOTAL	0	0	0	13,353	17,688	20,248	51,289

This table shows new power needs for the whole period including generating expansion plans in the three countries, mostly OCGT plants that are used to cover peak demand periods. As it can be observed, Spain demands new OCGT plants from 2025 onwards totalling 31,972 MW and 6,905 MW CCGT plants in the 2035 period to cover base demand. France and Portugal require OCGT capacity in the 2035 which amounts over 11,000 MW and 1,300 MW respectively.

This expansion plan is added to the existing one already planned by involved stakeholders (i.e., already requested by generators and in the case of renewables planned by governments). Therefore, the total installed capacity in the course of the whole period is the following:

Table 15 –Total capacity by country (MW)

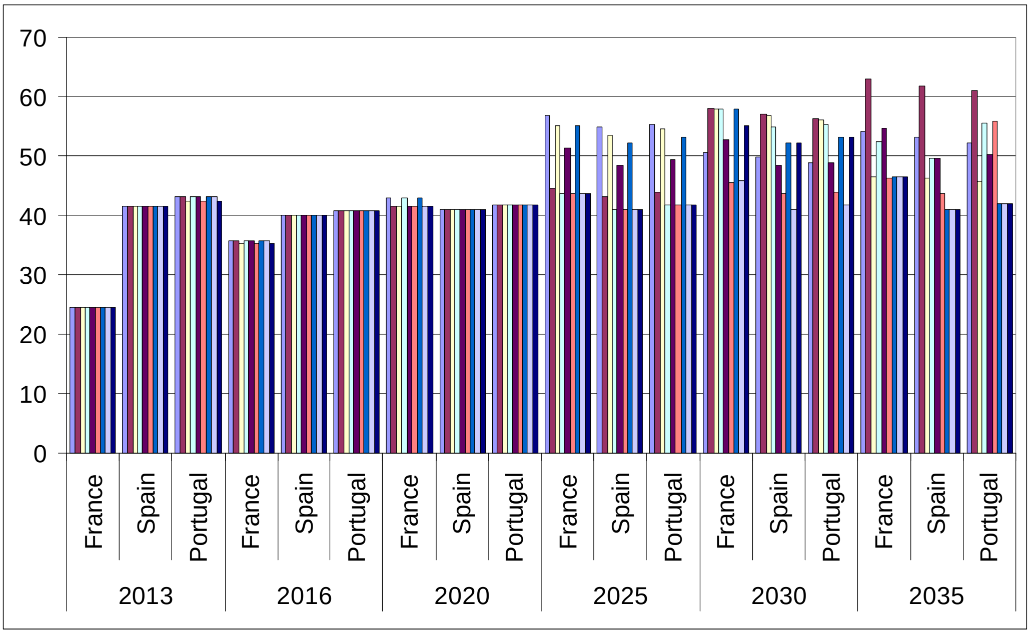
	Spain	France	Portugal	Total
2008	87,351	115,485	14,862	217,698
2010	91,353	118,772	17,430	227,555
2013	99,403	122,164	18,995	240,562
2016	103,380	121,212	20,655	245,247
2020	108,465	121,772	23,392	253,629
2025	125,318	122,997	24,982	273,297
2030	142,864	127,864	26,572	297,300
2035	157,842	136,531	29,489	323,862

Adding the new optimal expansion capacity to the existing and planned generating capacity, the total installed capacity in each country evolves from 217,698 MW in 2008 to 323,862 MW in 2035. The above table shows that installed capacity in Spain is expected to be higher than in France in year 2025 although France generates more power. This is due to the large amount of French thermal power to supply base demand, and also due to the large amount of wind power installed in Spain over the whole period.

But new installation decisions, apart from the one already envisaged, are based on price signals, so that new plants are added to the electricity system only if two conditions are met: first, the new added unit must be able to fully recover its investment costs; and second, the model decides the least cost alternative for expanding the generating system.

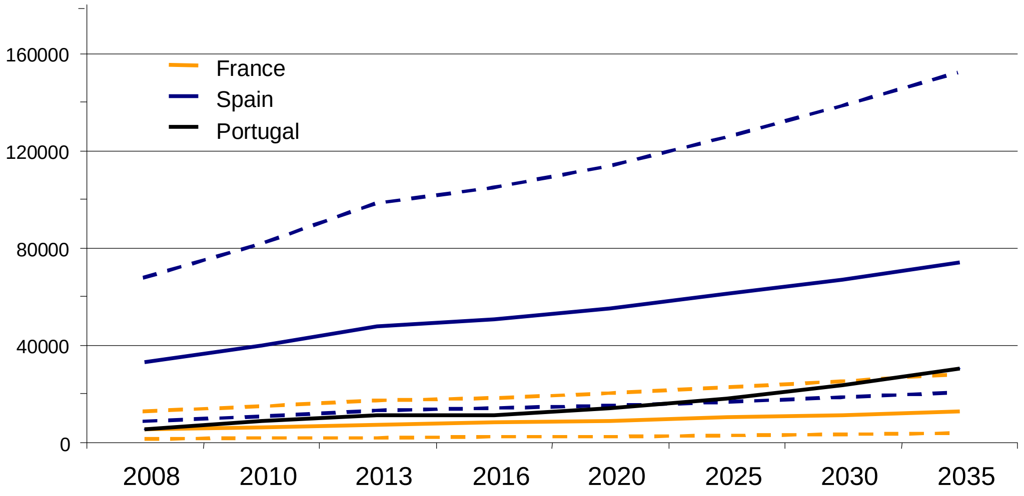
In this regard, price signals are based on marginal costs that are provided by country, season and block in every scenario. The next graph illustrates average marginal costs evolution over the whole period in the nine selected scenarios.

Graph 2 Yearly average marginal costs evolution by scenario (€/MWh)



Two different patterns can be observed in the above graph: in the first instance, price differences arise among countries at the beginning, specifically between France and the Iberian Peninsula countries. However, these marginal cost differences tend to decrease over time. Second, wind power scenarios provide different marginal costs at the end of the period, thus when wind power production is lower, peak capacity plants are obliged to dispatch in peak time, therefore increasing marginal costs prices. Wind power production by scenario is showed in the following graph:

Graph 3 Wind power production by country



The different wind power scenarios lead to different dispatches that vary across scenarios, resulting in different marginal costs along the whole period. This is especially relevant in the case of Spain, where the expected wind capacity is large enough to require additional capacity, not only in peak hours but also in off-peak hours.

However, generating expansion units is not the only alternative that the optimization model analyzes for better managing the regional electricity system. Additionally, transmission interconnection lines are also feasible in order to better manage demand requirements. In fact, the marginal costs' homogenization is due to interconnection flows that lead to the same marginal prices from the economic perspective (i.e., assuming the interconnection is fully available regarding the net transfer capacity). In this sense, a country with lower marginal prices and excess of generating capacity tend to export to neighbour countries its power excess at opportunity cost. This is only feasible in case that interconnection is large enough to provide this possibility. As this is not the case, at the beginning of the period marginal costs differ across countries. However, after the entry in operation of approved interconnection lines, prices tend to be homogeneous in the regions, as it happens at the end of period.

Nevertheless, approved interconnection plans are not enough to allow for optimal dispatching in the region since demand increases over time. Therefore, additional interconnection is required in order to provide the least cost dispatch. However, these new interconnection investments are obviously subject to total investment costs. As the standard interconnection available for this optimization process was overhead lines, the transmission capacity expansions resulting from the optimization process is as follows:

Table 16 –Transmission capacity expansions (MW)

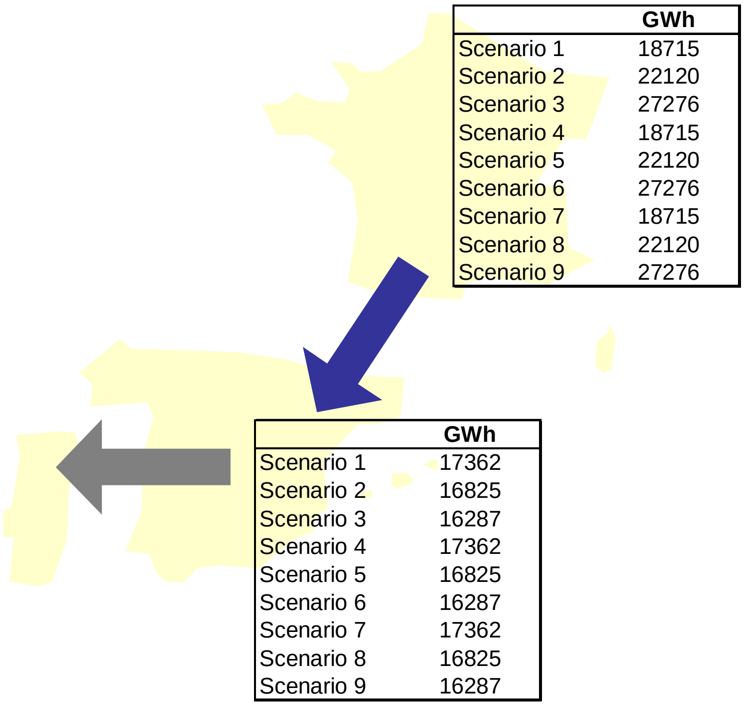
		2013	2016	2020	2025	2030	2035
France	Spain	0	1,000	1,000	1,000	1,000	1,000
Spain	Portugal	0	0	0	0	1,000	1,000

Thus, it is optimal that the production of cheaper nuclear power in France be exported to Spain, rather than investing in new thermal capacity in Spain. In addition, Spanish generation costs are lower than the Portuguese ones, so additional interconnection capacity is required at the end of the period between the two countries. This is feasible regarding transmission investment costs in overhead lines. Otherwise, it would be optimal to build new generation capacity. So, increase of competition is taken into consideration through the optimization process by allowing interchanges.

Due to the wind power scenarios' uncertainty the optimization model has to deal with, new interconnection plans are decided over the probabilistic function on wind power generation. In this sense, one of the advantages of ORDENA optimization model is that it provides a unique transmission expansion plan rather than different solutions depending on the simulated scenarios.

Furthermore, different wind power scenarios lead to different interconnection needs, so that interconnection expansion plans heavily depend on the wind power conditions in order to decide whether new interconnection capacity is required under the simulated scenarios. The next figure shows the annual interconnection flows in the region for 2016, to allow making efficient decisions.

Figure 19 Annual interconnection flows between countries by scenario (2016)



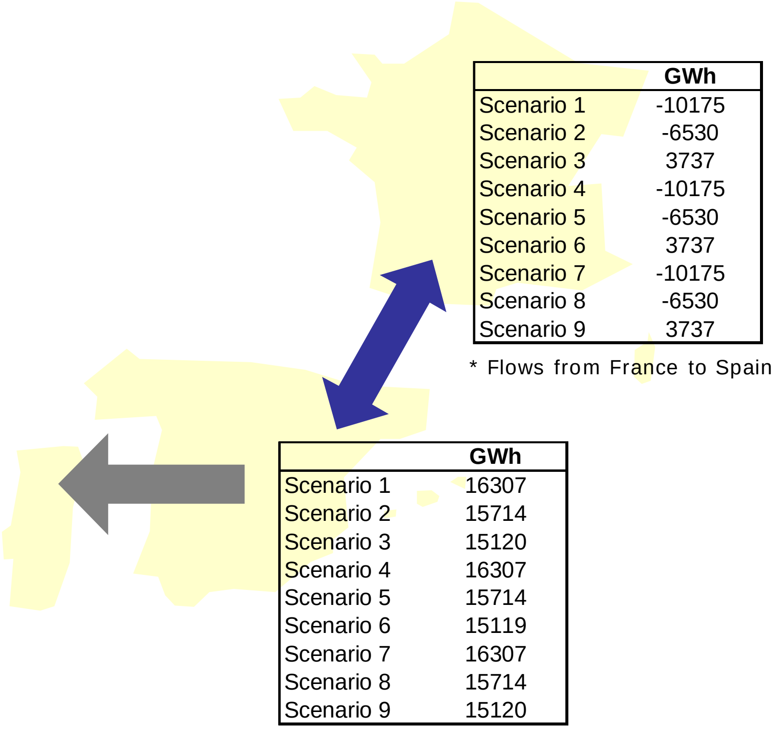
	GWh
Scenario 1	18715
Scenario 2	22120
Scenario 3	27276
Scenario 4	18715
Scenario 5	22120
Scenario 6	27276
Scenario 7	18715
Scenario 8	22120
Scenario 9	27276

	GWh
Scenario 1	17362
Scenario 2	16825
Scenario 3	16287
Scenario 4	17362
Scenario 5	16825
Scenario 6	16287
Scenario 7	17362
Scenario 8	16825
Scenario 9	16287

The interconnection flows' variability is higher in the Spanish-French border than in the Spanish-Portuguese one, so this volatility may lead to new interconnection capacity requests. Net flows are positive between France and Spain, implying that marginal costs are higher in Spain, as observed previously in. The same stands for Spain and Portugal, as in the former country marginal costs are lower than in the latter.

The following figure shows the same flows in year 2020.

Figure 20 Annual interconnection flows between countries by scenario (2020)



	GWh
Scenario 1	-10175
Scenario 2	-6530
Scenario 3	3737
Scenario 4	-10175
Scenario 5	-6530
Scenario 6	3737
Scenario 7	-10175
Scenario 8	-6530
Scenario 9	3737

* Flows from France to Spain

	GWh
Scenario 1	16307
Scenario 2	15714
Scenario 3	15120
Scenario 4	16307
Scenario 5	15714
Scenario 6	15119
Scenario 7	16307
Scenario 8	15714
Scenario 9	15120

As a result of the new transmission expansions between France and Spain in 2016 and 2020, interconnection flows are positive and negative depending on the wind power scenario. On the contrary, marginal costs still remain lower in Spain compared to Portugal, so annual net flows are positive from Spain to Portugal.

More specifically, annual interconnection flows are showed in the next table:

Table 17 –Annual interconnection flows (MWh)

		2013	2016	2020	2025	2030	2035
France	Spain	21,942	23,529	14,134	24,103	34,222	42,290
Spain	Portugal	15,972	16,997	15,877	20,392	13,372	15,841

As a result of the interconnection expansion planned and added because of the optimization model, annual interconnection flows increase over the period to provide efficient dispatching in generation, always in line with the least cost operation.

To sum up, generation and transmission expansion plans are provided according to the least cost criterion that minimizes the electricity system's operation. In addition, security of supply is taken into account by avoiding non-supplied energy, increase of competition is promoted by the use of optimal generation dispatching and use of interconnection, and the use of renewables is analyzed by introducing scenarios that allow for extreme wind conditions fully supported by the remaining generation units.

However, in order to ensure the transmission expansion plan improves the social welfare, a parallel optimization model that does not allow for new interconnection, apart from the one that has been already approved, has been run with the aim of comparing total costs from optimizing generation expansion model to generation and transmission expansion model. In this regard, the model including transmission expansion totals € 4,765 million less in dispatching efficiently from 2016 when first added transmission expansion is built to 2035. This amount would be the maximum to be spent in permitting processes, underground cables or any other obstacle encountered in the selection and construction process that would provide benefits to the regional citizens. Expenses over this amount would lead to social losses that are inconsistent with the selection of projects of European interest.

1.3.2 SDDP results

The SDDP model was run to check the operation of the power system under combined hydrological and wind scenarios in order to confirm the robustness of the ORDENA model's results.

If, under the aforementioned conditions, there were scenarios with an unreasonable amount of non-supplied energy, it is necessary to check the causes, modify the input parameters of the ORDENA model and obtain a new South Western power system expansion plan.

The SDDP established the adequacy of the expansion plan provided by the ORDENA model, so no further adjustments were necessary as it was previously mentioned in the scenarios' section. In this regard, the results provided by the simulations were satisfactory and demand was met under specific defined conditions if all generation plants were available in accordance to the parameters and results of the optimization expansion plan. This fact emphasizes the benefits of the interconnected regional power system in terms of social welfare increase.

Therefore, the following table shows the annual exports and imports for each country under some different scenarios (highest, lowest, and average production that are taken from the different stochastic hydrology and wind power data). The main role is played by the exports from France to Spain, and those from Spain to Portugal as it also happened in the optimization plan for representative years of the next decade. In addition, results from plans with and without new transmission expansion plan, are compared in order to show whether the transmission expansion plan is more efficient.

Table 18 – Cross border trading in the different scenarios

	GWh	SP-FR<-			SP-FR->		
Year		Lowest	Average	Highest	Lowest	Average	Highest
2008	Present	9,979	10,196	10,463	120	85	92
2016	TSO	16,402	16,764	16,652	832	962	966
2016	TSO+Ordena	21,816	22,341	22,457	2,377	2,691	2,718
2020	TSO	12,092	12,337	12,587	1,667	1,650	1,789
2020	TSO+Ordena	19,740	20,128	20,549	6,902	6,919	7,678
	GWh	SP-PO<-			SP-PO->		
Year		Lowest	Average	Highest	Lowest	Average	Highest
2008	Present	3	106	200	11,381	11,673	12,133
2016	TSO	520	1,548	1,950	13,800	14,208	15,927
2016	TSO+Ordena	520	1,548	1,954	13,617	14,119	15,788
2020	TSO	1,232	2,881	3,515	11,933	11,835	13,844
2020	TSO+Ordena	1,400	3,065	3,939	11,108	11,670	13,420

Please note that annual interconnection flows in 2016 and 2020 the expansion given by the ORDENA are higher than the one planned by the TSOs. It is worth to point out that the optimal transmission expansion plan includes new added transmission between Spain and France in 2016 and 2020. This fact provides a considerable increase in the cross border flows between these two countries.

Regarding marginal costs, it has to be stressed that there is a change in the average price profile during the simulated years. Prices in Spain and Portugal converge in 2016 as shown in the optimization model results, and the spread between Spanish and French prices decreases considerably from 2016 to 2020, also in line with the results provided by the optimization model. These two facts explain the increase of the Portuguese exports to Spain and the Spanish exports to France. The next table shows the results on marginal cost prices:

Table 19 - Average annual price in the different scenarios

	EUR/MWh	Spain			France			Portugal		
Year		Lowest	Average	Highest	Lowest	Average	Highest	Lowest	Average	Highest
2016	TSO	39.72	40.15	40.32	32.95	32.20	33.05	40.86	40.88	41.33
2016	TSO+Ordena	39.64	40.22	40.35	32.06	32.24	32.27	40.86	41.06	41.46
2020	TSO	40.28	40.76	40.72	42.80	45.36	46.16	41.01	41.26	41.78
2020	TSO+Ordena	40.16	40.77	41.91	43.36	43.54	45.11	40.97	42.10	42.64

There is no skyrocketing impact on prices when one scenario or another is considered, as the wind production is maintained reasonably stable in the different cases considered. However, an increase on prices is observed in the lowest hydro and wind scenario.

Table 20 - Annual wind production in the different scenarios

	GWh	Spain			France			Portugal		
Year		Lowest	Average	Highest	Lowest	Average	Highest	Lowest	Average	Highest
2016	TSO	53,472	63,977	72,049	10,421	11,692	13,510	8,425	10,005	12,081
2016	TSO+Ordena	53,472	63,977	72,049	10,421	11,692	13,510	8,425	10,005	12,081
2020	TSO	58,963	70,552	79,451	11,764	13,208	15,273	11,062	13,134	15,860
2020	TSO+Ordena	58,963	70,552	79,451	11,764	13,208	15,273	11,062	13,134	15,860

It has to be noted that wind production is only linked to the amount of wind estimated for each stage and to the capacity installed each year. Wind generation capacity does not change in a single year, so generation results on an annual basis are exactly the same, whatever the expansion considered in the cross border transmission lines.

The most important conclusion is that no deficit between generation and demand is found. The expansion plan given by the ORDENA model is feasible and does not present any problems from the operational and technical dispatch viewpoint.

Other important facts are:

- Wind within the cross border capacity is remarkably followed by an increase in the flows between the interconnected countries.
- In the simulation’s long term horizon there is an increase in the non-typical use of the interconnection, due to changes in the marginal cost profile of the countries (convergence between Spain and Portugal and reduction of the gap between Spain and France).

1.4 Extra SDDP results

This section presents the whole dataset of results regarding the SDDP simulations of the Spanish, French and Portuguese electricity sector in the medium- and long term. Ten wind scenarios have been run in order to show the variability in the availability of the wind available resource. The model provides different results in terms of marginal prices and cross border flows that takes into account the uncertainty of wind production.

Next tables show the wind generation in each country and scenario (GWh per year):

Table 21 – Wind generation by scenario

		SPAIN									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	72,049	56,977	63,977	67,859	56,207	63,334	53,472	57,731	62,095	70,949
2016	Ordena	72,049	56,977	63,977	67,859	56,207	63,334	53,472	57,731	62,095	70,949
2020	TSO	79,451	62,821	70,552	74,825	61,978	69,836	58,963	63,665	68,483	78,232
2020	Ordena	79,451	62,821	70,552	74,825	61,978	69,836	58,963	63,665	68,483	78,232
		FRANCE									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	10,421	12,734	13,482	11,461	11,692	12,625	13,459	13,510	12,288	12,287
2016	Ordena	10,421	12,734	13,482	11,461	11,692	12,625	13,459	13,510	12,288	12,287
2020	TSO	11,764	14,389	15,226	12,938	13,208	14,259	15,200	15,273	13,886	13,878
2020	Ordena	11,764	14,389	15,226	12,938	13,208	14,259	15,200	15,273	13,886	13,878
		PORTUGAL									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	9,134	11,609	8,425	10,005	10,918	11,655	10,844	12,081	10,677	8,267
2016	Ordena	9,134	11,609	8,425	10,005	10,918	11,655	10,844	12,081	10,677	8,267
2020	TSO	11,995	15,244	11,062	13,134	14,329	15,301	14,236	15,860	14,021	10,851
2020	Ordena	11,995	15,244	11,062	13,134	14,329	15,301	14,236	15,860	14,021	10,851

Next tables show the cross border flows by interconnection and scenario (GWh per year):

Table 22 – Cross border flows by interconnction

		FRANCE TO SPAIN									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	16,402	17,000	17,071	16,698	16,764	16566	17047	16640	16796	16652
2016	Ordena	21,816	22,727	22546	22,433	22,341	22212	22606	22339	22397	22457
2020	TSO	12,092	12,807	12,423	12,557	12,337	12478	12953	12739	12392	12587
2020	Ordena	19,740	21,055	20,861	20,452	20,128	20482	21295	20442	19995	20549
		SPAIN TO FRANCE									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	966	887	829	901	946	892	869	962	931	831
2016	Ordena	2,718	2,530	2,328	2,571	2,651	2,526	2,525	2,690	2,679	2,377
2020	TSO	1,788	1,621	1,748	1,671	1,671	1,637	1,673	1,649	1,656	1,666
2020	Ordena	7,678	7,217	7,362	6,947	6,997	7,078	7,375	6,918	7,081	6,902
		PORTUGAL TO SPAIN									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	1,114	1,950	767	1,341	1,547	1,150	1,762	1,443	1,600	519
2016	Ordena	1,130	1,954	767	1,341	1,547	1,150	1,762	1,443	1,600	519
2020	TSO	2,190	3,515	1,518	2,659	2,880	2,425	3,060	2,901	2,835	1,232
2020	Ordena	2,400	3,939	1,681	2,562	3,065	2,425	3,396	3,029	2,865	1,400
		SPAIN TO PORTUGAL									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	15,694	13,800	15,927	14,763	14,208	13,964	14,507	13,894	15,021	15,905
2016	Ordena	15,540	13,617	15,788	14,781	14,119	13,968	14,391	13,852	14,952	15,845
2020	TSO	14,038	11,933	13,844	12,822	11,835	11,759	12,429	11,925	12,982	13,806
2020	Ordena	13,832	11,108	13,420	11,924	11,670	11,433	11,572	11,514	12,966	13,541

Next tables show the total cost of the systems in terms of demand times marginal cost of the dispatch in each country and scenario (Million euros per year):

Table 23 – Total system costs

		SPAIN									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	13,627	13,886	13,736	13,758	13,832	13,679	13,847	13,639	13,658	13,891
2016	TSO+Ordena	13,613	13,899	13,727	13,833	13,808	13,677	13,862	13,650	13,619	13,871
2020	TSO	15,147	15,348	15,367	15,380	15,392	15,205	15,384	15,273	15,212	15,397
2020	TSO+Ordena	15,775	15,881	15,444	15,819	15,425	15,166	15,389	15,291	15,276	15,851
		FRANCE									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	18,200	20,789	18,532	18,516	18,834	18,020	18,130	17,766	18,627	18,684
2016	TSO+Ordena	17,905	17,851	17,705	17,864	18,060	17,849	17,966	17,653	17,860	17,706
2020	TSO	28,293	27,694	25,843	28,344	28,270	27,610	27,627	28,676	28,213	27,232
2020	TSO+Ordena	28,259	27,804	25,867	27,272	26,396	26,070	26,741	26,643	27,238	26,570
		PORTUGAL									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	2,843	2,882	2,886	2,866	2,873	2,860	2,873	2,832	2,866	2,910
2016	TSO+Ordena	2,851	2,883	2,886	2,880	2,868	2,859	2,874	2,833	2,866	2,907
2020	TSO	3,214	3,218	3,261	3,231	3,242	3,205	3,234	3,208	3,220	3,270
2020	TSO+Ordena	3,342	3,316	3,281	3,314	3,244	3,203	3,224	3,211	3,238	3,357

Finally, next tables shows the marginal cost of the system in each country and scenario (EUR/MWh per year)

Table 24 – Marginal costs

		SPAIN									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	39,48	40,32	39,88	39,82	40,05	39,72	40,15	39,70	39,67	40,02
2016	TSO+Ordena	39,37	40,35	39,76	40,02	40,00	39,64	40,22	39,51	39,45	40,15
2020	TSO	40,07	40,72	40,63	40,66	40,71	40,28	40,76	40,37	40,30	40,74
2020	TSO+Ordena	41,32	41,91	40,74	41,55	40,77	40,16	40,77	40,37	40,36	41,63
		FRANCE									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	32,57	36,20	32,95	32,92	33,45	32,20	32,39	31,78	33,05	33,26
2016	TSO+Ordena	32,39	32,20	32,06	32,26	32,66	32,24	32,41	31,89	32,27	32,02
2020	TSO	46,32	45,37	42,80	46,43	46,43	45,36	45,31	46,88	46,16	44,86
2020	TSO+Ordena	46,62	45,96	43,36	45,20	44,08	43,54	44,63	44,33	45,11	44,40
		PORTUGAL									
		1	2	3	4	5	6	7	8	9	10
2016	TSO	40,55	41,19	41,22	40,88	41,01	40,86	41,03	40,55	40,99	41,33
2016	TSO+Ordena	40,60	41,21	41,23	41,06	40,94	40,86	41,08	40,36	40,90	41,46
2020	TSO	41,07	41,19	41,67	41,26	41,44	41,01	41,39	40,94	41,19	41,78
2020	TSO+Ordena	42,34	42,28	41,87	42,10	41,45	40,97	41,27	40,97	41,35	42,64

1.5 Conclusions

Once the optimization and simulation models have been run, it may be concluded that the transmission expansion plan provided by the former model has been backed up by the simulation model. This implies that in terms of social welfare the expansion of new transmission capacity provides a better solution of only carrying out those plans presently approved by involved stakeholder.

Although the results provided by these models only attempt to show how the proposed methodology works with this example, final recommendations from this stage would be to go ahead with the selected transmission expansion plan between Spain and France in 2016 and 2020, to the next decision stage. It has to be highlighted that optimization and simulation models have been simplified in order to reduce data needs. However, these types of models are able to deal with much more detailed variables, that should be used if available. In this regard, the co-ordination and co-operation of involved stakeholders is crucial for proper methodology assessment. In the same line, the use of common databases is not the only requirement but the same methodology steps described in the methodology proposal must also be followed.

Once these two models are run, the next step should be the interconnection flow's simulation according to data provided by the optimization and simulation models. In case the results provided by this model are consistent with the interconnection expansion plan and simulation model results, the transmission added capacity could be selected in the list of candidates to be declared of European interest. The next stages would require the permitting and construction analysis before labelling the project as priority corridor for the EU.

2 The Electricity Interconnection Indicator Report

This section presents an example of the use of the Alternative # 2, that consists in the calculation of the Electricity Interconnection Indicator for all European Union countries, which allows determining where new electricity transmission interconnection capacity would be necessary in both 2008 and 2020. The calculations attempt to show how this type of methodology is able to make a preliminary assessment of the electricity transmission interconnection capacity priorities and the amount by which they increase.

However, this indicator relies on the available information and on a number of assumptions regarding the weight of the sub-indicators that comprise this formula. Therefore, the values presented under this methodology are open to discussion in terms of the values included for estimating the sub-indicators. In any case, this is just an example of the potential use of this methodology and can be refined according to the data provided by involved stakeholders and the discussion and interpretation of the values included in it.

As it was explained in the methodology, the indicator may be used for both countries and regions, so values are presented for the 27 EU Member States and for the nine regions already defined for the designation of electricity priority corridors. The results illustrate how this methodology can be combined with the TEN-E proposals in order to make a selection of priority projects to be fostered by stakeholders.

In this regard, once the electricity transmission interconnection capacity is calculated, a number of priority projects are proposed to show how the methodology can be applied. As it was previously mentioned, this methodology is simple and straightforward because the information requirements are relatively easy accessible, although it presents potential limits that complex methodologies would be more able to deal with. Nevertheless, it would be valuable to see whether the accuracy of this methodology is in line with the results provided by more detailed models.

Finally, as it was previously commented the objective of this methodology is to show whether the development of an interconnection indicator is feasible. If, based on discussion and possibly consultation, such an indicator proves to be beneficial, then more detailed studies will be needed to set the relevant parameters.

2.1 Countries and Regions

The Electricity Interconnection Indicator is calculated per country and per region. The regions that were considered are the following:

- North Sea: Belgium, Denmark, Germany, the UK, the Netherlands.
- Central Eastern Europe: Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia.

- Central Southern Europe: Austria, France, Germany, Greece, Italy, Slovenia.
- Central Western Europe: Austria, Belgium, France, Germany, Luxembourg, Netherlands.
- Northern Europe: Denmark, Finland, Germany, Norway, Poland, Sweden.
- Baltic countries: Latvia, Estonia, Lithuania, Finland and Poland.
- South Western Europe: France, Portugal, Spain.
- UK and Ireland: France, Ireland, the UK and the Netherlands.
- Eastern Europe: Greece, Hungary, Romania and Bulgaria.

The regions had already been included in the regional proposal for the proclamation of electricity transmission interconnection priority corridors. Some of the countries are included in more than one region, due to their strategic location in the EU. This is specifically relevant in the case of France and Germany, not just due to their location but also to their size, which as it will be shown, is able to determine the amount of capacity interconnection between regions.

2.2 The Electricity Interconnection Indicator (E_I)

The sub-indicators necessary to estimate the E_I are:

- the sub-indicator for the competitive structure of the electricity market: M,
- the sub-indicator for the security of supply: S,
- the sub-indicator for the amount of flow-based renewable power generation: R,

The E_I was calculated as a function of these sub-indicators:

$$E\_I = f(M, S, R)$$

The idea is that the electricity interconnection indicator E_I can be used to estimate the ‘optimal’ amount of interconnection capacity by multiplying it with the system’s capacity (C):

$$\text{optimal interconnection capacity} = E\_I \times C$$

The outcome of the above formula reflects the need for interconnection capacity (in MW) of a certain country or system. A comparison with the present amount of interconnection capacity will then show whether new investments are needed.

The following sections will develop the assumptions underlying the values of the sub-indicators composing the electricity interconnection indicator, but not the reasons for their construction that were already developed in the chapter on methodology.

2.2.1 The M sub-indicator

To calculate the M sub-indicator, the values of HHI and M_t are required.

The threshold M_t is assumed to have the value of 0.42 for countries, and 0.32 for regions, since regions are likely to be more competitive, or at least this is the requirement for the creation of a single electricity European market.

HHI is the Herfindahl – Hirschman index that measures the size of companies with respect to the power generation market. The percentages of each company's market share in any given country are being elevated to the power of 2 and added up. Values of this index vary between 0 and 10,000.

According to the information provided by the countries in the Annual Report to the European Commission, the companies' web- pages, the Ministries' information and the Transmission System Operator of each country, the size of power generating companies is being calculated as shown in the example for Belgium and Italy:

Table 25 – HHI in Belgium (2007)

Belgium	%
Electrabel	86
SPE	9
Others	5

Source: Elia System Operator

Table 26 – HHI in Italy (2007)

Italy	%
ENEL Group	34.8
Edison	13.1
ENI	9.2
Endesa	8.7
Edi Power	8.3
Tirreno Power	4
Others	21.9

Source: Regulatory Authority for Electricity and Gas (Autorità per l'energia elettrica e il gas)

The HHI index can be derived based on the companies' share in power generation:

Belgium: HHI= 86^2 + 9^2 = 7,477

Italy: HHI=34.8^2 + 13.1^2 + 9.2^2 + 8.7^2 + 8.3^2 + 4^2 = 1,628

Accordingly, the indexes for the rest of the countries and the nine regions have been estimated for two years: 2007 and 2020. The following tables, ordered by region, present the HHI values and the M sub-indicator estimated by applying the formula:

If: $((HHI)^{(0.5)}/100 - M_t) > 0$, Then: $M = (HHI)^{(0.5)}/100 - M_t$

OTHERWISE: M=0

This means that all HHI values below 1,800 will be 0 for the M calculation in the case of countries, and those HHI values below 1,000 will be set to 0 for the regions. It is important to clarify that market share values of the companies forming a region are properly decreased to the size of the region. This implies that, depending on the region under analysis, the size of any specific company varies depending on the total size of the region.

Another assumption underlying these calculations is the HHI value in year 2020, which is supposed to decrease by 25% as a result of the future increase in competition, due to the national markets' integration into regional ones. This is obviously a matter for discussion, although it seems reasonable to expect in the future an increase of competition that will not be homogeneous across countries. On the contrary, the indicator is increased by lowering the M_t value to 0.32, which is assuming that regional competition will be much more severe.

The tables are as follows:

Table 27 – M Values in North Sea Region (2007 and 2020)

North Sea	HHI 2007	HHI 2020	M 2007	M 2020
Belgium	7,477	5,982	0.44	0.35
Denmark	6,800	5,440	0.40	0.32
Germany	2,027	1,622	0.03	0.00
UK	906	725	0.00	0.00
Netherlands	2,391	1,913	0.07	0.02
North Sea Region	653	523	0.00	0.00

Table 28 – M Values in Central Eastern Region (2007 and 2020)

Central Eastern Europe	HHI 2007	HHI 2020	M 2007	M 2020
Austria	2,645	2,116	0.09	0.04
Czech Republic	5,402	4,322	0.32	0.24
Germany	2,027	1,622	0.03	0.00
Hungary	1,498	1,198	0.00	0.00
Poland	1,652	1,322	0.00	0.00
Slovakia	7,225	5,780	0.43	0.34
Slovenia	5,809	4,647	0.34	0.26
Central Eastern Europe Region	871	697	0.00	0.00

Table 29 – M Values in Central Southern Region (2007 and 2020)

Central Southern Europe	HHI 2007	HHI 2020	M 2007	M 2020
Austria	2,645	2,116	0.09	0.04
France	7,203	5,762	0.43	0.34
Germany	2,027	1,622	0.03	0.00
Greece	9,094	7,275	0.53	0.43
Italy	1,628	1,302	0.00	0.00
Slovenia	5,809	4,647	0.34	0.26
Central Southern Europe Region	1,258	1,006	0.04	0.00

Table 30 – M Values in Central Western Region (2007 and 2020)

Central Western Europe	HHI 2007	HHI 2020	M 2007	M 2020
Austria	2,645	2,116	0.09	0.04
Belgium	7,477	5,982	0.44	0.35
France	7,203	5,762	0.43	0.34
Germany	2,027	1,622	0.03	0.00
Luxembourg*	n/a	n/a	n/a	n/a
Netherlands	2,391	1,913	0.07	0.02
Central Western Europe Region	1,550	1,240	0.08	0.04

Table 31 – M Values in Northern Region (2007 and 2020)

Northern Europe	HHI 2007	HHI 2020	M 2007	M 2020
Denmark	6,800	5,440	0.40	0.32
Finland	2,426	1,941	0.07	0.02
Germany	2,027	1,622	0.03	0.00
Poland	1,652	1,322	0.00	0.00
Sweden	3,757	3,006	0.19	0.13
Northern Europe Region	619	495	0.00	0.00

Table 32 – M Values in Baltic Region (2007 and 2020)

Baltic Countries	HHI 2007	HHI 2020	M 2007	M 2020
Latvia	9,409	7,527	0.55	0.45
Estonia	9,409	7,527	0.55	0.45
Lithuania	6,400	5,120	0.38	0.30
Finland	2,426	1,941	0.07	0.02
Poland	1,652	1,322	0.00	0.00
Baltic Countries Region	835	668	0.00	0.00

Table 33 – M Values in South Western Region (2007 and 2020)

South Western Europe	HHI 2007	HHI 2020	M 2007	M 2020
France	7,203	5,762	0.43	0.34
Portugal	4,111	3,289	0.22	0.15
Spain	2,515	2,012	0.08	0.03
South Western Europe Region	3,117	2,493	0.24	0.18

Table 34 – M Values in UK and Ireland Region (2007 and 2020)

UK and Ireland	HHI 2007	HHI 2020	M 2007	M 2020
France	7,203	5,762	0.43	0.34
Ireland	2,858	2,286	0.11	0.06
Netherlands	2,391	1,913	0.07	0.02
UK	906	725	0.00	0.00
UK and Ireland Region	2,103	1,682	0.14	0.09

Table 35 – M Values in Eastern Region (2007 and 2020)

Eastern Europe	HHI 2007	HHI 2020	M 2007	M 2020
Greece	9,094	7,275	0.53	0.43
Hungary	1,498	1,198	0.00	0.00
Romania	1,561	1,249	0.00	0.00
Bulgaria	10,000	8,000	0.58	0.47
Eastern Europe Region	1,493	1,195	0.07	0.03

2.2.2 The S sub-indicator

To determine the sub-indicator for the security of supply, four parameters are needed:

The formula for the S sub-indicator is:

IF: [(PG • RenCorr)/PD < St] THEN: S = (St • (PG • RenCorr))/PD

OTHERWISE: S = 0

Where:

PG: Peak generation capacity (MW)
PD: Peak demand (MW)
RenCorr: Correction for the limited contribution of installed renewable electricity generation capacity
St: Threshold for the security of supply sub-indicator

The source of the data required for the calculation is "System Adequacy Retrospect 2007", provided by the Union for the Co-ordination of Transmission of Electricity (UCTE), as well as the Regulators' Annual Reports to the European Commission.

It is assumed that the threshold for the security of supply is 25%, although values for 10% to 25% are likely to be applied appropriately. In addition, the renewables' capacity is decreased, since wind and solar will not contribute to the security of supply for their total capacity. Therefore, the capacity obtained from RES is subtracted from the generating capacity that is able to cover peak demand as an extreme security of supply criterion.

For the estimation of the regional peak demand it is assumed that 90% of national capacity contributes to the regional demand so as to take into account peak demand coincidence.

The results for the S indicator are showed in the following tables:

Table 36 – S Values in North Sea Region (2007 and 2020)

North Sea	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Belgium	16,668	20,599	14,205	16,247	553	2,321	0.12	0.12
Denmark	12,866	11,975	6,408	7,305	3,329	4,012	0.00	0.16
Germany	130,662	151,017	78,500	91,484	23,328	36,749	0.00	0.00
UK	92,872	96,175	61,300	64,978	2,883	11,006	0.00	0.00
Netherlands	23,078	32,033	15,863	20,520	2,311	3,395	0.00	0.00
North Sea Region	276,145	311,799	158,648	180,481	32,403	57,483	0.00	0.00

Table 37 – S Values in Central Eastern Region (2007 and 2020)

Central Eastern Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Austria	19,245	23,554	9,438	11,796	1,135	2,432	0.00	0.00
Czech Rep	14,878	17,632	10,174	11,857	210	831	0.00	0.00
Germany	130,662	151,017	78,500	91,484	23,328	36,749	0.00	0.00
Hungary	9,473	9,932	6,180	7,994	41	241	0.00	0.04
Poland	32,220	39,073	22,729	29,895	418	1,632	0.00	0.00
Slovak Rep	7,718	7,980	4,410	5,139	9	105	0.00	0.00
Slovenia	3,310	3,565	2,087	2,780	1	23	0.00	0.00
Central Eastern Europe Region	183,381	211,567	120,166	144,852	25,141	42,013	0.00	0.00

Table 38 – S Values in Central Southern Region (2007 and 2020)

Central Southern Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Austria	19,245	23,554	9,438	11,796	1,135	2,432	0.00	0.00
France	115,143	118,195	88,960	101,245	2,328	8,390	0.00	0.17
Germany	130,662	151,017	78,500	91,484	23,328	36,749	0.00	0.00
Greece	14,579	19,889	10,414	15,293	933	3,176	0.00	0.16
Italy	88,680	103,754	56,822	75,401	2,388	8,195	0.00	0.00
Slovenia	3,310	3,565	2,087	2,780	1	23	0.00	0.00
Central Southern Europe Region	352,372	396,420	221,599	268,200	30,112	58,965	0.00	0.00

Table 39 – S Values in Central Western Region (2007 and 2020)

Central Western Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Austria	19,245	23,554	9,438	11,796	1,135	2,432	0.00	0.00
Belgium	16,668	20,599	14,205	16,247	553	2,321	0.12	0.12
France	115,143	118,195	88,960	101,245	2,328	8,390	0.00	0.17
Germany	130,662	151,017	78,500	91,484	23,328	36,749	0.00	0.00
Luxembourg	809	1,084	1,061	1,382	78	134	0.56	0.56
Netherlands	23,078	32,033	15,863	20,520	2,311	3,395	0.00	0.00
Central Western Europe Region	286,359	322,928	187,224	218,407	29,732	53,421	0.00	0.00

Table 40 – S Values in Northern Region (2007 and 2020)

Northern Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Denmark	12,866	11,975	6,408	7,305	3,329	4,012	0.00	0.16
Finland	17,935	20,139	14,955	18,000	180	350	0.06	0.15
Germany	130,662	151,017	78,500	91,484	23,328	36,749	0.00	0.00
Poland	32,220	39,073	22,729	29,895	418	1,632	0.00	0.00
Sweden	34,490	37,015	33,819	30,000	1,059	1,912	0.26	0.08
Northern Europe Region	228,172	259,219	140,770	159,016	28,313	44,655	0.00	0.00

Table 41 – S Values in Baltic Region (2007 and 2020)

Baltic countries	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Latvia	2,454	3,090	1,362	2,135	86	522	0.00	0.05
Estonia	2,851	2,614	1,548	2,016	117	206	0.00	0.06
Lithuania	3,731	5,311	2,200	2,630	161	232	0.00	0.00
Finland	17,935	20,139	14,955	18,000	180	350	0.06	0.15
Poland	32,220	39,073	22,729	29,895	418	1,632	0.00	0.00
Baltic countries Region	59,189	70,227	38,515	49,208	960	2,942	0.00	0.00

Table 42 – S Values in South Western Region (2007 and 2020)

South Western Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
France	115,143	118,195	88,960	101,245	2,328	8,390	0.00	0.17
Portugal	17,233	23,631	9,099	13,532	2,991	6,538	0.00	0.00
Spain	85,933	109,134	44,876	61,319	13,394	35,522	0.00	0.05
South Western Europe Region	218,309	250,960	128,642	158,486	18,713	50,450	0.00	0.00

Table 43 – S Values in UK and Ireland Region (2007 and 2020)

UK and Ireland	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
France	115,143	118,195	88,960	101,245	2,328	8,390	0.00	0.17
Ireland	7,165	9,003	5,035	7,435	969	1,897	0.02	0.29
Netherlands	23,078	32,033	15,863	20,520	2,311	3,395	0.00	0.00
UK	92,872	96,175	61,300	64,978	2,883	11,006	0.00	0.00
UK and Ireland Region	238,258	255,406	154,042	174,760	8,491	24,688	0.00	0.00

Table 44 – S Values in Eastern Region (2007 and 2020)

Eastern Europe	PG 2007	PG 2020	PD 2007	PD 2020	REN 2007	REN 2020	S 2007	S 2020
Greece	14,579	19,889	10,414	15,293	933	3,176	0.00	0.16
Hungary	9,473	9,932	6,180	7,994	41	241	0.00	0.04
Romania	21,525	22,094	8,681	12,576	21	130	0.00	0.00
Bulgaria	10,113	10,505	6,888	7,747	143	366	0.00	0.00
Eastern Europe Region	55,690	62,420	28,947	39,249	1,138	3,913	0.00	0.00

2.2.3 The R sub-indicator

The sub-indicator for the amount of flow-based renewable power generation can be obtained from the following formula:

IF: $(RenShare - R_t) > 0$ THEN: $R = (RenShare - R_t) * RenInt$

OTHERWISE: $R=0$

Where:

R_t: is assumed to have the value of 5%

RenInt: the impact of RES power generation on necessary available transport capacity between countries is set up to 80%

$$RenShare - \frac{renewable\_energy\_capacity}{total\_installed\_generation\_capacity} * 100\%$$

The information on the renewable energy capacity and the total installed generation capacity of all countries is based on the "European Energy and Transport Trends to 2030" report to the European Commission.

Table 45 – R Values in North Sea Region (2007 and 2020)

North Sea	RenShare 2007	RenShare 2020	R 2007	R 2020
Belgium	3%	11%	0.00	0.05
Denmark	26%	34%	0.17	0.23
Germany	18%	24%	0.10	0.15
UK	3%	11%	0.00	0.05
Netherlands	10%	11%	0.04	0.04
North Sea	12%	18%	0.05	0.11

Table 46 – R Values in Central Eastern Region (2007 and 2020)

Central Eastern Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
Austria	6%	10%	0.00	0.04
Czech Rep	1%	5%	0.00	0.00
Germany	18%	24%	0.10	0.15
Hungary	0%	2%	0.00	0.00
Poland	1%	4%	0.00	0.00
Slovak Rep	0%	1%	0.00	0.00
Slovenia	0%	1%	0.00	0.00
Central Eastern Europe	12%	17%	0.05	0.09

Table 47 – R Values in Central Southern Region (2007 and 2020)

Central Southern Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
Austria	6%	10%	0.00	0.04
France	2%	7%	0.00	0.02
Germany	18%	24%	0.10	0.15
Greece	6%	16%	0.01	0.09
Italy	3%	8%	0.00	0.02
Slovenia	0%	1%	0.00	0.00
Central Southern Europe	8%	14%	0.02	0.07

Table 48 – R Values in Central Western Region (2007 and 2020)

Central Western Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
Austria	6%	10%	0.00	0.04
Belgium	3%	11%	0.00	0.05
France	2%	7%	0.00	0.02
Germany	18%	24%	0.10	0.15
Luxembourg	10%	12%	0.04	0.06
Netherlands	10%	11%	0.04	0.04
Central Western Europe	10%	15%	0.04	0.08

Table 49 – R Values in Northern Region (2007 and 2020)

Northern Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
Denmark	26%	34%	0.17	0.23
Finland	1%	2%	0.00	0.00
Germany	18%	24%	0.10	0.15
Poland	1%	4%	0.00	0.00
Sweden	3%	5%	0.00	0.00
Northern Europe	12%	17%	0.06	0.10

Table 50 – R Values in Baltic Region (2007 and 2020)

Baltic countries	RenShare 2007	RenShare 2020	R 2007	R 2020
Latvia	3%	17%	0.00	0.10
Estonia	4%	8%	0.00	0.02
Lithuania	4%	4%	0.00	0.00
Finland	1%	2%	0.00	0.00
Poland	1%	4%	0.00	0.00
Baltic countries	2%	4%	0.00	0.00

Table 51 – R Values in South Western Region (2007 and 2020)

South Western Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
France	2%	7%	0.00	0.02
Portugal	17%	28%	0.10	0.18
Spain	16%	33%	0.08	0.22
South Western Europe	9%	20%	0.03	0.12

Table 52 – R Values in UK and Ireland Region (2007 and 2020)

UK and Ireland	RenShare 2007	RenShare 2020	R 2007	R 2020
France	2%	7%	0.00	0.02
Ireland	14%	21%	0.07	0.13
Netherlands	10%	11%	0.04	0.04
UK	3%	11%	0.00	0.05
UK and Ireland	4%	10%	0.00	0.04

Table 53 – R Values in Eastern Region (2007 and 2020)

Eastern Europe	RenShare 2007	RenShare 2020	R 2007	R 2020
Greece	6%	16%	0.01	0.09
Hungary	0%	2%	0.00	0.00
Romania	0%	1%	0.00	0.00
Bulgaria	1%	3%	0.00	0.00
Eastern Europe	2%	6%	0.00	0.01

2.3 Results

Having calculated the R, M and S sub-indicators and using the formula:

$$\text{EOI} = \sqrt{M^2 + R^2 + S^2},$$

the Electricity Interconnection Indicator can be calculated for countries and regions.

The interconnection value of Net Transfer Capacities,[66] which is the target size, can be obtained by multiplying the EOI through the Peak demand.

$$\text{IC} = \text{EOI} * \text{PD}$$

The difference between the target value and the existing interconnection size is shown in the graphics that follow.

If the sufficiency of interconnection capacity is less than 75%, it means that new transfer capacity should be added urgently. Those countries / regions with sufficiency over 125% do not need new interconnections in principle, or at least it can be regarded as not urgent, as for those with indicators below 100%. This will be presented at the end of this section by using figures to better illustrate the analysis.

The next table shows the results in terms of interconnection necessities in MW in 2007:

[66] Existing values of Net Transfer Capacities are based on the ETSO's Report http://www.etso-net.org/file/pdf/NTC_MatrixSummer2008_v3.pdf

Table 54 – EOI Values and Interconnection to be added per country (2007)

Country	EOI	Peak load	IC	Existing interconnection NTC	Interconnection to be added
Austria	0.09	9,438	890	3,650	0
Belgium	0.20	14,205	2,841	3,300	0
Bulgaria	0.20	6,888	1,378	1,000	378
Czech Rep	0.20	10,174	2,035	2,300	0
Denmark	0.20	6,408	1,282	4,480	0
Estonia	0.20	1,548	310	2,100	0
Finland	0.10	14,955	1,435	1,950	0
France	0.20	88,960	17,792	6,000	11,792
Germany	0.11	78,500	8,414	13,300	0
Greece	0.20	10,414	2,083	700	1,383
Hungary	0.00	6,180	0	2,700	0
Ireland	0.13	5,035	679	410	269
Italy	0.00	56,822	0	2,700	0
Latvia	0.20	1,362	272	2,250	0
Lithuania	0.20	2,200	440	2,980	0
Luxembourg	0.20	1,061	212	100	112
Netherlands	0.08	15,863	1,266	6,700	0
Poland	0.00	22,729	0	2,700	0
Portugal	0.20	9,099	1,820	1,100	720
Romania	0.00	8,681	0	1,550	0
Slovak Rep	0.20	4,410	882	2,650	0
Slovenia	0.20	2,087	417	1,270	0
Spain	0.12	44,876	5,273	2,200	3,073
Sweden	0.20	33,819	6,764	6,880	0
UK	0.00	61,300	0	2,080	0

It should be mentioned, that regarding priorities for the European policies, the EOI values for countries were limited to 0.2 and the EOI values for regions were restricted to 0.1, which represents a 20% and 10% interconnection capacity respectively.

As it can be observed in the table above, the total amount of new electricity interconnection capacity is close to 18,000 MW, the most relevant case being France that accounts for more than half of the total need. This is due to the country's special conditions, with a highly concentrated market. However, a number of countries are also placed at the 20% value but their interconnection capacity is high enough to reduce the need for additional interconnection capacity. Therefore, the indicator is quite sensible to the NTC value that is used in each country, so different NTC values lead to different necessities.

The results for the year 2020 are included in the next table:

Table 55 – EOI Values and Interconnection to be added per country (2020)

Country	EOI	Peak load	IC	Existing interconnection	Interconnection to be added
Austria	0.06	11,796	689	3,650	0
Belgium	0.20	16,247	3,249	3,300	0
Bulgaria	0.20	7,747	1,522	1,000	522
Czech Rep	0.20	11,857	2,329	2,300	29
Denmark	0.20	7,305	1,461	4,480	0
Estonia	0.20	2,016	403	2,100	0
Finland	0.15	18,000	2,736	1,950	786
France	0.20	101,245	20,249	13,800	6,449
Germany	0.15	91,484	14,151	13,300	851
Greece	0.20	15,293	3,059	700	2,359
Hungary	0.04	7,994	302	2,700	0
Ireland	0.20	7,435	1,487	410	1,077
Italy	0.02	75,401	1,748	2,700	0
Latvia	0.20	2,135	427	2,250	0
Lithuania	0.20	2,630	517	2,980	0
Luxembourg	0.20	1,382	276	100	176
Netherlands	0.05	20,520	986	6,700	0
Poland	0.00	29,895	0	2,700	0
Portugal	0.20	13,532	2,706	1,100	1,606
Romania	0.00	12,576	0	1,550	0
Slovak Rep	0.20	5,139	1,010	2,650	0
Slovenia	0.20	2,780	546	1,270	0
Spain	0.20	61,319	12,264	2,200	10,064
Sweden	0.15	30,000	4,533	6,880	0
UK	0.05	64,978	3,350	2,080	1,270

Again, the value of the EOI has been capped to 20% since this would imply the 20% of interconnection capacity in relation to peak demand.

For this year, new interconnection needs are placed to an amount that exceeds 25,000 MW. The NTC values used for this estimation depend heavily on the NTC values used to determine the capacity to be added in the future. In this case, the new French interconnection capacity is lowered due to the fact that new interconnection capacity has been used for this country. On the contrary, new countries are added to the list of countries that are eligible for increasing their interconnection capacity in order to improve their competition, security of supply and use of renewables. In this regard, the comments included in the report sets that NTC values are extremely conservative so that interconnection needed is therefore conservative.

Apart from considering countries, EOI values have also been calculated for the regions defined for the declaration of electricity transmission priority corridors. The results in year 2007 are following:

Table 56 – EOI Values and Interconnection to be added per region (2007)

Region	EOI	Peak load	IC	Existing interconnection NTC	Interconnection to be added
North Sea	0.05	158,648	8,547	15,350	0
Central Eastern Europe	0.05	120,166	6,305	16,720	0
Central Southern Europe	0.05	221,599	10,137	13,540	0
Central Western Europe	0.09	187,224	16,146	23,650	0
Northern Europe	0.06	140,770	8,343	20,390	0
Baltic Countries	0.00	38,515	0	4,200	0
South Western Europe	0.10	128,642	12,864	4,000	8,864
UK and Ireland	0.10	154,042	15,404	2,490	12,914
Eastern Europe	0.07	28,947	2,032	3,100	0

As it is shown above the only two regions with interconnection needs are isolated from the remaining EU Member States. Total interconnection needs exceed 20,000 MW, which are sensible to the NTC values, as it happens with the countries analysis, that are conservative. It must be stressed out that the NTC is the internal capacity without considering external borders to other regions. This happens because this analysis attempts to show how internal regions must first be interconnected before being integrated into the single electricity European market. Total new capacity is around the same value provided in the single country analysis, although different country necessities arise for that analysis.

However, in case the interconnection is not updated regularly, the regions are likely not to be integrated into larger areas as it is shown in the next table for year 2020.

Table 57 – EOI Values and Interconnection to be added per region (2020)

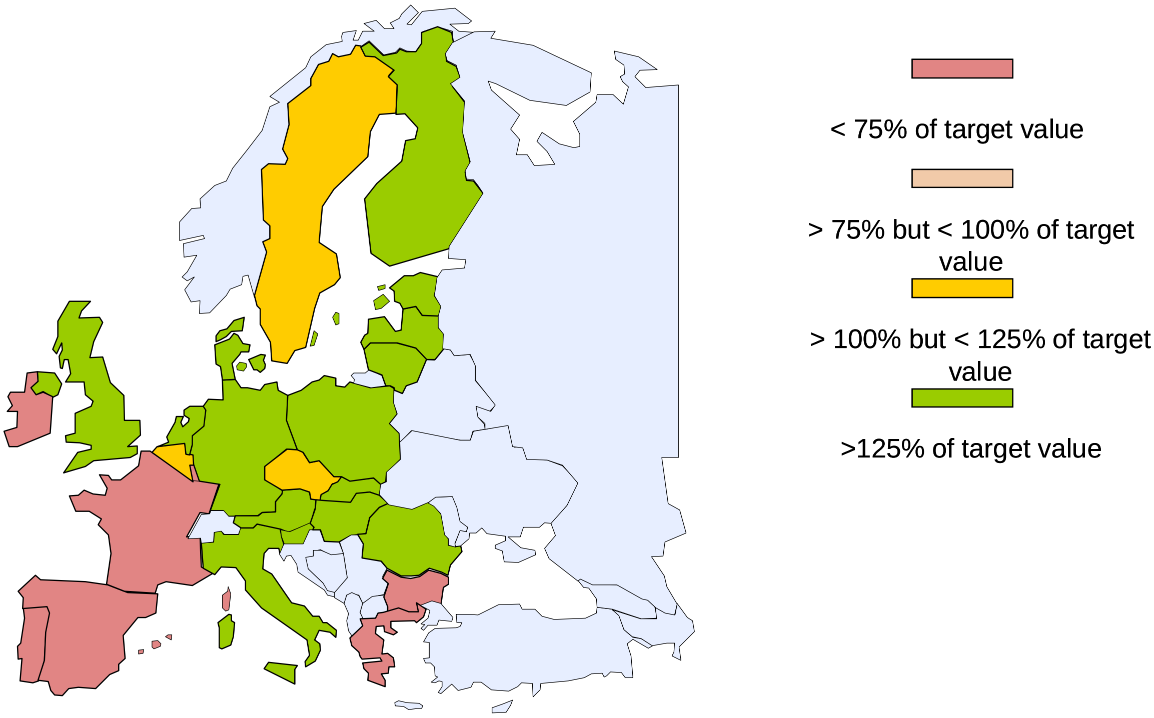
Region	EOI	Peak load	IC	Existing interconnection	Interconnection to be added
North Sea	0.10	180,481	18,048	15,350	2,698
Central Eastern Europe	0.10	144,852	14,485	16,720	0
Central Southern Europe	0.07	268,200	19,398	13,540	5,858
Central Western Europe	0.09	218,407	19,822	23,650	0
Northern Europe	0.10	159,016	15,902	20,390	0
Baltic Countries	0.06	49,208	2,734	4,200	0
South Western Europe	0.10	158,486	15,849	4,000	11,849
UK and Ireland	0.10	174,760	17,476	2,490	14,986
Eastern Europe	0.03	39,249	1,221	3,100	0

The table above depicts that in case new interconnection capacity is added in the coming years many regions will possibly not form part of the single electricity European market. This is especially relevant for those areas located at the EU borders, while it is less likely to happen in central Europe. As it has already been mentioned, the electricity system tends to isolate the regions at the border, while the areas located in central Europe are favored by the border interconnection capacity of limiting countries. For this scenario, the total new interconnection is over 35,000 MW, which is in line with the requirements of the single country analysis performed above.

Below follows a detailed analysis for every country in the region or regions where it belongs. Later, a comparison of the results obtained for regions is also provided to compare the results provided by the country analysis and to test how consistent the indicator is.

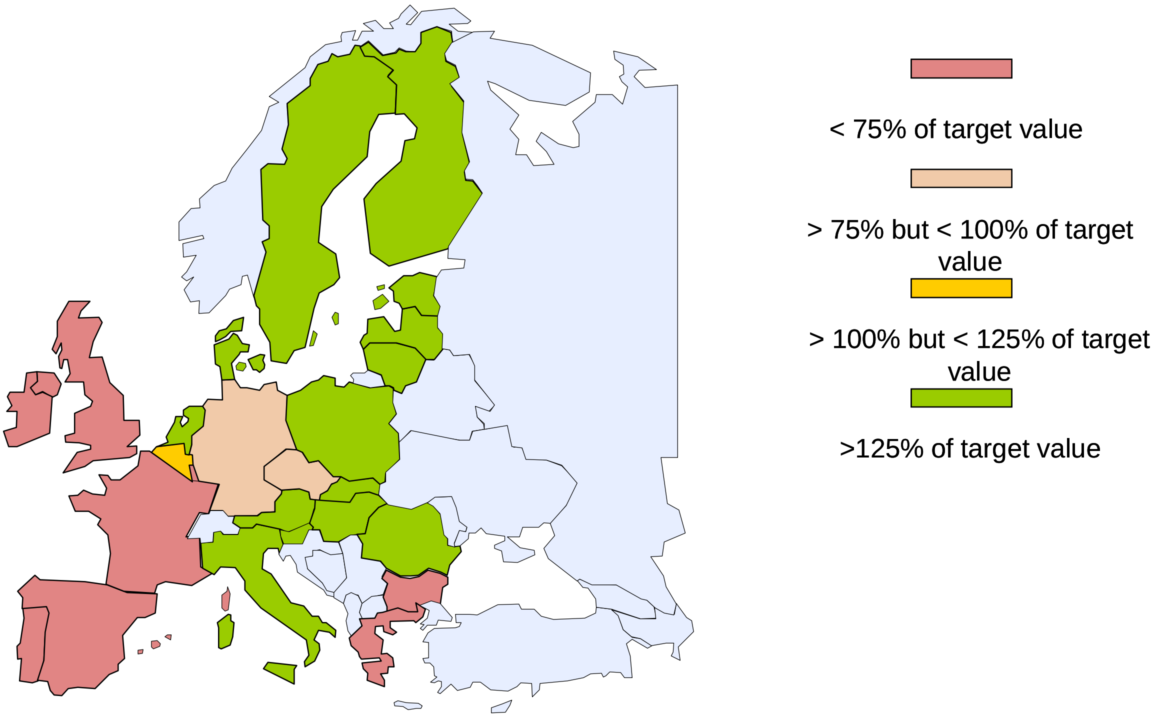
The country analysis for year 2007 is presented in the next figure:

Figure 21 Interconnection needs by country (2007)



As illustrated in the above figure, those countries that are placed at the EU borders are likely to need new interconnection capacity, especially the ones located at the south border. This situation would be even worse in the case that no interconnection is constructed in the coming years, as shown in the next figure:

Figure 22 Interconnection needs by country (2020)



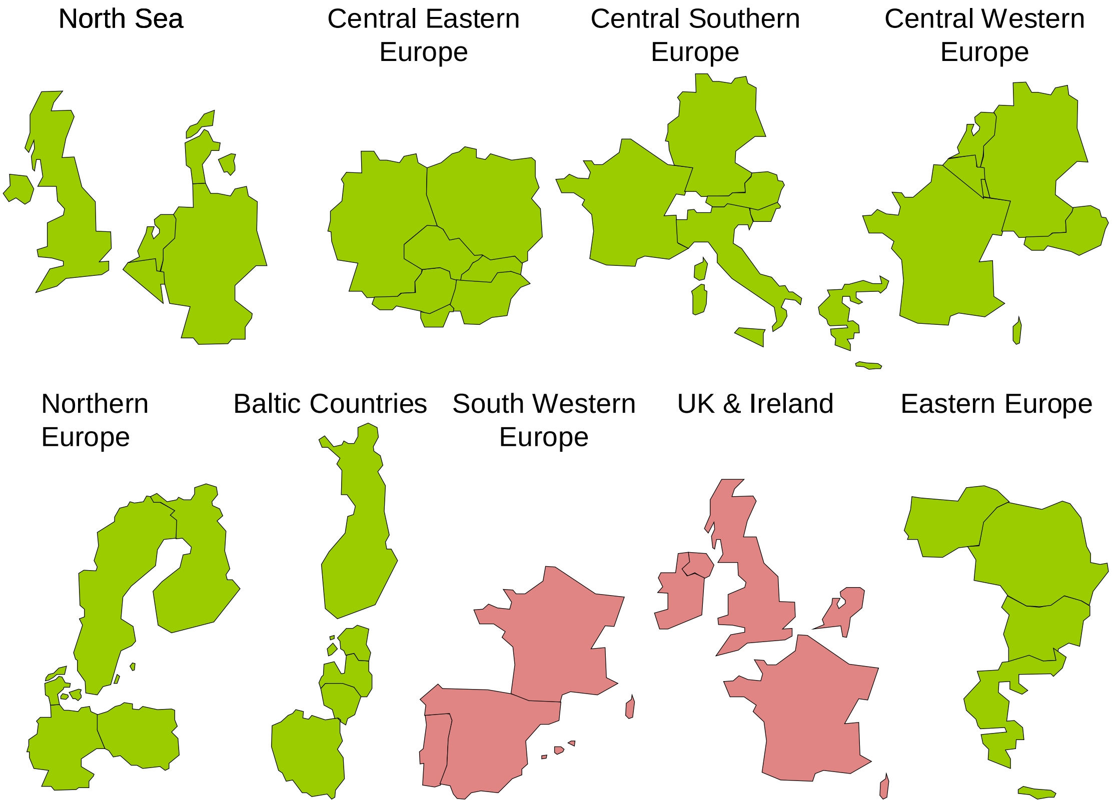
The figure above shows that in year 2020 other countries are likely to be under the optimal interconnection requirements to be part of the single European electricity market. This is the case of Germany and Czech Republic. Obviously, the countries included in the first figure are also likely to need new interconnection capacity. The only exception is Sweden, which because of the underlying assumption of improving competition in year 2020, is decreasing its EOI value, thus lowering its interconnection capacity needs.

In general, it must be pointed out that Southern countries are mostly affected because of the lack of interconnection capacity and therefore, these countries could obtain higher benefits by increasing their interconnection capacity. However, the interconnection's potential increase is sometimes limited because of these countries' geographical isolation.

In order to evaluate the consistency assessment, all cited regions are analyzed to see whether regional interconnection capacity differs from the results obtained in the country-by-country calculations.

The next figure shows the current new interconnection necessities in all European regions.

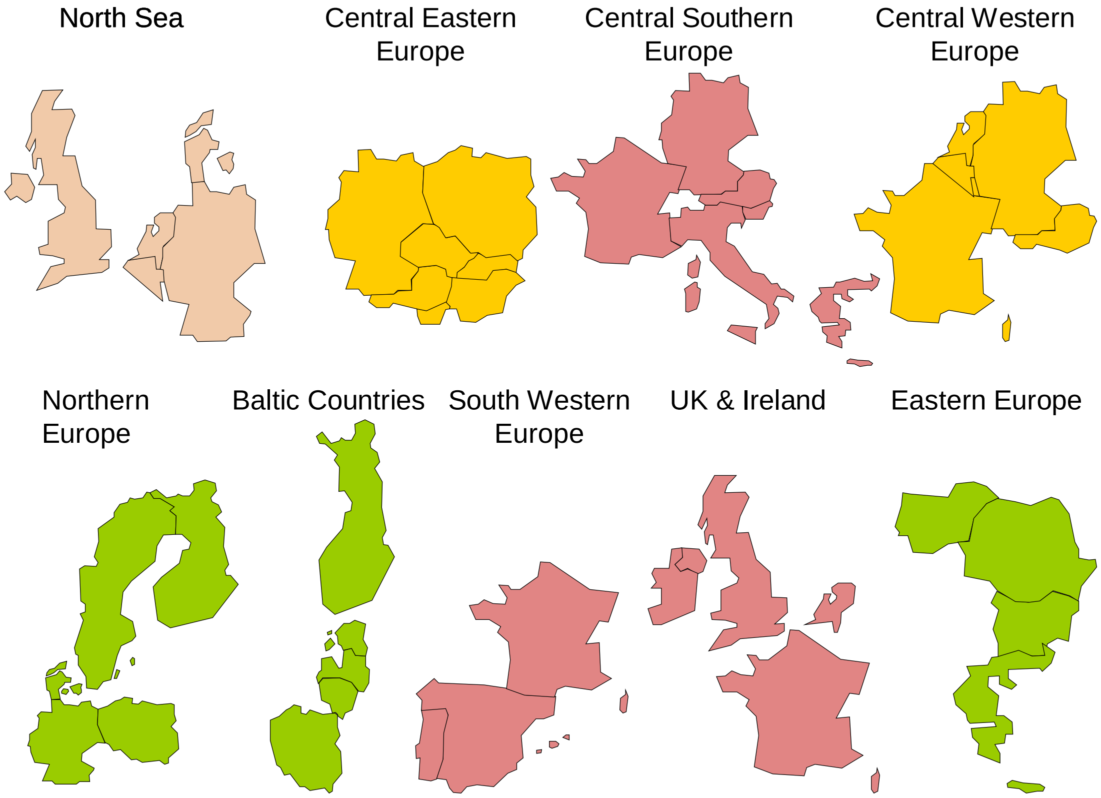
Figure 23 Interconnection needs by region (2007)



As illustrated above, the needs are basically focused on two regions: South Western Europe and the UK & Ireland; this result is mainly consistent with the ones obtained for the individual country analysis. Two countries involved in these regions, the UK and the Netherlands were not included in the individual analysis, which implies that network reinforcements should be focused on the remaining countries. On the contrary, countries included in the individual analysis are not included in any region with urgent necessities. This is the case of Greece and Bulgaria, so further assessment of these two countries would be necessary in order to discuss whether these investments are really necessary for improving the integration of these two countries into the regions they belong.

The next figure shows the new interconnection necessities for 2020 in all European regions.

Figure 24 Interconnection needs by region (2020)



As in the case of the individual analysis where new interconnections are not built, other regions are likely to be out of the single electricity European region. This is the case of the North Sea region; two more regions also decrease their interconnection capacity to lower limits like Central Eastern Europe and Central Western Europe.

This analysis is in line with the results provided by the individual country analysis, such as Germany or the Czech Republic. The Northern European countries are well interconnected, so under this methodology no new interconnection is necessary. However, as it was previously commented, this criterion is simple and in the case of these countries, for instance the Baltic countries, further assessment is necessary. From the point of view of the interconnection capacity they have enough capacity in terms of peak demand, but the real situation shows that because of their small size they are quite isolated from the other neighboring countries.

In general, it can be concluded that the use of this type of methodology is easy to develop but it is subject to a number of assumptions that definitely limit the results. However, it can be useful to provide a first assessment that is valid for setting these urgent interconnection needs. Unfortunately, there are two main drawbacks: the first is the use of the available information that is subject to discussion, and the second is that this methodology does not provide any cost-benefit measure for analyzing whether electricity customers obtain benefits for constructing new interconnections. This is relevant in the sense that many of the countries with interconnection necessities are relatively isolated from the rest of the EU countries because of their geographical location. This is more complex regarding additional difficulties, such as the case of islands and existing mountains that separate countries, which can increase the cost of the interconnection investment largely. All these aspects can be analyzed by using other types of models that take into consideration the expansion costs of new interconnections.

2.4 Interconnections

As a result of the former study, a number of interconnection necessities have arisen from the use of indicators. Therefore, taking into account the use of this methodology, a number of interconnection projects may be prioritized from the rest of the European priority projects. From the list of projects presented in the TEN-E guidelines, and following the results of the previous sections the projects of interest will be the following:

- Aveline (FR) - Avelgem (BE) line
- Moulaine (FR) – Aubange (BE) line
- Connection of Poland and Lithuania, including the upgrading of the Polish electricity network and the PL-DE section as necessary to allow participation in the internal energy market
- Estlink undersea cable link between Finland and Estonia
- Neuenhagen (DE) – Vierraden (DE) – Krajnik (PL) line
- Dürnrohr (AT) – Slav•tice (CZ) line
- New interconnection between Germany and Poland
- Sentmenat (ES) – Becanó (ES) – Baixas (FR) line
- Valdigem (PT) – Douro Internacional (PT) – Aldeadávila (ES) line and Douro Internacional facilities
- Undersea cable link between England (UK) and the Netherlands
- Undersea cable link between Ireland and Wales (UK)

These interconnection projects affecting the regions that urgently need further investment in new interconnections should be prioritized in accordance to the results provided by this methodology. In addition, the cables that are planned for the Baltic countries are also included in spite of not being highlighted as required in the methodology.

On the contrary, projects for countries outside the EU are avoided since this is out of the scope of the methodology's requirement. The remaining projects, mostly in Denmark, Austria and Italy are not included since these countries were not considered in the highlighted regions, and many of them internal projects rather than interconnections.

In summary, this is an example of how this methodology could be used for the sake of the integration of regions defined for the declaration of projects of European interest. Despite the fact that this is merely a simple example and it tries not to decide what interconnections should be carried out and which ones should not be promoted, it provides reasonable results on the most urgent necessities in terms of new interconnections. Although it is not able to value whether the interconnection would be beneficial for the interest of the electricity customers, it is likely that the benefits derived from this investment may be adequate by far because of the absence of interconnections.

3 Methodological approaches comparison: the Northern Italy region

This Annex is devoted to compare the two methodological approaches in evaluating projects of European interest in electricity. To this aim, the Northern Italy region is considered as an example with the only purpose of showing the use of both approaches, namely Alternative #1 and Alternative #2. In this regard, the results do not attempt to select specific priority corridors or projects of European interest or to suggest the application of those methodologies to the northern Italy region but to compare the two methodologies within a specific region, as well as to show how Alternative #1 can be applied to another particular case.

The examples included in this Annex were already presented to the participants of the electricity workshop on Priority Corridors that was held in Brussels on September 5th, 2008. The attendants to this workshop included agents involved in the electricity operation of the Northern Italy region that were interested in how new methodological approaches could assist them into the selection of new cross-border transmission investments.

Regarding the contributions of the workshop, present status of priority projects require global support from the involved stakeholders in this process. So, the first analysis relates to the indispensable use of a common methodological framework to identify priority corridors, which should aim at selecting projects that maximise the net benefits of the electricity customers of the region, while being also suitable to remove the existing obstacles in the designation of transmission corridors and the better use of existing mechanisms that would favour the optimal use of existing interconnections. Thus, present status of priority corridor of EU interest require urgent action on the following aspects:

- The designation of electricity transmission corridors of EU interest is difficult due to the complexities derived from electricity physical and technical constraints. The large number of interactions that may arise between existing and potential interconnections makes this process long and difficult to deal with unless powerful tools are used. Furthermore uncertainties on the expansion of generation which is privately decided by investors introduce additional difficulties. However, under no doubt the selection of any electricity transmission corridor of European interest must pursue the objective of increasing the benefits for the European citizens. Projects that do not comply with this priority criterion must be avoided since the European citizens will pay without obtaining a positive benefit. To this aim, the use of a sound methodology is essential for the entire process of selecting candidates of European interest. Furthermore, existing methodologies must be improved to fully comply with the European policy objectives. In this regard, we consider that the presented methodological proposal attempts to solve some of the gaps detected in the selection of transmission corridors in the recent experience (i.e., national or bilateral). Additionally, the use of a common methodological framework agreed by all the involved stakeholders would facilitate achieving agreements on the expansions to be developed. It should be noted that there are commercially available more powerful models than that used in this example. Additionally, it is likely that a model for European wide use may deserve a tailored development.

- As it has been mentioned, the European policy objectives are part of the requirements that any proposed methodology must comply with. So, any methodological framework must include in its development the most critical aspects in which the European electricity sector is currently involved. These aspects are basically three, for the next decade: the security of supply, the increase of the competitiveness of the electricity sector, as it has been stressed in the past regulatory development launched by the EC; and facilitating the increase of renewable sources use for generating purposes that is also in line with the European policies, particularly the 20/20/20 rule.

- In this regard, the legal framework may be also modified in order to ease the promotion of those eligible projects that would result in social welfare increase. Additional legal proposals must be made to better manage the construction of priority corridors.

- As a result of the complexity of selecting projects of priority interest, there are a number of aspects that require dramatic improvement in order to facilitate the entire process. Perhaps, the most relevant aspects are those related with obtaining the rights of way for corridors, which varies across countries and limits the possibility of timely expanding the electricity interconnections due to different reasons (e.g., lack of political support, technical difficulties, etc.). Priority corridors selection may lead to developing interconnections in the short term, such as the use of existing rights of way, highways, etc., not only by assuming the shortest timing (a presumably feasible system of rights of ways), but also by providing for those interconnections whose rejection is less likely to occur. In the same sense delays in the construction process due to long authorisation procedures and veto powers of local authorities also hamper the adequate electricity system's development. In this regard, the improvement of existing processes is crucial to continue with the formation of the single electricity European market. For instance, the use of auctions to appoint the responsible to build the new facility, with well defined schedules and penalties for delays. Some foreign experiences show excellent results, for instance in Brazil or Peru.

- Finally, not only cross-border obstacles jeopardise the proper functioning of the European electricity market, but also existing mechanisms can be improved in order to benefit European electricity customers. The appropriate definition of net transfer capacity and the mechanisms that allow for interchanges can be modified in accordance to the electricity interchanges fostering without prejudice of security of supply standards. For instance the use of point to point transmission rights may increase the existing cross border capacity without additional investments. Existing limits are sometimes too restrictive in this regard, then resulting in social welfare decreases.

Hence, under the above framework the Northern Italy region is involved, as it happens with many European regions. Therefore, from the perspective of the use of a common methodological tool, it is interesting to see whether this scheme assists in the selection, acceleration and implementation of priority corridors in electricity.

In this regard, this report develops two different approaches that may facilitate this entire process. In our view, the key issue relates to coordination of involved stakeholder, which in fact this would foster the rationality of proposing new interconnections in the region if these projects benefit the electricity customers.

As a result, this Annex compares the two approaches and a series of conclusions may be extracted from this analysis. Again, it has to be pointed out that the provision of specific projects is a matter of TSO companies, regulators and private entities.

3.1 The two methodological approaches

The results provided in the study, and presented as an example in the workshop on the Northern Italy region, are based on the use of the two proposed methodologies for the designation of electricity transmission corridors in the EU cross borders. These two alternatives are:

- Alternative #1: based on the use of optimisation and load flow models

- Alternative #2: based on the use of multi-criteria analysis by calculating indicators

The first methodological approach consists of the use of a hierarchy of planning models, each with a different time horizon and level of detail. This type of modelling is composed of the following three models that are necessary to be estimated for matching both transmission and generating planning needs. These models are run iteratively as follows:

- Model 1 – Optimal Expansion: Generation and transmission model with long term horizon (in this case 35 year), using a simplified modelling of the transmission system, but taking into consideration all the existing and planned generation and transmission facilities.

- Model 2 - Market Simulation: Optimal medium term simulation (in this case for the first 10 years) with an optimal load flow model (OLF).

- Model 3 - load flow, stability, short circuit, reliability studies are performed for the optimal solution with a 3-5 year horizon, based on typical generation-demand profiles arising from model 2.

As the life of cross border interconnections is likely to be longer than 30 years, a reasonable planning process should consider such a horizon. On the other hand, detailed load flow and stability studies involve a very detailed representation of networks. Therefore, for the Northern Italy example presented in the workshop, the third stage of the methodology is not presented since its functioning and results are widely known by the TSOs. Additionally, the market simulation model was only run for two representative years of the next decade in order to show how the methodology should be applied.

The hierarchy of planning models provides an outcome that fully complies with the selection criteria requirements and with the fulfilment of the EU policy. This is done through the benefits' estimation, based on the following approaches:

- Cost savings: through the use of Optimal Expansion models, the benefits linked to the designation of a specific transmission corridor are estimated. The model output provides the best alternative for investments in electricity transmission infrastructure in monetary terms.

- Renewables development: planning models have the ability to identify the least cost solutions for transmission taking into consideration the intermittent nature of renewable energy sources for generating purposes. Benefits will result in cost savings (fuel and emissions) that are translated into monetary terms.

- Each previous topic should be confirmed by load flow analysis carried out on the complete interconnected network, aimed at verifying the above mentioned results.

- Improvement in quality of supply: OLF models both with deterministic criteria and Montecarlo simulation can provide estimation of number of service interruptions and unserved energy, which should be valued at Value of Lost Load (VoLL). Therefore, simulating models provide results in monetary terms. They also allow to asses N-1 or even more stressing situations.

- Inclusion of emissions policy:

    - Considering CO_2 through emission costs.

    - Through constrains to sector emissions.

- Reduction of market power potential: simulation models provide estimation on the increase in social welfare when competition increases through the increase of the interconnection capacity across countries.

The second methodological proposal consists of the development of an 'Electricity Interconnection Indicator' ('E _ I') which provides a first-order insight into the need for additional interconnection capacity for each country (or system). Obviously, such a ‘quick and dirty’ indicator is not very advanced in the sense that it provides the exact economic optimum for new investments. Nevertheless, it is able to generate a rough indication on the need for additional interconnection capacity.

An advantage of the E_I is that it may be calculated quickly from easily accessible information. Nevertheless, it should always be taken into account that it is far from perfect, so it needs to be applied with cautiousness.

The suggested Electricity Interconnection Indicator E_I is being calculated per country (or market zone) and is derived from four sub-indicators:

- An indication of the competitive structure of the electricity market: M
- An indication of the security of supply: S
- An indication of the amount of flow-based renewable power generation: R
- And optionally: an indication of the price level of a country: P.

The E_I will be calculated as a weighted function of these four sub-indicators: E_I = f(M, S, R, P).

In this example we only provide the result of the first three indicators since the last one is difficult to deal with.

3.2 Alternative #1

This section provides comments of Alternative #1 with special attention to main assumptions used for estimations aiming at simplifying the parameters needed for the estimation.

Basically, data used for these models are based on Primes[67] results and public available information for the countries that form the region: Italy, Slovenia, Austria, Switzerland, France and Germany. The last one has been included since it is part of the region defined in Chapter 2. In a real world planning process it would be necessary to include other countries that may influence cross border between Italy and the rest of Europe.

There were made assumptions on the prices of fuels used in the different generation technologies, which allow for estimating the variable costs for the whole analysed period (30 years). Regarding power transmission lines, current NTC are considered in the interconnection.

[67] Of course cross border expansions and trade are extremely sensitive to the assumptions on generation expansion, arising mostly from Primes studies. Particularly some high volumes of cross border trading can be attributed to the generation expansion schedule.

There were made assumptions on the evolution of the CO_2 emission prices, based on:

- It was assumed the 20/20/20 policy is successful, so the development of renewable and energy efficiency.
- This allows that the 20% reduction in CO_2 emission is achieved with partial substitution of coal generation by gas production of CCGTs.
- So CO_2 price forecast is based in the equilibrium between variable cost of CCGT and coal fired plants.
- CO_2 price is added to fuel price to calculate the variable cost of each generation unit.

Finally, a number of simplifications has been made so as to ease the estimation since the main pursuit is to show the methodology abilities. The most relevant simplification is the avoidance of internal congestion within countries, only taking into account border constraints. It is obvious that a more detailed analysis should take this into consideration in further evaluations, since Germany and Austria are internally congested and since usually NTC depends on the behaviour of the internal network of the Countries.

Concerning generation expansion plans the nuclear debate is avoided, so that this assumption reduces the possibility of having new nuclear investment if this is not economically viable. In fact, the uncertainty concerning nuclear power is not completely solved, despite it seems that countries like France already opted to approve new investments in nuclear power. A reasonable scenario could include new nuclear investments in period in countries like France or Switzerland.

In addition, different wind power scenarios are considered for Italy, Germany and France, remaining constant for the other countries. Thus, the optimization model selects the transmission and generation expansion plan that better fits with these scenarios.

For the selection of new transmission capacity a range of projects is considered. As the Alps mountains are in the middle of the regional cross-borders the projects costs increase substantially. Analyzing different alternative map routes for new interconnections, it was decided to provide different values by depending on the selected route. Therefore, different expansion costs are considered by taking into consideration the possibility of constructing projects featured by the following:

- 400 kV lines with transmission capacity from 1,000 to 1,200 MW.
- Routes between 50 and 75 km, with underground cables at some routes and repowering overhead cables in order alternative routes.

- DC technology with converter power stations and AC technology by depending on the route.

As a result of these assumptions, the optimization model identifies a number of projects that might be of interest for the region between 2008 and 2020. The model showed optimal transmission plans by taking into account new power generation plants already approved and new economic power generation plants as required by model optimization process.

Concerning the list of projects, many of them are already analyzed by TSOs and national authorities, so a number of them are feasible. Some others could be made by repowering existing lines, as it is already planned by some TSOs. Finally, an alternative option would be increasing existing commercial capacity in countries, but always in line with security of supply standards. As a result of these policies, the interconnection capacity could increase so as to optimize resources and improve current situation.

Once the list of projects is identified, the model is also run without the expansion option in order to check whether benefits are positive of not. In this regard, the net benefit with the expansion for the whole period will be some 31,704 million euros.

Hence, the optimal model has selected a series of candidate projects that are then included in a complete network simulation model - that takes into account the real grid topology - so as to check if it complies with the N-1 criterion and non-supplied energy is detected. In order to verify so the simulation model is run for two years (2016 and 2020) under weekly dispatch basis and assuming the same demand and installed capacity projected in the optimization simulation. In addition, new simulation on different wind power flows by country are made with the purpose of verify the generation and the transmission is able to deal with extreme scenarios. From the estimation of wind power flows, that differ from country to country, and with the installed capacity, different scenarios are made so as to stress the transmission system and allow for the interchange of power by taking into account wind intermittency.

Once the model parameters are introduced the model is run then showing that the transmission plan expansion plan would not incur in non-supplied energy for any the scenarios analyzed. Again the model is run with and without optimal transmission expansion plan to see what the benefits are as a result of new transmission investments.

Therefore, the list of candidates would have to be analyzed in the final stage, the load flow simulation model to verify that the list of candidates comply with the technical requirements. After this stage, the route selection would be finally proposed with the subsequent analysis in terms of local support, environmental feasibility, rights of way and projects costs.

Finally, after these stages, taking into account the results of the load flow studies together with the dynamic analysis, it is possible to better tune the benefits of the new interconnection project, assessing exactly their value, that - in common experience - is usually different by the one evaluated with a more simple approach.

3.3 Alternative #2

This section provides comments of Alternative #2 with view to select the new interconnection capacity that is necessary to be added in the region. In this regard, information was obtaining from public available sources and the calculation of the Electricity Interconnection Indicator is easy as it was shown in Annex II.

In this regard, the information selected for the estimation is the one already shown in Annex II. As it could be observed in the main text of this report, the calculation is easier through this type of methodology and it may provide a rough value in relation to interconnection needs. These requirements would then require further analysis by involved stakeholders in order to determine what routes are feasible and if load flows are technically appropriate for their implementation. In general, the results of this methodology may be useful for the initial calculation of interconnection necessities of involved countries in future network planning development regarding the interest of the EU.

As a result of the calculations, new capacity interconnection needs are identified by using these weighted indices that roughly indicate what additional capacity is required by any country that form the region. As it was previously mentioned, the indices are not based on monetary units but other parameters, so that results differ from those obtained by applying Alternative #1. in any case, it is interested to compare results from both alternatives in order to check similarities and differences.

3.4 Final assessment on approaches

The overall conclusion is that Alternative #1 is much more data intensive, so that results are more detailed and additionally it allows for the cost benefit estimation in monetary units. On the contrary, Alternative #2 is less data intensive so results are less accurate. However, it may provide a quick and easy understandable assessment on priority projects needs.

Both alternatives are able in a first and approximate step of the assessment to deal with effects on competition, security of supply and use of renewables, so in this regard both methodologies comprise with the objectives set by the EU so as to select priority corridors.

It is obvious that the coordination of involved stakeholders is crucial if real examples are analyzed. In this case, the following aspects should be also taken into account:

- Regional analysis is something that has not been done yet regarding interconnection expansions. Both alternatives can provide a regional assessment and also a national one.

- National internal congestion is necessary to be taken into account. In this regard, Alternative #1 is able to do that since optimal and simulation models allow for that possibility that must be included. On the contrary, Alternative #2 only deals with national or regional information, so it is not able to provide this type of result.

- Cost / benefit analysis requires monetary quantification in order to select and rank projects. In this sense, Alternative #2 is not able to provide monetary units but indicators. Alternative #1 provides optimal solutions based on the minimization of system costs. Once the optimization model provides a list of candidates and the simulation model verifies its feasibility, the load flow simulation and the environmental assessment and rights of way analysis may provide a rank of preferable options that would benefit the electricity customers of the region. Also concerning benefit assessment it is necessary a further check of the real achievement of the results taking into account the real results of the load flow studies.

- Scenarios are necessary to analyze future options. However, results are less accuracy when the number of scenarios increase, so that the complexity in the decision making process rises substantially. In this concern, Alternative #2 is simple, and therefore it does not introduce complex results. Opposite to this, Alternative #1 may lead to excessive complexity when many assumptions are introduced. Thus, it is essential the participation of all the agents that may provide information and/or opinion in the entire process.

In general, Alternative #1 is more powerful than Alternative #2, although at the same time it is more linked to assumptions. Both approaches are able to provide results on projects of European interest as the first stage in selecting priority corridors. The entire process requires coordination and harmonisation, so the use of a common methodological framework is critical if selection of projects is to be supported by the EU in a time span of less than five years. As it has been shown, both approaches may provide results, although these would need further assessment on their validity by involved agents, mainly with regard to the complete network models held by each TSO and by common organization such as ETSO and UCTE frame. Otherwise, the use of a common framework would not incur in the optimal results in terms of projects and planning horizon.

4 Long term expansion planning models

4.1 Characteristics of Planning Models

The objective of expansion power planning studies is to determine a sequence of capacity reinforcement in generation and transmission so as to meet the future electricity demand complying with the conditions of lowest cost (as a proxy of highest social welfare). It is sought to minimize the investment, operation and maintenance costs, as well as the expected cost of the expected unserved energy.

These requirements are to be achieved while meeting reliability, social, financial, political, geographical and environmental constraints. The power planning effort implies therefore the minimization of total costs plus the optimization, or at least an adequate representation, of the power system operation (i.e., a sound simulation of the energy dispatch), while meeting an acceptable (or pre-specified) level of supply reliability.

In principle, the power planning problem is a typical exercise in operations research which justifies the adoption of a systems approach. This approach is necessary to assess both the expansion plan as a whole and, quite frequently, the economic merit of any particular project. Methodologies for addressing this problem were developed and refined largely starting at the sixties with the access of planners to powerful computers, and then expanded with the spread of use of computers.

These methodologies are fairly sophisticated since the overall optimization needs to deal with a spread range on uncertainties. Elements of uncertainty are those upon which there is a lack of definite knowledge and can result in the failure of achieving a sound development program. Risks are the chances of harm or losses to agents (producers, investors consumers) inherent to decisions taken within an uncertain environment. Thus, uncertainty refers to lack of knowledge about future events and risk refers to the possible adverse consequences of this uncertainty.

In power systems planning there are many different types of uncertainties. In some cases, the probabilities of various outcomes can be derived from past observations (e.g. wind or water availability when data is sufficient). However, in many cases uncertain future events are not related to well known historical data, but are rather events that are singular and do not repeat themselves. In these cases, any probabilistic prediction would be judgemental rather than statistical (for instance future use of nuclear power). Uncertainties can differ also in regard to the amount of the variation (e.g. dispersion of forecasts deviations), the magnitude of the risk associated, the frequency of risk (onetime or periodical risks), and whether the risks are limited to a particular project or program, are correlated to other risks or are generic.

The development of stochastic optimization models have improved substantially the possibility to include uncertainty in planning models. These types of models could be used in conjunction with global energy planning models like Primes or Markal, to set general parameters of the energy sector, including environmental policies implementation. In this case a four staged planning process would be suitable, starting for the most general process, and moving down to the specialized models (planning, simulation and power system analysis)

4.2 Stochastic Optimization Models

This type of model considers the extension of the traditional capacity expansion model of power planning based on a least-cost approach by incorporating uncertain (stochastic) variables.

Thus, the idea is not to give up the existing approach because of uncertainty, but instead to accommodate it. The method takes into account a set of scenarios and, instead of analyzing them successively (in the manner a traditional scenario approach would), it directly takes all of them into account in the decision evaluation process. Technically, the method can also be seen as an extension of the standard decision tree approach where the different branches – corresponding to different scenarios - bifurcate at the time when the uncertainty is assumed to be resolved. In practice, a few branches in the tree are generally sufficient to capture most of the effects of uncertainty. The key problem is therefore to structure scenarios into an event tree capturing the effects of uncertainty while trying to minimize the optimization computational effort.

Different scenarios are considered with associated discrete probabilities. The planning process is formulated as a mathematical program to minimize total expansion, fuel and operating costs subject to demand and capacity constraint, and a direct current representation of the transmission system. Solution techniques involve the application of decomposition methods, that allow converting the total problem that may involve tenths of million of variable in a chain of smaller size programming problems (thousands).

4.3 An example of Stochastic Planning Model

In this section is described a commercial planning software. The commercial name is not mentioned, as the main purpose is only to show what type of result can be obtained with the state of the art planning software, as well as what types of inputs are required.

This model is a computational tool for determining the least-cost expansion (generation and interconnections) of a multi-regional hydrothermal system (typical renewable as wind, biomass and solar is also considered). It represents details of the system operation taking into account in-flow uncertainties, emission constraints, and minimum capacity constraints, among other features.

It is used both by planners in environments with centralized power sectors and by regulators and investors in modeling competitive environments. It is also used for regional planning.

Modeling Aspects

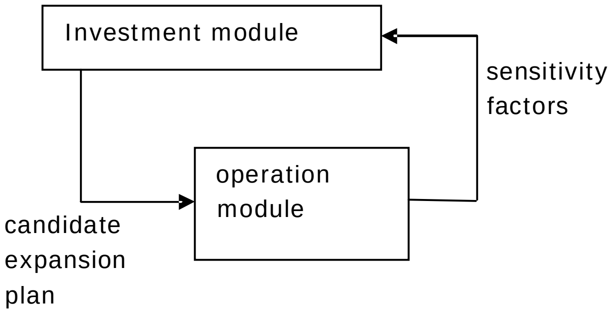
It is an integrated expansion model formulated as a large scale mixed integer optimization program with the following features:

- Flexibility of investment & operation steps (year, semester, quarter, month)
- Integer and continuous decisions variables (to consider discrete investments as transmission lines, large hydro or thermal plants, etc.)
- Optional (candidate) and obligatory projects (existing, ongoing or decided)
- Sets of associated projects
- Sets of mutually exclusive projects
- Precedence constraints
- Minimum capacity constraints for different groups of technology and for different time intervals, allowing to represent governmental energy policies
- Reference marginal cost calculation
- Environmental constraints: SO_2, NOx and CO_2 emission
- Fuel availability constraints
- Multiple scenario analysis (including and large number of renewable scenarios of wind and hydro generation)
- Analysis of a complete or partial expansion plan defined by the user

The solution is achieved using advanced techniques of MIP (Mixed Integer Programming) and Benders Decomposition.

Outputs include the optimal expansion plan (reinforcement schedule of generation and transmission, installed capacity per stage, investment costs, disbursement schedule, emissions, operation of all the power plants etc.) and detailed operating results.

The solution approach used by the described model is illustrated below:



The expansion problem is divided into two modules, investment and operation. The objective of the investment module is to determine a candidate expansion plan. The candidate plan is then evaluated by the operation module, which calculates the expected value of operational plus interruption costs along the study period.

The feedback from the operation module to the investment module is given by sensitivity factors, which indicate the reduction in operation cost resulting from an incremental increase in the capacity of each candidate plant. In other words, the sensitivity factors indicate the operational benefit of constructing or reinforcing each supply option. This incremental benefit information is sent to the investment module, where it is compared with the additional cost of changing the expansion schedule or including a new plant. The investment module then produces a revised candidate expansion plan, which is sent once more to the production module for evaluation. The iterative scheme, known as Benders decomposition, proceeds until an optimal plan is produced.

The Benders decomposition scheme is computationally efficient and allows the solution of large planning problems. Because the investment and operation modules are separate, it is also very flexible. The described model uses a specialized integer programming scheme for the investment module and can use different optimization techniques in the operation module. As an illustration, one starts with model's own operation module, which is very fast but does not represent all the weekly details of system operation. After some iterations between investment and operation modules, the revised candidate plan is closer to the optimal solution. Model's operation module is then replaced by a more detailed scheduling model. The iterative process between investment and operation then continues for additional iterations to guarantee the best plan. As a result, a high-quality expansion plan can be produced with a reasonable computational effort. The separation of investment and operation modules also allows for the possibility of adapting the modules for some specific characteristics of the system being analyzed. This is the key issue that allows to consider a practically unlimited number of renewable scenarios.

4.4 Desirable Characteristics of Planning Models

The necessary model for identifying priority corridors needs not only to obtain optimal solutions but also to have a set of characteristics oriented to facilitate agreements among the multiple stakeholders linked to each relevant transmission project. In order to meet these needs planning models must have a number of characteristics:

- Transparency: It is essential that models be understandable by all model users and stakeholders to the planning problem. It should be possible to answer the question ‘why did the model produce a particular result?’ by identifying the assumptions and the influence structure for every scenario. Lack of transparency may be a problem if documentation is incomplete and inaccurate, and if the model is expressed in reduced form equations and correlations such that coefficients do not correspond to natural concepts. Transparency can be achieved thorough a model tailored to needs and agreements of policy markets and the working groups (TSO) responsible to carry out the planning, and making available the model to all the stake holders. So a tailored development of the model is recommended, conduction to an open code computer program.

- Flexibility: Models must be designed and implemented so that new data observations, data revisions and changes to model structure can be made accurately and efficiently. Flexibility can be achieved if the model and the code that realizes it are fully documented and if a team with the capacity to implement change is maintained over time.

- Coherency: Both energy supply and consumption options must be assessed within an integrated framework that assures the physical coherence of energy scenarios: coherence between economic growth, energy demand growth and fuel prices; between sources of energy and uses for energy; energy efficiency objectives and demand growth; etc.

- Rich structure: The structure of the models should be sufficiently rich that all stakeholders can explore the scenarios of interest to them or the ones they advocate.

- Consensus Building: Models should embody only those structures and parametric data for which there is reasonable consensus among stakeholders. When consensus does nor exist, the model should be capable of incorporating alternatives.

- Credibility: Models must be accepted as credible by all stakeholders. Credibility often rests exclusively on the credentials of the model developers (institution and investigators). However, the more important element of credibility is model validation. Because planning models are intended for exploring the feasible region in systems whose future is influenced by the decisions of the planner, the usual test of validation, which is to see how well the model predicts the future, is not appropriate. In planning models there are three validation criteria.

- The model should be able to replicate historical data, however, accuracy of the validation should be consistent with the level of simplifications used to model,

- It must be agreed that the representation of processes in the model correspond to accepted mathematical description of each phenomena, that are directly meaningful to the stakeholders.

- It is necessary a wide agreement on what is relevant to consider and which are the necessary simplifications. In spite of the increased possibility of new solvers to manage huge number of variables, this is always the limitation in the accuracy of any planning mode