RE-Shaping: Shaping an effective and efficient European renewable energy market

D13 Report:

Network extension requirements for an enhanced RES deployment

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ECOFYS	Ecofys The Netherlands
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The core objective of the RE-Shaping project is to assist Member State governments in preparing for the implementation of Directive 2009/28/EC and to guide a European policy for RES in the mid- to long term. The past and present success of policies for renewable energies will be evaluated and recommendations derived to improve future RES support schemes.

The core content of this collaborative research activity comprises:

- Developing a comprehensive policy background for RES support instruments.
- Providing the European Commission and Member States with scientifically based and statistically robust indicators to measure the success of currently implemented RES policies.
- Proposing innovative financing schemes for lower costs and better capital availability in RES financing.
- Initiation of National Policy Processes which attempt to stimulate debate and offer key stakeholders a meeting place to set and implement RES targets as well as options to improve the national policies fostering RES market penetration.
- Assessing options to coordinate or even gradually harmonize national RES policy approaches.

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1 Introduction

In 2009, the European Union adopted the Renewable Energy Directive (2009/28/EC) which intends to reach a 20% renewable energy share in total energy consumption by 2020. This overall target is broken down to national targets. The individual member states (MS) are responsible to further define targets in the National Renewable Energy Action Plans (NREAPs) for the sectors electricity, heating and cooling and transport and even by technologies. The electricity sectors will contribute the largest share to reach the renewable target. By 2020 approximately 34%-35% of the electricity consumption within the EU will stem from renewable energy sources (RES-E).

The EU energy roadmap is under discussion to follow up on this goals and describing a way to a decarbonised power system by 2050. It is clear already by now, that this pathway will require major adjustments of the electricity infrastructure and market design.

Electricity has very specific technical and economic characteristics, which require a thorough analysis of the future development in order to incorporate the increasing RES-E shares. In particular the required match of supply and demand at any time with challenges to store electricity economically in large quantities imposes the imperative to develop an adequate system which ensures the security of supply. Since investments in the electricity sector are capital intense and have a lifetime of usually at least 40 years, it is crucial to have a plan which steers investments in a long-term efficient direction. The politically desired shift towards a low carbon electricity sector provides a framework for this long-term plan which allows analysing the path to this target.

The components of the electricity system are highly interdependent. The development of renewable and conventional generation technologies, the grid infrastructure and the demand provide potential developments and flexibility options which fundamentally affect the other components.

Matching supply and demand at each instant in time has two dimensions, the temporal dimension and the geographical dimension. If an oversupply occurs at a certain time in a certain area, there might be a chance to either transfer the energy to a different area or to store in for later use. This temporal and geographical coordination has been present in the electricity sector for a long time. The degree of this challenge, however, increases dramatically with an increasing RES-E share due to its variable nature. The system development in the past took many years to reach the state of the current infrastructure. The pace at which the RES-E share increases requires a timely adaptation of

the system to cope with the quickly increasing challenges. Since the development happens so quickly, finding an efficient long-run solution requires a thorough analysis of the path to reach the target of a low carbon electricity sector.

Integrating high RES-E shares into the European power markets requires efforts from all parts of the power system, the conventional and renewable power generation, the grid infrastructure and the demand side to balance temporal and geographical imbalances of demand and supply. In order to enable markets to meet the short-term operational challenges and at the same time to provide signals to facilitate the required adaptations from different system components over time, a well balanced market design is required. All of the above mentioned system components require a well defined market design in order to provide the relevant benefits to the market in the short- as well as in the long-term.

This report will focus on the policy challenges related to the extension of the transmission grid, especially its size, structure and financing. The issues of market design are addressed in deliverable 11 of the Re-Shaping project.

Chapter 2 reviews a number of studies, who examined the network requirements of an increased RES-E deployment. Chapter 3 describes the technological options available to implement the network requirements. The following chapter four describes the regulatory implications of bulk power system operation. Chapter five illustrates the data requirements towards a European network study model. Finally, the role of regulation of financing the infrastructure is described in chapter 6.

2 Review of existing studies on EU grid expansion needs

The impact of an enhanced deployment of RES-E, and in particular wind energy on the electricity network has been analysed on a European scale in a number of studies conducted throughout past years. Figure 1 provides an overview of the recent years and indicates the maximum modelling horizon of the studies.

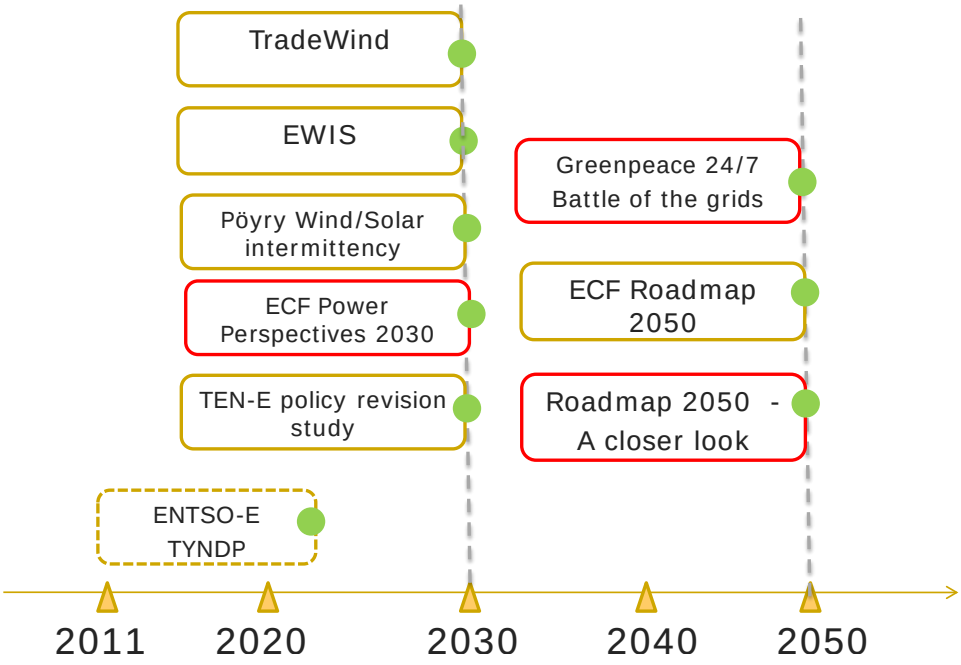

Figure 1: Selected European Renewables Integration studies (red) and their maximum timeframe

Subsequently, we offer a concise review of these studies, focussing on the approach taken and the key findings gained related to grid expansion needs.

- *TradeWind,* published in February 2009 by a consortium headed by the European Wind Energy association EWEA was the first study which observed the large-scale cross-border wind power transmission and market design at European level [TRD09]. The focus of the study was on the analysis of cross border power flows. One of the main issues to be addressed was to explore to what extend large-scale wind power integration challenges could be met by reinforcing interconnections. The results show that current cross-border transmission bottlenecks will get more

severe and 42 onshore interconnectors were identified which should be upgraded until 2030 to cope with an enhanced deployment of wind energy.

- The *European Wind Integration Study* (*EWIS*), published by ENTSO-E in March 2010 identified the most efficient measures to integrate large-scale wind power generation into Europe's transmission networks and electricity systems for 2015 and gives and outlook to 2020 [EWI11]. In contrast to the *TradeWind* study, it focuses on short- to medium-term measures to realise the benefits arising from an increased wind power penetration across Europe. A detailed network model was used to analyse short-period snapshots of interest. Complementary to that, a year-round analysis covering the whole period up to 2015 has been carried out by using a 25-node NTC-market model. On the basis of a cost-benefit-analysis a set of 150 beneficial grid reinforcement projects have been identified for the period up to 2015.
- The core question of the *North European Wind and Solar Intermittency Study (NEWSIS)* conducted by *Pöyry* and published in March 2011 was about the influence of wind and low-carbon generation on the electricity markets in North-West Europe [PÖY11]. The study concluded besides other findings, that an increased wind and solar penetration will increase the overall electricity price volatility, investment in thermal plants will become more risky and an enhanced interconnection between countries could help balancing the power system only to a limited extent. The findings focus on the geographical area of North-West Europe and have been derived by using a 15-node NTC-market model.
- The study *The revision of the trans-European energy network policy (TEN-E)*, published in October 2010 by the European Commission includes results from a power system study by KEMA and the Imperial College of London using a 29-node dispatch and investment model, the applied power systems analysis framework (APS model) with a modelling horizon until 2030 [EUC10a]. The model was adjusted to be able to reflect the assumptions of the PRIMES scenarios.
- The *Roadmap 2050* study published by the European Climate Foundation in April 2010 aimed to examine conceivable pathways to a low-carbon economy in Europe, while maintaining energy supply security as well as environmental and economic goals of the European Union [ECF10]. The major finding of the study is that, under the condition that immediate action is being taken, it is possible to achieve an economy-wide reduction of GHG emissions of at least 80% compared to 1990 levels at justifiable additional costs. The underlying electricity network has been modelled with the same model as the TEN-E study mentioned before.

- The 3rd Energy Package mandated ENTSO-E to publish a *Ten-Year Network Development Plan (TYNDP)*. The first Pilot TYNDP was published in June 2010 [ENT10]. It was based on a bottom-up approach, aggregating the investment projects in national network development plans. To integrate RES into the network, to integrate the European electricity market and guarantee the security of supply 35,000 km of new transmission lines and 7,000 km of line upgrade projects were identified.1 Out of the total of 42,000 km, which represents (14% of the existing transmission lines), TSOs plan to complete about 18700 km in the coming five years, and 23400 km in the next five-year period.[2] The next Ten-Year Network Development Plan is scheduled for publication in June 2012. This version of the TYNDP will include a top-down modelling of network requirements, which includes the renewable energy scenarios of the National Renewable Energy Action Plans (NREAP) which have not been available in 2010. While the 2010 version of the TYNDP did not include a scenario of grid development in the North Seas, this will be included in the 2012 version.

Most of the studies mentioned before have applied simplified network models by using Net Transfer Capacity (NTC) values to represent the available transfer capacity between adjacent network zones[3]. This approach neglects the influence of zone-internal network configurations. Moreover, the actual physical power flows are in general not adequately represented as loop power flows are not considered. To gain further insights on grid expansion needs, which comprise both the required extension of transfer capacity and the increase in grid length, studies with a more detailed grid representation have to be reviewed.

Three recent studies, published in 2011 (market in red in Figure 1), fulfil this requirement by considering a more detailed grid representation of the European transmission network.

- The report *Battle of the grids*, published by Greenpeace in January 2011, is based on research by Energynautics and published in a technical report, the *European Grid Study 2030/2050* [GRP11]. It is examining a renewable Energy penetration of 68% in 2030 and 99.5% in 2050. Two scenarios are analysed. A “high grid” sce-

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[1] 20,000 km of new or reinforced lines are attributed to the realization of RES-E targets, while an overlapping with the other goals exists.

[2] For some projects in the study phase, the length is not identified, which means that the given numbers define a minimum number.

[3] An exception is the EWIS study, which considered the full physical network representation to analyse snapshots.

nario includes the import of solar energy from North Africa while the “low grid” scenario assumes that renewable energy installations are located closer to the demand. The calculations are based on a 224 node European network model.

- The study *Power Perspectives 2030: On the road to a decarbonised power sector*, published by the European Climate Foundation in November 2011 builds on the Roadmap 2050 study by ECF discussed before. It aims to “provide a view on the progress necessary by 2030 to remain on track to a fully decarbonised power sector” [ECF11]. Similar to the Greenpeace study, it analyses scenarios with different levels of network expansion. The analysis is based on a 48-node transmission network.
- The study *Roadmap 2050 – a closer look*, published by EWI and Energynautics in October 2011 compared the economic differences of an “optimal grid extension” case (A) and a “moderate grid extension case” (B) [EWI11]. While in case A, the optimal grid and generation capacity extension is calculated, while in case B the increase of interconnection capacities is limited to projects which are included in the TYNDP. The network model is the same 224 node-model as used in the Greenpeace study mentioned before.

These three studies are analysed further in the following sections with respect to the required additional grid length extension, the resulting cross-border NTC capacities as well as the curtailment assumed for fluctuating RES-E. To complete the picture two indicators summarising the assumptions of the studies in terms of storage utilisation and underlying generation mix are presented thereafter.

As all studies describe different scenarios but do not present values and model results for all scenarios in a consistent way, a full comparison is not possible. Furthermore, the indicators in the following analysis are not independent from each other and therefore should not be interpreted as such. In fact, the focus of the following analysis is on the concise description of available model results.

Grid length extension

Figure 2 shows the grid extension requirements ranging from 42,000 km (which is equal to the planned additions according to the Ten Year Network Development Plan)

up to 500,000 km compared to 2010 in the most extreme case. Although there is a visible relationship between the assumed share of RES-E and the required additional grid length, the ranges of values are large and can reach a factor of two. The different data points originate not only from different studies but also from various scenarios which differ among others in the assessed time period.

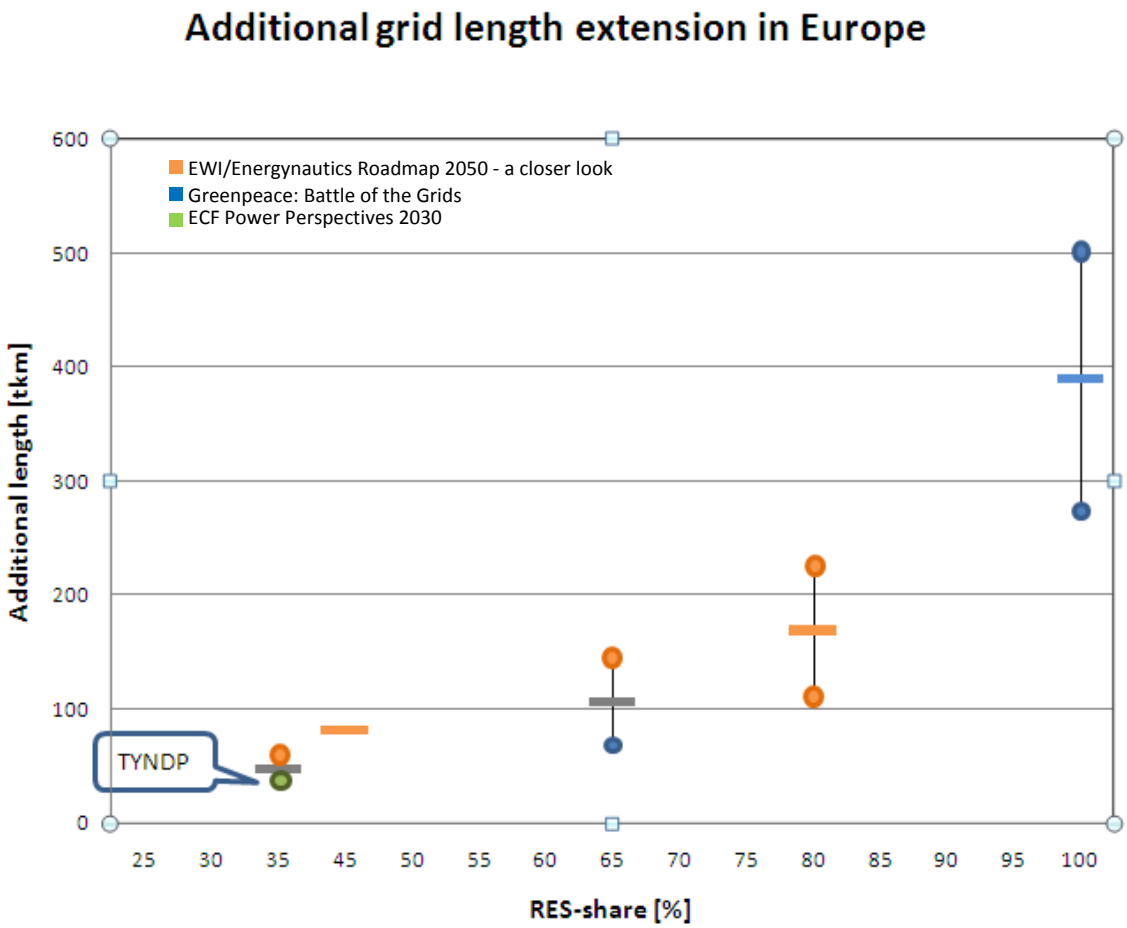

Figure 2: Additional grid length required as a function of the RES-E share, according to three studies[4]

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[4] This figure uses a distinct color code to indicate the sources of origin; whereby grey bars represent average values combined with corresponding MIN/MAX values

The most influencing factors on these differences are the various assumptions of the studies and scenarios regarding the underlying generation mix, the spatial distribution of the renewable generation units, the available back-up capacity including storages and assumptions regarding the future electricity demand. Indeed, the *ECF Power Perspectives 2030* study carried out a less transmission scenario and concluded that a shortfall in transmission expansion would require more back-up capacity and would lead to higher curtailment levels of fluctuating renewables, more volatile prices as well as slightly higher emissions. Whereas the *ECF study* focused on lower levels of RES-share, the other two studies modelled higher penetration levels of RES. The data points from the Roadmap 2050 study are a result of the *Optimal Transmission Grid* scenario (scenario A), which aimed to optimise the transmission grid in terms of minimising total system cost. Scenario B (moderate transmission grid) is represented with the lower data point at the 80% penetration level.

The two data points at 100% RES-share originate from the *Regional*- (lower point) vs. the *Import*-scenario of the *Greenpeace study*. Whereas the *Regional* scenario assumed an increased local solar PV and wind generation capacity, the *Import* scenario assumed a more centralised generation on best European sites and an import of 60 GW from North Africa. In this scenario a Supergrid was assumed to be in place which led to additional 220,000 km to be built by 2050. We conclude that the planned grid reinforcements and extensions of the TYNDP are at the lower end of the results and that across all studies a higher RES-share goes along with an increase of the transmission grid. However, the actual extension needs depend strongly on the assumptions made.

Transfer capacity extension

Figure 3 depicts the corresponding NTC capacity extensions. As more studies report the NTC capacities rather than the total transmission line extensions, more data points are shown in this graph. It essentially confirms the message of the previous figure. However, it should be noted that NTC capacities cannot be translated directly into grid extension length. NTC capacities only refer to cross-border transfer capacities and cannot be translated directly into a specific physical line. What is more, the methodology of NTC calculation leaves degrees of freedom which make it difficult to translate these figures directly into lines and cost. Related to costs it is important to be clear about the assumptions made in terms of transmission technology (HVAC vs. HVDC) and the way of installation (overhead vs. cable). Big variations in costs could be explained for the most part by these facts. As most studies have not reported detailed

results in terms of installed technology and corresponding costs, no consistent statement can be derived.

The two data points at a share of 75 and 80% RES-share are taken from two different scenarios of the *Roadmap 2050 study*. The upper point (75% RES-share) refers to the *Optimal Transmission Grid*-scenario, whereas the lower point (80% RES-share) assumes a moderate transmission grid expansion according to the levels aimed by the TYNDP to be reached by 2050. This implies among others a higher amount of available storage capacity (cf. Figure 6), a greater utilization of local, less efficient[5] renewable generation sites and, as a consequence, higher total system costs. The significant bandwidth at a 100% RES-share rises from the fact that each data point refers to a different scenario as discussed above.

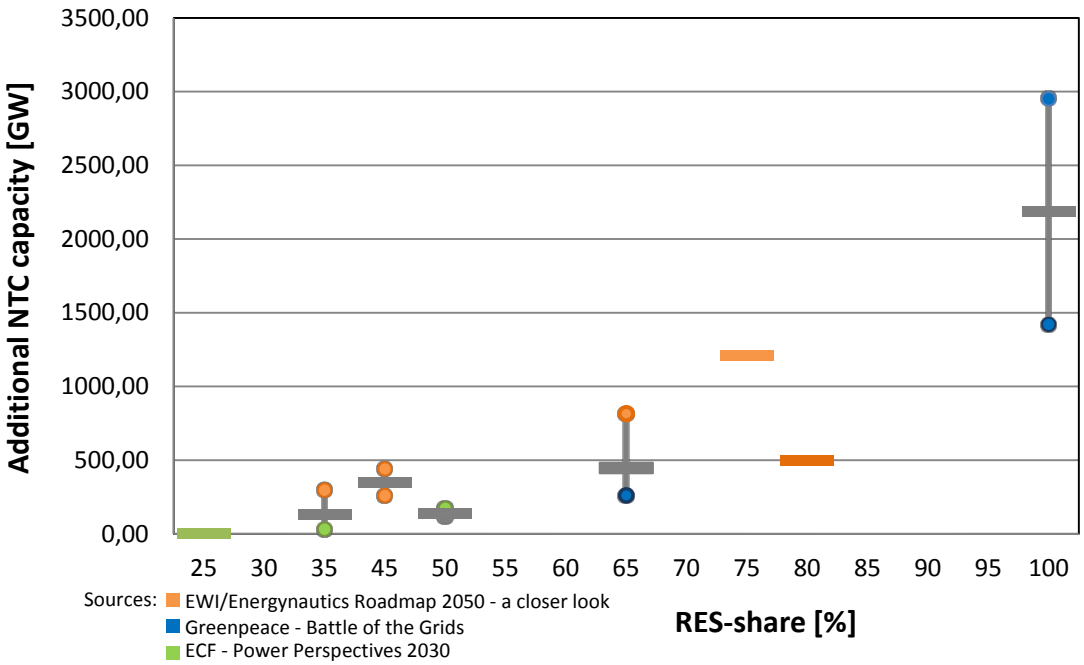


Figure 3: Additional Net Transfer Capacity (NTC) extension needs as a function of RES-share, according to three studies

Curtailment of fluctuating RES-E

Figure 4 depicts the various levels of curtailment from fluctuating renewable generation. As can be seen, there are significant differences in resulting needs for curtailment

[5] *Efficiency* has to be interpreted in terms of achievable full-load hours in this case.

at a certain RES-share. Equally, as stated before, the levels of curtailment depend strongly on the underlying assumptions and shall not be interpreted as being independent from other influencing factors. One obvious dependency could be expected between the required NTC extension and the level of RES-curtailment. However, the analysis of the scatter chart depicted in Figure 5 does **not** show a strong correlation between these two factors. This underpins the previous statement that various influencing factors have to be taken into account. For example, the maximum point of 7% RES-curtailment at a 50% RES-share is the result of a scenario which assumes less additional transmission capacity[6] combined with a high share of fluctuating renewable energies and therefore requires a high amount of additional back-up capacity.

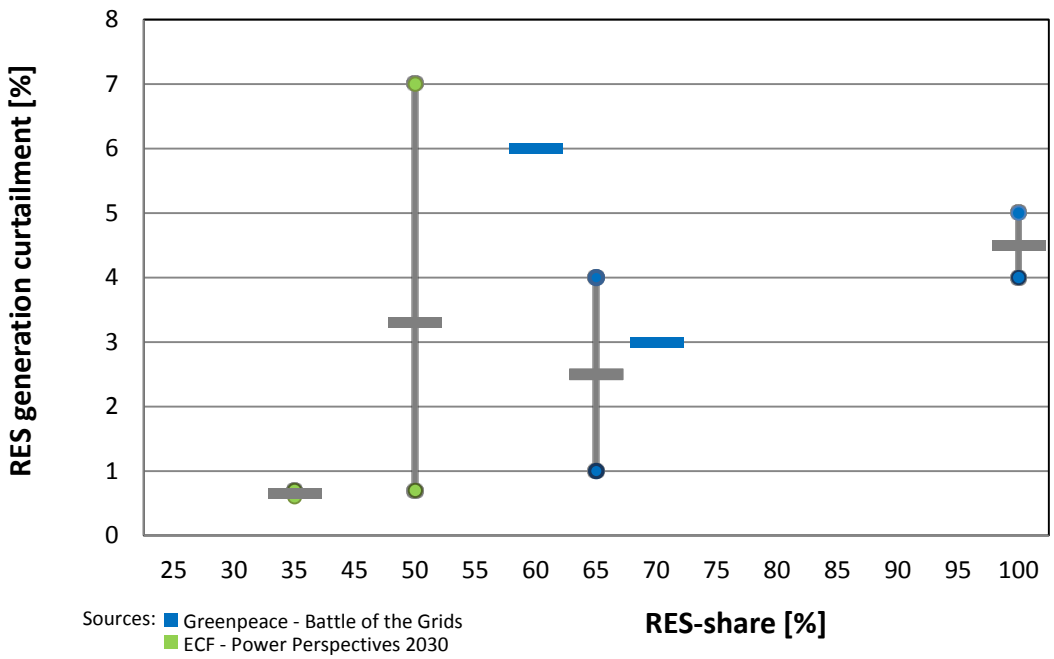


Figure 4: Curtailment of fluctuating RES-E in various scenarios as a function of the RES- share, according to two studies

[6] In detail it was assumed that only half of the projects aimed by the TYNDP can be realised and furthermore a maximum NTC-barrier of 5000MW per boarder has been implemented.

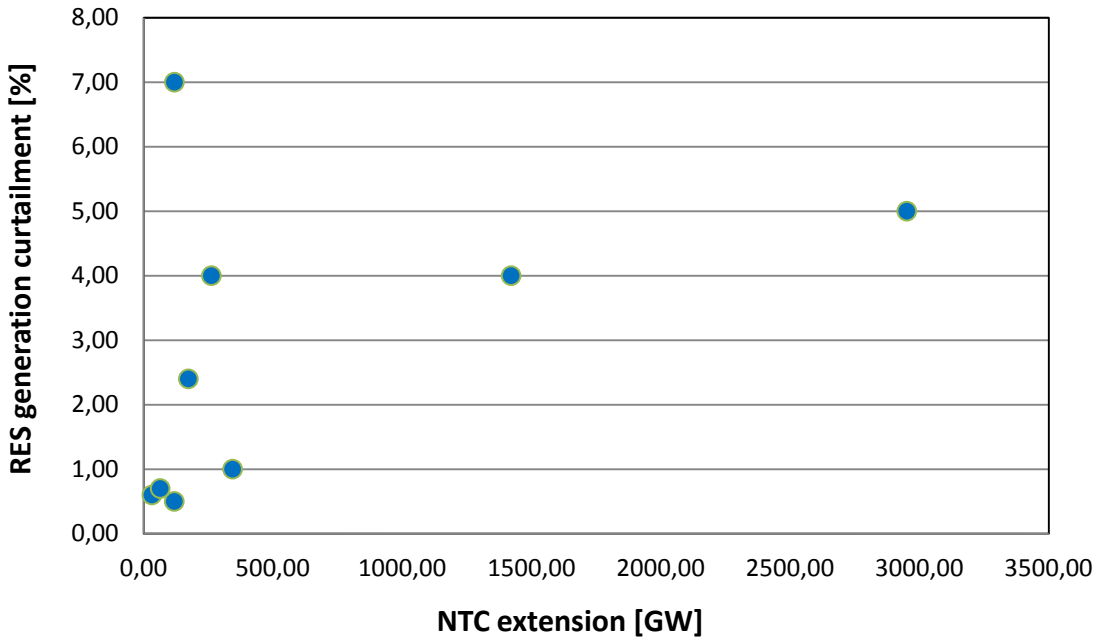


Figure 5: RES generation curtailment as a function of additional NTC extension against 2010, according to two studies

Storage

Figure 6 completes the picture as is illustrates the bandwidth in the assumptions of an additional factor - the need for storages. Both do have an influence on the required grid extension needs. First, it should be pointed out that a decrease in NTC extension by a factor of more than two, as assumed in the *Roadmap 2050 study* scenarios at 75% and 80% RES-share in Figure 5 goes along with an increase in storage utilization by the same order of magnitude (see Figure 6). Second, at a RES-share of 65% the *Greenpeace study* proposes a significant lower grid length extension and corresponding NTC extension than the *Roadmap 2050 study* (cf. Figure 2)..

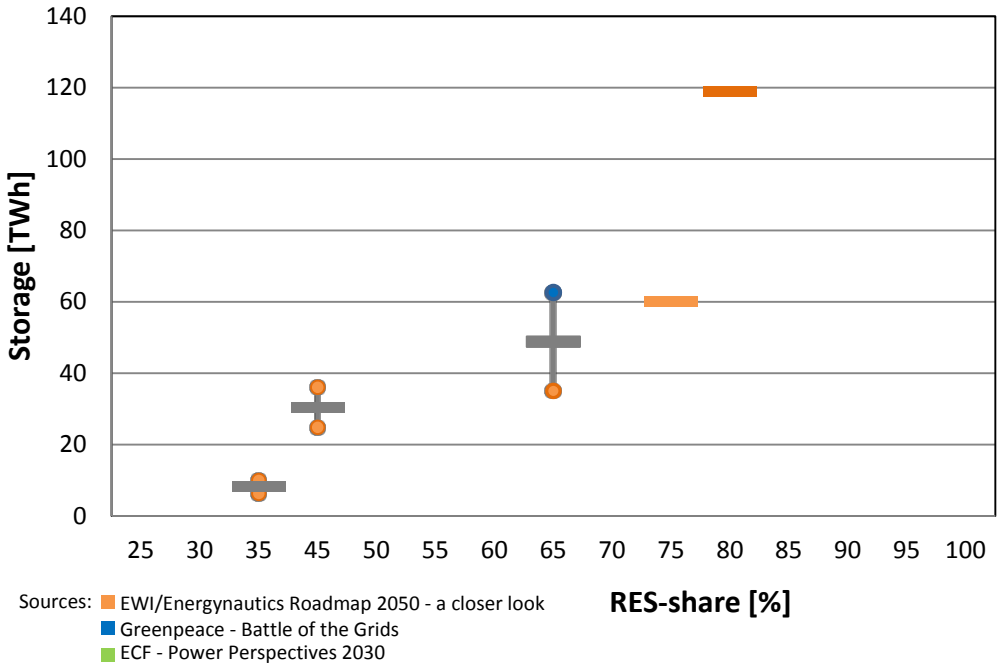


Figure 6: Storage utilization as a function of RES-share, according to three studies

The following main conclusions can be drawn from the analysis of existing studies:
On one hand a clear correlation between the RES-E share and the required network expansion can be seen. On the other hand, the numbers show a range for similar RES-E penetration levels. This indicates a high dependency on the input parameters and other framework assumptions of the studies. These framework parameters are concerning the spatial distribution of the RES-E, the curtailment policy and the use of storage.
Naturally, if network expansion is calculated on a purely economical basis, high values for network expansion emerge and transmission is relatively cheap compared to other flexibility options. If e.g. acceptance and permission problems keep network expansion below the economic optimum, operation costs of the power system and curtailment of RES-E will increase. Hence there is no absolute minimum value for required network extensions, but it is a matter of trade-offs and acceptable cost. However, it is still difficult to assign values to these trade-offs since the study methodologies are not always designed to do so. Consequently, there is a clear need to examine the trade-offs in more detail with a high-resolution network model and with a transparent methodology and assumptions.

3 Technological options for bulk power transfer and policy implications

The factors related to the implementation of bulk power transmission can be categorised in three main areas, as presented in Figure 7:

1. ***Technology:*** the respective options are limited to two main transmission technologies (High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC)) combined with two implementations (Overhead Lines (OHL) or Underground Cables (UGC)).
2. ***Topology:*** two configurations are possible; either dedicated overlaying point-to-point high capacity links or overlaying meshed network structures.
3. ***Infrastructure:*** significant implications and possible synergies are introduced by existing infrastructure (such as existing electricity grid, highways, waterways) can be decisive parameters for the realisation of new transmission projects.

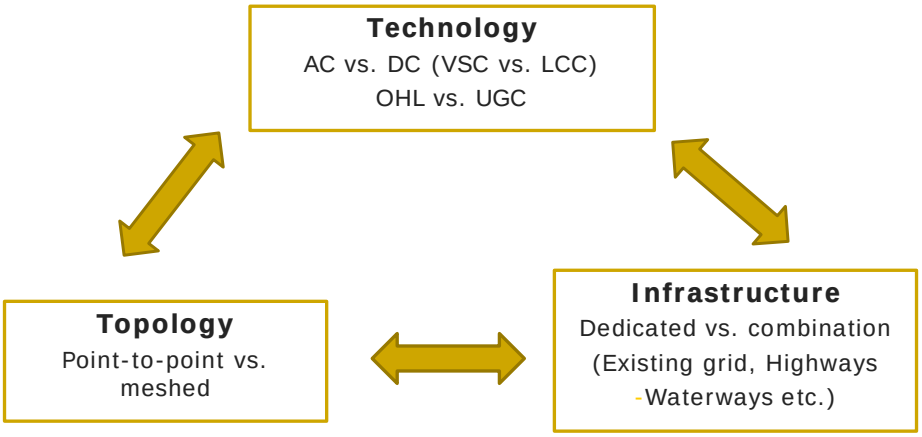


Figure 7: Main factors related to the planning of bulk power transmission.

3.1 Technology options

The decision on the implementation option for a specific transmission project from a set of technology alternatives is summarised in Figure 8. For the decision making process a transmission project can be classified as a ***transmission task*** subject to specific ***externalities*** [OUD09]:

1. ***Transmission task:*** corresponds to the purely techno-economic characteristics of the project, defined mainly by the transmission capacity and distance. This

point of view corresponds to a 'Greenfield' approach, disregarding specific implementation implications. In this respect, the choice of the most suitable technology to fulfil a transmission task can be taken based solely on the techno-economic characteristics of the technology alternatives.

2. ***Externalities:*** the implementation of the project imposes additional constraints related to the environmental impact of the project, the public acceptance and the system operational requirements. The supervising policy framework, by imposing rules for the quantification of these factors, defines their impact on the technology choice (e.g. choice of UGC implementation instead of OHL).

The implementation technology is chosen as the economic optimal option that can fulfil the transmission task and in addition satisfy all externalities. Different technologies offer different advantages with respect to these factors, making the final choice project-specific. To comprehend how the main decision variables affect the decision-making process for the implementation of transmission projects, we present below the central points on the debate on competing technologies.

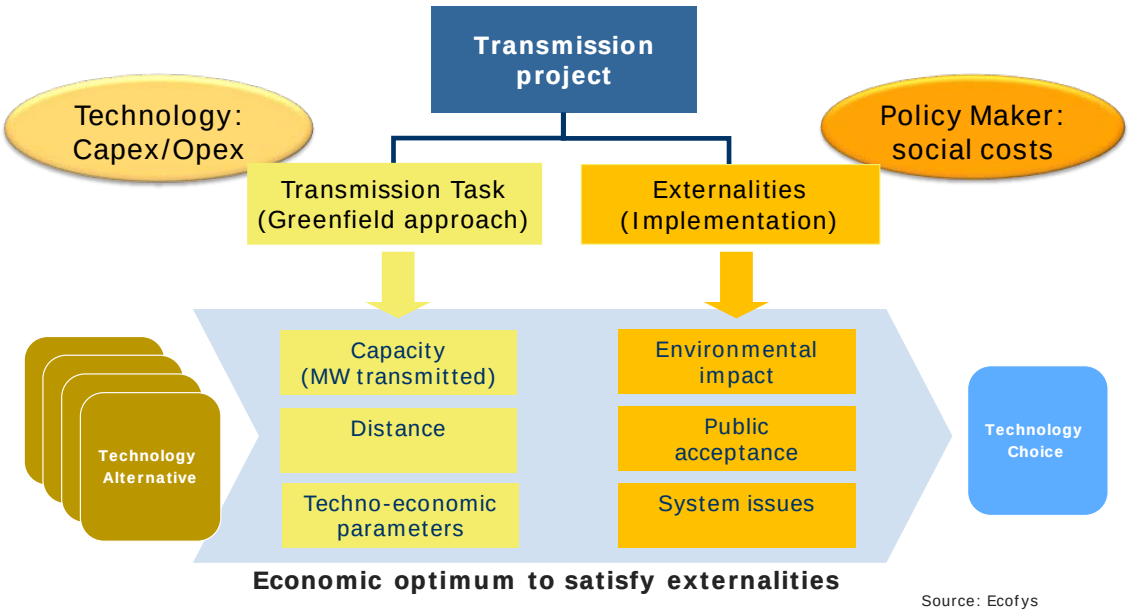


Figure 8: Transmission project: framework of the technology choice.

3.1.1 Transmission capacity and intensity

The capacity that each technology can transmit economically is a first decision parameter. The choice is taken based on the joint consideration of the project's capex (terminals and conducting circuits) and lifecycle opex (mainly transmission losses). The reduction of transmission losses is achieved by either increasing the conducting diameter (which however translates into higher costs for conducting circuits since more conductors are needed), or by increasing the voltage level (which necessitates the use of more expensive terminals and conducting circuits).

Therefore, in the respective literature, different 'optimal' values for specific technology options are reported, mainly due to the fact that solutions are tailored to the respective transmission task. Although the characteristics of each technology define the enabling capacity per circuit, the transmission corridor capacity is defined by the number of parallel circuits. How each technology supports this placement on the expense of the line economics and corridor space requirements can be a decisive parameter for the optimal technology choice.

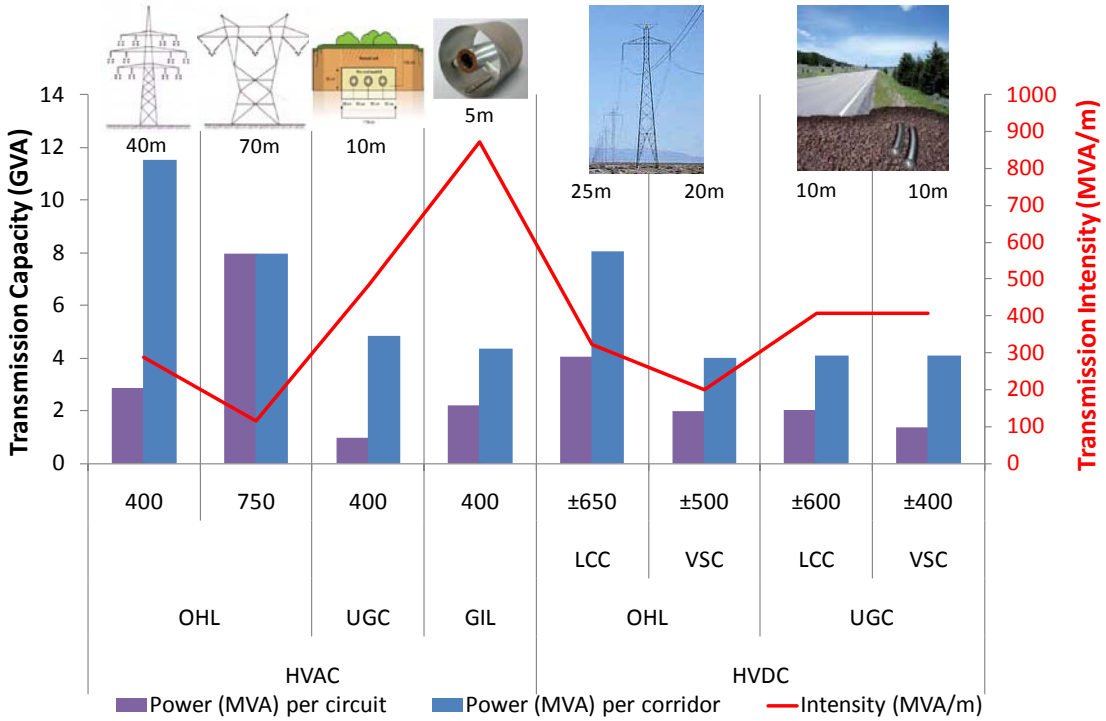


Figure 9: Basic technology choices: capacities and transmission intensity[7].

To gain a representative view on the comparative merits of each option, the characteristics for the different technology options optimised for a typical 4000MW/400km transmission task are presented in Figure 9 [DEN11] defined as the optimal capacity per circuit, the capacity per corridor and the transmission intensity of the corridor (corridor capacity divided by the corridor width). The main characteristics of the options are summarised below:

- OHL configurations present the highest capacities however combined to more extensive corridors. HVAC 750kV OHL offers the highest transmission capacity per circuit, but HVAC 400kV OHL and HVDC LCC ±650kV OHL reach higher corridor capacities because they enable the combination of multiple circuits in single towers. HVDC VSC is a newer technology with lower transmission capacities which however offers advantages for the better system integration compared to HVDC LCC (it does not require a strong grid at the infeed points and in addition can support the grid at the connection point). Considering space requirements, HVAC technologies require larger corridors due to their higher electromagnetic emissions and larger towers than for HVDC transmission, triggering higher public opposition.
- Public opposition to UGC implementation is minimal since the transmission line is not visible. UGC configurations present lower capacities per circuit but the highest transmission intensity due to their reduced space requirements. HVDC UGC offer the highest capacities combined to easier installation and no requirements of extra equipment for reactive power compensation. On the other hand, HVAC 400kV UGC (HVAC GIL or HVDC) can be easily combined with existing HVAC systems (partial undergrounding).

Therefore, although multiple technologies enable the economical transmission of high power capacities, the final choice depends on the techno-economic assessment of the project and the respective system and spatial integration issues. These points are discussed below.

[7] VSC stands for Voltage Source Converter, LCC for Line Commutated Converter and GIL for Gas Insulated Lines.

3.1.2 HVDC vs HVAC

HVDC transmission presents specific advantages that make it unique option for several implementations. HVDC OHL conducting circuits are less expensive with comparison to the HVAC OHL, requiring smaller towers and fewer and smaller diameter conductors. Similarly, HVDC UGC are of smaller diameter and more simple than HVAC UGC[8]. On the contrary, HVDC terminals (converter stations) present higher conversion losses than HVAC terminals (transformer stations). Taking into account system issues, HVDC is the main option for the connection of asynchronous areas or for long submarine connections. Further, both HVDC technologies allow the control of the line power flow. Furthermore, HVDC VSC offers significant options for the stabilisation of the HVAC system at the connection points. These system issues are of increasing importance for the management of systems with high RES penetrations.

A main disadvantage of HVDC transmission is the need of dedicated expensive terminals for AC to DC conversion at the ends of each transmission link. This makes HVDC transmission a favourable option for longer and higher power links, where the high terminal costs are balanced by the reduced line costs. In practice, there is a breakeven distance where HVDC transmission becomes more economic. This fact is depicted in Figure 10 for different capacities where the costs as a function of the transmission distance are presented. On the contrary, HVAC is more advantageous option for highly meshed networks due to easy transformation and meshing.

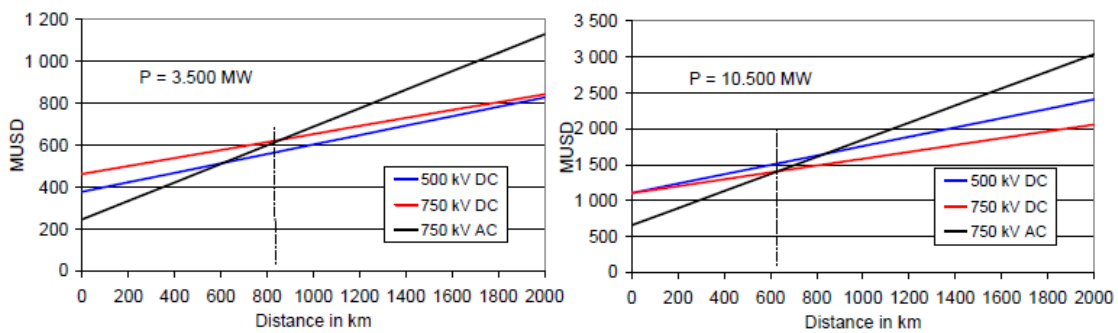


Figure 10: HVDC OHL vs. HVAC OHL costs as function of the transmission distance for two transmission tasks [WEI].

8 In addition, HVAC UGC require extra components for reactive power compensation which is not needed for HVDC.

The choice between the two HVDC technologies will depend on the future technology advancements mainly of HVDC VSC. At the moment, HVDC LCC is a proven technology which offers higher capacities per circuit and lower terminal losses but requires a strong HVAC grid at the point of connection. HVDC VSC presents a better system integration performance (it is able to support the HVAC grid at the connection points) and its terminals are significantly more compact, but still has not reached the capacity levels of HVDC LCC. Especially for the connection of RES resources that are often in remote areas, the HVDC VSC system stabilisation performance is of main importance. Concerning the future developments, the ability of HVDC VSC to support a multi-terminal (MT) operation may qualify this technology as central HVDC option. In contrast to typical point-to-point HVDC links, a MT operation can allow the realisation of HVDC meshed overlaying network configurations using terminal stations for the power exchange with the HVAC grids. Such configuration enables a better management of the power flows in such a grid while in addition allows a secure overlay network design due to the meshed structure (power flows may be redirected to other branches in cases of faults). However, still such an option is not technically possible, with main technical barrier being the implementation of circuit breakers (switching equipment) to facilitate the safe MT operation.

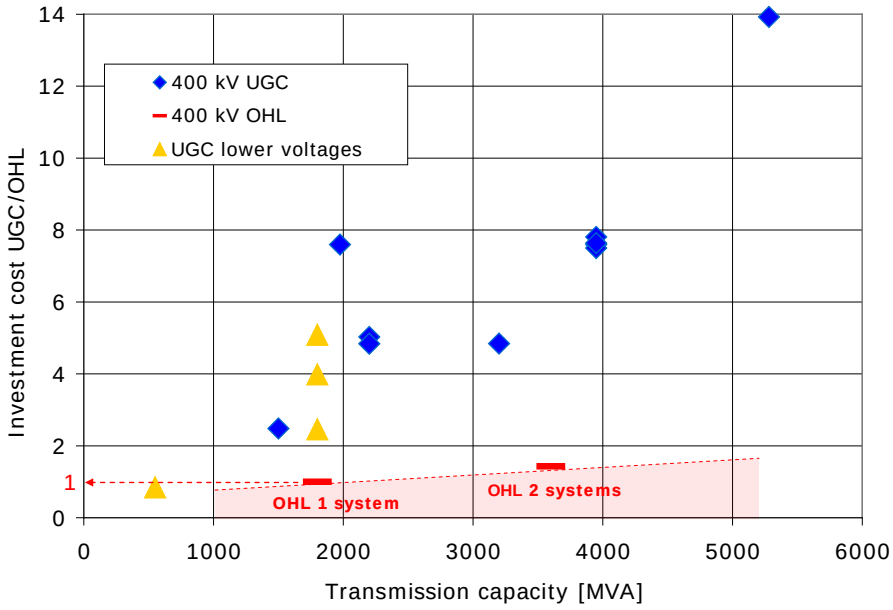


Figure 11: Investment cost of an UGC compared to a OHL [ECO08]. The single circuit 400kV OHL is used as reference for the calculation.

3.1.3 Overhead lines and underground cables

UGC is the implementation option with the highest public acceptance. However, UGC present higher investment costs, due to the higher cable costs per km compared to OHL and due to higher installation costs resulting from the required civil works. In Figure 11, the cost factors for UGC with respect to a single-circuit OHL are presented for typical cases reported in related literature [ECO08]. As shown in Figure 11, the expected range for HVAC UGC costs is generally between 5 and 10 compared to an HVAC OHL, while factors above 10 can be reached when comparing with high capacity double circuit links and if specific structures are needed (e.g. tunnels) due to increased costs for civil works.

However, the option of partial undergrounding can be an efficient way to reduce the costs while keeping high public acceptance, for both technologies, HVAC or HVDC. In this case, UGC is used for the parts of the project where the main public opposition is met. As reported in [ENTSO10], assuming that one tenth of the length of the project is subject to partial undergrounding and that the investment cost of this section is 5 to 10 times the cost of the OHL section, the partial undergrounding would lead to an increase of the investment cost by a factor of 1.5 to 2.

3.2 Infrastructure implications

Future projections show the need of significant new transmission capacity. In this respect, efficient land planning is necessary in order to facilitate the necessary new transmission corridors and achieve the required public acceptance. Synergies with the generic existing infrastructure (e.g. energy grid, transportation corridors, waterways) should be explored towards an optimized solution. Furthermore, taking into account the age of the current assets, a holistic view on infrastructure optimisation should be adopted, where existing infrastructure as well as different energy carriers is considered. This optimisation can be classified in three categories based on the considered planning horizon, as presented in Figure 12:

I. *Existing electricity grid*: in the short-term, the replacement of existing corridors with high-capacity corridors could be performed. For example, HVAC 400kV could be replaced by high capacity HVDC circuits with minimal changes in existing towers (use of HVAC towers) [ABB09] (this would of course imply necessary investments in converter stations).
II. *Existing generic infrastructure:* in medium term, part of the new transmission corridors could be combined with existing transportation or other existing infra-

structure corridors, minimizing the costs and delays with respect to spatial planning [VDE11].

III. *Other energy carriers:* in the long term synergies among various forms of energy could represent an opportunity for system improvements. Current research activities indicate that the combination of energy carriers (electricity, heating and gas) could possibly introduce significant potential for optimisation based on concepts of multi-carrier transmission and energy hubs [ETH11].

The need for new transmission corridors raise significant concerns on the impact of the externality costs of the projects. Solutions that can come from the combination of infrastructures lead to reduction of these externalities, which in most cases are the main obstacles hindering the implementation of transmission projects. Therefore, the presented short- and mid-term options could play a significant role on the planning of transmission for the next period.

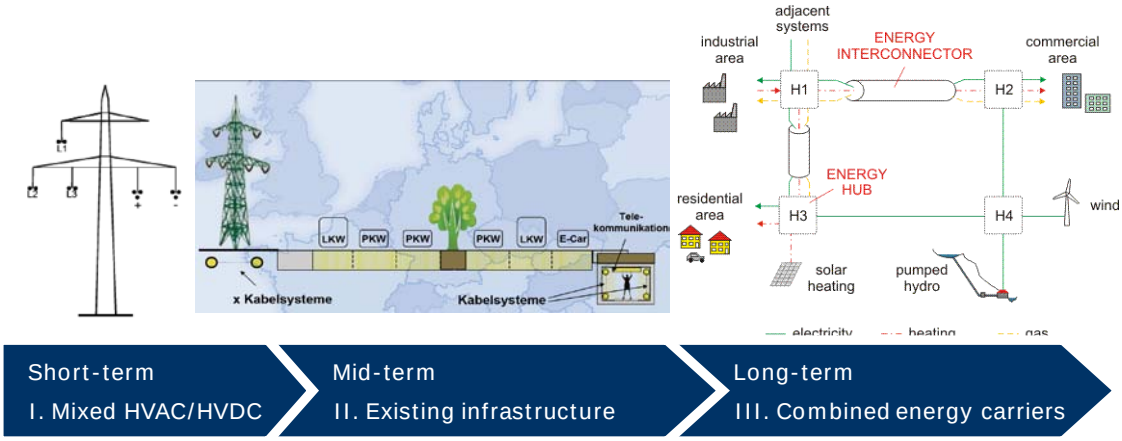


Figure 12: Combination of HV transmission infrastructure with existing infrastructure [VDE11], [ABB09] [ETH11].

3.3 Network topology options: Supergrid

Incorporating bulk transmission in the current system is envisaged as the construction of an overlay network (supergrid). In principle both transmission technologies (HVAC or HVDC) could enable this network with respective pros and cons. HVAC can be easily connected to the existing transmission network using transformer stations but does not offer significant power flow control options and draws the higher opposition from the

public. HVDC can be more economical for such long transmission distances (depending on the adopted configuration and the number of terminal stations), offers power flow control options and has a more compact UGC implementation, making it more suitable to combine to existing infrastructures (mid-term development, Figure 12). The implementation of a HVDC supergrid poses significant challenges with respect to the adopted topologies, which are discussed below.

In many studies the development of point-to-point (P2P) HVDC links is proposed as the first step towards the required transmission infrastructure upgrading. This concept considers the construction of a number of overlaying high capacity links to facilitate the flow across the main congested directions (see Figure 13, P2P). This option allows the use of HVDC LCC for the implementation of higher capacity links. However, such a development path entails specific risks and hidden costs. Firstly, the adoption of an unmeshed P2P configuration inevitably translates into system security issues, since in case of loss of single links the power cannot be easily re-directed to another path. Secondly, in such configuration the underlying HVAC network should facilitate the power distribution from the high capacity infeeds, inducing extra costs and realisation risks. Therefore, a meshing of the HVDC links and the adoption of a multi-terminal (MT) structure for the overlay network should be considered with a higher number of terminal stations, which will allow the optimal management and secure operation of the supergrid and the alleviation of investments in the underlying HVAC networks.

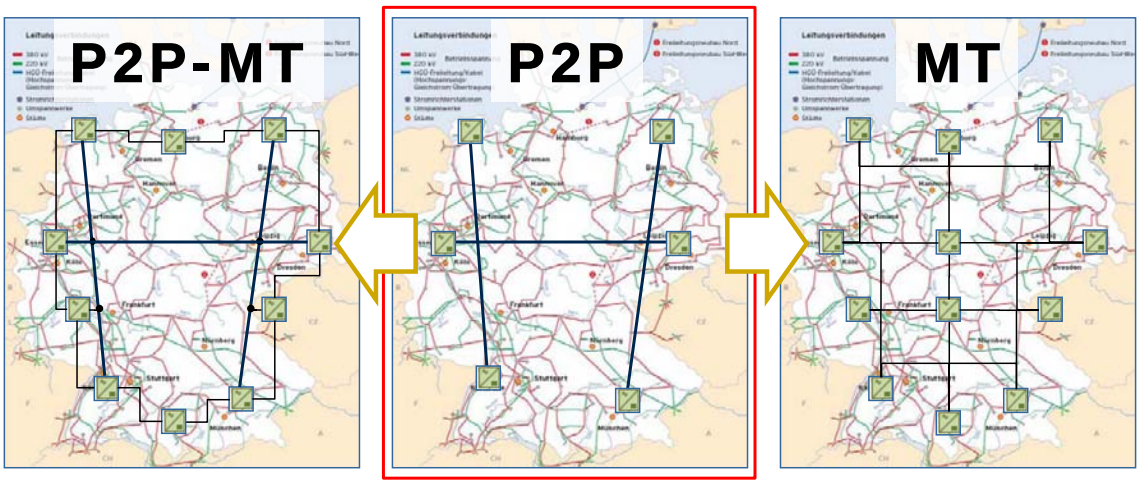


Figure 13: Options for the transition from point-to-point (P2P) to a meshed configuration (P2P-MT or MT).

A central point is how to accommodate the optimal evolution of such a HVDC P2P towards overlaying HVDC meshed network structures. In Figure 13 two possible developments are depicted towards a mixed P2P-MT or a MT configuration. While a purely MT configuration is based on HVDC VSC, in a mixed P2P-MT configuration, the P2P high-capacity links are first implemented based on HVDC LCC and in parallel a lower capacity MT network ring is built to facilitate the power distribution and ensure security. Significant risks concerning R&D developments and transition issues can be identified:

- *R&D developments*: As discussed, the HVDC VSC circuit breakers should be developed to enable the MT operation in both configurations. Further, for a purely MT configuration, HVDC VSC should enable significantly higher capacities. The cross-connection of the P2P links and MT network should be made based on DC/DC inverter stations, which however are not still commercially available for such power classes [VDE11].
- *Transition issues*: It is necessary to coordinate the HVDC P2P developments in an early stage for the transition to meshed structures. To optimise the topology, the capacity and spatial planning of the P2P links should ensure the further developments. Therefore, long-term system studies are necessary that can set the target towards the long-term configuration.

As discussed, a MP2P configuration can be supported by the current HVDC technologies, including high capacity HVDC LCC links, but at the expense of more terminals for limited feed-in points. For a MT configuration a more optimised structure could be achieved using more feed-in points and higher meshing, which could increase security and alleviate investments in the underlying HVAC network. However, for this solution R&D developments should enable MT operation with HVDC VSC. It is necessary to coordinate the HVDC P2P developments in an early stage for the transition to meshed structures. To optimise the topology, the capacity and spatial planning of the P2P links should ensure the further developments. Therefore, long-term system studies are necessary that can set the target towards the long-term configuration.

3.4 Conclusions:

Transmission technology, topology and infrastructure are interrelated choices that have a significant role on the final implementation of transmission projects. Although the techno-economic parameters of each transmission technology are significant decision variables for the final technology choice, the externalities related to the implementation

of the project are often the decisive factors. Based on the current state of the art, it appears that an efficient solution has the following properties:

- HVDC-VSC
- mixed infrastructure use (AC towers, highways)
- Mixed OHL and UGC
- meshed overlay network structures

The main policy implication is that the infrastructure optimization is a complex process affecting diverse players and large areas. A high-level long-term international planning and coordination is required to achieve a gradual development towards an optimized topology. Uncoordinated gradual development may lead to sub-optimal investment allocation and transmission expansion.

4 Regulatory implications of bulk power system operation

4.1 National vs. European planning perspective

As discussed in chapter 2, a high divergence is observed on different studies results on network investments, due to differences in the initial assumptions concerning RES penetration levels and geographical allocation, and due to differences in the adopted methodology. In this respect, a unified methodological framework and converging initial assumptions could reduce the variability of the results and allow sound decision making. However, in many cases diverging results are a consequence of diverging perspectives and scope of the network optimization exercises.

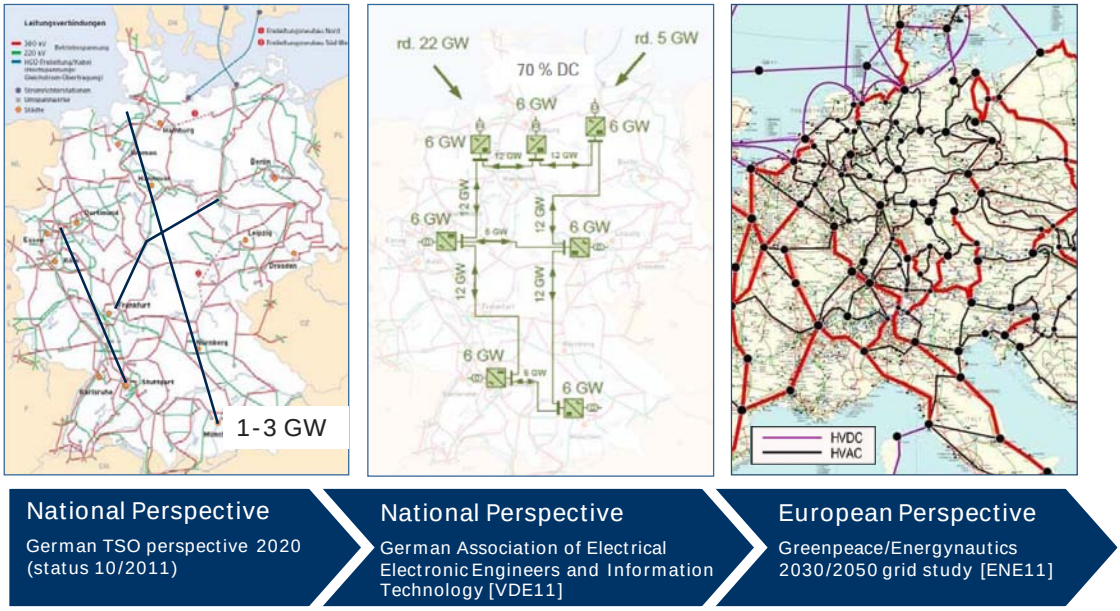


Figure 14: Grid extension results from different studies, indicating the differences between national and European planning perspective.

To comprehend how these factors affect the resulting network investments, in Figure 14 the structure of the overlay network for the area of Germany is presented, based on two studies that adopt a national perspective and a study that follows a European perspective. For the national studies, differences in the adopted configuration result into different structures for the overlay network, as discussed in section 3.3. In addition, the

adopted perspective (national vs. European) may lead to significant deviations in the results, due to the different optimization targets.

- National planning underestimates the impacts from cross-continental flows and the role that the national network plays as a part of the interconnected European system. In this respect, the network planning seeks the cost optimal solution for the area under consideration and in most cases leads to an underinvestment decision compared to a planning that considers a larger geographical scope.
- Based on a European perspective, the optimal network structure derives as the cost optimal solution for the continent as a whole. In this respect, when it leads to a cost optimal solution, the network planning will result to network structures that enable harvesting remotely located RES potentials (at the outer areas of the continent, be it solar energy in the south or wind and hydro energy in the north). In order to support cross-continental flows, higher levels of network investments may appear in national zones. In this respect, the allocation of the respective costs to the benefited parties is of utmost importance.

Network planning has traditionally been performed based on the different national perspectives. This has resulted in the current European interconnected system comprising more or less of weakly meshed “national islands”. This planning perspective has inherited significant problems to the operation of the interconnected system, with TSOs being steadily confronted with unexpected power flows (e.g. from sudden changes in variable RES in other control areas or from loop flows), endangering the system operation. To reduce these risks, it is therefore important to adopt a European network planning perspective and to define clear planning steps that can streamline the decision making process.

4.2 Recommended planning steps and critical issues

A necessary precondition towards the realization of the required network infrastructure is the adoption of a stable policy RES-E framework. EU-wide decisions on RES-E shares, mix, location and deployment timeframe will shape the network of the future. Taking into account that network assets have a lifetime of 40 to 50 years, commitment to clear, long-term targets concerning the continental RES shares will provide the stable framework necessary for network development, ensuring financial stability for the network manufacturing industry and for grid investments. These targets have to be sufficiently ambitious and be followed from appropriate mechanisms for the translation

of the global to national targets, which is central for the localization of the RES resources. In addition, the share of variable RES to the total RES-E mix will be of utmost importance for the resulting network configuration since higher shares should be supported by stronger interconnections for regional balancing.

In this respect, the following steps for the planning of overlay network structures can be identified:

1. *Coordinated European overlay network planning*

   EU should proceed to a European-wide network planning towards the optimal continental network development. European-wide network studies should be performed based on the adopted RES-E targets which will identify the structure of the overlay network. Impacts to the network from the adopted mix and target setting should be investigated in an early stage. Since untapping of remote RES potentials translates into sheer increase in network investment costs, the network costs should be included when comparing remote RES-E options to local potential. The adopted overlay structures should be tested against their robustness with regard to their implementation taking into account the synergies with existing infrastructure and the options offered from different technologies. Taking the implementation constraints into consideration the respective investment magnitude for the overlaying infrastructure will be established. These considerations should be taken into account within the Modular Development Plan on pan-European Electricity Highways System 2050 (MoDPEHS) which will be elaborated until 2014.

2. *Extensions of the underlying HV distribution networks*

   Such an overlay network structure presupposes underlying HV distribution networks that can enable the distribution of the power in the feed-in points. Since the respective costs are inversely proportional to the degree of meshing of the overlay grid, these costs should be included in the comparison of the different overlay network configurations in order to reach an optimal choice.

The main critical issues concerning the planning of the infrastructure are identified as follows:

1. The future developments in transmission technologies and the possible use of higher voltage levels should be considered and respective R&D activities should be supported.

2. The planning of overlay networks should be aligned to the planning of sub-transmission grids that are responsible for the power distribution from the feed-in points.

3. The current primary regulation reserves in the interconnected system of 3000 MW should be increased to accommodate higher power links

4. The supply chain of DC Technologies should be secured by the definition of supporting market conditions

5. HVDC LCC, although offering higher capacities, requires strong local network which can be critical issue for its application in remote areas where RES-E are located.

6. HVDC VSC is the technology that can support a multi-terminal operation, however the concept is not yet operational due to technical problems. In any case, the system advantages offered by HVDC VSC promote this technology as the most possible option for a HVDC overlay grid

7. An overlaying network with low degree of meshing may present issues concerning its operational security and N-1 adequacy

8. A continental-scale long-term planning increases the requirements for the coordination between the different national authorities in EU.

5 Data requirements for detailed studies

As discussed, bulk power transmission will have a considerable influence on the sub-transmission network. As shown in Chapter 2, the adoption of simplified network equivalents leads to an underestimation of the planning complexity since it overlooks the impacts on the lower network levels. As a result, a significant variation in the resulting investment requirements is observed, hindering the decision making process. A sufficiently detailed European network dataset is a major prerequisite for obtaining a better insight on the implications of the future infrastructure developments. In this respect, we present some experiences with the current available dataset (UCTE study model 2008 - STUM) and discuss the main data requirements towards a European networks study model.

5.1 Current status: the UCTE "Study model"

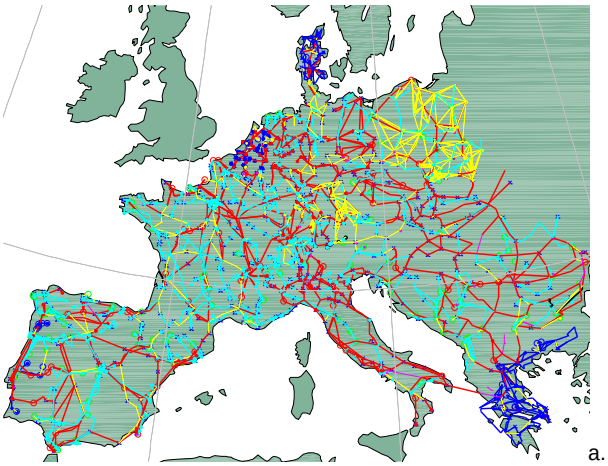
The STUM covers the ENTSO-E Regional Group Continental Europe (RG CE, former UCTE area). The STUM made available to the consortium is a derivate of the winter and summer reference cases (snapshots) for the year 2008, based on AC load-flow reference data sets corresponding to the seasonal forecasted state of the transmission grid of RG CE. The data include a detailed representation of the network topology, (a list of network nodes and branches, i.e. lines and transformers with their respective electrical characteristics) and the net power injection at respective system nodes[9]. The model includes higher voltage levels, while lower voltage levels (for some countries below 220kV) were suppressed according to TSO information.

In order to meet the TSO confidentiality restrictions, the RE model was modified and information was limited solely to what is necessary for the AC load-flow calculation. Indicatively, parallel lines were equivalenced to one element, all geographical information were omitted, operational power limits of lines and equipment were not provided and only net balance was provided for each node (positive balance on load side, negative balance on generation side). Due to the poor data quality, the AC power flow solution presented unacceptable overloading of specific system branches.

Due to these limitations, the raw model provided by ENTSO-E was not suitable to be used for dispatch optimization exercises. Main limitations were the lack of information

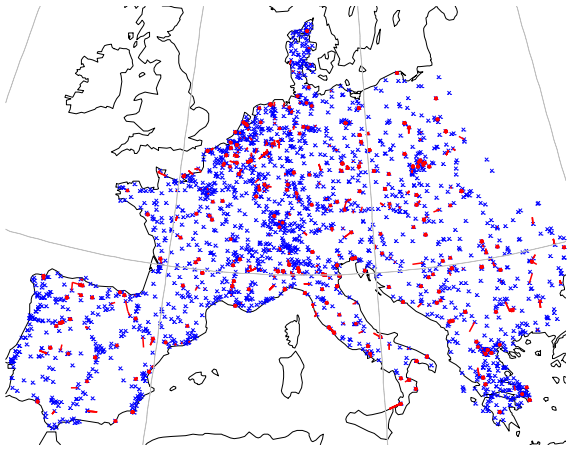
9 Indicatively, the winter snapshot includes 6265 lines, 1098 transformers, 4283 nodes and a total net demand of 205GW.

on the type and location of power plants in the system, the poor quality of the data on the operational capacity limitations of the network branches and the distortions to the system structure due to the equivalencing of parts of the network. To enable the use of the model for dispatch optimization analysis, a specific procedure was undertaken for the geographic referencing of the STUM (Figure 15a), and its matching to a detailed power plant database (1545 units in total, Figure 15b).

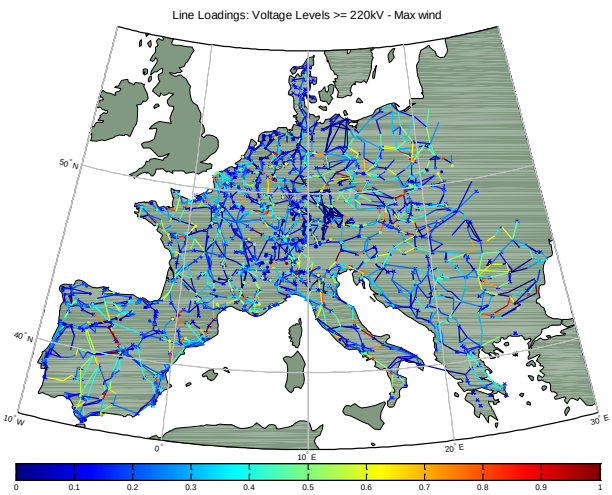


a.

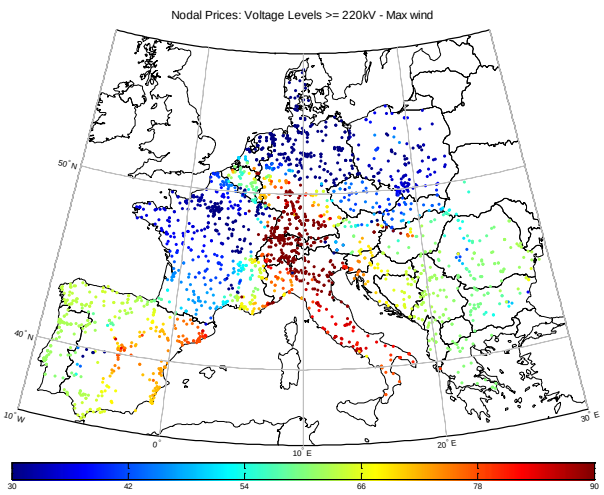
Line voltage levels (red 380kV, cyan 220kV, blue 150kV, yellow: equivalent elements)



b. Power plant locations and connection to respective network nodes



c. System power flows for the high wind scenario



d. System nodal prices for the high wind scenario

Figure 15: UCTE STUM and power plant geographic representation and results from the dispatch optimisation.

Due to the poor data quality, specific assumptions were undertaken for the correction of the inconsistent branch operational limits and in order to ensure the solvability of the

model for an 80% derated case. The adopted methodology allowed the construction of a consistent optimization model that could be used for the analysis of the system operation under different wind power infeed scenarios. The continental power flow and nodal prices results of the model runs for the high wind penetration snapshot are presented in Figure 15c and Figure 15d.

Although the model results showed a good fit to the operational experience, the poor data quality hindered the use of the model for a quantitative assessment of the network expansion requirements. Instead, the model was used for comparative analysis on the impacts of different market designs.

5.2 Data requirements towards a European networks study model

A concise network dataset should be available in order to allow the study of the network impacts from the incorporation of variable RES. Some main requirements that this dataset should fulfil are the following:

- *Geographic referencing:* the geographic coordinates of all system elements should be provided in order to allocate the future demand and generation and allow the detailed estimation of the required corridors. This information will allow the quantification of the impact of externalities for specific implementations (public acceptance, spatial planning, existing infrastructure).
- *Network structure:* the electrical characteristics of all network elements should be clearly defined, without the equivalencing of elements or parts of the network.
- *Operational capacity limits*: the operational capacity limits for each network element should be provided in a concise and uniform manner based on a common definition. Major systematic changes on the capacity limits due to environmental conditions should be included in the dataset.

The model should be evaluated and cross-checked to show a good match with operational results.

6 The Role of Regulation in Financing Infrastructure Investment

Electricity network investments are generally characterised by lumpiness and scale economies, meaning that initial oversizing that provides additional capacity for evolving transmission needs is often the welfare optimal solution. In practice, however, the ability to secure investment rests on the provisions granted through the regulatory framework in which the actors operate. A range of public and private participants are involved in the transmission investment process, and their interaction will be crucial for Europe to deliver on its energy and climate objectives.

The European Commission (EC) estimates that EUR 140 billion of electricity transmission investment will be required by 2020 [EUC10][10]. Correspondingly, in their latest Ten Year Network Development Plan, the association of European electric transmission system operators (ENTSO-E) suggested some 35,000 km of new lines and 7,000 km of upgrades to existing lines are required in the next nine years, accounting for 14% of the existing network [ENTSO10b].

This not only raises the question of who will finance the new grid investment, but also impacts on the ownership question. At the European level, the increased role of EU budgets, bonds guaranteed by the European Investment Bank, infrastructure funds as well as cost sharing arrangements (Inter-TSO Compensation mechanism) and bilateral deals (50-50 cost sharing) are discussed. The proposed Infrastructure Package regulation was developed by the EC to tackle outstanding issues surrounding planning and permitting projects of European priority, methodologies for cost and benefit allocation and, ultimately, expediting finance flows.

6.1 Review of Existing European Regulatory Approaches

The investment challenge facing European TSOs and the regulatory structure in which they operate can be categorised by: i) the willingness of regulators to support investment, and ii) the ability of existing utilities to raise the required investment under current conditions. The latter is particularly important since most investment is pursued by transmission system operators (TSOs) at the national or sub-national level.

Designs of regulatory regimes vary significantly across Europe due to historical factors such as existing institutional structure and the approach taken to liberalise the power

10 Consisting of EUR 70 billion for onshore networks (including EUR 28 billion for cross-border interconnectors), EUR 30 billion for offshore, and EUR 40 billion for storage and smart grids.

sector. The resulting EU regulatory landscape is fragmented and each regulatory authority has varying levels of power, independence and effectiveness.

The table below highlights five national regulators and the various structural metrics that can illustrate their capacities such as staffing, sectors and number of companies under their regulation, year established and budget. A number of differences are apparent: how established various regulators are in their current setting (e.g. 1997 for Italy, 2005 for Germany); the number of companies that must be regulated (e.g. 850 distribution system operators (DSOs) and 4 TSOs in Germany, one DSO and one TSO in France); the staffing numbers related to electricity networks (e.g. 86 in Italy to 441 in the UK).

Table 1: Selected country breakdown of regulator structures.[11]

Country/ Region	Regulator	Status	Estab-lished	Sectors	Electricity Companies		Budget 2010 (EUR)	Staff 2010	Funding
France	CRE	Independent commission	2000	Electricity & Gas	1 D	1 T	20 mil	131	Network regulation
Germany	BNetzA	Ministry	2005	E, G, com., rail & post	850 D	4 T	160m	2400	State budget
Italy	AEEG	Independent	1997	E & G	170 D	1 T	18m	86	Tariffs, network regulation
Spain	CNE	Independent ministerial agency	1999	E, G & oil	329 D	1 T	30m	213	Surcharge on consumption
UK	Ofgem	Independent	2000	E & G	7 D	3 T	79m	441	Tariffs, licensing fees
EU	ACER	Independent	2011	E & G	-	-	8/9m	40-50	Member State/EU budget

[11] Sources: [IEAFR09], [IEAES09], [IEAIT09], [IERN11]. Abbreviations: T = electricity transmission, D = distribution, CRE = Commission de régulation de l'énergie (Energy Regulatory Commission), BNetzA = Bundesnetzagentur (Federal Network Agency), AEEG = Autorità per l'energia elettrica e il gas (Gas and Electricity Energy Authority), CNE = Comisión Nacional de Energía (National Energy Commission), Ofgem = Office of the Gas and Electricity Markets, ACER = Agency for the Cooperation of Energy Regulators.

The rich experience gathered across different European countries offers the opportunity to learn about the benefits, risks and costs of different regulatory regimes. Berg [BERG00] and Stern & Holder [STERN99] identified several criteria that can be used to determine the performance of the regulator based on the regulator design and process implementation:

Institutional design of regulator

1. Clarity of roles and objectives (removes confusion arising from government/regulator interactions)
2. Autonomy (free and independent from undue political influence)
3. Accountability (clearly defined process and rationale for decisions and handling appeals)

Regulatory processes

4. Participation (communications, consultations and consistency with stakeholders)
5. Transparency (openness of the process)
6. Predictability (reputation that facilitates planning and flexibility by using appropriate mechanisms for changing conditions).

Some of the features that differentiate European regulators are characterized in Table 2 for five European regulators. Because of such – often subtle – differences, financial investors and rating agencies struggle to fully appreciate the specific characteristics of companies owning transmission assets.

Table 2: Regulatory features in selected regulatory authorities. Sources: [REAL10], [ROLB11], [IERN11]

Regulator	Length of control period	Price setting	Regulatory control	Handling of/investment inclusion in RAB	Current remuneration of investment
France – CRE	Five years	Cost based	Ex-ante	Separate CAPEX/OPEX Fixed Assets	ROE post-tax 6.90% ROA pre-tax 7.3%
Germany – BnetzA	Five years	Revenue cap	Ex-post	TOTEX Fixed Assets + Working Capital	Pre-tax ROE: For expansion 9.29% (reduced to 8.2% following consultation October 2011) For maintenance 7.56%
Italy – AEEG	Four years	Revenue cap	Ex-post	Separate CAPEX/OPEX Fixed Assets + Working Capital	WACC pre-tax: 6.90% with 2% - 3% adder for new investment
Spain – CNE	Four years	Revenue cap	Ex-ante	Separate CAPEX/OPEX Fixed Assets	ROA 6% 2009
UK – OFGEM	Five years	Revenue cap	Ex-ante	Separate CAPEX/OPEX Fixed Assets	WACC 5.05% post-tax cost of equity, pre-tax cost of debt

Interviews with financial investors and rating agencies illustrated the challenge for analysts to develop a differentiated perspective on regulated network utilities and rate TSOs appropriately – in fact, a common framework across countries, across network assets, sometimes even based on the approach applied to generation assets, is used when assessing TSOs.

Under the current situation, it might be challenging for transmission owners to communicate to investors and rating agencies the strength of their risk profile or to explain the need to raise additional equity. This raises the question of how the set of European policy instruments currently under discussion can:

- help the identification and replication of successful regulatory practices from the rich European experience;
- assist TSOs with undertaking potentially new financing strategies that are viewed positively by the financial market and shareholders; and
- encourage convergence on simple regulatory and financing structures to facilitate appropriate assessments of TSOs by investors and rating agencies.

6.2 TSO Strategies for Financing Transmission Investment

The estimated volume of electricity transmission investment required in the next decade implies a significant increase of current volumes of transmission investment relative to 2020.

For six TSOs in Europe, whose control regions cover approximately 50% of the generation capacity in the EU, the next figure highlights their 2010 market value (based on equity and debt data available), and the envisaged 2020 evolution using available 'planned' and estimated investment figures. What it shows is that the value of new transmission assets planned over the next ten years is of the same magnitude as the current market value of European transmission assets, while the EC estimates that even more is required.

Where transmission system operators and their respective national governments have started to discuss detailed investment plans up to 2020, existing TSOs may face difficulty in using debt alone to finance this investment.

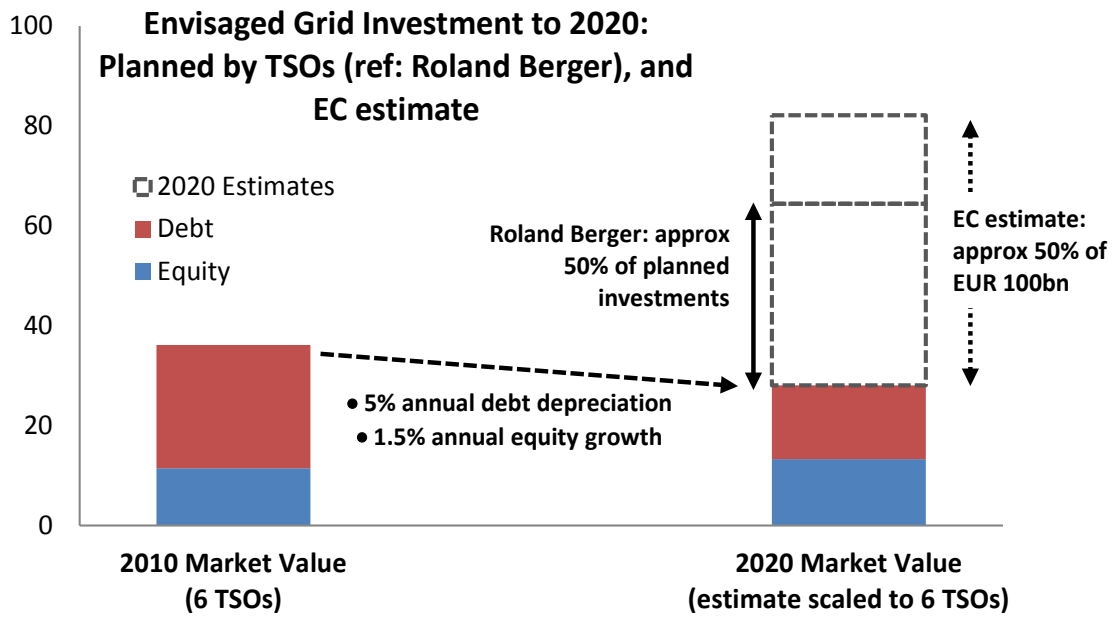


Figure 16: Market value of current transmission assets compared to investment needs (based on equity and debt available from 6 TSOs covering approx. 50% of EU generation capacity (UK, FR, IT, DE (2), ES) - hence planned investments were also scaled by 50%). EC figures exclude estimated EUR 40 billion for smart meters and storage. Sources: [ROLB11], [TSO0910]

From an investor perspective, TSOs are generally categorised as defensive investments with potential for stable and predictable growth, and by their ability to invest in infrastructure at low-cost, to meet regulatory requirements and to provide adequate yields to shareholders. TSOs are thus expected to uphold shareholder dividend promises, rather than focussing on increasing their asset bases by investing in capital expenditure.

This suggests that some change is necessary if the projected investment volumes are to be brought forward. A set of possible business models emerged from interviews with stakeholders, which reflect TSO trajectories to raising capital.

Private companies involved in infrastructure investment have – and will continue to have – the final say on which financial structure is best suited to their needs. Public policy and regulation at the national level can only provide support or (unintentional) obstacles for certain financial approaches, and thus can impact on financing costs that ultimately feed through to consumers. Table 4 describes the scenarios for further developments that can be envisaged to deliver the envisaged investment volumes. Some of the scenarios can be combined.

Table 3: Possible TSO financing strategies and challenges in meeting the required investment volumes.

Scenario	Description	Challenges
I.	**Issue additional equity**. TSOs maintain their current dividend yield pay-outs to shareholders and issue additional equity to finance the desired levels of growth.	This strategy requires clear communication to the financial markets justifying the dilution of existing ownership (e.g. when National Grid changed its strategy and issued new rights, the share price dropped). This might be of further concern where TSOs are in (partial) public ownership, and national governments might not have the resources to increase investment while exhibiting reluctance to reduce their ownership share.
II.	**Further reduce risks for investors**. The regulatory environment is further developed to reduce the (perceived) risk and allow for higher leveraging of equity.	Rating agencies assess the risks facing TSOs against a set of factors including stability and predictability (of business model, regulatory regime, etc.). Changes might thus initially be perceived as discouraging, and might then require time to have positive impacts on ratings.

Scenario	Description	Challenges
III.	**Shift to growth model**. TSOs position themselves as growth entities and retain earnings to increase their equity base.	Are existing earnings sufficient to deliver the necessary growth rates, and will the market believe that grid infrastructure has a persistent growth perspective? The (perceived to be inherently) risky business model of growth entities might 1) reduce the level of possible leveraging, while 2) result in existing equity owners not fully appreciating the new risk profile, which creates additional uncertainties due to changes in the ownership structure.
	Hybrid approaches TSOs or third parties finance individual lines on a project-specific approach (hybrid system of TSOs and 'merchant' lines).	This allows third parties to enter investment areas where incumbent TSOs lack incentives or capacity to take forward investments.
IV.	Project finance raised against revenue from congestion management on the line ('pure' merchant approach).	Cash-flows based solely on congestion revenues of new line are extremely volatile and difficult to value, limiting the ability to leverage equity and increasing financing costs. However, investors targeting high returns could be enticed (private equity, etc.). An example of pure merchant investment is the UK-NL Brit-Ned interconnector, a new entity set up between UK's National Grid and NL's TenneT.
V.	Project finance raised against regulated concessions for a specific line guaranteeing future income.	Stable revenue (e.g. with a long-term contract), asset backed investments (e.g. a transmission line), and limited operational risk (e.g. no link to system operation) facilitate high leveraging of equity and low-cost finance. The challenge lies in how individual lines can be integrated into the maintenance, operation, and future development of the overall network, and who has capacity for and should take responsibility for network planning, as well as gathering public acceptance for the project.

The financing strategies can be combined with varying levels of success, for example scenarios I (Issue Additional Equity) and IV/V (Hybrid Approaches): could be paired, since third parties could carry out private infrastructure investment alongside typical investment planned by the TSO.

In the following, we discuss in more detail the options policy makers have to strengthen the regulatory framework so as to further reduce risks for investors.

Options to reduce (perceived) investor risks at the national level

Investors in grid infrastructure benefit from the safety of regulatory guarantees combined with the securitisation through the physical asset. Grid investment should therefore, in principle, be more attractive – and allow for lower financing costs – than public debt. In practice, however, while costs of capital for TSOs are lower than for other industries, they are significantly higher than for public debt. What can individual European countries or European institutions do to improve this situation?

A combination of policy options as detailed above could potentially encourage confidence in infrastructure investment. The national regulatory regime plays an important role in network development: providing access to finance, providing appropriate costs of capital, and offering the flexibility for future network development and operation. Their refinement and further (gradual) strengthening is therefore key to European grid development.

At the same time, there are a number of policy processes that have targeted a European approach to network development and financing: (i) the bi-annual Ten Year Network Development Plans (TYNDP) as managed by ENTSO-E, and (ii) the Infrastructure Package, a regulation proposed by the European Commission (EC) which brings together national and European infrastructure financing, planning, and development.

Table 4: Policy Levers to Encourage Investor Confidence

Policy Levers to Encourage Investor Confidence	
Certainty in recovering investment costs	▪ Define a regulatory asset base for the depreciation period of assets, rather than restricting explicit guarantees to a regulatory period (e.g. 3-5 years). ▪ Limit the scope of incentive schemes to revenues associated with operational costs.
Confidence in remuneration level	▪ Build on the tradition of improving tariff-setting methodology, but possibly shift emphasis from incentivizing operation and maintenance costs to facilitating low-cost financing. ▪ Further standardise methodologies to determine cost of capital, and establish the role of national courts and European institutions in reviewing regulatory decisions on weighted costs of capital.
Regulatory asset base time lag for new investment	▪ Address remaining time lags between incurred investment costs for new lines and remuneration as part of the regulatory asset base.
Operation risk	▪ Uncertain costs of re-dispatch to address internal constraints can be avoided with small zones or nodal pricing schemes. ▪ Liabilities for blackouts can be avoided where operation is shifted to an independent system operator (ISO).
Diverse ownership structure	▪ The evaluation of the regulatory regime represents about 40% of the rating. Where it is evaluated very highly (e.g. UK), little further improvement is possible. How can the policy environment impact other factors that determine the rating (e.g. business model or financial structure), and would this be captured by current rating methodologies? ▪ If a large number of grid companies are covered by a common regulatory framework, financial markets will develop a rating tailored to grid companies instead of joint evaluation with other utilities. This allows grid companies – and ultimately users – to fully capitalise on the attractive risk profile.

6.3 European Cost Allocation and Financial Support

Network development has traditionally been carried out at the national or sub-national level, but coordination and cooperation at the regional and European levels is becoming increasingly important.

Transmission projects have positive impacts on the network and system security in neighbouring countries, enhance the benefits of a common energy market, and can facilitate the EU-wide sharing of renewables and energy storage. However, such international benefits are typically not reflected in national grid expansion decisions. Without a coordinated approach to grid planning and development, investments can result in sub-optimal lock-ins and inefficiencies. ENTSO-E's TYNDP was a first step towards a more integrated perspective; the EU Infrastructure Package now provides a comprehensive approach to EU grid expansion.

Financial support within the Infrastructure Package plays a relatively small role. The Infrastructure Package envisages the provision of EUR 9.1 billion in EU public financial support (grants, loans or guarantees) for benefits that are widely spread across Europe. This budget is for gas *and* electricity networks and is small compared to the electricity infrastructure investment need of EUR 100 billion in on- and off-shore networks.

The details of how such financial support would be allocated are still being discussed. One option could be to use EU financial support to fill the gap between benefits calculated for countries that are proposing the projects and the project costs (assuming this is warranted, given EU-wide benefits of the project). However, the implementation could create three difficulties. First, it would give national regulatory authorities incentive to calculate fewer benefits for projects, so as to limit the domestic contribution by accessing EU funding. Second, projects for which limited national benefits are calculated will be difficult to communicate to the public and to move through the planning processes. Third, the time required for negotiations between EU Commission and the countries proposing a project could jeopardize timely grid development.

Alternatively, EU financial support could be allocated independent of the benefits calculated by project proponents. A variety of options are available, including extended support for planning costs, allocation to the earliest projects to create incentives for an accelerated process, allocation to those projects with the most project proponents to encourage cooperation, and earmarking for economically weaker regions.

The discussion underlines the value of targeted use of EU public funds to unlock specific projects with large European benefit (e.g. innovative technologies). This has the

additional advantage of ensuring that support is focused on a few projects and thus relevant to project decisions – which would not be the case if support were distributed across all infrastructure investment.

The Elements of the EU infrastructure Package

The Energy Package is intended to expedite competitive, secure and sustainable operation of the European energy markets. A European strategy was needed to facilitate infrastructure planning, financing and accelerated development under medium- to long-term energy and climate objectives. In October 2011, the European Commission unveiled its proposal for the Infrastructure Package, aiming to facilitate an environment for public and private investment in European energy network and storage development.

Main Components

1. **Projects of Common Interest:** Methodology to identify and select projects that are deemed necessary for implementing priority corridors - Projects of Common Interest (PCIs)
2. **Permitting:** Shortening and streamlining national and European permit-granting procedures, and improving public involvement
3. **Removing Regulatory Barriers:** Removing regulatory barriers for investments in infrastructure of European relevance (one component of which is the allocation of benefits and costs of new lines).
4. **Financial Support:** Providing appropriate direct financial support for PCIs where the necessary funding is not available – fund of EUR 9.1 billion.

Next steps

- ***End of 2012:*** *Adoption of proposed regulation by European Parliament and EU Council of Ministers.*
- ***Beginning of 2013:*** *Planned entry into force of proposed regulation.*
- ***End of 2013:*** *List of Projects of Common Interest for 2014-2022 period to be finalised.*
- ***2014:*** *Planned entry into force of Connecting Europe Facility (CEF), through which energy infrastructure can access EUR 9.1 billion.*

Grid tariffs provide the primary source of revenue against which grid investment was and will be financed. Therefore, EU financial support can have the greatest impact where it supports processes to strengthen this national regulatory structure, thus reducing regulatory risk and financing costs for investors.

7 Summary and conclusions

The main messages of this report can be summarised as follows:

- The existing studies on a European scale which examine the network reinforcement show very high variations of required network expansion. The most influencing factors on these differences are the various assumptions of the studies and scenarios regarding the underlying generation mix, the spatial distribution of the renewable generation units, the available back-up capacity including storages and assumptions regarding the future electricity demand.

- If e.g. acceptance and permission problems keep network expansion below the economic optimum, operation costs of the power system and curtailment of RES-E will increase. Hence there is no absolute minimum value for required network extensions, but it is a matter of trade-offs and acceptable cost. However, it is still difficult to assign values to these trade-offs since the study methodologies are not always designed to do so. Consequently, there is a clear need to examine the trade-offs in more detail with a high-resolution network model and with a transparent methodology and assumptions.

- Transmission technology, topology and infrastructure are interrelated choices that have a significant role on the final implementation of transmission projects. Although the techno-economic parameters of each transmission technology are significant decision variables for the final technology choice, the externalities related to the implementation of the project are often the decisive factors. The main policy implication is that the infrastructure optimization is a complex process affecting diverse players and large areas. A high-level long-term international planning and coordination is required to achieve a gradual development towards an optimized topology. Uncoordinated gradual development may lead to sub-optimal investments.

- Data transparency is crucial for all planning exercises. The lack of transparent network data influences the possibilities to conduct meaningful studies on required transmission infrastructure.

- The main critical issues concerning the planning of the infrastructure are identified as follows:

    1. The future developments in transmission technologies and the possible use of higher voltage levels should be considered and respective R&D activities should be supported.

2. The planning of overlay networks should be aligned to the planning of sub-transmission grids that are responsible for the power distribution from the feed-in points.
3. The current primary regulation reserves in the interconnected system of 3000 MW should be increased to accommodate higher power links
4. The supply chain of DC Technologies should be secured by the definition of supporting market conditions
5. HVDC LCC, although offering higher capacities, requires strong local network which can be critical issue for its application in remote areas where RES-E are located.
6. HVDC VSC is the technology that can support a multi-terminal operation, however the concept is not yet operational due to technical problems. In any case, the system advantages offered by HVDC VSC promote this technology as the most possible option for a HVDC overlay grid
7. An overlaying network with low degree of meshing may present issues concerning its operational security and N-1 adequacy
8. A continental-scale long-term planning increases the requirements for the coordination between the different national authorities in EU.

- While the Infrastructure Package plays a relatively small role to finance through EU public funds it does aim to provide a comprehensive regulatory approach to EU grid expansion that builds on and incorporates existing initiatives and institutions.
- The national regulatory regimes are important elements of network investment and expansion: providing access to finance, delivering appropriate costs of capital, and offering the flexibility for future network development and operation. Their refinement and further (gradual) strengthening is key to European grid development, improving confidence in grid infrastructure investment and thus enhancing RES-E deployment.

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