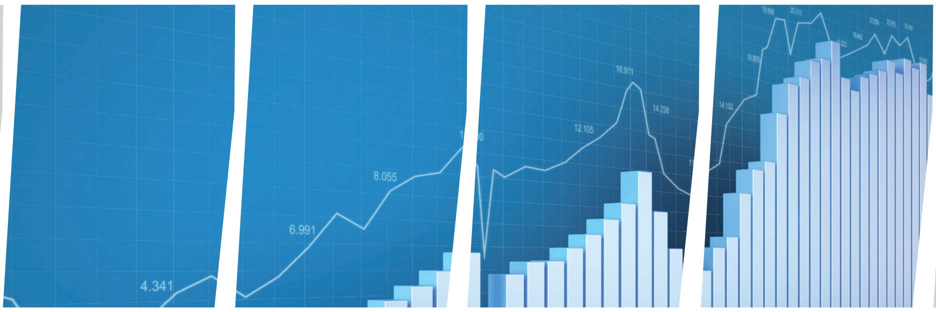
European Investment Bank

The EU bank

EIB Working Papers 2012 / 04



Green Electricity Investment in Europe: Development Scenarios for Generation and Transmission Investments

Christian von Hirschhausen, Workgroup for Infrastructure Policy (WIP), Berlin University of Technology

Green Electricity Investment in Europe: Development Scenarios for Generation and Transmission Investments

Abstract

This study analyzes issues related to “green”, i.e. low-carbon electricity investment in Europe. While traditionally the focus of attention was on green transmission lines, it has become clear in the course of this study that even though high-voltage electricity transmission is an important element of the decarbonization, there is **no** green transmission as such. Rather, transmission is greened by decisions on the upstream energy mix; in an extreme view, transmission investment is but a residual from generation decisions, because the choice of the generation portfolio, and its location, directly implies which transmission infrastructure is required. Therefore, green investment necessarily entails an integrated vision of generation and transmission (as well as storage, demand-side flexibility, etc., which for the sake of simplicity we consider to be part of generation). Both require a specific approach to investment since purely market-based competition will not bring about the energy mix that Europe has opted for, e.g. a low carbon energy mix, sketched out in its Energy Roadmap 2050.

The objective of this study, hence, is to clarify the role of green investment in the context of the Energy Roadmap 2050, to discuss the estimates of the investment challenge, and to outline technical-economic development scenarios (storylines) for further development. This is done both conceptually and through some empirical evidence. The study discusses various estimates of the investment challenge, finding both a high variance of these estimates, and that financing generation investment is the real challenge. Investment strategies will differ significantly between the stylized development scenarios that we sketch out, varying the focus between European-wide and more nationally oriented strategies, and defining different levels of cross-border cooperation; as of today, it is unclear which scenario will dominate. We conclude that the issue at stake is not over- or underinvestment in the European electricity sector as such, but that different development paths have different implications for generation and transmission infrastructure, and for the financing thereof. Finally, the investment needs must be assessed in the light of the political and institutional scenario that is expected to occur.

JEL classification: L51, L94

Christian von Hirschhausen, Workgroup for Infrastructure Policy (WIP), Berlin University of Technology

Table of Contents

List of Figures

List of Tables

1. Introduction

This study analyzes issues related to "green", i.e. low-carbon electricity investment in Europe. While traditionally the focus of attention was on green transmission lines, it has become clear in the course of this study that even though high-voltage electricity transmission is an important element of the decarbonization, there is no green transmission as such. Rather, transmission is greened by decisions on the upstream energy mix; in an extreme view, transmission investment is but a residual from generation decisions, because the choice of the generation portfolio, and its location, directly implies which transmission infrastructure is required. Therefore, green investment necessarily entails an integrated vision of generation and transmission (as well as storage, demand-side flexibility, etc., which for the sake of simplicity we consider to be part of generation). Both require a specific approach to investment since purely market-based competition will not bring about the energy mix that Europe has opted for, e.g. a low carbon energy mix, sketched out in its Energy Roadmap 2050.

The objective of this study, hence, is to clarify the role of green investment in the context of the Energy Roadmap 2050, to discuss the estimates of the investment challenge, and to sketch out technical-economic development scenarios (storylines) for further development. This will be done both conceptually and through some empirical evidence. The study is structured in the following way: the next section sets out the context of the energy transformation that Europe is about to undergo, as well as the challenges of green investments in the electricity sector, both in the field of transmission and generation. We identify the specifics of transmission investment in a decarbonized, largely renewable-based context: among them are the necessity to coordinate long-term planning of electricity generation and transmission investment, the externalities of electricity transmission resulting from physical laws ("loop flows"), the high uncertainty about system-wide developments, and others; likewise, we identify some idiosyncrasies of generation investment, in particular the necessity to overhaul the current market design. Section 3 provides estimates of the significant investment challenge of transmission lines and generation, finding that the generation challenge is about 5–10 times higher (in €terms) than the transmission challenge; furthermore, we find a significant gap between low and high estimates, indicating that these figures can only serve as a rough point of orientation. Section 4 then discusses potential future patterns and trade-offs of electricity sector investments, and identifies different development scenarios for the European electricity sector: investment strategies will differ significantly between the stylized development scenarios that we sketch out, varying the focus between European-wide and more nationally oriented strategies, and defining different levels of cross-border cooperation; as of today. While the approach chosen for this study is positive, i.e. without normative judgments about which scenario or policy is "better" than others, there are implications for the financing: the instruments to be used will differ according to which scenario will materialize in which sector, and which regulatory relation will be established between generation and transmission. Section 5 concludes.[1]

2. Challenges of "green" electricity sector investments

2.1 The context

With the Energy Roadmap 2050, the European Commission (2011a) has confirmed its ambition, set out in the Energy and Climate Package of 2007, to move towards a largely decarbonized energy system by 2050, with a reduction of greenhouse gas (GHG) emissions by at least 80 %, compared to 1990 (see Figure 1). The policy objectives of this energy transformation have been set out until 2020, e.g. in the 20-20-20 objectives (greenhouse gas abatement, share of renewable energy, energy efficiency increase) and the national renewable energy action plans (NREAPs). While a goal has been set to limit greenhouse gas emissions beyond 2020 (1.74 % annually), policies and targets regarding renewable and efficiency beyond 2020 are currently ongoing. In any event, the Energy Roadmap 2050 has defined a long-term vision for the decarbonization of the European power sector, which is to decarbonize almost fully.

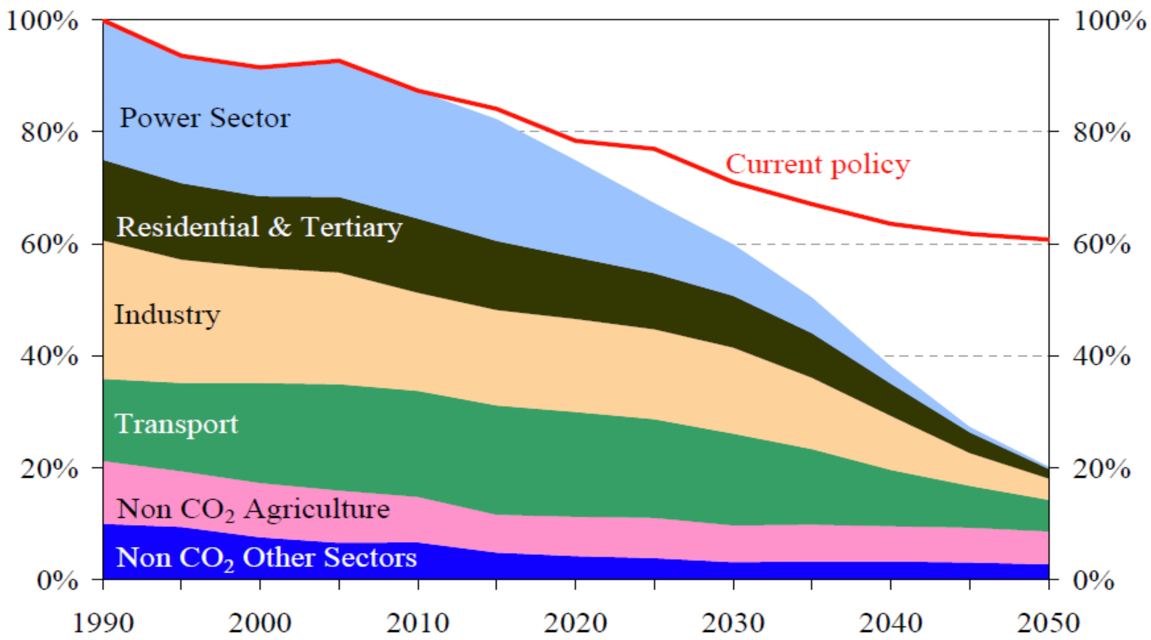
The low-carbon energy transformation has shifted the focus from transmission issues to the combined generation-transmission package. In the old world, the focus was on regulating transmission lines between ("dirty") baseload power plants and large centers of consumption. Today, issues in the value chain of an interactive, renewables-based energy system are more complex, and always imply generation and transmission issues.

In fact, recent years have brought about national attempts to coordinate generation investment with transmission planning, such as the UK (Electricity Market Reform, EMR), France (Loi Nome), Germany (nuclear phase out and attempts to secure backup capacity centrally), and Poland (capacity investments). The upcoming discussion about capacity investments at the national and the European level, and the need to design policies for green investments to achieve the 2050 targets (~ 2/3 or more of generation from renewable in all scenarios), as well as diverging speeds of market integration furthermore complicate the situation. One therefore has to address the idiosyncrasies of both, the transmission and the generation activity, and assess the investment needs jointly.

---

1 This document was conceived as a background study for the EIB/Bruegel report on "Investment and Growth in the Time of Climate Change". We thank particularly Armin Riess for providing guidance and discussions, Georg Zachmann for commenting on the manuscript, and the entire editorial team; at Workshop for Infrastructure Policy (WIP), thanks to Clemens Gerbaulet and Alexander Weber for research assistance. The usual disclaimer applies.

Figure 1: The EU Low-Carbon Energy Roadmap 2050



Source: EC (2011a, p. 5)

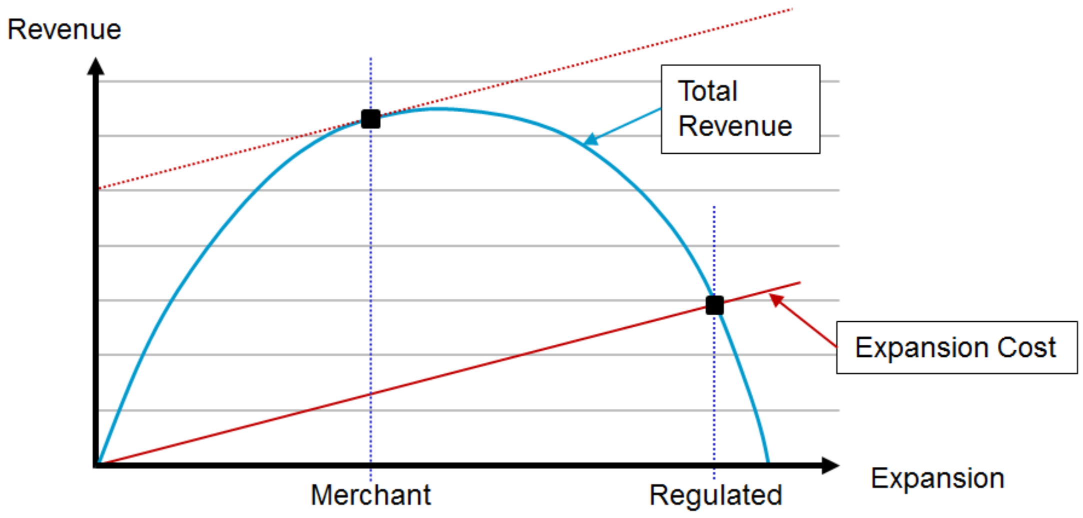
2.2 *Specifics of transmission*

In the context of decarbonization, transmission investment certainly plays an important role. Electricity transmission investment is considered a key element of any climate policy fostering the large-scale integration of renewable energy into the electricity system. By accessing large-scale sources of renewables and connecting them to demand centers, ambitious renewables targets can be met. While traditional transmission policy has focused on the short-term efficiency of operating networks, through benchmarking and price- or revenue-caps, the issue of new, green transmission investment is relatively recent. In the international context, Europe is at the forefront of attempts of developing cross-country, or even cross-continental electricity transmission. Studies on the perceived need of massive transmission investments abound, e.g. Tröster et al. (2011) proposing a European backbone grid, European Climate Foundation (2010, 2011) estimating the needs for a decarbonized European electricity sector, or, most recently, the EU Energy Roadmap (EC 2011a). The European Infrastructure Priorities (Impact Assessment, EC 2010b) assume investment requirements of € 142 bn. for electricity transmission, € 45 bn. of which would be delivered under current conditions anyway (business-as-usual). Last but not least, the Ten Year Network Development Plan (TYNDP), developed by the European Transmission System Operators (ENTSO-E 2010) also suggests a high need for transmission expansion, though no explicit mention is made to "green" factors as a main driver.

Electricity transmission investment has specific technical, economic, and institutional features that distinguishes it from other investments in traditional, competitive sectors. As a natural monopoly, i.e. having a subadditive cost function preventing any competition, transmission is for the most part subject to regulation. In all cases, allowed revenues are subject to a regulatory constraint, which may be more or less fixed (e.g. revenue-cap regulation) or indexed to the reported or expected costs (cost-plus regulation); given the strong role of investment, the cost-plus elements generally outweigh the cap elements (revenue- or price-cap). There is a controversial debate whether this cost-plus regulation, or the rate-of-return variant thereof (focusing on the remuneration of capital employed) induces overinvestment. But in the case of electricity transmission, there is a general consensus that a certain level of overinvestment is superior to underinvestment; thus, the theoretical argument has lost much of the controversial character it had in the academic debate in the 1980s/90s.

Another idiosyncrasy in electricity transmission is the wedge between the optimal investment volume, and the limited investment by a private merchant investor (Kirschen and Strbac 2004, Chapter 8). Ideally, optimal regulation would lead to a situation where the revenues collected on a line correspond to the expansion costs. Assuming a merchant investor does not have to fear competitors for his investment or any regulation, he would choose a monopoly-sized extension, because his private benefits do not correctly reflect the social benefits of the investment. In effect, the extension volume is much lower than the optimal investment volume. Although this assumption may seem strict, loosening it does not really help to solve the problem. On one hand, transmission investments are lumpy and not neatly scalable as textbook economics requires them, i.e. investment is restricted to a discrete action space, which still leads to misrepresentation of social benefits in terms of private benefits. On the other hand, if transmission investment was continuous, another issue remains: electricity prices are volatile over time and not easy to forecast – especially not in terms of spreads between different nodes. This would, assuming a reasonable level of risk aversion, also lead the merchant investor to choose an investment volume below the socially optimal level. This is illustrated in Figure 2 for the case of a merchant investment without regulation.

Figure 2: Merchant and regulated grid investment effects.

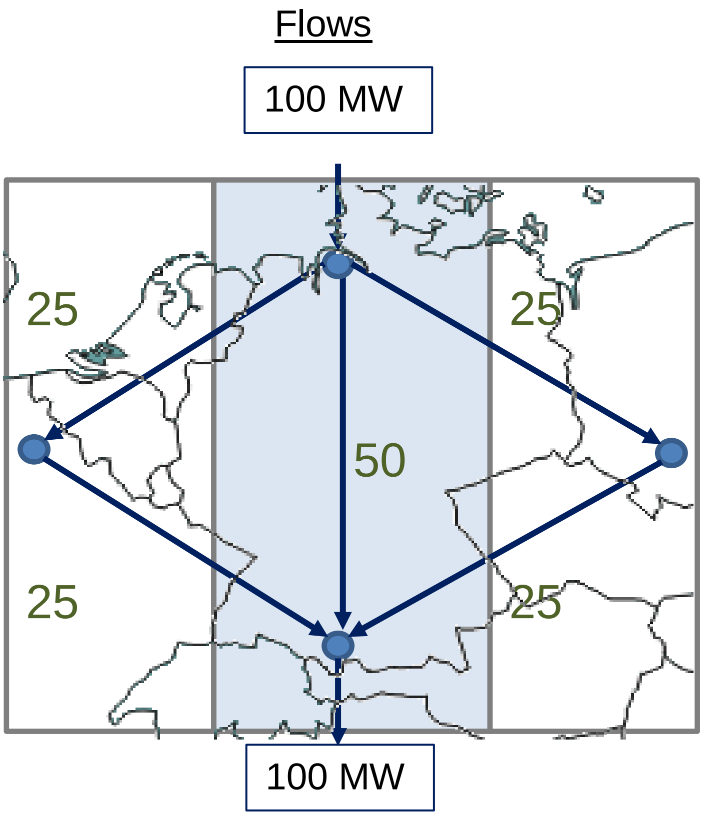


Source: own depiction, based on Kirschen and Strbac (2004, p. 237)

Network externalities in a meshed electricity network occur due to physical laws, the Kirchhoff's voltage law and the nodal law, as well as Ohm's resistance law. In a nutshell, electricity flows between two points use different pathways along the grid, in inverse proportionality to the resistance of the line. Figure 3 provides a stylized yet real-world example for a seemingly "inner German" flow of 100 MW from northern to southern Germany, that in reality passes through lines in the Netherlands, Belgium and France in western Europe, as well as Poland and the Czech Republic in eastern Europe. Technically blocking one border, e.g. the German-Polish border, redirects the flows accordingly. In general, the more meshed an international network is, the more difficult is it to attribute economic benefits to one specific line. This has led to a controversy between theoretical models of optimal cost and benefit allocation, and hands-on algorithms to solve the issue pragmatically by rules of thumb in practice (see Olmos and Pérez-Arriaga 2009, THINK 2012).

Further idiosyncrasies stem from the long-term planning horizons necessary (several decades), the need to coordinate transmission expansion with forecasts of generation and load, the need to supply plenty capacity (i.e. overcapacity) which is difficult to measure due to contingency requirements (n-1)-criterion), and so forth. From these specifics one derives not only uncertainty about costs and distributive effects of transmission investment (Rosellón et al. 2011: Egereret al. 2012), but also a significant information asymmetry between the network planner and the executing transmission operator or merchant investor.

Figure 3: Loop flows in electricity grids.



2.3 Specifics of generation

Investments in generation (plus storage and demand-side management) are more specific in the transformation context than in the "old world". In the latter, it was relatively easy to determine the value of any power plant due to the firm available capacity of all technologies. With a dominant share of intermittent renewables, not only will wholesale prices be lower on average, due to the many hours when residual load is small, but revenues will also become more volatile. Private investment decisions therefore interact directly with the regulatory framework. Most likely, a split between private investments in power plants and regulator-induced generation investments will emerge.

A look at the cost structures of different technologies implies that green generation is largely identical with renewable technologies. Schröder et al. (2012) have conducted a survey of cost estimates, finding that nuclear power has the highest investment costs and high variable costs, even excluding insurance costs, which would increase costs by another large factor. Thus, regardless of whether or not one considers nuclear energy as low carbon, nuclear is not an option for additional generation capacities and should not be considered part of a sustainable green electricity mix. Neither is carbon capture, transportation, and storage (CCTS) an option, because it has not been able to establish itself as a low-carbon technology, and is therefore unlikely to gain significant market share until 2030 (Hirschhausen et al. 2012).

The current market design, based on wholesale prices fixed through a merit-order process, is unlikely to bring about sufficient green investment in generation. Renewable generation is generally capital-intensive but has low variable costs. Likewise, flexible backup capacity (e.g. gas power plants) is unlikely to be financed under the current market design because it would not have sufficient load hours to refinance itself. It comes as no surprise, therefore, that new market designs are pondered by the European Union and the Member States. The combination of a large share of renewables and some backup capacity is definitely a new challenge to electricity generation investment. In any event, the location and the type of renewable and gas-fired power generation will have a strong impact on transmission as well, and that there may be a trade-off between the degree of concentration and the wish to limit transmission lines through connecting more decentralized generation structures.

3. Estimates of the investment challenge: transmission and generation

While most experts agree that there is an investment challenge, there is a wide discrepancy between the concrete estimates of this challenge, i.e. in € terms. Both the absolute value of investment needs and the split between transmission and generation are to a certain degree endogenous, i.e. driven by policy choices. Given the complexity of future scenarios, it comes as no surprise that estimates about future investment needs vary widely in scope, scale, and geography. Instead of providing point estimates of these investments, this subsection should therefore inform why estimates vary so widely.

There is a large number of studies available on the scope, scale, and geography of the investment challenge and no consensus has emerged on the precise figures. We analyze and compare transmission and generation investments as a part of the overall energy system costs of two major studies available: i) the Energy Roadmap 2050 (EC 2011a), including estimates from the Infrastructure Package; and ii) European Climate Foundation (2011, Power Perspectives): there is a significant variance between the two, as would be the case with any other pair of studies. A consensus that seems to emerge is that the generation challenge is 5–10 times higher than the transmission challenge.

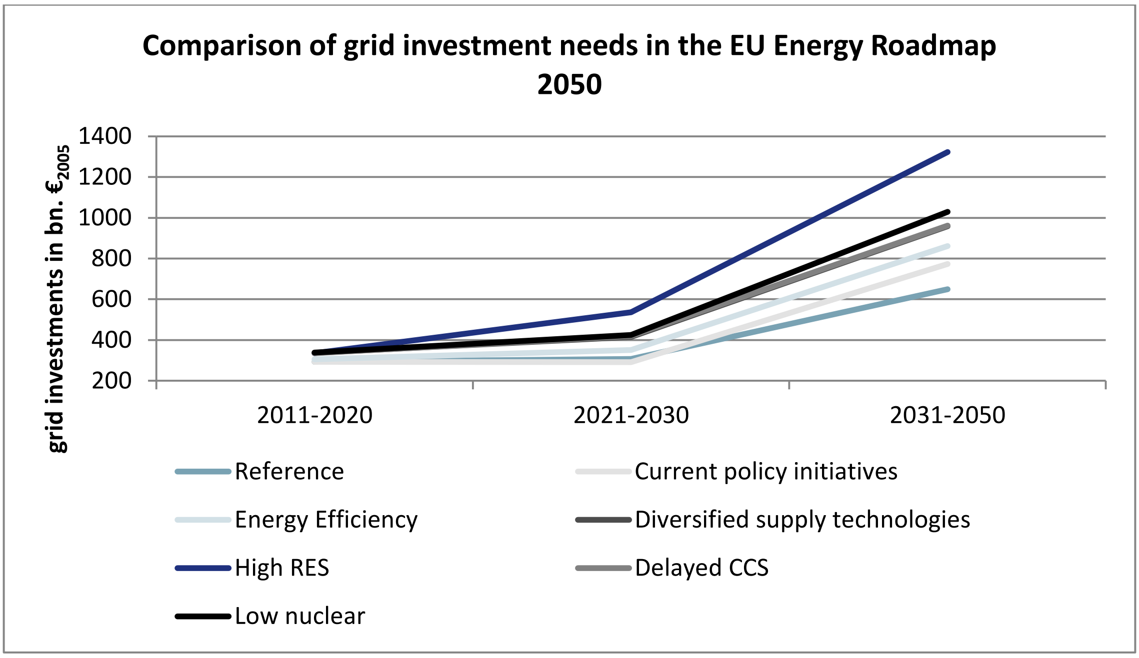
3.1 Transmission investment: high figures and high variance

The difficulty in assessing transmission investment is that it depends crucially on assumptions about the trajectory of the energy system development, the distribution between domestic investments and cross-border lines (called interconnectors), and the subjective assessment of transmission companies about the importance of certain lines. We shall highlight the breadth of estimates to illustrate the large uncertainty inherent in these figures.

3.1.1 Aggregate infrastructure needs by scenario

A detailed analysis of infrastructure investment needs is provided in the Energy Roadmap 2050 (EC 2011a). In particular, this modeling exercise produced a differentiation of investment needs by policy scenario: thus, the reference and the current policy initiative (CPI) scenarios yield the lowest investment requirements. The three traditional technology scenarios, i.e. “diversified supply technologies”, “delayed CCS”, and “low nuclear”, more or less converge with respect to infrastructure requirements, with slightly higher values in the “low nuclear” case with a higher CCS penetration. There is a clear infrastructure bias in the renewable scenario “RES”, with support measures leading to a 75 % share of RES in final energy consumption, and 97 % in electricity consumption. Starting from a similar level in the next decade (2011–2020), infrastructure requirements increase more rapidly in the subsequent decade (2021–2030), and then peak between 2031–2050, with € 1,323 bn. (see Figure **4**). Further decomposition of these figures is required to test the plausibility of the results, since they seem to be on the high side.

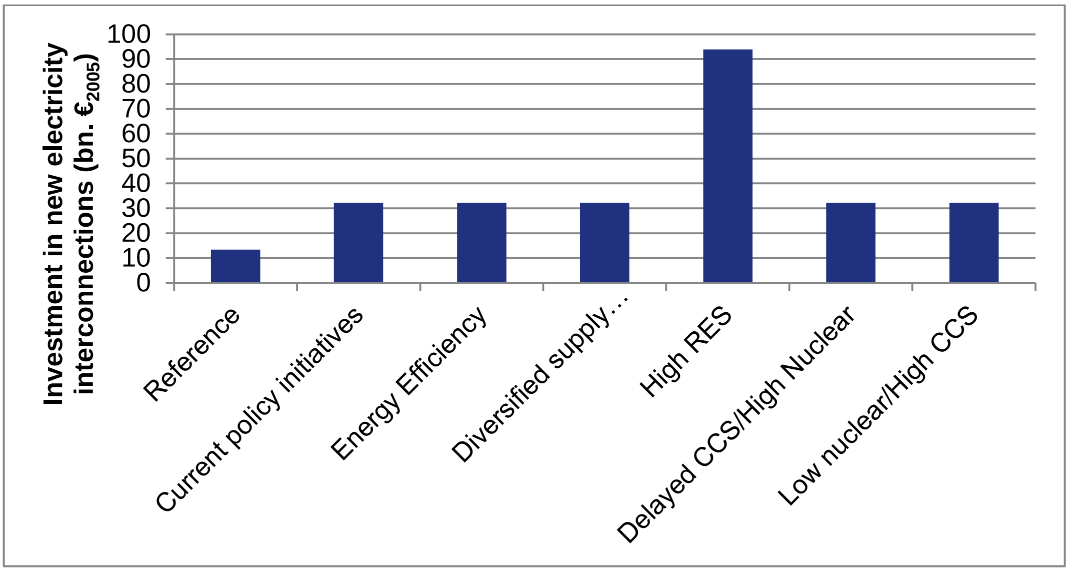
Figure 4: Comparison of grid investment needs in the EU Energy Roadmap 2050



Source: EC (2011c, p. 27)

Figure 5 presents estimates of investments in new electricity interconnections (i.e. cross-border lines) from 2006 to 2050. Once again, in the RES scenario the amount of investments needed is higher than in the other scenarios. This is caused by very high investment figures in 2031–2050 (€ 50.8 bn.), while in all other scenarios investments in new grid interconnections have fallen to almost zero. Comparing these figures to the total grid investments clearly shows a tendency towards grid reinforcement measures especially in 2031–2050.

Figure 5: Comparison of investment figures in new electricity interconnections to 2050

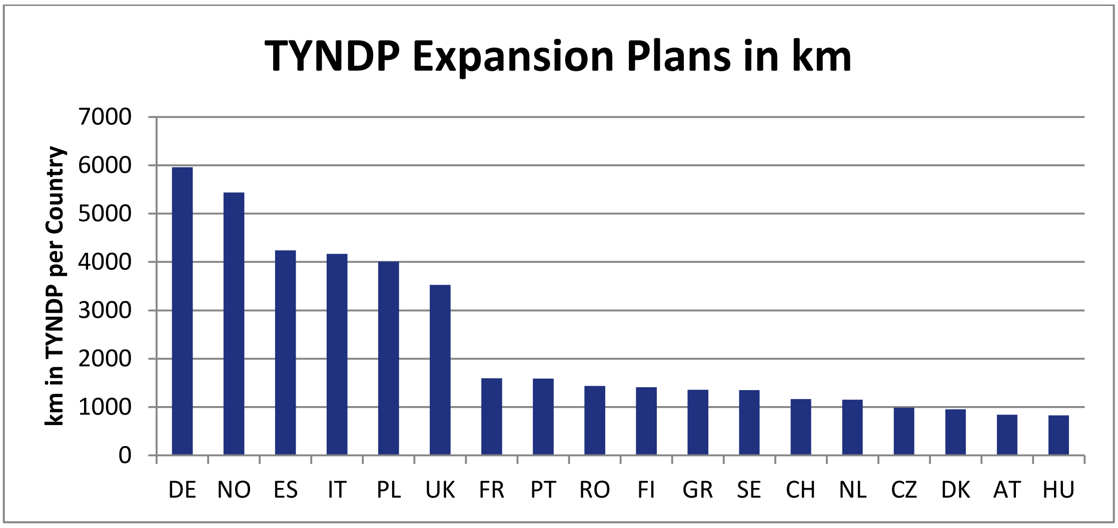


Source: EC (2011c, p. 28)

3.1.2 Investment needs expressed in line-kilometers and by degree of urgency

Additional insight is provided by the analysis of the physical transmission projects under development in Europe and the distinction most transmission companies make between "urgent" lines and others. Thus, the first Ten Year Network Development Plan (TYNDP) from the ENTSO-E, released in June 2010, gives an outlook over all grid development activities in the ENTSO-E region. It includes on a line-by-line basis all developing projects and lists "Projects of European significance". The amount of grid reinforcements varies by country, with Germany accounting for the highest potential needs with almost 6000 new built and reinforced kilometers according to the TYNDP. Figure 6 shows the sum of all grid expansion and reinforcement plans for most of the countries. Six countries (Germany, Norway, Spain, Italy, Poland and The United Kingdom) account for the majority of grid reinforcements (57 %).

Figure 6: TYNDP expansion plans in km for selected countries

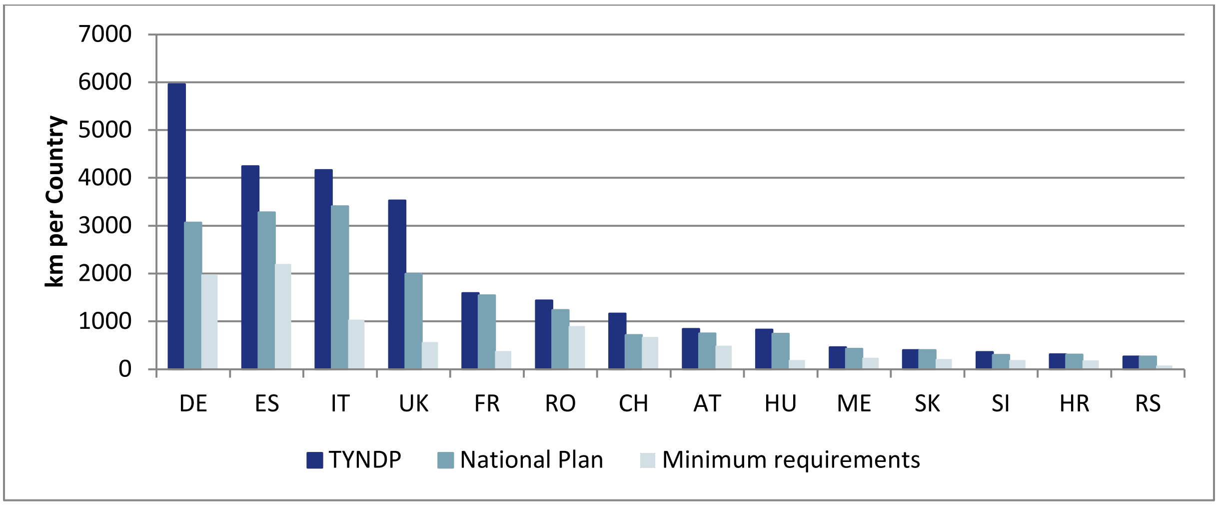


Source ENTSO-E (2010) Table of Projects, own depiction

Even more complicated is the differentiation of investment needs by the degree of urgency. It is rational that network operators try to schedule a maximum of investment projects, knowing that only a certain number of them will really make it to implementation within the envisaged time frame; thus the development plans should not be regarded as "must have" but rather they open up real options that the network operators and/or society may benefit from in the future.

A distinction can be made between this wish list and the minimum requirements that network planners define as unavoidable to maintain system stability. Somewhere in between one might situate "urgent" projects. Figure 7 shows the total transmission investments for the TYNDP (ENTSO-E 2010) as well as for selected countries. There seems to be a certain discrepancy between the national development plans and those projects recorded in the TYNDP.[2] Most interestingly, however, is the characterization of “minimum requirements” (as identified by ourselves based on information provided by the system operators). For the TYNDP as a whole, about 20 % of total investment plans seem to be “required”; this figure does not vary significantly amongst the major countries.

Figure 7: Comparison of TYNDP and national grid development plans of selected countries



Source: ENTSO-E (2010), own research

3.2 Generation investments dwarf transmission

A key finding of this study is that the real challenge of green investments lies in generation much more than in transmission. In the traditional analysis, where transmission investment is reduced to the costs of steel, cables, transformers, and a little bit of soft- and hardware (generally referred to as “production costs”), transmission is very cheap compared to the costs of generation or storage. Logically, optimization models put almost no limit to transmission investment, which becomes the grease of a continent-wide equalization of production costs. According to neoclassical economics, transmission expansion is optimal once the congestion revenue equals the long-run incremental costs, estimated sometimes as low as $ 4/MWh (Kirschen and Strbac 2004, p. 238). This is clearly way below the capital costs of generation.[3]

Hence the overall cost of transmission in total system costs is low. Taking ECF (2011) as a representative example for a comparative approach: transmission investment

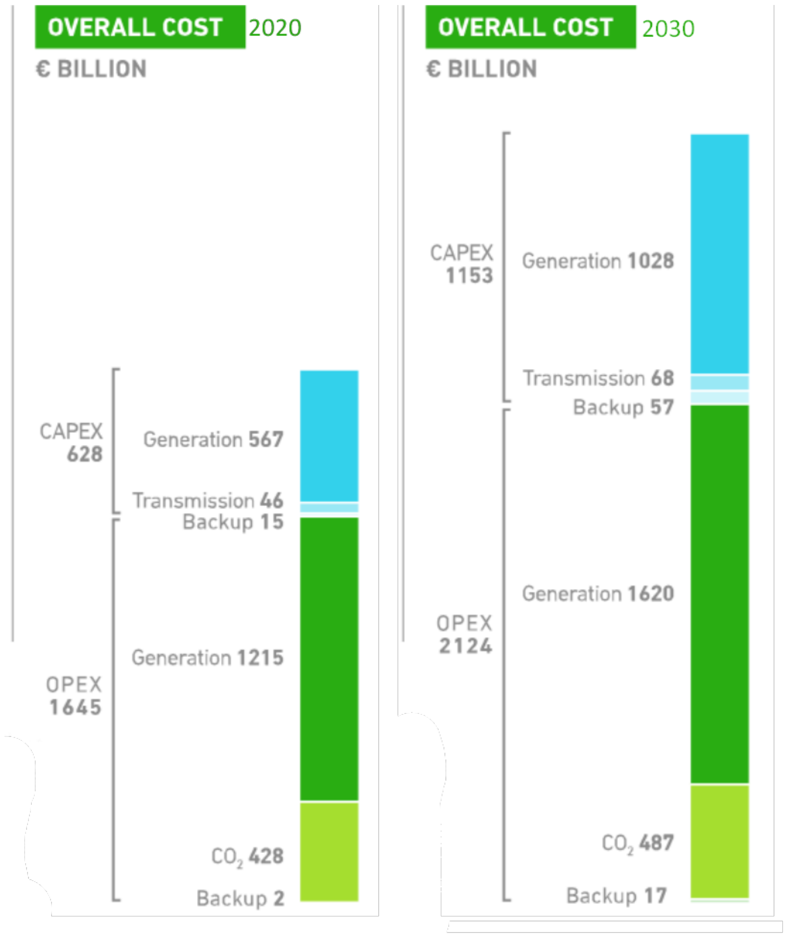
---

2 However, it should be taken into account, that the TYNDP is unlikely to be very different from a compilation of updated national plans including cross-border projects. This is mainly due to the fact that ENTSO-E resembles the respective national TSOs which would have only limited use of developing and posting different plans through different channels.

3 This perspective may change, though, when one takes into account transaction costs as well. A certain countervailing effect comes from a more realistic assessment of the real costs of transmission investments. In fact, total costs of any economic activity are comprised of the production costs, i.e. assembly and installation of lines, as well as the transaction costs, i.e. all operations having to do with the preparation, the implementation, and the ex-post observation of transmission siting. Whereas it is easy to quantify the former, the assessment of transaction costs, planning, negotiations, lawyers etc. is more difficult, and no hard quantitative evidence is available. However, given anecdotal evidence of some well-known projects of the recent past (e.g. Pyrenean-crossing, Wahle-Mecklar in Germany) suggests that transaction costs are likely to dwarf production costs by one to two dimensions. If this is the case, then the assessment of transmission infrastructure as the “cheap glue” of the energy system needs to be revised. However, this issue will not be further developed here.

(CAPEX) only amounts to a mere 6 % of overall costs, i.e. € 46 bn. / € 2,273 bn. by the year 2020, and € 68 bn. / € 3,277 bn. by 2030 (see Figure 8). This is in line with other estimates, e.g. the European Infrastructure Priorities (Impact Assessment, EC 2010b), which puts electricity transmission investments at € 142 bn., over total system costs of about € 1,000 bn. As laid out above, the Energy Roadmap 2050 (EC 2011a), too, estimates a similar relation, with the costs of interconnection (€ 60–90 bn.) out of a total of € 1,700–2,300 bn. system costs.

Figure 8: Share of transmission investment in overall energy system costs (2020 and 2030)



Source: ECF (2011, pp. 9,10)

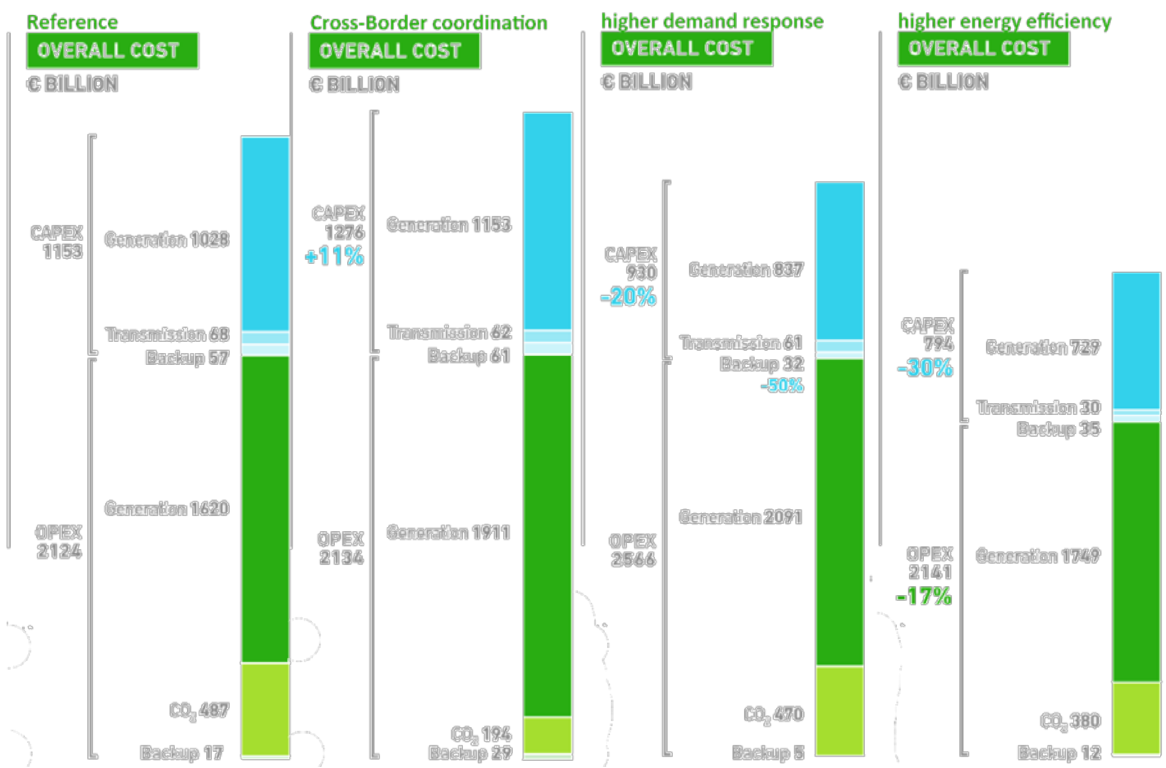
Additional variance is generated by development scenarios of the energy system focusing on different levers to achieve the decarbonization and the energy transformation. Referring once again to the ECF (2011) modeling exercise provides insights into the effects of different policy scenarios (see Figure 9):

- Better "cross border coordination" can reduce the need for transmission investment by 10 %, from € 68 bn. to € 62 bn. This is in line with other studies, e.g. Neuhoff et al. (2011), showing that a more intelligent use of the network can avoid costly expansion;

- The scenario "higher demand response" contributes equally to a reduction of transmission requirements, to € 61 bn., whereas the strongest impact is on backup capacity, e.g. of gas power plants, which are reduced by 50 %. The overall investment costs are decreased by 20 %;
- "Higher energy efficiency" has the strongest impact in more than halving transmission investments, down to € 30 bn.

Note that in all those scenarios the bar for generation dwarfs transmission investments. Clearly, it is more challenging to generate green electricity Europe-wide, than to transport it.

Figure 9: Transmission investment to 2030 in different energy system scenarios



Source: ECF (2011, pp. 10-13)

3.3 *Some case study evidence on interdependence*

This subsection highlights the uncertainty in quantifying future energy system architecture, and the investment levels related thereto. The case studies highlight the difference between development paths that all pursue the same objective, i.e. to increase the share of renewables according to the decarbonization strategy sketched out above under different institutional settings.

3.3.1 *North and Baltic Sea Grid: One objective, multiple pathways*

The North and Baltic Sea Grid (NBSG) is one of the largest pan-European infrastructure projects, developed to harness large amounts of renewable electricity, but also raising concerns about the implementation in largely nationally dominated regulatory regimes. Several studies have highlighted the technical potential and challenges and the financial needs of different realizations of “the” North and Baltic Sea Grid. In particular, there is a controversy about the timeline of choosing the grid design for the larger long-term structure in the region: should the grid be designed today with a view of an integrated market by 2050?, or should one pursue a decentral “step-by-step” approach dominated more by Member States‘ short-term preferences? The first approach would clearly hint towards a meshed grid, whereas the second approach would favour national and bilateral approaches.

In this context, two ways of tapping the “blue battery” exist, with quite different implications for investment strategies:

- In a centralized approach, Norway would be fully integrated into the Internal Energy Market (IEM), including its full integration into the European Infrastructure Priorities (EC 2010a), the North and Baltic Sea Offshore Grids, and a single European wholesale market. A meshed network between Norway, the UK, and the coastal European countries would lead to a wide integration of the respective electricity markets. This would increase total welfare of Norway as a whole, but it would also raise the price level in Norway substantially;
- In a regional approach (“trade” scenario) Norway could rent out its storage capacities to individual Member States, such as the Netherlands, the UK, or Germany, and engage into bilateral contracts with any of these countries, covering both the costs of transmission lines and a rent for using the storage. The regional approach would shield Norway from price effects of the interconnection, and it would assume supply security to the other partners, thus making capacity instruments even less necessary.

Egerer et al. (2012) provide a detailed scenario analysis of the technical-economic aspects of the North and Baltic Sea Grid. They discuss the two development paths for the North and Baltic Sea Grid, i.e. a (i) trade-oriented, bilateral scenario, versus the (ii) meshed grid, integrated scenario, and derive the implications of these designs for different types of stakeholders. One important effect of the choice of a development scenario, with particular relevance to financing the transmission lines, is the following: the congestion rents, that might be used to finance the transmission, diminish significantly with the introduction of tradelines, and even more so with the meshed architecture: In the Base 2009 (i.e. system as of 2009) scenario, the congestion rents in the North Sea lines sum up to about € 50 million per year, and for the Baltic Sea about € 30 million. However, these congestion rents vanish with the full realization of both, the “trade” and the “meshed” scenario. Except for the cable between Norway and the Netherlands (“NorNed”), none of the existing cables is able to finance itself.

3.3.2 Trade-off between location of generation and transmission in Germany

Besides challenges of reducing plant capacity, the investment challenge is also influenced by strategic location of future power plants might play an important role in the need for transmission expansion. A recent study by Boldt et al. (2012) shows the effect of transmission capacity needs for different generation scenarios in the year 2030 for

Germany. The study assumes a reference case, where 63 % of installed capacity in Germany is installed in northern Germany, while 62 % of demand occurs in the southern regions. This is a realistic estimate as potentials for wind energy are relatively high in Lower Saxony, Schleswig-Holstein and Mecklenburg-Western Pomerania. The demand concentration in the southern Germany corresponds to today's real demand and is unlikely to change significantly in the future. By contrast, a scenario "Strategic South" uses the same demand structure but strategically installs parts of the wind capacity as well as natural gas turbines close to the demand centers in southern.

The study then calculates the use of current and future transmission lines, and the congestion along individual lines. In the reference scenario, the study finds high congestion between the North-East and Thuringia-Bavaria, a corridor that plays a significant part in the transfer of renewable wind energy to the south as well as conventional generation mostly from lignite in the North-East. Congestion generally occurs more often in the direction North to South. The "Strategic South" scenario reduces congestion significantly, especially in the aforementioned Thuringia-Bavaria region. Also transfers of renewable capacities from the far north of Germany through lower Saxony do not lead to congestion anymore as the demand in the south can be covered locally most of the time.

The case study thus confirms the trade-off between generation and transmission investment, while it is not meant to make a normative judgment about which options might be preferable.

4. Outlook: three stylized scenarios for the green investment challenge

4.1 High uncertainty about future European development paths

What are the issues related to investment when looking ahead?

While the previous section mainly indicated uncertainty about level and structure of investment needs, there is additional uncertainty about the development of the energy system at large, be it the nature of generation (centralized vs. decentralized), transmission network architecture (Supergrid DC-backbone vs. gradual AC network extension), the trade-off between networks, storage, and demand-side management to deliver peak electricity, and the like. In addition, the regulatory framework is rapidly changing, too: on the one hand, attempts to integrate markets continue; on the other hand, there are recent national attempts to define national capacity instruments to assure national supply security (e.g. in the UK, France, Germany and Poland); and the installation of phase shifters at national borders to protect countries against electricity flows from abroad adds to the tendencies of re-nationalization of energy policies (Supponen 2011). Recent delays in the emergence of important projects of common interest such as the Norwegian interconnection with the North Sea Grid, or the EU-MENA connections, have indicated that urgent investment needs might be lower than generally assumed for the long term. Last but not least, the slow progress of existing transmission projects indicates that often capital availability is not the limiting factor for transmission expansion, but that other factors play a more important role, such as negotiations over the distribution of costs and benefits, planning, acceptance and implementation issues (Roland Berger 2011).

Indeed, when exploring the underlying reasons for variance, one aspect not sufficiently accounted for are the different geographical and institutional trajectories of how to reach the low-carbon targets. Indeed, all of the scenarios mentioned so far assume a perfectly integrated European-wide market (IEM), not only among the 27 EU-member countries, but also with close neighbours (e.g. Switzerland, Norway, North Africa). While this is one possible outcome, empirical indicators as well as lessons from other regions (U.S., Latin America) indicate that full integration may not occur even after decades of attempts. In Europe, too, one observes a certain national focus of energy security policies that is in contrast with the vision of the IEM, connected by "cheap" infrastructure.

Thus, in addition to the uncertainty elaborated until here, there is also great uncertainty about the future integration paths of the European electricity sector. Although one scenario, full integration, is the default expectation set out by the Third Energy Package, it may well be that decentral cooperation intensifies, too, and perhaps more rapidly and sustainably than the centralized solution. In addition, some Member States may also prefer to pursue their own, national approach to securing their energy supply and opt out from several European provisions, or not even decide to join in the first place (such is the case of the non-EU country Switzerland). Hence, instead of prescribing one optimal path towards full European integration of all electricity sub-markets, it seems appropriate to identify stylized scenarios as well as "no regret" investment strategies regarding transmission and generation investment.

Before addressing a perceived over- or underinvestment, we need to analyze the drivers for investment, and the role that transmission and generation play under different development scenarios. We therefore sketch three stylized development paths that differ both by the geographic scope of the level of coordination between generation and transmission investments and the contractual forms of these cooperations. Table 1 sketches the axes of the scenario-matrix: on the vertical axis, we distinguish the geographical scope, between a fully European-wide exchange of electricity, and a more regional focus; on the horizontal axis, we imagine whether coordinating institutions are in place at the European level, or not. Ignoring the upper right quadrant, we derive three stylized scenarios:

1) rapid completion of the internal energy market with a perfectly functioning, EU-wide market system and with European-wide energy superhighways (scenario "Europe centralized");

2) a more decentral integration of local or national energy markets, relying more on bi- or trilateral contracting, under the umbrella of some European framework (scenario "Regional+"); and

3) a decentral development with purely nationally focused policies of supply security, and the absence of further European harmonization (scenario "national approaches").

These are explored more in-depth in the following subsections.

Table 1: Matrix of stylized development scenarios

		European coordinating institutions …	
		… in place	… not in place
Geographic Scope …	… Europe-wide	1) "Europe centralized"	./.
	… Regional	2) "Regional +"	3) "National"

4.2 Scenario 1: European-wide energy superhighways ("Europe centralized")

In Scenario 1, Europe-wide energy superhighways with European coordination in place ("Europe centralized"), Europe-wide planning of generation and infrastructure dominates, and the institutions of coordination at a European level are in place. In a simplified way, one can consider that the competencies of infrastructure planning, investment coordination, and regulation move to the European level, such that the location of generating capacities and of transmission lines are optimized European-wide. In the extreme, infrastructures span from North Africa to Sweden and from Turkey to London. This vision clearly drives some of the infrastructure proposals discussed above to reach the 2050 targets, such as ECF et al. (2010) and Tröster, Kuwahata, Ackermann (2011). Energy superhighways are constructed irrespective of national borders, at a more rapid pace than previously realized, and abstracting from institutional obstacles present on site.

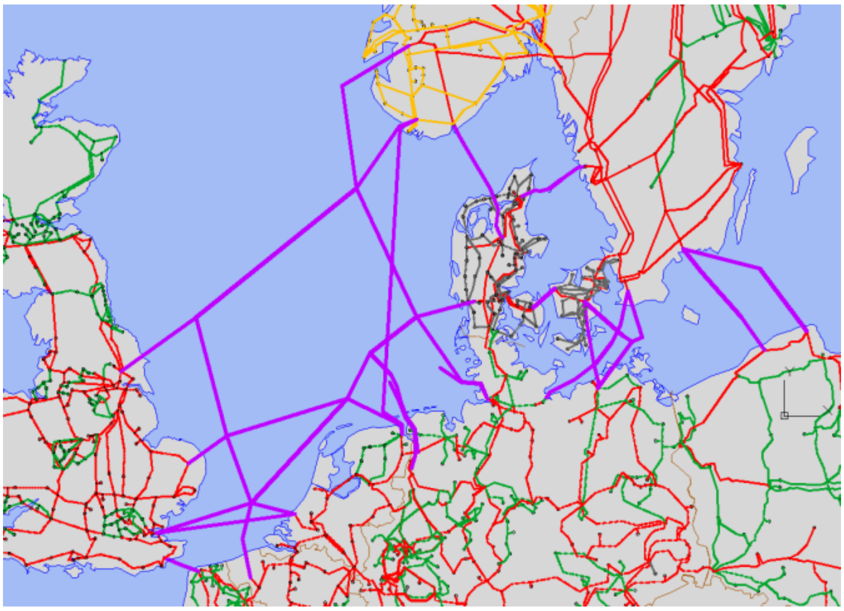
The "Europe centralized" scenario is grounded in neoclassical modeling and analysis, which assumes that infrastructure is very cheap when compared with electricity generation, thus leading to an easy solution to maximize overall European social welfare. Cost minimization is performed across countries, but also between generation and transmission. Non-EU countries, e.g. Switzerland and Norway, are treated as if they were fully integrated and adhered to EU legislation, such as the Internal Energy Market (IEM) rules, i.e. Directive 2009/72 (EC 2009a) and Regulation 714/2009 (EC 2009b, part of the "Third Legislative Package" or "Third Package" in short), as well as all forthcoming Framework Guidelines and Network Codes.

An extreme example of the "Europe centralized" approach is the connection of North Africa to the rest of Europe for the large-scale transfer of electricity, be it from solar, wind, or natural gas. Figure 10 shows the archetype backbone network, with lines spanning from Saudi-Arabia to the UK, and from Algeria to Norway. Another example is the North Sea Grid, as presented as a large-scale solution to the storage question (see Decker et al. 2011, Egerer et al. 2011), which is depicted in Figure 11.

Figure 10: Vision of the Desertec-Eumena Integration

Source: Desertec Foundation (2012)

Figure 11: Vision of the North and Baltic Sea Grid



Source: Egerer et al. (2011)

Two types of doubts are raised against the general euphoria towards pan-European electricity highways (sometimes called "Supergrids"): the ambitious expansion plans are in contradiction with the modest progress in realizing renewables-based high voltage lines; thus, pilot projects such as the North Sea Grid or the Mediterranean Electricity Grid (also called TransGreen, Desertec, etc.) are struggling to get off the ground. In many countries, even simple transmission projects are only advancing slowly.[4] Thus, while the "centralized" solution of pan-European electricity highways is the most promoted one, one should not discard the option of decentral, regional diffusion of renewable energies.

4.3 Scenario 2: Decentral approaches and contractual cooperation ("Regional+")

In Scenario 2 there are some coordinating institutions in place at the European level, but the focus of fulfilling the green objectives and investments lies at the regional level, i.e. between neighboring countries. We shall call this scenario "Regional+", in which Member States solve issues at a less central level, where the focus is more on cross-border cooperation than on pan-European connections. Member States remain the main decision-making authority, but they engage into contracts with neighboring countries, e.g. for expanding interconnector capacities to secure reliable supply. These transactions can either be governed by European-wide regulation, such as the Third Package with all its provisions, or by bi- or multilateral contracts struck between neighboring countries (such as the German cold start reserve contract with Austrian suppliers).

Note that this scenario is by no means incompatible with the objectives of the internal European market, i.e. creating a level playing field; however, Europe's role would be rather to provide a general framework for decentral contracting, e.g. for balancing reserves, as discussed in the Framework Guidelines; this may include special provisions for integrating non-EU countries as well. Drivers in favour of a more decentral scenario may be lower transaction costs of finding specific solutions to specific problems at the local level, e.g. capacity, stability, reactive power. Thus, problems of information asymmetry between the decision level and the local issues at stake may be reduced, flexibility be introduced in the solution space, and established forms of local cooperation be maintained and enhanced.

One aspect of the regional approach is also that it might accommodate relations with third countries more flexibly. For it should not be overlooked that three key players in the decarbonization of the European energy system are not EU-member countries: Norway, a key player in the North Sea Grid, and a potential "blue battery" for continental Europe; North Africa, a potential supplier of large volumes of solar electricity; last but not least, Switzerland in the core of the European electricity network. The recent history of infrastructure development is full of examples of regional coordination, and it seems to be the rule rather than the exception. In electricity, countries like France or Germany have developed transmission lines to Switzerland to secure regional optimization, a development that might be assumed to connect the "blue battery" of Scandinavia to continental Europe and the UK. In addition, the decentral level

[4] In the case of the North and Baltic Sea Grid, a look on interconnection projects between Norway and continental European countries may help aligning the idea of Europe-wide centralization of transmission expansion with current reality. Although the NorNed Cable between Norway and the Netherlands is in operation since 2008, a link connecting Norway and Germany which was already under conceptual planning in 2008 ("NorGer") project was struggling until 2012. One obstacle was the denied exemption from network regulation (Art 17, 714/2009, EC 2009b). However, only after political intervention from the German Federal Ministry of Economics and Technology (BMWi) in summer 2012, including a financial commitment, the project is now planned to be in operation in 2018. This illustrates the fact that national interests and national political support still play an important role.

might also be suited to react to the recent trend to create national capacity instruments that threaten the harmonization of the single market. Indeed, to prevent Member States from introducing national capacity markets, the widening of the national resource base through regional cooperation is a plausible alternative, whereas a European solution to the problem might be too far away.

4.4 Scenario 3: Individual approaches to solving supply security issues ("national")

In a further alternative, Scenario 3, the focus remains national, and there are no or only few additional European-wide coordinating mechanisms. Thus, one observes individual approaches to solving supply security issues with largely domestically driven energy policy. Supply security and transmission investments are treated from a national perspective, with domestic legislation decided largely independently of European strategic considerations. Due to electricity interconnection and some traditional trading relations, electricity trade with neighbouring countries continues to exist, but it is kept at a low level, or is even strategically manipulated, e.g. through phase shifters located at the borders. Effects by these policies on neighbours, be they positive or negative, are largely ignored.

Note that the description of the scenarios follows a purely positive approach, i.e. we do not imply any judgement neither on the favourability nor the probability of them. It can be expected that certain stakeholders would express priorities towards one or the other scenario: thus, countries moving rapidly towards domestically defined capacity instruments will tend to favour a national approach, whereas friends of Supergrids would rather see Scenario 1 implemented. While we are not blind towards the pros and cons that certain stakeholders will express vis-à-vis the scenarios, we limit our discussion to a positive description of the implications of the scenarios in terms of the nature and the volumes of the green investments, and the financing consequences thereof.

4.5 Implications for Financing

Financing issues can be structured according to two issues: one is the raising of capital between a variety of sources; the other is the allocation of cost, which might contribute to raising the money to cover infrastructure costs, though not necessarily. Here we focus on the first aspect, i.e. raising of capital, see THINK (2012) for a more detailed discussion. With respect to raising the financial means for investment, too, there is a need for a comprehensive approach that looks at both, transmission and generation.

With respect to transmission, there is a general consensus that financing is not the most difficult challenge, and there "is no indication that credit ratings will create serious financing problems for TSOs in Europe" (Roland Berger 2011, p. 5). Transmission is traditionally a regulated business, so that financing is generally assured through regulated user fees, the disputes between regulators and transmission system operators being reduced to the appropriate rate of return on capital. This does not mean that "money plays no role", but that the traditional financing of transmission lines is not a serious obstacle. Off course, improvements in the institutional framework can be achieved, both on the debt and the equity side. However, the real problems of getting regular transmission built are not financial, but obtaining building permits and regulatory issues. In addition, specific types of projects might require special intervention on financing, too, such as interconnectors, offshore grid connections, combined grid solutions, or security of supply projects (Roland Berger 2011, p. 7). The Roland Berger study (2011, p. 8) also suggests levers to improve the financing conditions for transmission projects, such as facilitating equity financing by removing institutional barriers and using grants and new equity funds structured on a targeted basis, enhancing debt financing conditions by adjusting EIB lending and giving TSOs better access to corporate bond markets, and introducing specific measures for particular types of projects, such as interconnectors, offshore grids, and security of supply projects.

By contrast, the financing of green investments in generation, as well as storage and demand-side management, is not only subject to higher risk, but in many cases low-carbon investments do not yet pay for themselves even under favourable conditions. In addition to the conventional ("dirty") investments in firm electricity, there are two different types of installations required to green the electricity sector in the European Union and the Member States: (i) Renewable generation capacities, which can be both firm (e.g. biomass, geothermal) and intermittent (e.g. wind, solar), and which still need some financial support to achieve the targets of the Energy Roadmap 2050 and the decarbonization objective; (ii) supply security-related capacities that are needed to provide system security in the case of rare, unexpected events. These go beyond the traditional analysis of primary, secondary, and tertiary reserve, for which market rules are already developed or are in the process of being established. Backup capacities consist of a combination of firm generation capacity, storage capacities, and demand-side capacities to reduce peak-demand. Therefore, the estimation of security-related capacities and instruments to finance them is a complex issue that nonetheless has a direct link to transmission: without firm transmission availability, backup capacities cannot be provided to the customers.

In addition to the differentiation between transmission and generation issues, there will be different channels for investment depending on the development scenario. The different energy system development scenarios have different implications for financing, and also for the role of different financial institutions therein: in a nutshell, while the "European central" scenario requires a strong role for planning and financing at the European level, the "national" decentral scenario puts more weight on national actors, Europe being limited to avoid lock-in effects from the national approaches. Thus, there is no doubt that the role of European institutions will be significant in scenario 1 ("Europe centralized"), whereas national public institutions will play a more important role in scenario 3 ("national").

5. Conclusions

This study has highlighted the specifics and challenges of green investment on the way towards a largely decarbonized European electricity sector by 2050, with a focus on the needs to be addressed in a perspective to 2050. Beyond the initial scope of this study, limited to "green transmission investment", we find that a combined assessment of transmission and generation is required to cope with the challenge of greening the system. Transmission is only green when it transports low-carbon energy, so that the choice of the generation mix, and its respective location, is intrinsically related to the need for high-voltage transmission.

Furthermore, we find that green investment will strongly depend upon the type of development scenario to reach the decarbonization objectives. Indeed, rather than to focus on one first-best trajectory, experience from other regions, and recent events in Europe indicate that different development scenarios should be envisaged, and the implications for financing resulting thereof be discussed and compared. We also find that any investment strategy will depend upon the trajectory of the overall energy system. Thus, in a “Europe centralized” scenario, there is ample room for pan-European electricity networks, which become less relevant in a “national approaches” scenario. Any financing strategy, too, will first have to analyze the implications of these three different scenarios on the financing of green electricity sector investment in Europe. We find that the issue at stake is not over- or underinvestment in the European electricity sector as such, but that different development paths have different implications for generation and transmission infrastructure, and for the financing thereof. In that context, a positive, differentiated analysis seems more appropriate than a normative request for more investment as such. Finally, the investment needs must be assessed in the light of the political and institutional scenario that is expected to occur.

References

Boldt, Jenny, Lisa Hankel, Lilian Charlotte Laurisch, Felix Lutterbeck, Pao-Yu Oei, Aram Sander, Andreas Schröder, Helena Schweter, Philipp Sommer, Jasmin Sulerz (2012): The Integration of Renewable Energies into the German Transmission Grid – A Scenario Comparison. Electricity Markets Working Papers, WP-EM-48a.

Decker, Jan De and Achim Woyte (2010): D4.2 - Four Offshore Grid Scenarios for the North and Baltic Sea. http://www.offshoregrid.eu/images/pdf/pr_pr100978_d4%202_20100728_final_secured.pdf.

Desertec Foundation (2012): Sketch of possible infrastructure for a sustainable supply of power to Europe, the Middle East and North Africa. Internet: http://www.desertec.org/fileadmin/downloads/press/DESERTEC-Map.zip.

EC (2009a): Directive 2009/72/EC 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

EC (2009b): Regulation 714/2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation 1228/2003.

EC (2010a): Energy Infrastructure Priorities for 2020 and Beyond – A Blueprint for an Integrated European Energy Network. Communication COM(2010) 677/4, Brussels.

EC (2010b): Impact Assessment: Energy Infrastructure Priorities for 2020 and Beyond – A Blueprint for an Integrated European Energy Network. Commission Staff Working Document, SEC(2010) 1395 final. Brussels.

EC (2011a): A Roadmap for moving to a competitive low carbon economy in 2050. Internet: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0112:FIN:EN:PDF.

EC (2011b): Commission Staff Working Paper – Energy infrastructure investment needs and financing requirements. SEC(2011) 755 final.

EC (2011c): Commission Staff Working Paper – Impact Assessment Accompanying the document Energy Roadmap 2050. Part 2/2. SEC(2011) 1565.

ECF (2011) Power Perspectives 2030 – On the road to a decarbonised power sector in Europe (ECF). Brussels http://www.roadmap2050.eu/attachments/files/PowerPerspectives2030_LaunchPresentation.pdf. Accessed 11 February 2012.

ECF (European Climate Foundation), McKinsey & Company, KEMA, The Energy Futures Lab at Imperial College London, Oxford Economics (2010): Roadmap 2050: A practical guide to prosperous and low-carbon Europe. Vol.1: Technical and Economic Analysis. Available at: http://www.roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf. Accessed 21 December 2011.

Egerer, Jonas, Christian von Hirschhausen and Friedrich Kunz (2011): The North Sea Grid – Technical and Socioeconomic Analysis with a Focus on Welfare Effects. Electricity Markets Working Paper WP-EM-47.

ENTSO-E (2010): Ten-year network development plan 2010–2020. Brussels.

Hirschhausen, Christian von, Johannes Herold and Pao-Yu Oei (2012): How a "Low Carbon" Innovation Can Fail - Tales from a "Lost Decade" for Carbon Capture, Transport, and Sequestration (CCTS). Economics of Energy and Environmental Policy (EEEP), Vol. 1, No. 2 (March 2012).

Kirschen, Daniel and Goran Strbac (2004): Fundamentals of Power System Economics, Wiley; 1 edition (May 31, 2004).

Neuhoff, Karsten, Rodney Boyd, Thilo Grau, Julian Barquín, Francisco Echavarren, Janusz Bialek, Chris Dent et al. (2011): Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity. Electricity Markets Working Paper WP-EM-43.

Olmos, L. and I.J. Pérez-Arriaga (2009): A comprehensive approach for computation and implementation of efficient electricity transmission network charges. MIT CEEPR Working Paper 09-010. Also published in an adapted version in Energy Policy, Vol. 37, No. 12, pp. 5285–5295.

Roland Berger (2011): The structuring and financing of energy infrastructure projects, financing gaps and recommendations regarding the new TEN-E financial instrument Tender No. ENER/B1/441-2010. Brussels, Final report to the European Commission, Directorate-General for Energy (July 31, 2011)

Rosellón, Juan, Ingo Vogelsang, and Hannes Weigt (2011): Long-run Cost Functions for Electricity Transmission. Energy Journal, Volume 33, Number 1.

Schröder, Andreas, Maximilian Bracke, Clemens Gerbaulet, Roman Mendelevitch, Christian von Hirschhausen (2012): Current and Prospective Costs for Electricity Generation. mimeo

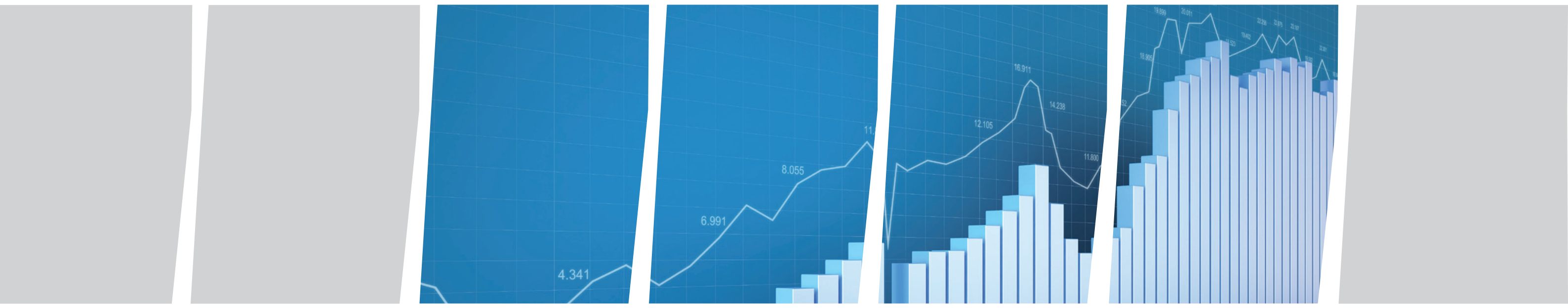
Supponen, Matti (2011): Influence of national and company interests on European Electricity Transmission Investments. Dissertation, Espoo (Finland).

THINK (2012): EU involvement in electricity and natural gas transmission grid tarification. Final Report THINK Topic n° 6. Project leader: Christian von Hirschhausen; research team: Sophia Ruester, Claudio Marcantonini, Xian He, Jonas Egerer, Jean-Michel Glachant.

Tröster, Eckehard, Rena Kuwahata, and Thomas Ackermann (2011): European Grid Study 2030/2050. Brussels/Langen, Study Commissioned by Greenpeace International.

European Investment Bank

The EU bank



Contacts

For general information:

Information Desk
Corporate Responsibility and
Communication Department
(+352) 43 79 - 22000
(+352) 43 79 - 62000
info@eib.org

European Investment Bank
98 -100, boulevard Konrad Adenauer
L-2950 Luxembourg
(+352) 43 79 - 1
(+352) 43 77 04
www.eib.org/economics