Cost of Non-Europe
in the Single Market for Energy

ANNEX III

Modern and extended European energy infrastructure, to meet the Union's energy policy objectives of competitiveness, sustainability and security of supply

Research paper
by Georg Zachmann

Abstract

In this paper we show that market integration in the European Union can reduce the cost of electricity. First, through various case studies, we indicate that competition and integration in the different electricity market segments have led to substantial cost savings. Second, we show that increasing interconnections between countries reduce the cost of producing electricity. This effect is particularly important when countries can re-optimise their power plant park within the joint system and when high shares of renewables require substantial back-up capacities. Furthermore, connecting countries with strongly differing profiles of renewable energy feed-in is exceptionally beneficial. And third, we demonstrate that the value of interconnections have started to increase again. The full benefits of the internal market can only be reaped with an appropriate market design and an appropriate infrastructure.

To create a stable investable single energy market, a common vision for a consistent European market design needs to be developed.
AUTHOR
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Introduction

Enabling seamless cross-border trade in energy will help to deliver on all three European energy policy targets – security, sustainability and competitiveness. Security would be increased because local supply shortages can be addressed by importing energy from elsewhere. A larger-than-national market allows competition between national energy companies, leading to increases in efficiency and reductions in prices. Finally, in a European market, intermittent supply of energy from local renewable sources can be reliably averaged across wide geographic areas, reducing the need for (and thus costs of) back-up capacity and system-stabilising services. However, if physical and administrative barriers to cross-border trade remain, the cost of energy to the European economy will increase, and security of supply will be undermined.

Based on this logic, the European Union has been striving for more than 20 years to establish an internal energy market by taking steps to remove remaining physical and administrative barriers. Harmonised technical rules should enable the seamless trade in energy between all member states. A European framework should set the conditions for the provisioning of sufficient physical transmission capacity. The target has been made concrete. The Conclusions of the European Council of 4 February 2011 set a deadline of 2014 for the internal energy market to be completed. But both the legal framework and the physical transmission capacity entail major technical and economic challenges.

This report describes the merits of a European energy market, but also the obstacles and the current approach to overcoming them. Notwithstanding existing efforts, we argue that the vision needed for a truly European energy market is lacking. A bolder blueprint is required to overcome the physical and administrative barriers to cross-border trade in electricity. We conclude by proposing such a blueprint.

In the first part, we provide an illustrative quantification of the cost of non-Europe in the electricity market. Based on the empirical literature on market integration and competition we conclude that moving away from a patchwork of purely national systems allows substantial efficiency improvements. We include, for example, inefficiencies resulting from the absence of cross-border reserve sharing, competition, cross-border demand/supply stack smoothing and cross-border balancing. These results are then extrapolated to the European situation to illustrate the potential order of magnitude.

Based on a simplified model we also quantify the corresponding cost in terms of inefficiencies related to investment decisions and operations. We find that the cost of non-Europe increase with the share of renewables; that integration is most valuable when the involved countries re-optimise their power plant park to fit in the joint system and that coupling markets with less correlated renewable production provides the largest benefits.

Based on the prices paid for using cross-border transmission capacity we conclude that the value of interconnection has increased between 2012 and 2013 by 12 per cent.
The analysis will then describe the state of affairs by outlining the special role of regulation and coordination in energy markets. That is, it will answer the question “Why does the single market not self-organise?” To do this we briefly introduce the most important features of the energy sector that complicate the development of an internal market for energy. To give one example, the natural monopoly characteristics of energy networks require their tariffs to be regulated, which ultimately requires (national) public authorities to create incentives for network extensions.

Based on this, we explain that a functioning internal market requires both compatible national energy market designs and sufficient physical infrastructure. On market design, we highlight the most important aspects. Based on a survey of the relevant recent studies (e.g. EIB, OECD, European Commission, ECF, ENTSO-E) and the academic literature (e.g. Hirschhausen et al, 2012) we analyse the infrastructure requirement under different assumptions. This comparison allows us to identify drivers for different infrastructure requirement expectations.

Finally we outline a purely techno-economic first-best solution. We will argue that institutional constraints will prevent the implementation of a first-best system. We therefore conclude by sketching out the elements of a feasible solution to deliver on Europe’s energy policy objectives that takes these constraints into account.

1. EU energy policy targets: security of supply, sustainability, competitiveness

EU energy policy strives to deliver on the “magic triangle” consisting of security, sustainability and competitiveness of energy supplies. In the context of network infrastructure security has two main dimensions. The external dimension consists of providing sufficient infrastructure to ensure that Europe can reliably acquire its energy needs. In order to prevent import disruptions (in particular for natural gas) and to reduce the price setting power of the foreign suppliers Europe is committed to build and maintain a diversified portfolio of physical import channels (pipelines, LNG terminals). The internal dimension of network security entails the ability to safely deliver energy to where it is needed. In terms of electricity this involves mainly the stability of the electricity system with respect to individual incidents2 – but also the minimisation of local supply disruptions3. For natural gas, the internal network security also entails to provide

---

2 For example the n-1 criterion foresees that the electricity system should be able to withstand the failure of whatever individual component, i.e., no individual component should alone be systemic.

3 Completely preventing supply disruptions is not economically sensible as the cost of the over-redundancies needed to achieve the target far exceed the cost of minor disruptions. National and
a strong internal network that is able to largely compensate regional supply disruptions caused by the cutting-off of specific external supplies.

**Sustainability** in terms of network infrastructure is more difficult to define. One dimension is to provide the network needed for the integration of sustainable energy sources, in particular renewables. This is a challenge as some of these newly developed sources will be in sparsely connected regions. In addition, the intermittent nature of renewable electricity sources such as solar and wind requires energy exchanges over wide areas to efficiently balance regional shortages.

**Figure 1: More renewables and higher reserve margins**

Source: own calculations based on IEA data

Note: there are two main reasons for the coincidence of high reserve margins and high shares of renewables: (1) building up renewables typically happens outside the market and thus might lead to overcapacities that are only reduced over time (2) renewables cannot ensure to provide their maximum capacity at the time of peak-load, hence more capacity needs to be installed.

In terms of **competitiveness**, network infrastructure has to maintain a trade-off. Network infrastructure has economic cost that have to be borne by energy consumers. However, network infrastructure also enables saving cost by allowing accessing the cheapest energy sources.

individual preferences for the security-vs-cost trade-off differ.
2. The cost of Non-Europe

In a world without transaction cost more centralisation always increases efficiency. Any “union” of countries faces essentially a trade-off between two opposite forces: the economies of scale that can be achieved by enlarging the market, and the heterogeneity of preferences among the participants to the integrated area. Scale economies foster the creation of larger and larger markets, while the costs of mediation among different needs prevent unions to grow too large. Now, the larger the number or the more heterogeneous the countries’ preferences, the more likely it is that the transaction costs of mediation outweigh the benefits achievable through the integrated market⁴.

This also holds for the energy sector, where on the one hand preferences, resource allocation and historic path dependencies resulted in very heterogeneous energy systems. On the other hand efficiencies from cooperation in energy sectors are substantial.

There are efficiencies from the cross-border coordination of the use of existing assets (static efficiency) and efficiencies from the cross-border coordinated development of the asset structure (dynamic efficiency). One example for static efficiencies is the monetary gain from replacing, at a given hour, electricity produced in an expensive gas turbine at one side of the border by electricity produced by wind turbines on the other side of the border. Dynamic efficiency would arise from building only one gas turbine to balance both systems instead of two turbines at each side of the border. In this section we will present wide evidence on the benefits of integration base on historic evidence, a literature survey, a simulation exercise and recent data on cross-border trade.

2.1. Many benefits of integration have already been reaped

<table>
<thead>
<tr>
<th>Key findings</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Due to the substantial benefits, significant integration of electricity markets already happened long before the EU was created.</td>
</tr>
<tr>
<td>• Removing remaining barriers is likely to provide additional benefits.</td>
</tr>
</tbody>
</table>

European energy market integration is a continuous process that reaches back almost a century. Already in a dry winter following a hot summer in 1921-’22 the decrease of hydroelectric production in Italy was partly compensated by imports from Switzerland that were made available as France exported electricity from coal-fired plants to Switzerland.⁵ Due to the large potential gains, cross-border electricity trade continued through-out the protectionist interwar period.

⁴ Altomonte and Nava (2006).
Table 1: Cross-border lines in North-Western Europe in 1949

<table>
<thead>
<tr>
<th>From/To</th>
<th>AT</th>
<th>BE</th>
<th>DK</th>
<th>FR</th>
<th>NL</th>
<th>NO</th>
<th>CH</th>
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<tbody>
<tr>
<td>FR</td>
<td></td>
<td>1x65kV</td>
<td>1x70kV</td>
<td></td>
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<td></td>
<td>2x60kV</td>
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<td>IT</td>
<td>1x130kV</td>
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<td>1x70kV</td>
<td>1x150kV</td>
<td></td>
<td></td>
<td>1x130kV</td>
</tr>
<tr>
<td>NL</td>
<td></td>
<td>1x220kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SE</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>1x80kV</td>
</tr>
<tr>
<td>DE</td>
<td>2x220kV</td>
<td>9x110kV</td>
<td>1x220kV</td>
<td>1x110kV</td>
<td>1x150kV</td>
<td>2x220kV</td>
<td>3x110kV</td>
</tr>
</tbody>
</table>

Source: OEEC, Interconnected 52-55 quoted from Lagendijk (2008)

Table 2: Cross-border lines in North-Western Europe in 2011

<table>
<thead>
<tr>
<th>From/To</th>
<th>AT</th>
<th>BE</th>
<th>DK</th>
<th>FR</th>
<th>NL</th>
<th>NO</th>
<th>CH</th>
</tr>
</thead>
<tbody>
<tr>
<td>FR</td>
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<td>1x110kV</td>
<td>1x220kV</td>
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</tr>
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<td>IT</td>
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<td>1x220kV</td>
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<td></td>
<td>1x110kV</td>
</tr>
<tr>
<td>NL</td>
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<td>4x380kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
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<td></td>
<td>2x110kV</td>
<td>2x380kV</td>
<td></td>
<td></td>
<td>2x110kV</td>
<td>1x220kV</td>
</tr>
<tr>
<td>DE</td>
<td>20x110kV</td>
<td>11x220kV</td>
<td>2x380kV</td>
<td>1x110kV</td>
<td>2x220kV</td>
<td>3x380kV</td>
<td>6x380kV</td>
</tr>
</tbody>
</table>

Source: ENTSO-E Statistical Yearbook 2011

Before the war most lines were intended to pool resources by connecting very different systems. One striking example is the connections between France and Switzerland that served to bring electricity generated from French thermal plants to Switzerland during off-peak hours in return for electricity produced in flexible Swiss hydro-plants during peak hours (same for Germany and Austria). These transactions allowed both countries to maintain complementary fuel mixes and were commercially beneficial to both sides. During and after WWII the energy sectors in most European countries became owned or at least largely controlled by their respective governments. Since the 1950s, cooperation between national energy sectors in Europe (within the two political blocks) was strengthened. Both blocks went from individually controlled cross-border lines to

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6 Examples are the nationalisation in the UK in 1947 and in France in 1946, the Energiewirtschaftsgesetz of 1935 in Germany that created regional monopolies and the 1946 decision in Sweden to give the state-owned Vattenfall a monopoly in the national grid. (see Heddenhausen, M. (2007))

7 Even joint ownership of high-voltage power-lines was proposed in 1947, but renounced by
synchronise their respective joint systems. In the West synchronisation – that is that national systems form a large pool with a joint frequency - happened in 1957. In 1959 the exchange of electricity - that was strongly regulated since the protectionist interwar period – became liberalised allowing national energy companies to more flexibly engage in corresponding transactions. The primary target of this removal of physical and administrative barriers more than 50 years ago was to increase security of supply by allowing imports/exports on short notice. Significant investments in a strong and internationally meshed high-voltage network (see Table 1 and Table 2) allowed increasing electricity exchanges between countries (see Figure 2). Interestingly, between 1949 and 2011 the relative strength of bilateral connections was largely maintained and only one unconnected country-pair (DE-DK) was connected.

The structure of national monopolies exchanging electricity on a bilateral basis continued until the early 1990s. By then it became apparent that integrated monopolies were not sufficiently incentivised to cut cost and improve service quality. In international electricity trade for example, it was by no means ensured that the dispatch in the joint network was minimising cost. Even though most integrated companies tried to only switch-on the cheapest plants in their respective country required to meet demand, cheaper plants in neighbouring countries often remained idle because optimisation was a national matter.

Figure 2: International trade (imports plus exports) over production

Sources: IEA Electricity Information 2001, 2005, 2011; Eurostat, World Bank, Lagendijk

Note: West - Austria Belgium France Luxembourg Netherlands; East - Czech Republic Estonia Hungary Poland Romania Slovak Republic Slovenia; South - Greece Italy Portugal Spain; North - Denmark Finland Norway Sweden; British Islands - United Kingdom Ireland

member states (Lagendijk 2008, p130f).
To overcome corresponding inefficiencies the European Union initiated a large project of liberalising and integrating the European electricity market. This project consisted of regulating the network business and establishing competition between generators within and between countries. As a result, electricity started to more regularly flow from low cost countries to high cost countries leading to increasing and more volatile net trading positions (see Figure 3). Currently, the European Union is engaged to finalise this project of integrating the energy wholesale markets. By 2014, a framework for completing market integration should be put in place.

![Figure 3: Annual net exports by selected countries](image)

Sources: IEA Electricity Information 2001, 2005, 2011; Eurostat, World Bank, Lagendijk

To sum up we conclude that electricity market integration in Europe has been a continuous process. A European dimension to the electricity sector existed long before the European Union with its single market project or even the European Communities. This on the one hand confirms the huge benefits of cross-border cooperation in the electricity sector. It on the other hand also indicates that important benefits were reaped long before the European Union was created. The question to be addressed in this report shall hence not be what the cost of non-cooperation is, but which benefits could be reaped by deepening cooperation even further.

2.2. Literature Survey

**Key findings**
- There are numerous well-identified benefits of integration and competition.
The single market for energy has numerous benefits. They could broadly be characterised as benefits of using markets for allocation ("competition") and benefits of integrating systems ("integration"). Competition and integration can improve the use of existing assets ("static") and/or investment decisions ("dynamic"). Numerous studies demonstrated corresponding effects empirically.

**Table 3: Categorisation of benefits**

<table>
<thead>
<tr>
<th></th>
<th>Static</th>
<th>Dynamic</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Competition</strong></td>
<td>- Reduced mark-ups</td>
<td>- Less investment withholding</td>
</tr>
<tr>
<td></td>
<td>- Improved operation</td>
<td>- Improved investment decisions</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Integration</strong></td>
<td>- Cross-border optimisation of operation</td>
<td>- Cross-border optimisation of investment decisions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Cross-border optimisation of company structures (M&amp;A)</td>
</tr>
</tbody>
</table>

But the two effects of competition and integration cannot be easily analysed in isolation. Competition is impossible in small energy systems as there are significant effects of scale and scope in energy companies. Consequently, in small systems only one or two companies might have an optimal size – reducing the scope for competition markedly. On the other hand, integrating systems that feature a non-market based allocation of goods is difficult as the value of the exchanged service cannot be easily determined. But in which direction should electricity, for example, be traded if it is unclear on which side of the border it is more valuable. Hence, competition and integration are largely intertwined.

**Benefits from integration**

Basically, efficiencies in electricity trade can inter alia arise from the benefits of exchanging differences in resource endowments in different countries (trading intermittent-vs.-hydro resources), the possibility to maintain more diversified portfolios of power-plants in larger areas and the reduced need for reserves in larger zones (reserve need for thermal units increases with the square root of total capacity).

A number of empirical studies find a positive relation between integration and productive efficiency. Bergman (2003), for instance, uses the creation of a single Nordic market for electricity as a case study to illustrate that competition induces substantial productivity increases in the power industry. This is mainly suggested by the fact that since 1996 the production of electricity in Sweden has increased by more than 15%, while generation capacity has been slightly reduced. Moreover, in connection with the restructuring of the network and retailing segments of the industry, personnel and other costs have been heavily reduced.
In the recent past numerous studies analysed the effects of integration on the different segments of the electricity market:

- Gerbauleta et al. (2012) investigate four scenarios of different tertiary reserve market cooperation (currently purely nationally organised in Germany). Results are pointing towards lower overall system costs by about 10% in the case of one unified tertiary reserve market called "Geralpina" (German, Swiss and Austrian markets), which is preferable over all possible bilateral coalitions.

- Haucap et al. (2012) analyse the German reserve power market, which was subject to important regulatory changes in recent years. The aim of the paper is to understand whether or not the reforms led to lower prices for minute reserve power (MRP)\(^8\) and they find that the reforms were jointly successful in decreasing MRP prices, leading to substantial cost savings for the transmission system operators.

- Abbasy et al. (2009) find that integration of different balancing regions has a potential to reduce the costs of balancing within multinational power markets. The total annual balancing cost before regulating power market integration is about EUR 180 million per year (corresponding to no interconnection available), and drops down below EUR 100 million per year when 10% of interconnection capacity is available for balancing. This means a balancing cost reduction of about EUR 80 million per year.

- Mansur and White (2008) indicate that employing a more centralised market design – that is only possible in unified trading areas - substantially improved overall market efficiency, and that these efficiency gains far exceeded implementation costs. Indeed, they find that adopting the organized market design in this region produced efficiency gains of over USD 160 million annually, substantially exceeding the (one-time) USD 40 million implementation cost. These efficiency gains arise from supply-side allocative efficiency improvements and from superior information aggregation about congestion externalities, enabling the organized market to support greater trade.

**Benefits from competition**

Extending the national market to an international market reduces the market power of individual players. As displayed in Figure 4 the concentration of the generation sector in France drops drastically when it forms a joint market with its neighbours. Full integration could essentially lead to an unconcentrated market.

\(^8\) Two types of MRP have to be distinguished: incremental (positive) reserve power and decremental (negative) reserve power. While the former is used when the demand for electricity exceeds the supply of electricity, the latter is needed when more electricity is generated than consumed.
More competition does in theory lead to increasing production and lower prices as well as incentives for more efficient operation and investment. Hence social welfare increases because less market power is exercised (lower mark-ups on prices) and costs are controlled more aggressively.

The results of Zarnic (2010) indicate that the mark-ups have declined due to EU-wide liberalization efforts, but the mark-up premium of incumbent firms is on average larger than theoretical models would predict under effective economic integration. The average price-cost margin is estimated at almost 45% for the largest consolidated firms, but it has declined due to EU-wide liberalization efforts in the order of 2% each year from 2003 onwards for those firms. The results show that price-cost margins are negatively associated with better functioning of wholesale and retail markets, but better market access has not led to competitive market outcomes due to prevailing market concentration and insufficient unbundling of transmission and distribution channels. The estimation suggests that an increase in market concentration of 10 percentage points is equivalent to an increase in the average price-cost margin of 0.7%.

Several empirical studies focus on the efficiencies brought about by increasing competition in energy markets. These efficiencies are realized mainly through a better
usage of inputs, such as labour, and through strong cost reductions. Shanefelter (2008) considers improvements in productive efficiency that can result from a movement from a regulated framework to one that allows for market-based incentives for industry participants. She finds that merchant owners of divested generation assets employ significantly fewer people, but that the payroll per employee is not significantly different from what workers at utility owned plants are paid. As a result, the new merchant owners of these plants have significantly lower aggregate payroll expenses. Decomposing the effect into a merchant effect and a divestiture effect, she finds that merchant ownership is the primary driver of these results. Similarly, Fabrizio, Rose and Wolfram (2007) adopt the agency model for their study and this suggests that firms may not minimize costs in less competitive or regulated environments. The study finds that the division of the utility company faced with competition, i.e. the generating sector, responded with a decrease in costs, while other sectors and companies not faced with competition did not share this response. The results suggest statistically and economically significant declines in input use associated with regulatory restructuring. The results suggest modest medium-term efficiency benefits from replacing regulated monopoly with a market-based industry structure.

However this efficiency enhancement also affects capital usage; Davis and Wolfram (2012) argue that deregulation and consolidation are associated with a 10% increase in operating efficiency, achieved primarily by reducing the frequency and duration of nuclear reactor outages. At average wholesale prices the value of this increased efficiency is approximately USD 2.5 billion annually for the 103 US reactors. Ten years before, Hiebert (2002) also found evidence that plant efficiencies are associated with capacity utilization of the plant and also with the number of plants under utility management. He also found that regulatory restructuring activity in certain US states is associated with improvements in plant operating performance. Nevertheless, this productivity improvement does not affect all types of firms in the same way. Zarnic (2010) finds that productivity gains of European electricity firms deriving from reforms implemented in the last decade are associated with high-productivity firms close to the technology frontier (i.e. firms able to transform inputs to outputs efficiently), while no significant impact is found for the laggards (i.e. firms which still need technological catch-up). Similarly, not all kind of reforms are likely to produce efficiencies. Knittel (2002) argues that programs tied directly to generator performance and those that modify traditional fuel cost pass-through programs are associated with greater efficiency levels. For example, among the former, there are direct efficiency reward programs, such as heat-rate programs, providing incentive to reduce heat rate of generation facilities, and Equivalent Availability Factor, increasing the % of the time a plant is available to produce electricity. The latter category, instead, includes programs aimed at providing greater incentive to reduce fuel costs. Other programs have no statistical association with efficiency levels.

The empirical results of the reviewed studies are summarised in Table 12 in the Appendix.
2.3. Simulation

Key findings

- Better use of existing resources is a starting point for integration and offers some initial benefits.
- In addition, optimisation of the joint system creates further “dynamic efficiencies”
- The benefits increase depending on how different interconnected markets are.
- The value of integration increases as the share of renewables increases.

The following simulation is not a representation of the European market but should illustrate the value of market integration on a stylised example.

We show the benefits of coupling two markets by considering two imaginary countries, labelled Country A and Country B, for a period of one year. Each of the two countries has its own supply and demand profile. The two countries can be described by their power plant configuration, by the profile of the renewables feed-in, and by the profile of the demand. In terms of power plants we categorise the existing plants in the two countries into four groups: (i) intermittent renewables (wind, solar), (ii) nuclear, (iii) coal and (iv) gas. Table 4 details some of the data we used, and our ad-hoc assumptions on the fixed and variable costs.9

Table 4: Data used for static simulation

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<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Renewables</td>
<td>23,000</td>
<td>13,000</td>
<td>120,000</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>5,500</td>
<td>3,900</td>
<td>190,000</td>
<td>10</td>
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<tr>
<td>Coal</td>
<td>7,100</td>
<td>22,600</td>
<td>100,000</td>
<td>21</td>
</tr>
<tr>
<td>Gas</td>
<td>7,600</td>
<td>10,600</td>
<td>40,000</td>
<td>35</td>
</tr>
</tbody>
</table>

It should be noted that the supply of renewables and the vertical network load are not constant over time, but random. We use realistic data for both. Figure 5 provides a graphical description of the data we used in the simulation.

Since the two countries are neighbours, they show high correlation in their renewables feed-in pattern and vertical network load. In fact, the renewables feed-in shows a

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9 Data on the installed capacity for different power sources, the vertical network load, and the wind and solar feed-in for Country A and Country B correspond to the 8,760 hours of the year 2012 in the German zones served by TenneT and Amprion, respectively. We do this for reasons of completeness and availability. As for the data on fixed and variable costs, we use the values reported in Delarue E. et al.(2011).
correlation of 67% between the two countries. Also, the 1000 hours with the highest renewables feed-in in Country A coincide with 359 hours that are among the 1000 hours with the highest renewables feed-in in Country B. The vertical network load is also highly correlated at 78%, and 190 hours are among the 1000 hours with the highest load in both countries. This already indicates that geographic averaging between directly neighbouring countries might have somewhat limited benefits because of insufficient heterogeneity as both countries would need the last available resources at the same time.

**Figure 5: Graphical description of the data**

![Graphical data](image)

We will analyse three cases. The first, no-trade case consists of the optimal schedule of the existing power plants when the two countries are isolated. In the second case, up to 5% of the total generation capacity in the smaller zone can be traded between zones, i.e., maximum transmission capacity is assumed to be 2160 MW. Finally, in the third case we assume unlimited transmission capacity between the two countries.

If we take the system cost in the first case as 100, then having 5% transmission capacity takes this cost to 99.1 (-0.9%), while having unlimited transmission capacity further reduces the system cost to 98.1 (-1.9%).

**Table 5: System cost under different scenarios**

<table>
<thead>
<tr>
<th></th>
<th>No Integration</th>
<th>5% Transmission</th>
<th>Full Integration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total costs</td>
<td>100</td>
<td>99.1</td>
<td>98.1</td>
</tr>
</tbody>
</table>

10 For solar and wind energy considered separately, the number of hours that are among the 1000 hours with the highest load in both countries is 865 and 578, respectively. Solar also shows very high correlation between the two countries, at almost 98%. Wind has 76.5% correlation.

11 Imported electricity is assumed to have an additional variable cost of 0.1 Euro/MWh
Up to this point we have considered static efficiency, i.e. the countries optimize generating costs given their current power plant park. We now move to an analysis of the effects of dynamic efficiency: the two Countries are allowed to optimize their fossil power plant park. Again, we consider three scenarios: no-trade, reduced transmission capacity, full-trade. We find that the efficiencies of trade increase when countries can reconfigure their plant parks from two parks that are optimal in a national setting to ones that are optimal in a joint setting (see Table 6). This efficiency effect of trade gets more important – it increases from 2.5 per cent of the total system cost to almost 5 per cent of the total system cost – when we double the share of renewables in each country.

Table 6: Total system costs with optimal capacities under current and high RES penetration, with varying level of market integration

<table>
<thead>
<tr>
<th></th>
<th>No Integration</th>
<th>5% Transmission</th>
<th>Full Integration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Renewables</td>
<td>100</td>
<td>98.9</td>
<td>97.5</td>
</tr>
<tr>
<td>High Renewables</td>
<td>100</td>
<td>97.5</td>
<td>95.4</td>
</tr>
</tbody>
</table>

The above analysis provides a lower bound for potential efficiency gains as the cost of the technology are similar in the two countries and as both consumption and renewables feed-in are highly correlated between country A and country B. To illustrate this fact we repeat the analysis with a country pair characterised by much lower correlation of

$^{12}$ We modify the data by increasing by 10% the vertical network load when it reaches its peak value. Also, we impose a 200,000 Euro/MWh cost for every MWh of unfulfilled demand. This makes sure that the system has a 10% reserve margin at all times.
renewables feed-in (12.7%)\textsuperscript{13}. Furthermore, the 1000 hours with the lowest feed-in of solar and wind in country A do in no hour coincide with the lowest feed-in in the new country C. Hence, one might think of country C as a far distant country. The first finding is that integration of markets with uncorrelated renewables does not lead to higher benefits than integrating markets with correlated renewables. The reason for this counterintuitive finding is that we start with two systems that are both characterised by overcapacities.

Table 7: System cost under different scenarios – with weakly correlated renewables

<table>
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<th></th>
<th>No Integration</th>
<th>5% Transmission</th>
<th>Full Integration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total costs</td>
<td>100</td>
<td>99.2</td>
<td>98.2</td>
</tr>
</tbody>
</table>

If we allow for re-optimisation of the system we find that averaging the less correlated renewables allows substantial cost savings. In the high renewables scenario the cost savings through integration could reach almost 7% of the total cost of the electricity system.

Table 8: Total system costs with optimal capacities under current and high RES penetration, with varying level of market integration, with weakly correlated renewables

<table>
<thead>
<tr>
<th></th>
<th>No Integration</th>
<th>5% Transmission</th>
<th>Full Integration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Renewables</td>
<td>100</td>
<td>97.7</td>
<td>95.6</td>
</tr>
<tr>
<td>High Renewables</td>
<td>100</td>
<td>96.6</td>
<td>93.3</td>
</tr>
</tbody>
</table>

We conclude that the efficiency potential of better using existing systems through integration is substantial, but that a significant share of this potential is already reaped at rather low levels of integration. At high levels of renewables significant cost-savings arise from re-optimising the national systems with respect to demand and supply situation in the joint system. The benefits of jointly optimizing a system of a high share of lowly correlated renewables are substantial at larger levels of integration.

2.4. Bottom-up quantification

Key findings

- There is a substantial cost of non-Europe, which will not generate the benefits of integration and competition, but quantification is difficult.
- The value of interconnection is rising again.

In this section, we will evaluate the benefits of a truly European electricity market empirically. The electricity sector is important. Its turnover of EUR 420 billion represents more than 3 per cent of European GDP\textsuperscript{14}. Correspondingly, already small efficiency gains in the electricity sector represent significant absolute efficiencies.

\textsuperscript{13} Actually, we shift the renewables feed-in of country B by 722 hours. All other assumptions are kept equal.
\textsuperscript{14} The turnover is calculated based on 3086 TWh net electricity generation times an average final sales
Extrapolating the efficiencies identified in the literature survey to the EU27 market would correspond to EUR 11 billion of payroll cost savings\textsuperscript{15} and to EUR 289 million per year of balancing cost savings (corresponding to a 10% total interconnection capacity)\textsuperscript{16}. In addition, literature on full market integration shows promising results when moving from a national towards a full-integration scenario; simple extrapolation of these results to the EU27 level would induce total system cost to decrease by EUR 6 billion\textsuperscript{17}. Deregulating and consolidating electricity markets in the US led to an increase in nuclear operating efficiency, the corresponding value for the EU would be EUR 2.35 billion annually\textsuperscript{18}. Market reforms in the electricity sector are proved to be successful in decreasing Minute Reserve Power prices and leading to substantial cost savings for the TSOs; the estimated effect on Europe amounts to EUR 4.7 billion annual cost savings in the MRP markets\textsuperscript{19}. Evidence suggests that adopting an organized market design in the US produced efficiency gains – similar efficiency improvements in Europe would value around EUR 700 million annually\textsuperscript{20}.

\begin{itemize}
\item \textsuperscript{15} Eurostat reports data on average personnel cost only. Personnel costs are the total remuneration payable by an employer to an employee for work carried out. This is divided by the number of employees (paid workers), which includes part-time workers, seasonal workers etc, but excludes persons on long-term leave. As we are interested in total payroll costs, we multiplied EUR 43,000 (average personnel cost) times the number of employees in the sector 800,000 (source Eurelectric) and obtain 34 billion (Payroll cost in electricity generation in the EU in 2012). Thus 32.3 per cent are EUR 11 billion.
\item \textsuperscript{16} Abbasy et al. (2009) estimate EUR 80 million balancing cost savings per year (corresponding to a 10% total interconnection capacity) for the Netherlands, Nordic Region and Germany. As these countries jointly represent 27.7% of the total gross electricity generation, the corresponding effect on EU27 would be EUR 289 million balancing cost savings.
\item \textsuperscript{17} Gerbauleta (2012) estimate total system cost reduction of EUR 10 million per month, re-dispatch cost decrease by EUR 0.2 million monthly. The study focuses on the region including Germany, Austria and Switzerland, which jointly represent 20.6% of the total gross electricity generation; the corresponding effect on EU27 would therefore amount respectively to EUR 48 million and EUR 0.97 million total and re-dispatch cost savings.
\item \textsuperscript{18} Davis and Wofram (2012) estimate the value of this increased efficiency being approximately USD 2.5 billion annually in the US nuclear power market (in 2012 EUR 1.95 billion). The most recent data on nuclear power plants in Europe and US report an installed electric net capacity of 122 GWe and 101 GWe respectively (http://www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-world-wide.htm and http://www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-europe.htm). Therefore the effect scaled on EU would be 2.35 billion.
\item \textsuperscript{19} Haucap et al. (2012) estimate EUR 1950 and EUR 1400 million cost savings respectively for incremental and decremental MRP in Germany’s market for 46 month. As this country represents 18.6% of the total gross electricity generation, the corresponding effect on EU27 would be EUR 4.7 billion cost savings per year.
\item Mansur and White (2012) indicate that employing an organized market design realized increased efficiency gains of 163 billion Dollar (or EUR 131 million (2005)) in a region in the Eastern US, which switched from a bilateral to an auction market design. As of Summer 2009, PJM Interconnection (the examined electricity market in Eastern US) had installed generating capacity of 167,326 megawatts, which amounts to 19.7% of the EU27 total electricity installed capacity. Therefore, scaling to the European case, the realized efficiency gains from trade would amount to EUR 690 million.
\end{itemize}
All reported values for the extrapolation on the EU situation are purely indicative as the conditions are entirely different between the individual empirical cases and the EU as a whole. Furthermore, some of the benefits might overlap and other potential benefits are not considered. Consequently we restrain from providing a total of potential efficiencies.

Another way to approach the benefits of integration is by analysing the market participant’s willingness to pay for cross-border lines. Suppose there are two geographical areas, and each generates electricity up to some quantity. With perfect connection between the two areas, market forces would drive the price to the same level. Instead, if there is limited interconnection capacity, the prices in the two areas will in general be different. Thus, TSOs can extract a rent by exploiting the price difference between two areas, selling interconnection capacity through auctions.

Europe is characterized by a multiplicity of electricity price areas and by an imperfect interconnection between them. It is therefore possible for TSOs to collect congestion rents. Previous data shows that more than EUR 1.6 billion of congestion rents were obtained by TSOs in Europe in the period 2006-2009.21

CASC (Capacity Allocating Service Company) is the central auction office for cross-border transmission capacity and runs yearly, monthly, and daily auctions, coordinating TSOs in 10 countries across Europe.

The following graphs report the value of the transactions (allocated capacity × price) of the yearly and monthly auctions. Compared to 2012, 2013 saw an overall increase in the value of the transactions. While in 2012 the auction result in the CASC countries was about EUR 750 million, the first four month of 2013 indicate an annual value of more than EUR 900 million.

Most of this stems from the auction of annual transmission capacity usage rights. Traders valued the right to use the interconnectors in 2013 by more than 10 per cent more than in 2012 as the corresponding auction revenue raised from EUR 400 million to EUR 450 million.

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21 Supponen (2012).
22 Complete data for monthly auctions spans the period April, 2011 to April, 2013, since some countries joined CASC in 2011.
23 It should be noted that the data under analysis here only includes yearly and monthly auctions. Daily auctions are outside of the picture.
Countries in Northern-Central Europe led this growth: the value of the transactions, in fact, almost doubled for them. This increase in value was largely due to an increase in prices as the auctioned interconnection capacity only grew by around 2.5 per cent. This increased willingness to pay for interconnection indicates an increasing demand for transmission lines.

In Southern countries, instead, the picture is more stable: the value of the transactions fell by 4 per cent in 2013 compared to 2012, and the interconnection capacity sold was essentially the same (+0.6%) – reflecting a recession induced reduction in electricity consumption.

The total value of interconnector usage could also serve as an upper bound for the economic investment need in new cross-border capacities. At a 10 per cent interest rate merchant investors would be unwilling to spend more than EUR 9 billion (10 x 900 million) on increasing the capacity of the considered cross-border lines.

Countries in Central-North Europe show an increase in the transacted value starting from the final quarter of 2012. There is some degree of seasonality in the monthly transacted value, especially for the Belgium-to-Netherlands connection, which is more active during the summer months, and the Germany-to-Switzerland connection, more active during winter. This seasonality of the transacted value is due to price, probably due to seasonal variations in prices inside the two price areas.
Figure 8: Results of monthly interconnector auctions in 1000 Euros

Source: CASC

Does integration lower prices?²⁵

Market coupling is one of the key-policies for achieving the EU single electricity market. The EU Commission praises the price-lowering effects of market integration in the Internal Market Communication: “Market opening, increased cross-border trade and market integration, and stronger competition … are keeping energy prices in check”.

²⁵ This box largely reproduces the Bruegel blogpost of 25.09.2012 entitled “Market coupling does not lower prices!” by Georg Zachmann.
And common sense would indeed suggest that in competitive markets the average price of two market zones will be equal or lower when they are coupled than when they are separate. In fact, coupling should lead to lower average prices for typical electricity markets (increasing marginal cost on the supply side and price-inelastic demand). The intuitive reason is that the most expensive MWh in the expensive country might be replaced by switching on one additional MWh in the cheaper country. As marginal cost is increasing the switched-off MWh will be disproportionally more expensive than the switched on MWh. In our example (see Figure 9 below) in the first market 10 MWh with marginal cost of 158-176 EUR are switched on while 10 MWh with marginal cost of 176-239 EUR are switched off, hence average prices decrease from 185 to 176 EUR per MWh.

In a Cournot competition setting this effect is amplified by the increase in the number of players in the joint market. This increased competition in the joint setting will drive down prices compared to the separate market setting. In our example (see Figure 10) coupling two monopolistic markets (with similar cost curves) to one duopolistic market drives down the average price by 7 per cent.

Figure 9: Market coupling with well behaving cost functions under perfect competition

Figure 10: Cournot competition setting: Coupling two monopolistic markets to one duopolistic market
**Figure 10: Market coupling with well behaving cost functions under imperfect competition**

![Graph showing market coupling with well behaving cost functions](#)

**Figure 11: Producer and consumer surplus as well as congestion rent**

![Graph showing producer and consumer surplus](#)

However, this ideal result does not hold in all real-world situations. In 2012, market coupling in Central Western Europe caused average prices to rise. Higher prices and lower total generation cost increased producer surplus by EUR 428 million, while the consumer surplus decreased by EUR 67 million. Deducing the reduction in congestion rent of EUR 263 million the net welfare effect was EUR 98 million in 2012 and hence still significantly positive (see Figure 11).
But why can market coupling – against the intuition presented above - increase prices? One explanation is the non-linear shapes of electricity cost curves (compared to microeconomic textbook cost curves). When moving to a cost function with a long flat left that becomes very steep at the right end the above outlined proposition that market coupling leads to lower average prices (due to the flattening supply curve and the competition effect) does not need to hold anymore. As illustrated in the example below (see Figure 12) the price might converge to the higher price when the more sizable low price zone is forced to accept higher prices due to coupling. If for example at a given point in time, the electricity price in Germany was set by coal-fired power plants (~EUR 50) and by nuclear plants in France (~EUR 0) coupling both markets might increase the average price. This would, for example, happen if there was no additional nuclear plant in France available. In this situation all French and German nuclear and renewables capacity would run, but to meet the joint Franco-German demand some German coal plants would need to run as well – hence these expensive units would set the joint price.

Figure 12: Market coupling with non-linear cost functions under perfect competition

3. Why does the single market not self-organise?

Key findings

- Electricity markets do not self-organise in a socially optimal way.
- Consequently markets need to be designed.
- Path dependencies and national politicians’ desire to keep control of the sector cause inconsistencies between member states’ market designs.

There are essentially four reasons why public intervention is necessary to design an efficient European energy market:
First, the gas and electricity sector are confronted with the fact that one part of the value chain is a natural monopoly that requires public intervention to produce socially desirable results. As the different parts of the energy value chain are firmly interlinked, network regulation strongly affects the generation, storage and consumption segments.

Second, the electricity sector is a very complex construct. Individual actor’s actions have significant externalities on all other actors. As those externalities cannot be dealt with (internalised) by vertical integration public intervention is necessary to achieve socially desirable sector structures.

Third, in the member states very different market arrangements emerged. Those arrangements are a priori largely incompatible across borders and trading hence requires interfaces. The complexity of interfaces of making different energy products seamlessly tradable between more than 30 incompatible markets is huge. The solution to this - harmonising rules – however, entails significant redistributive effects between market participants. Hence public intervention is required to strike stable arrangements.

And fourth, energy is a strongly politicised product in all countries. Consequently, self-organisation of cross-border markets is politically constrained.

### 3.1. Network is a natural monopoly

Energy networks are natural monopolies. That is, building a second network to compete with the existing one would neither be beneficial from a company nor a societal perspective. Consequently, in all EU countries electricity networks are regional monopolies. So that this market power is not abused, TSOs are not free in setting the network tariff. In most EU countries, regulators try to ensure that the income of TSOs only slightly exceeds the operational and capital expenditure.

This tariff setting power of regulators is also used to indirectly incentivise the natural monopoly to invest in innovation, quality improvements, cost reductions and line extensions. To deal with this complex question very heterogeneous national regulatory arrangements emerged.

### 3.2. System nature of the energy sector

Electricity systems are made up of a great variety of interlinked generation, transmission and storage assets. The assets are partly complementary (power plants need to be connected to transmission lines), and partly substitutes (a power plant supplying local demand might be replaced by a transmission line that brings electricity from elsewhere). Individual decisions have an impact on all other actors (the ‘system nature’ of the electricity sector). The physical features of electricity require a high degree of interaction between all parts of the electricity-sector value chain. Changing one part of the system has immediate consequences for the entire system. Adding one transmission line might result in the overloading of another, and a new power plant might require network extensions hundreds of kilometres away. Networks cannot be evaluated in isolation: many benefits of network extension can be equally well or better secured by changes at other levels of the value chain. Better coordination, demand response, energy efficiency
and generation management can relieve congestion, increase reliability and mitigate market power.

The fact that electricity networks have to be seen as a part of a system implies a chicken-and-egg problem for generation, storage, transmission and load investments. A generation investment might only make sense if it is properly integrated into the transmission grid. However, as long as there is no generation, there is no need for transmission investment.

3.3. Incompatible sector arrangements locked-in in national interests

Investment in transmission would be a lot easier if all major stakeholders had the same preferences. However, investor interests diverge and partly conflict. Electricity generators in zones with low prices would like to be connected to higher price zones in order to export. Such connections would also be appreciated by the consumers in the zones with high prices. Meanwhile, generators in high price zones would prefer to prevent cheap imports, and consumers in low price zones do not want to compete with other customers for low-price electricity. The picture is even more complicated in zones with different seasonal price patterns. For example, storage operators prefer connections to zones with high price volatility because this allows them to buy at low prices and sell high. Consumers residing close to the storage capacity, however, are not fond of ‘importing’ higher volatility through a new line connecting to a zone with extreme price volatility.

Transmission system operators (TSOs) – the owners and operators of transmission infrastructure in one country\(^{26}\) – also have complex preferences. They live from the regulated tariffs they charge to the users of their infrastructure. If regulators grant them the right to recover high rates of return on their transmission investments, they would prefer to overbuild the network (‘gold plating’). Overbuilding the network means abundant capacity and peace of mind in terms of network operation. However, low regulated rates of return and the possibility to be reimbursed for costs resulting from managing an insufficient network might incentivise a TSO to delay investment. Additionally, TSOs might find that restricting cross-border flows is a cheap way to ensure national system security. Furthermore, if the TSO is still partly integrated with a generation company, the incentives for the generation part of the business (e.g. enabling exports, preventing imports) might spill-over to the preferences of the TSO (Supponen, 2011).

National energy regulators are typically biased towards short-term tariff reductions (Meeus et al, 2006). Hence, they often prefer tariff reductions over investment in transmission. Their task is to maximise the welfare of national network users, and, as such, they have no incentive to consider the positive cross-border spillovers of their decisions. Regulators risk being captured by some of the aforementioned interest groups (e.g. generators in importing zones).

\(^{26}\) Some TSOs operate in multiple countries (e.g. the Dutch TSO TenneT owns a central German TSO), others only in part of a country (e.g. the German TSO Amprion operates only in the western part of Germany).
Another group of stakeholders is local residents, who often dislike new transmission lines in their backyards. A study commissioned by the European Commission has identified local opposition as one of the main obstacles to transmission system investment.

The issue of diverging stakeholder interest is amplified by the differing availability of information to different parties. The TSO has the best information on the cost of operating existing transmission lines and constructing new ones, while the generators/storage operators possess the best information on their own costs and extension plans. Consumers have the best view of their future consumption. There is a risk that stakeholders might strategically withhold information or strategically react to the investment decisions of others (Sauma and Oren, 2007).

Historic "path dependencies" caused the different interest of the different stakeholders to materialise in different market arrangements in each legislation. As illustrated in Figure 13 a different starting point for the physical electricity system and its ownership resulted in sector rules that were typically favourable to the incumbent players. Such favourable regulation reinforced the specialisation pattern of the physical electricity system. Consequently, the member states developed market designs that were implicitly supportive for their local producers, consumers and transmission companies. Due the different starting points these systems were largely incompatible between countries. Making even individual segments compatible is difficult as changing even seemingly minor items of the market design produces loser. One example is moving the gate closure - i.e., the hour by which all traders should notify the market operator of their supply and demand curves - forward to harmonise two systems and allow more information on renewables to be taken into account in the scheduling of conventional plants. This would leave less time for transmission system operators to optimise the dispatch and might reduce the need for balancing. Hence, typical providers of balancing power (gas turbine) and transmission system operators might lose.

Figure 13: Interaction between power plant part and regulation

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27 The interests of other stakeholder groups such as traders and power exchanges are not discussed here, although their business models (providing a national trading platform, arbitraging price-differential) are not always helped by more transmission investments.
28 Roland Berger (2011, p9): “Project developers identify public opposition as a key problem”.
29 This includes large industrial consumers as well as electricity suppliers that typically monitor the demand patterns of their final customers.
3.4. National energy policies

Conflicting interests are not restricted to individual stakeholders. Countries also have different preferences. Low-cost producers such as Norway might, for industrial and social policy purposes, want to restrain exports in order to restrict prices, while other countries strive to increase their exports. Transit countries know that if they build too many transmission lines, the price differentials between the country it imports from and the country to which it exports will decrease such that the total arbitrage rent (volume times buy price minus sell price) decreases. Thus, transit countries might want just enough international interconnection to maximise their rents. Due to the highly volatile national demand and supply position, the optimal transmission level for a country is difficult to establish analytically. Hence, national preferences with respect to individual projects are strongly driven by the advocating power of stakeholder groups.

On a political level, countries prefer to keep control of energy policy and are thus sceptical about increasing the levels of coordination and harmonisation. Hence, they retain the operation and extension of the transmission system as an issue at national level. As a consequence, the rules for incentivising transmission investments are different in the different EU member states. National network extension plans are not regularly exchanged, and developments in the power plant park are not communicated to neighbouring TSOs. As a consequence, national energy strategies might be inconsistent – for example all Nordic countries plan to increase their energy exports – and internal network investments are ill-coordinated across borders.

4. Quantification of infrastructure investment need

Key findings

- “Optimal network” depends strongly on the assumptions
- Predicted infrastructure need differs markedly between studies
- The process of determining the “optimal network” is more important than figures

Determining optimal infrastructure need is a challenging exercise that crucially depends on a number of assumptions.

(1) The most important issue is which measure should be optimised by the infrastructure investment. Minimising short-term system cost, minimising congestion, minimising system losses, minimising electricity prices, maximising expected welfare in each member state individually or maximising expected European welfare are only some of the possible target functions. Each target leads to different “optimal” network layouts, investment volumes and distribution of benefits among the affected stakeholders. For example, minimising national system operation cost might lead to an overbuilding of domestic lines and a reduction of cross-border capacities. In a high-cost country this might benefit producers (that would be faced with lower imports) at the detriment of
consumers. By contrast, a strategy to maximise European welfare might strengthen cross-border links but, maybe, not entail connecting certain remote renewables. Hence, the target function for network investments is a serious political choice!

(2) The second important determinant of an optimal infrastructure is the development of the energy system in the coming decades. Corresponding assumptions are notoriously difficult. The “optimal network” might significantly change depending on the expected demand at a certain network point. If for example a large aluminium smelter (1000 GW) locates in the South of Germany instead of in the North an extension of electricity lines between Czech Republic and South Germany might become beneficial to accommodate the increased loop-flows.

(3) A third important decision is which technical options are considered when optimising the network investments. Excluding options from the optimisation might lead to significantly higher deployment of other options and hence higher cost. To give one example, if one does not allow for demand side management in the network planning, the optimal transmission network will need to be significantly stronger. Consequently, optimising the system by only planning high-voltage cables is likely to be excessively expensive.

(4) A related element is the cost assumptions of the different options. If, for example, only the cost of the physical hardware of high-voltage lines is considered, they will always appear the cheapest solution. However, also considering the cost of getting approval, buying rights of way, compensating residents, etc. the cost of a new transmission line might exceed the cost of strengthening existing corridors (e.g., through high temperature cables) or doing changes on other parts of the value chain (e.g., curtailing exceptional wind peaks).

(5) A fifth determinant of which network investments are “optimal” is the assumed market design. Research has shown that moving from the current sub-optimal market coupling of large national zones to centrally optimising dispatch via nodal pricing (different prices at each node of the network depending on the physical network) can increase transmission capacity by up to 30%. Hence, the optimal network extension under an advanced market design might differ greatly from the network that would be optimal if dispatch continues to be based on overlapping national and European rules and markets.

A number of studies tried to estimate the need in physical (km build) and monetary terms. The assumptions differ markedly and so do the results.

Roland Berger’s report (2011) carries out an analysis of 2010-2020 energy transmission investment needs. Their figures show that distribution and transmission together will require around EUR 600 billion during the above mentioned period, of which approximately 200 billion will be devoted to improving transmission infrastructures. The majority of these investments will involve electricity transmission (65%), while the remaining 35% will go to natural gas transmission. According to the EC, approximately 50% of the EUR 200 billion planned transmission investments is at risk of not being realised due to delays in permitting procedures and the general difficult access to finance and lack of adequate risk mitigation mechanisms. The same report also compares past and future planned TSO investments; the average annual TSO investment for electricity
projects during the period 2005-2009 used to be around EUR 5.8 billion, while the forecasted amount for 2010-2020 reaches EUR 9.8 billion, with an increase of nearly 70%. Major differences exist between electricity TSOs in Europe in terms of their past investments. In the period 2005-2009, investments in energy transmission infrastructure were focused on Western Europe (AT, BE, DE, FR, UK, IE, LU, NL), which saw annual investments of EUR 3.2 billion. This region is also the one presenting the largest relative increase in the period 2010-2020 (+94% from 2005-2009 investments).

The European Infrastructure Priorities (2010) argues that, since the electricity sector is expected to face increasing demand in the future and since the electricity generation mix is changing, with less fossil fuels and more renewable and variable energy sources, large-scale investments are needed at a level not seen over the past decades. The study quantifies the infrastructure investment needs for electricity in 2011-2020 as follows: EUR 70 billion for transmission infrastructure, EUR 32 billion for offshore grid infrastructure and EUR 40 billion for smart grid infrastructure. As a result, the total investment need amounts to EUR 142 billion for electricity (while the total system costs are estimated to be around 1000 billion).

![Image of infrastructure investment needs](image)

A 2013 OECD working paper compares two different scenarios in terms of grid development and shows that, in a grid expansion scenario, the share of wind power relative to total power generated within the EU would reach 12% by 2020, gaining more than two basis points over the grid shortage scenario. This implies that adequately developed domestic grids may allow for a lower installed wind generation capacity to achieve the same renewables objectives by 2020. Moreover, the cost of meeting renewables objectives would be almost 38 billion dollars greater under the grid shortage scenario. In addition, if domestic grids are well-reinforced, average Effective Capacity Factor in the EU may strongly increase compared to both the baseline and the grid shortage scenario.
The Energy Roadmap 2050 also refers to several policy scenarios. The reference scenario yields the lowest investment requirements, while the traditional technology scenarios converge to a slightly higher investment level both by 2030 and 2050. A clear-cut result is provided by the renewable scenario (with a 75% share of RES in final energy consumption), especially during the 2031-2050 decade. Indeed, infrastructure requirements reach EUR 1323 billion. The High RES scenario presents a total grid investment cost in 2011-2050 of approximately EUR 2195 billion, which compared to the reference scenario level (i.e. 1269 billion), suggests an increase in infrastructure requirements of about 73% from the baseline scenario.

The Ten Year Network Development Plan 2012 (TYNDP) from the ENTSO-E, gives an outlook over all grid development activities in the ENTSO-E region. The amount of expected grid investments for all projects of pan-European significance in the coming ten
years varies by country, with Germany accounting for the highest costs with EUR 30.1 billion according to the TYNDP. The total investment costs within the whole ENTSO-E perimeter are estimated to be around EUR 104 billion (EUR 23-28 billion within the period 2010-2014, according to ENTSO-E TYNDP 2010). Presently, the European transmission network consists of approximately 305,000 km of routes. Completing the projects of pan-European significance will lead to refurbishing about 9,000 km of existing assets and building 43,200 km of new assets in the long-term, increasing the total length of the network by 17% over the coming ten years (of which 76% are overhead, and 24% underground or subsea). Comparing the power system costs to, on the one hand, present, limited, Net Transfer Capacities, and on the other hand future NTCs once projects of pan-European significance are implemented, shows that long-term cross-border transmission projects of pan-European significance will help alleviate total annual generation operational costs by about 5%. For higher generation costs that can be expected by 2020, this represents about EUR 5 billion.

ECF’s study (2011) shows that the share of transmission expansion investments in overall energy system costs will be comparatively low during the next decade, i.e. 46 billion out of 2273 in 2020 and 68 out of 3277 in 2030. Required investments both in generation and transmission are substantially reduced in presence of cross-border coordination, higher demand response and higher energy efficiency. Indeed, transmission costs reduce up to 56% with high energy efficiency, i.e. from 68 to 30 EUR billion.

Rebours et al. (2010) argue that an increase of cross-border capacity between France and its neighbours by 7 GW would have an annual cost of about EUR 380 million and a benefit of EUR 980 million, hence a net benefit of about EUR 600 million. According to the authors this corresponds to the optimal reinforcement as only increasing the capacity by 5 GW is leading to EUR 200 million lower benefits while increasing the capacity by 10 GW leads to more than EUR 200 million higher cost.

Von Hirschhausen et al. (2012) discusses various estimates of the investment challenge, finding both a high variance of these estimates, and that financing generation investment
is the real challenge. He argues that the issue 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 consequently for the financing. In that context, a positive, differentiated analysis seems more appropriate than a normative request for more investment as such. Last but not least, the investment needs must be assessed in the light of the political and institutional scenario that is expected to occur. Indeed in a “Europe centralized” scenario, there is ample room for pan-European electricity networks, which become less relevant in a “national approaches” scenario. Furthermore, he argues that more completely considering “transaction cost” would lead to significantly higher cost assumptions for networks and hence alternative.

To sum up, the dimension of the optimal network depends strongly on the assumptions that are being made. This is the main reason why different studies obtain strongly diverging results concerning investment needs and the economic consequences of investment choices. This implies that the process used to reach a certain result is more important than the resulting outcomes.

Thereby, the Spanish example might serve as a call to caution. Between 2008 and 2010 the spending on electricity transmission infrastructure has been increased by 18% to EUR 865 million and even exceeded the German spending in 2010. It is now becoming obvious that Spanish consumer have to pay for a network that is over-dimensioned for their needs at the moment and in the foreseeable future.
Evaluating the current approach to the internal market

Key findings

- The current market design and the planned improvements will not result in a truly integrated market in which production, consumption and investment decisions are based on market signals that incentivise optimal operation.
- The current approach towards planning and funding European energy infrastructure will not allow all benefits of the single market to be reaped.
- Infrastructure planning and funding is still driven by the interest of TSOs - not the welfare of European citizens.
- Harmonising interfaces is likely to prove unworkable – an internal energy market requires joint operation of systems and markets.

There are two main building blocks for the internal market - the market design and the provisioning of physical infrastructure. In the following we will describe the current and foreseen approach to both of them and provide a critical evaluation with respect to the internal market.

1. Market design

Key findings

- Limited consistency between national market designs (important parts of the joint system are not part of the joint market).
- Lack of a “grand-design”
- No visibility of the future market design => uncertainty

1.1. Current approach

Electricity is not a single-dimensional product that is produced, exchanged and consumed. Electricity has multiple dimensions that can be individually traded. Key determinants of the electric service are (in simplified terms):

- **The volume of electric energy**. This is the most straightforward component typically measure in Megawatt hour (MWh) at the wholesale and kilowatt hour (kWh) at the retail level.
- **The location of delivery**. As any good and service electricity only has a value when delivered to the customer. Consequently, electricity is more expensive in countries at which it is more difficult to produce and cannot easily be imported. However, for administrative reasons electricity has within most European
countries (the Nordic countries and Italy being exemptions) the same price at the wholesale level at each location.

- **The speed of delivery.** Electricity travels at the speed of light. But, facilities to produce or consume it need time and sometimes fuel to ramp-up or ramp-down. Consequently, the shorter the notice the more expensive it typically is. To schedule deliveries of using the latest available information on the stochastic demand and supply (e.g., renewables) a sequence of markets is established. A long-term forward market for annual or monthly deliveries that typically covers the largest amount of volumes, a day-ahead market that largely determines the scheduling of the plants with low variable cost and long ramping times (e.g., nuclear and lignite plants), an intraday market in which upcoming information on changes in supply and demand are settled and eventually power plants with short-to-medium ramping times (e.g., gas turbines) are re-scheduled and a balancing market in which very short-term deviations from the initially planned schedule are exchanged.

- **The ability to stabilise the system.** This entails (i) maintenance of the balance between generation and demand using turbine speed generators (Primary Control), (ii) maintenance of exchanges with other control areas at the programmed levels and returning the frequency to its set value in case of a major frequency deviation, thus restoring primary control reserve (Secondary Control), (iii) restoration of an adequate secondary control reserve (Tertiary Control), (iv) starting operating and delivering power without assistance from the electric system (Black-start Capability) and (v) injecting or withdrawing reactive power to keep system voltage within prescribed levels at specific nodes (Reactive Power). These five services are typically referred to as ancillary services.

- **The availability to meet demand.** There is a value in being sure that electricity is delivered when needed. Such insurance can theoretically be provided by outbidding competing consumers for a given limited supply in the long-term markets. Resulting high prices would encourage necessary investments and ensure supply adequacy. In markets with high regulatory risk and administrative barriers this mechanism might not provide the optimal supply adequacy. Consequently, other mechanisms/markets to remunerate market participants for their contribution to supply adequacy are being considered/implemented in the EU and elsewhere.

- **The “technology externality” of electricity.** Installing new technologies implies technological and organisational improvements. The initially high cost of deploying a not fully mature technology translate into valuable learning, both at the side of technology providers and the entire system that has to accommodate new technology. This is for example relevant for the deployment of new technologies.

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30 There is a longstanding academic and political debate about the need for capacity mechanisms. See for example the Public Consultation on generation adequacy, capacity mechanisms and the internal market in electricity: http://ec.europa.eu/energy/gas_electricity/consultations/20130207_generation_adequacy_en.htm
The different parts of the electricity value chain (can) produce/consume different combinations of these dimensions. For example, nuclear power plants provide at their location capacity and reactive power and can hence either provide secondary reserve or produce electricity and reactive current on long or short notice (day ahead, intraday). To a limited degree nuclear plants are also able to provide frequency and voltage control as well as balancing services. Wind turbines by contrast do only provide stochastic capacity contributions. When the wind blows they will produce electricity and if correspondingly equipped reactive current. They can provide some downward balancing.

For each of the dimensions different trading arrangements can be found. And indeed, within the member states the trading arrangements for all dimensions differ significantly. For example, each EU country has adopted a different set of policies to achieve its national renewable energy target. Policy tools include green certificates, feed-in tariffs, obligations, direct subsidies, preferential grid access regulations, tax breaks, and so forth. The actual size of the different support schemes for renewables is difficult to assess because they often mix fiscal (direct support), para-fiscal (for example compulsory apportionments collected by network operators) and non-fiscal (regulatory) instruments.

The numbers that the EU’s directorate-general for competition collects on state aid for environmental protection – a by many means imperfect indicator for RES-E support – hint to large divergences inside the EU. In 2009 such state aid amounted to 1.1 per cent of GDP on average in the EU-27. But it was 2.4 per cent of GDP in Germany and only 0.12 per cent of the GDP in Italy. Consequently, the national systems for RES-E support in Europe differ both in structure and in size. This is economically inefficient as it leads to different prices for the same good (electricity produced from renewable sources) within the Union.

One striking illustration for the inefficiency of the fragmented support schemes is that there are currently stronger incentives for installing solar cells in northern Germany than in southern Italy. This is one of the reasons why the European Commission has been pushing for a transferability of RES-E achievements. Such transferability – for example through the obligation of any member-state’s support scheme to accept foreign ‘green’ electricity – should quickly lead to a harmonisation of the support schemes and prices for RES-E. Thus, a single market for electricity generated from renewable sources would develop. However, the European Commission has so far failed to push through plans to
achieve such transferability - because the fragmentation of Europe's renewables market reflects the political preferences of EU member-states. Countries would rather reduce their dependence on imported energy and support their home-grown renewables industries than subsidise the RES-E production in another member-state. The success of the RES-E support instruments will create new challenges for the electricity sector. Between 2005 and 2010 Germany deployed about 9 gigawatts (GW) of wind turbines and 14 GW of solar panels, amounting to about 18 per cent of the total installed electricity generation capacity. Spain deployed 10 GW of wind and 4 GW of solar, which represents 15 per cent of its total installed capacity.

As pointed out above, the EU is on course to meet its 2020 renewables target and it is now discussing equally ambitious renewables targets for 2030. By 2050, Europeans hope to get all their power from renewable or carbon-free sources. This transition changes the nature of the power sector. Coal or gas-fired power plants burn a valuable resource for producing electricity. By contrast, the input (or variable) costs of wind and solar power are zero. That means that wind and solar power installations typically run irrespective of the electricity price. As the penetration of RES-E in EU power markets increases, conventional power plants are often idle and median wholesale electricity prices drop. Yet some conventional plants are still needed when a cloudy, low-wind period coincides with high electricity demand. They provide the back-up capacity for intermittent renewables sources. However, in the current system, coal and gas-fired plants will close unless they can recover their fixed (construction and maintenance) costs by charging very high prices in the few hours they are needed. To date there is no consensus whether such a system of highly volatile prices (very low prices when RES-E plants are sufficient to meet demand and very high prices if they are not) is politically sustainable and sufficient to incentivise the provision of back-up capacity needed to run the system securely. Consequently, member-states are contemplating alternative mechanisms to make it worthwhile for power companies to provide back-up capacity. Judging by current discussions around the EU, such incentives are likely to be non-market based and incompatible from one country to another.

Interestingly, only the market for one dimension is completely Europeanised – the market for emission allowances. In the day-ahead market a seemingly stable but arguably inefficiently interface – namely market coupling – is being established. On the intraday, reserve and balancing segment some countries are just about to introduce domestic markets – but cross-border trading is still limited.

Finally, most countries do not have markets for “greenness”, capacity and “location” which implies these dimensions are at most implicitly exchanged across borders. As a matter of fact, these dimensions are provided administratively in the member states based on national preferences. This is increasingly inefficient because cross-border exchange of these dimensions entails huge potential gains. A European market for renewable deployment could significantly better use the existing natural resources. For example, if the 32.3 gigawatts of subsidised German solar power had been installed in Greece, the value of the additional electricity generated due to the 50 per cent higher level
of sunshine would have valued around EUR 600 million in 2013\(^{31}\). In addition, less clustered built-up of renewables would increase the stochastic capacity contribution of renewables through geographic averaging over wide areas. Sharing of generation and demand response capacity across borders entails a substantial cost reduction potential. A level of supply security comparable to today's might be feasible with significantly less power plants if each country could count on its neighbours in situations of stress. “The reserve margin as a percentage [...] of system size declines inversely with the square root of system size (the statistical law of large numbers)”\(^{32}\). That is, when nine equally sized systems with a reserve margin of 21 per cent are joined together, the reserve margin in each country might be reduced by one third to 14 per cent.

With the role out of renewables the currently not (or only partially) internationally traded dimensions such as intra-day deliveries, balancing, supply adequacy, “greenness”, “location” and ancillary services are supposedly gaining in importance. The observed wind energy forecast errors for Germany in 2012, for example, imply that sometimes up to 6000 MW of additional capacities have to be switch-on in the intraday market while at other times up to 10000 MW have to be switched-off (see Figure 14). In 2012 in more than 1000 hours more than 2000 MW needed to be switched-on and in more than 400 hours more than 2000 MW needed to be switched-off.

**Figure 14: Day-ahead wind forecast error in Germany 2012 in MW**

![Histogram showing wind forecast errors in Germany 2012](source: Bruegel based on TenneT, Amprion, 50Hertz and TransnetBW)

1.2. Performance

\(^{31}\) Greece has an annual solar return of about 1500 kWh/kWp while Germany only features 1000 kWh/kWp. The baseload electricity price in Germany is currently about 38 EUR/MWh.

The integration of west-European day-ahead electricity wholesale markets is the biggest success of the single energy market policy. Already the possibility to reserve transmission capacities through auctions allowed better cross-border trade leading to partial price convergence between countries\(^{33}\) (Zachmann (2008)). The market coupling introduced between Belgium, France and the Netherlands in 2006; Belgium, France, the Netherlands, Germany and Luxembourg 2010; Italy and Slovenia 2011; as well as for some direct current links (Germany-Sweden, Norway-Netherlands, Poland and Sweden) substantially reduced price discrepancies between countries. For example, the frequency of hours with identical wholesale prices across the German-Dutch border rose from 12% in 2010 to 87% in 2011, when coupling was introduced\(^{34}\).

For other market segments performance depends on the region-specific arrangements. Cross-border balancing and intraday markets work quite well in the Nordic countries since 1999. Cross-border exchanges are significant and the market is liquid even though it only corresponds to 1% of the turnover of the day-ahead market. The system began trading activities in Germany in 2006/07. A joint intraday market was launched by the Dutch, Belgian and Nordic power exchange in 2012 but volumes are still very small. In other regions, for example between Poland and Germany no structured cross-border trade is possible in the intraday market.

The value of location of electricity deliveries is largely remunerated in the day-ahead and the intraday/balancing market in the Nordic countries. There, bringing electricity to supply-constraint parts of the country is providing higher revenues. For example in April 2013 bringing electricity from central Sweden (43,91 EUR/MWh) to the connected Norwegian region of Trondheim (46,37 EUR/MWh) was about 5 per cent more beneficial than bringing it to the likewise connected Norwegian region of Tromso (44,48 EUR/MWh). In the highly meshed continental European grid, such intra-country differentiation of electricity prices is not employed. Hence, bringing additional electricity to north Germany - where it is often excessively available due to the concentration of wind power in this region – has the same value than bringing it to south Germany where it is scarce when the sun does not shine on the Bavarian solar panels.

Finally, ancillary services, “greenness” and adequacy/capacity are currently not traded across borders. Table 9 indicates that the dimensions of the electricity sector that are currently increasing in importance are not internationally exchanged today. Moreover, the economic benefits of a European market for these dimensions are particularly big. Consequently, the costs of Non-Europe are increasing.

\(^{33}\) 59% of the studied hourly pairs of national wholesale electricity prices in 2002–2006 converged.

\(^{34}\) ACER Press Release (ACER- PR-02-12) (CEER- PR-07-12).
Furthermore, the different dimensions of electricity obviously interact. For example, (i) a country with a market for supply adequacy will typically see lower prices in hours with extremely high demand than a country without such a market – as the peak capacity in the first case is already remunerated through the capacity mechanism, (2) if international intraday trading is not possible because interconnectors cannot be nominated within the day, patterns of international day-ahead trading change, (3) if renewables are supported with feed-in tariffs negative prices at the wholesale market might appear and (4) if providing electricity to a specific supply constraint location is not remunerated by the market, other administrative instruments to ensure supplies need to be devised. Consequently, even if some parts of the market design are harmonised across borders one cannot speak of a functioning single market for this dimension as inconsistencies for the trading of other dimensions are spilling-over to the harmonised segment.

1.3. Ongoing progress

The inconsistencies in the national market designs are acknowledged at the European level. The Commission concluded that more top-down guidance in the form of a “Target Model” would be desirable. Hence, European Regulators and stakeholders came up with a “Target Model” by the end of 2009. The translation of the Target Model into framework guidelines (and eventually network codes) started in early 2010. In largely simplified terms, the process foresees that the Agency for the Coordination of European Regulators develops four framework guidelines on capacity allocation and congestion management, network connection, system operation and balancing. Based on these guidelines the

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35 Such as Transmission Must Run Service, Load Shed Scheme Service and Black Start Service.
European Network of Transmission System Operators develops European network codes. These European codes should cover all provisions that are relevant for cross-border trade. After these codes are (possibly amended and) approved by the Regulator they become binding. The current draft codes indicate that they are in fact guidelines that retain a lot of flexibility on how they are transposed into the individual member states network codes. For example, Article 24 of the draft network code on capacity allocation and congestion management allows member states to maintain the current model of capacity calculation based on a simplified representation of the network or to move to a model based on the true physical representation.

<table>
<thead>
<tr>
<th>National network operation in a single market</th>
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The operation of national or sub-national electricity networks has significant spill over effects onto neighbouring systems. These interdependencies were highlighted by the 2006 blackout in Germany that spilled over as far as the Iberian Peninsula, and by the 2003 blackout in Italy caused by a failure in Switzerland. The tedious searches for the parties responsible for these major incidents are a clear indication of the complexity of the electricity system and its governance.

Different TSOs have drawn different conclusions from the blackouts and the increasing injection of only partly predictable wind and solar power: (1) the Dutch TenneT and the Belgian ELIA tried to improve their capability to deal with cross-border events by merging with German TSOs, (2) several TSOs are installing devices to limit cross-border flows, in order to retain control over their domestic systems, (3) groups of TSOs established two regional centres for coordinating electricity system operation. Nevertheless, all systems are still operated nationally and collaboration is limited to ad-hoc initiatives. To prevent black-outs, the inadequacy of the cooperation arrangements for managing the real-time electricity system are currently resolved by imposing high security margins and by accepting inefficient nationally-focused operational decisions. This ultimately has an impact on the demand for transmission assets (for example, more phase-shifting transformers and fewer cross-border lines).

In addition to this European harmonisation of the network codes, some countries are improving their cooperation on issues such as system operation or day-ahead and intraday market coupling.

In terms of market coupling, for example, the stakeholders in central western European countries are working on introducing “flow-based market coupling” an algorithm that should allow optimal day-ahead and intraday trading of electricity between countries, given the real physical constraints of the network. Furthermore, initiatives are in place to extend market coupling to an increasing number of countries, e.g., coupling the Nordic and the central western region as well as coupling the Visegrad4 countries. Finally, closer cooperation on system operation is institutionalised in regional centres such as Coreso and the TSO Security Cooperation.

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36 Five major TSOs set up Coreso, a Regional Coordination Service Centre in 2008 in central western
1.4. Insufficiencies

The envisaged changes to the market framework are insufficient for establishing the internal energy market. First, the harmonisation of rules relevant for cross-border trade is organised as a bottom-up agreement between system operators based on general framework guidelines. These rules will be codified in the form of twelve ‘network codes’ that deal with technical issues such as the allocation of cross-border transmission capacity or the requirements for generators. Due to the complexity of the electricity sector and the widely differing preferences of stakeholders, a compromise providing no more than fairly general direction. In addition, the short timeframe for drafting the network codes – only 12 month are foreseen in order to complete the process in time for the 2014 deadline – could give undue influence to the TSOs that have a significant information advantage with respect to technical issues, and which are responsible for drafting the codes. It is, for example, conceivable that TSOs will shift costly responsibilities for system stability onto network users. The tight political deadline might force ACER and the European institutions (Council, Parliament and Commission), that have to adopt the codes through comitology, to favour speed over thoroughness. Only when the network codes are implemented we will learn how widely they might be interpreted. Consequently, this approach might lead to a wide range of rules in the participating national systems, which is unlikely to bring about workable interfaces at all borders for all dimensions of electricity trade.

Second, network congestion within countries will be dealt with differently from network congestion between countries. This discrimination is necessary to be able to consider countries as single price zones. For example, the price of electricity in the port city Hamburg is the same as in Freiburg in southern Germany even when the 600km transmission line between both cities is congested because of an abundance of power from coastal wind turbines. At the same time, the price in Freiburg might be different from the price in Colmar, 30 kilometres away in France, even when the transmission line between Freiburg and Colmar is not congested. Such a disregard of physical infrastructure, implied by the imposition of country-based price zones, induces an overly conservative calculation of cross-border transmission capacities. The end result is higher-than necessary price differentials between the zones/countries. In addition, planned technical improvements to the existing scheme (NTC-based market coupling) towards a more advanced scheme that takes the physical network better into account (flow-based market coupling) as well as the extension of market coupling to other countries is facing technical difficulties. At the beginning of 2013 it became known that the start of market coupling is postponed. Market coupling is a system that in principle would ensure that price differentials between countries only arise when no additional transmission capacity can be made available. Already last year the deadline for the start of the arguably more advanced “flow-based market coupling” in the Central-Western region (Austria, Benelux, Europe, and eleven TSOs set up the ‘TSO Security Cooperation’ in central eastern Europe.

37 This section largely draws on Zachmann (2013, p.6).
France) had to be postponed from September 2012 to November 2013 at the earliest\(^{38}\). Now, the coupling of the Nordic markets with the Central-Western markets has also been delayed from the beginning of this year to November 2013\(^{39}\).

Third, a more general point. According to the target model, the single electricity market will only provide harmonised signals for the operation of existing assets (including generation, transmission, storage and demand-side response). National markets/regulations will remain pivotal for investment in new assets. Nationally implemented markets for capacity and ancillary services favour the construction of certain technologies in certain countries. In 2010, about 40 per cent of newly installed power plants in the EU were either wind or solar (Jäger-Waldau et al, 2011). These types of plants are largely built based on national support schemes and are thus exempted from the single electricity market. If the share of nationally organised electricity sector segments (renewables, capacity mechanisms, ancillary services) continues to increase at the current pace, a ‘deep single market’ that also drives optimal investment decisions will be unachievable.

Consequently, the target model – even if fully implemented – is unlikely to deliver a fully-fledged single market in which it is irrelevant for the remuneration of a supplier whether it is sited in the same or a different country to its customer.

2. Funding, financing and planning of infrastructure

**Key findings**

- Most transmission lines in Europe continue to be based on national plans, centred around domestic welfare increase or network cost reduction and funded by domestic network users
- Cross-border transmission capacity has not been substantially increased in the past five years
- Previous European schemes (EERP and TEN-E) lacked the system-wide overview and were either underfunded or too short-term to unlock new projects
- The cross-border cost-allocation foreseen in the infrastructure package might potentially become quite powerful – but for the time being is only concentrated on a limited number of politically selected individual projects
- Network planning continues to be driven by the TSOs, which monopolise the information on the technical details of the energy system, but whose incentives are not necessarily aligned with societal objectives

The establishment of sufficient energy infrastructure is the second part of the EU’s vision for a single energy market. The Commission has estimated that EUR 142 billion will have to be spent on electricity grids up to 2020. There are diverse motives for extending and reinforcing the transmission network. Additional power lines might help the integration of renewables and produce implicit environmental benefits by, for example, allowing well-connected wind turbines to replace generation from polluting conventional power plants. Other reinforcements increase the reliability and operational flexibility of the transmission system or reduce congestion, dispatch costs and losses. Furthermore, network investment that allows more electricity to be transmitted to certain areas can substitute investment in generation or storage in import-constrained areas (‘load pockets’). Finally, a substantial benefit of transmission reinforcement is its mitigating effect on local market power, exercised by generators in load pockets (Awad et al, 2006). The diversity of the motivations makes it difficult to establish the total investment needed for the most cost-effective network development (see last section in the first chapter). However, the literature largely agrees that there is a need to increase transmission investment in Europe for three reasons.

First, investment has dropped to a historic low in the past decade, resulting in some modernisation backlog (see the historic figures in section 2.3 below). Second, the massive deployment of renewables (see Figure 1) will require additional investment in order to adapt the network to the changing location of electricity generation, and to allow for the wide geographic averaging of electricity injections from intermittent sources. And third, in order to develop the single market, sufficient electricity flows across borders need to be enabled.

2.1. Current approach

Funding

Most energy infrastructure in Europe is provided at member state level and funded through a “regulated asset base” model. To incentivise a TSO to construct new transmission infrastructure, the regulator allows the TSO to include all new assets in the ‘regulated asset base’ if they were part of the investment plan approved by the regulator. The regulator’s approval is based on a more-or-less sophisticated cost-benefit analysis. When the approved project is finalised, its capital cost becomes part of the ‘regulated asset base’. The TSO can now pass on the higher cost to the network customers. In short, a national regulator approves – based on the welfare of national network users – the investment plan of a national TSO that is then allowed to claim back the capital cost from national network users.

For some cross-border projects – such as the sea cables between Norway and the Netherlands – a second funding scheme has been tested. Investors might seek the right to

40 Regulators or governments need to approve all investment projects before they are allowed to be financed via tariffs.
41 In addition, single purpose lines to connect new users are often funded by the new generation, storage, or consumption unit that required the connection.
use a transmission line exclusively for some time. They then can earn money by selling line capacity to traders or by using it themselves to transport electricity from a low-price area to a high-price area. This is known as the merchant interconnector approach. This approach suffers from the drawback that the optimal investment for an individual company is less than the socially optimal investment – if the inter-connector is too big, the price difference between the zones collapses and there is no more money to be made through arbitrage. Hence, profit-maximising merchant investors have systematically under-built network extensions. Furthermore, such an approach is not well suited for complex networks.

A third approach has been to contribute public money to politically selected transmission projects. The EU has for example allocated funds for lines with cross-border effects in the framework of the Trans-European Networks for Energy (TEN-E, see discussion on page III-50) and the European Energy Program for Recovery.

**National Planning**

Currently, network extension in most EU countries is based on decentralised planning. TSOs forecast future power plant fleets and electricity demand in their areas. They deduce from these forecasts the likely need for new lines. National TSOs differ in the degree to which they coordinate with power plant and storage facility investors, administration, regulators, consumers and foreign TSOs. The TSOs will thereby propose projects that are commercially viable for them. For a TSO a line is viable when it reduces those cost that a TSO is not allowed to fully charge to the customers. Thus, on the one hand a TSO might be inclined to propose even overly expensive lines that slightly reduce the re-dispatch cost of a TSO as long as the regulator accepts that the TSO can include the investment cost in the regulated asset base. On the other hand a TSO might not be interested in closing a minor gap that prevents substantially increasing international electricity trade when this would cause higher re-dispatch cost. That is TSOs do not necessarily have an incentive to propose the most cost-effective line. Nevertheless, they are the only body carrying out the planning in all European countries as no other institution has sufficient technical expertise for this complex task. The regulators largely rely on the information provided by the TSOs when they assess the economics of the individual projects the TSO has proposed. Furthermore, even policy makers and regional authorities are typically only considering the projects proposed by the TSOs when deciding on corridors or public co-funding.

**European Planning**

Until 2010 transmission planning was in general an exercise conducted on the level of the member states (or transmission zones). Projects with cross-border impacts were of course discussed and adjusted between TSOs, but no joint planning of the networks was carried out. Since 2010 a formal procedure has been put in place to structure these interactions. TSOs now have to share some of this information with the European Network of Transmission System Operators for Electricity (ENTSO-E) which uses these inputs to build a 10-Year Network Development Plan. This European plan was the first common European network modelling exercise based on massive data gathering and a structured consultation process. Hence it is a big step towards more transparent and more common
network planning. The European plan identifies extensions, which affect transfer capabilities between individual TSOs, needed in addition to what the TSOs are planning for themselves. Supponen (2011) has noted “ACER has to give an opinion on the ten year network development plan and to verify that the national plans are coherent with the European ten year plan. If they are not, ACER shall make recommendations to amend either the national plan or the ten year plan. ENTSO-E and the ACER shall monitor the implementation of these plans”. Based on the 10-Year Network Development Plan a number of “projects of common interest” (PCIs) are identified. These projects (i) are granted a preferential treatment in order to speed up the necessary authorisation process, (ii) are funded jointly by the concerned TSOs (ACER can decide on a cost-distribution key if national regulators cannot agree) and (iii) might – when the Connecting Europe Facility is in place - also benefit from European co-financing.

2.2. Performance

Recent network extension

<table>
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<tr>
<th>Key findings</th>
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<td>Transmission network development has been quite different in different member states.</td>
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<tr>
<td>Cross-border transmission capacity has in general not substantially increased in the past five years.</td>
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</table>

While the TSO forecast and the European Commission proposal both foresee significant growth in transmission investment, network developments have at best been mixed in the last five years. On the one hand, Spain has seen a boom (and bust) in terms of extending the size of its high-voltage network. On the other hand German investments remained at their 2007 level for half a decade and net transfer capacities with neighbouring countries have not increased. Finally, France almost doubled the investment in transmission without extending the length of the network. In terms of international transmission lines France increased the capacity of the lines from/to Belgium and Spain as well as towards Germany, maintained the capacities from/to Switzerland and England and reduced the capacities from Italy and those towards Germany. Overall, the total net transfer capacity from/towards France slightly decreased by 1 per cent / 9 per cent between 2009 and 2013.

Table 10: Change in annual average net transfer capacity between 2009 and 2013

<table>
<thead>
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<th>Import from France</th>
<th>Export to France</th>
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<tbody>
<tr>
<td>Germany</td>
<td>21%</td>
</tr>
<tr>
<td>England</td>
<td>-6%</td>
</tr>
<tr>
<td>Belgium</td>
<td>8%</td>
</tr>
<tr>
<td>Spain</td>
<td>48%</td>
</tr>
<tr>
<td>Italy</td>
<td>-39%</td>
</tr>
<tr>
<td>Switzerland</td>
<td>-2%</td>
</tr>
</tbody>
</table>

Source: RTE[https://clients.rte-france.com/lang/an/clients_producteurs/cie/ntc_annuelles.jsp]
By contrast, transmission investment is on the rise in the United States and China. In China, in 2009 alone, 2078 km of ultra-high voltage transmission lines were added and state investment in the power transmission system was EUR 38.5 billion (Cheung, 2011). In the US, the recent increase in transmission investment is predicted to continue from, currently, about EUR 7 billion per year to EUR 10.5 billion per year. Even though investment volume is an imperfect proxy for transmission system improvements, Europe appears to be falling behind on this critical issue, even though it is considered crucial for achieving all three energy policy goals: security, competitiveness and sustainability.

Infrastructure development is, of course, not primarily about the kilometres built and the money invested, but about the substantive improvement of the network’s capabilities. Hence planning and funding the right projects is crucial.

**Figure 15: Length of 220kV circuit in km at the end of the year**

![Figure 15](image)

*Source: ENTSO-E*

**Figure 16: Length of 400kV circuit in km at the end of the year**

![Figure 16](image)

*Source: ENTSO-E*
Figure 17: Investments in electricity networks by TSOs

Source: BNetzA, REE, RTE, Ofgem

Policy performance

**Key findings**

The European instruments have at best performed modestly. The Trans-European Energy Networks were seen as too small and the selection of projects too political. The European Energy Programme for Recovery managed to significantly support important projects. Because of the tight schedules and given the large size of the projects it is likely that some of the projects would have proceeded without EU co-funding (i.e., the need for the funding is difficult to establish). Finally, the first 10-year network development plan in 2010 was seen as a mere compilation of national plans and implementation of almost half of the projects was delayed. The second plan in 2012 contained important methodological improvements, but still does not provide an independent top-down evaluation and prioritisation of network extension needs.

The Trans-European Energy Networks (TEN-E) funding program started in the mid-90s to push the development of the European energy infrastructure, in particular the electricity and gas networks. It was believed that private interests alone were enough to drive the projects forward with no need for strong EU intervention in the implementation phases. A contribution for the initial exploratory phases was deemed sufficient to speed up the process.

Therefore, the TEN-E program was established to facilitate the initial phases of a project, namely feasibility studies. Since it did not need to cover implementation costs, which
constitute the bulk of the total project costs, the allocated budget for the TEN-E program was always low and averaged around EUR 20 million annually.

Typically, aid would be given to partially cover the costs of studies, which could then result in the implementation of the project itself. However, only a small percentage of implementation costs could be covered by TEN-E funding. In any case, the first years of operation (before 2001) saw only 2 out of more than 50 projects receiving TEN-E funds for their implementation phase. Later in time the TEN-E program changed to accommodate the need for more flexible aid, and started to focus increasingly more on projects of common interest and their implementation phase.

The period 1996-2006 saw 354 applications for funding, of which 211 (60%) were approved. Each received EUR 1.3 million on average. The selection was a bottom-up process and left no space for the identification of infrastructure gaps in a top-down manner.

In a 2009 report evaluating the program in the period 2000-2006, 76% of the beneficiaries stated that the TEN-E co-funded studies provided little to no help in facilitating the further co-financing of the investment. Also, 78% of the beneficiaries believed the study for which they received funding did not further the investment project in other ways. Additionally, almost two thirds of the member states found the TEN-E instruments to be inadequate in steering and guiding the development of the European energy structure. Furthermore, even if 92.6% of the studies that were funded in the period 2004-2006 recommended to implement the project, only 48% had already started in 2009, and only 8.7% were completed.

Finally, the selection of projects has also been criticised. Proost et al (2010) find that many projects do not pass the cost-benefit test and only a few of the economically justifiable projects would need European subsidies to make them happen.

Table 11: TEN-E budget

<table>
<thead>
<tr>
<th></th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feasibility Study</td>
<td>50% max</td>
</tr>
<tr>
<td>TEN-E funding</td>
<td>10% max</td>
</tr>
</tbody>
</table>
The TEN-E program aimed to act as a catalyst, and thus played an important role for risky projects and feasibility studies. However, the approach was a bottom-up selection of existing projects. The absence in the TEN-E program of a top-down approach that could push for the development of the most important infrastructure projects, and the shift in focus towards a low-carbon energy system led to the development of the TYNDP (2010, 2012).

The European Energy Programme for Recovery (EEPR) was established in mid-2009 to provide financial support to highly strategic projects in the energy sector. It was created not only as means to bolster the completion of the internal energy market and the reduction of greenhouse gas emissions, but also as a means to stimulate economic activity and growth in a time of crisis. The allocated budget was of about EUR 4 billion of which almost 60% were allocated for the electricity and gas networks. The remaining funds were for offshore wind projects and carbon capture and storage projects. 59 projects received funding to date. Of these, 12 involve the electricity infrastructure and received funding for EUR 904 m (22.7% of the total budget), while the 17 gas interconnection projects received EUR 1285 m.

Up to the end of 2011, 44 projects were selected. They involved gas pipelines (incl. reverse flow capability), gas storage units, electricity interconnectors and off-shore connections. When the Commission’s 2012 report was written, 30% were completed, 41% were proceeding according to schedule, while another 30% were progressing slower, behind schedule. Given the long advance times of investments in the energy sector, the substantial success rate of the projects under the EEPR indicates that many of them were funded in a very mature state. It is hence not unlikely, that a number of the projects would have proceeded without the EEPR money.

The 10 year network development plan is one of the most ambitious projects for European network infrastructure. The plans imply, for the first time, to take the European dimension of network planning into consideration. The quality of the plans increased significantly between the pilot in 2010 that was merely a collection of national plans and the plan in 2012 that was based on some top-down analysis. For 2014 ENTSO-E foresees a formal cost-benefit analysis, the formal consideration of projects proposed by other parties than the TSOs and a further increase in stakeholder involvement.

So far, due to the non-binding nature of the plan, its actual implementation is somewhat mixed. The evolution of the status of the individual projects in the 2010 plan reported in the 2012 TYNDP indicates that about half of the projects are delayed. According to this report only 52 per cent of the projects proceed as planned, 28 per cent are postponed.

<table>
<thead>
<tr>
<th></th>
<th>Budget</th>
<th>Allocated</th>
<th>Allocated yearly</th>
<th>Average allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>TEN-E 95-99</td>
<td>90.20</td>
<td>18.04</td>
<td>0.79</td>
<td></td>
</tr>
<tr>
<td>TEN-E 00-06</td>
<td>148.00</td>
<td>126.20</td>
<td>18.03</td>
<td>1.30</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th># Proposals</th>
<th>Funded</th>
<th>% funded</th>
</tr>
</thead>
<tbody>
<tr>
<td>TEN-E 95-99</td>
<td>168</td>
<td>114</td>
<td>67.9%</td>
</tr>
<tr>
<td>TEN-E 00-06</td>
<td>186</td>
<td>97</td>
<td>52.2%</td>
</tr>
</tbody>
</table>
because of delays in the authorisation process, 6 per cent are delayed because generators rescheduled their plans and 13 per cent are delayed for other reasons.

2.3. Ongoing progress

Key findings

- The EU Infrastructure Package will provide accelerated permitting, provisions for cross-border cost-sharing and possibly EU financial assistance to projects of common interest.

The EU identified a huge investment gap for energy infrastructure: EUR 400 billion for distribution networks, EUR 140 billion for electricity transmission (EUR 40 billion for smart grids, EUR 70 billion for interconnectors, EUR 30 billion for offshore connections) and EUR 70 billion gas transmission. Of the transmission they estimate that EUR 60 billion are not commercially viable and EUR 40 billion are not getting permission. To close this gap the Commission proposed the Energy Infrastructure Package that especially targets investments in interconnectors.

The corresponding Regulation on guidelines for trans-European energy infrastructure has been amended and adopted by Parliament and Council on April 17th 2013. The guidelines define a small number of trans-European priority corridors on which European action for energy infrastructure should primarily focus. For electricity, four corridors are determined. The Commission will identify ‘projects of common interest’ that are necessary to implement the corridors. These projects will primarily benefit from an accelerated permit granting, provisions for cross-border cost-sharing and possibly EU financial assistance to projects of common interest.


43 Northern Seas offshore grid (“NSOG”): integrated offshore electricity grid development and the related interconnectors in the North Sea, the Irish Sea, the English Channel, the Baltic Sea and neighbouring waters to transport electricity from renewable offshore energy sources to centres of consumption and storage and to increase cross-border electricity exchange. North-South electricity interconnections in Western Europe (“NSI West Electricity”): interconnections between Member States of the region and with the Mediterranean area including the Iberian peninsula, notably to integrate electricity from renewable energy sources and reinforce internal grid infrastructures to foster market integration in the region. North-South electricity interconnections in Central Eastern and South Eastern Europe (“NSI East Electricity”: interconnections and internal lines in North-South and East-West directions to complete the internal market and integrate generation from renewable energy sources. Baltic Energy Market Interconnection Plan in electricity (“BEMIP Electricity”): interconnections between Member States in the Baltic region and reinforcing internal grid infrastructures accordingly, to end isolation of the Baltic States and to foster market integration inter alia by working towards the integration of renewable energy in the region;
Permit granting for projects of common interest should be speed up to less than three and a half year by creating a one-stop-shop to manage the permit granting process, ensure most preferential treatment in Member States and increasing transparency and enhanced public participation.

To fund these projects of common interest, the regulation obliges the national regulators to grant sufficient returns for the corresponding projects. The by probably most important provision in the regulation is the empowerment of ACER to enforce a sharing of construction costs between the concerned national regulators, in case they find no solution themselves. Finally, the regulation determines the conditions for eligibility of these projects for EU financial assistance. EU funding for this regulation is to be negotiated in the context of the Connecting Europe Facility financing instrument. The Commission has proposed that EUR 9.1 billion be allocated to energy infrastructure in the next multiannual financial framework (2014-2020). On 8 February 2013 the European Council agreed to reduce the amount to EUR 5.1 billion.

2.4. Insufficiencies

Key findings

The EU Infrastructure Package is supposed to deliver more cross-border electricity transmission. It is an extension of the current system of national-welfare centred regulations, a system which does not target the optimisation of the EU electricity network, and as such is inconsistent with a truly single market.

The ‘regulated asset base’ model has proved workable in the national context. However, in the international or cross-border context it fails because both domestic and cross-border transmission lines cause significant spillovers onto neighbouring countries’ networks that are not properly considered by national regulators and TSOs. The most straightforward problem is that the benefit of a new cross-border line might concentrate in one country, while its cost mainly accrues in another. The regulator in the latter country will not be inclined to approve a corresponding investment plan. The extreme version of this case is that a domestic line in one country to reduce congestion in a neighbouring country would never be approved by the first country’s regulator. In addition, cross-border lines – even though they have a net benefit – might, for example, shift welfare from consumers to producers within a country. If regulators focus in their cost-benefit analysis only on consumer welfare, they might be inclined to oppose such projects. As a consequence, network development based on national cost-benefit analysis is not going to deliver an efficient European electricity network.

The current legislation and practice on European planning and funding will not deliver a truly European electricity network, either. The European 10 year network development plan is a non-binding proposal by ENTSO-E to the individual TSOs. As the plan is developed by the European transmission system owners and operators it is likely to focus on projects that are commercially viable for this segment of the industry, even though
other projects might be more sensible from a societal point of view. In addition, no stakeholder is legally accountable if the information it transmitted to ENTSO E, on which the European plan is based, proves wrong ex post. Hence, the plan cannot ensure synchronisation of the different stakeholders’ investment decisions. The lack of accountability for the accuracy of submitted information may allow individual stakeholders to distort or hide information in order to influence the overall European plan. The non-binding nature also casts a degree of doubt over the credibility of the European plan as it may allow individual TSOs to delay investments in certain lines they are not particularly interested in. This uncertainty may discourage generators from coming forward with investments, the profitability of which depends on the realisation of certain lines. Finally, the technical planning and the resulting selection of projects is not transparent. The model and major assumptions are not disclosed. Consequently, challenging the set-up proposed by ENTSO-E is virtually impossible.

The special permitting and funding rules for the projects of common interest – in particular the right of ACER to enforce a compromise on cross-border cost sharing - are big step in the direction towards a more European network infrastructure. However, the focus on a limited number of projects risks ignoring the system nature of the meshed energy network. Consequently, the emphasis might be on building more border crossings rather than investing in the most efficient marginal improvements. In addition, in order to satisfy private or public interests (e.g. for low or high prices) and as the selection is based on a bottom-up process, only lines with limited impact might be brought forward. Finally, despite detailed criteria, the ultimate choice of projects to be granted the ‘common interest’ status might not be driven by efficiency motives, but by the requirement to disburse the scarce EU budget money ‘fairly’.

Consequently, the infrastructure package is unlikely to be a final breakthrough in the development of infrastructure for the single European electricity market.
Proposal

Key findings

- A “grand bargain” solution to implement a purely European energy market is unlikely because of the heterogeneous preferences and national path-dependencies within the EU.

- A second-best solution would consist of complementing the current national-based system with a European layer of system planning and operation.

- Efficiency could be further increased by making more dimensions of electricity tradable across-borders. This would require introducing transfer mechanisms to overcome inherent redistribution effects.

Based on the above analysis, we will in this part describe a first-best solution for European energy infrastructure investment to meet the Union’s energy policy objectives of competitiveness, sustainability and security of supply. We will then outline the political constraints faced by such an approach. For example, any major reform that involves the harmonisation of national schemes will have significant redistributive effects on market participants. Some countries might even be worse-off when introducing a solution that is preferable from the total-welfare perspective. This is amplified by political considerations and different preferences. Thus, we will ultimately explore the properties that a feasible solution to set-up a truly European energy infrastructure investment should have.

1. A first best market-based solution

Comprehensive electricity markets are complex structures. Individual countries or regions have been able to come up with viable approaches for using the existing, and constructing new parts of the energy system (see box). One first best market-based solution consists of:

1) A **single regulator** overseeing the development of the market design and regulating the tariffs of the natural monopoly part of the business (transmission system operator, transmission system owner, distribution system operator and owner).

2) A **regulated independent system operator** that optimises the dispatch of the existing units in a cost-minimising way through a transparent mechanism, and that proposes network extensions based on a process that involves all stakeholders.
3) Owners of the transmission system can choose whether they want to build new lines according to the independent operator’s plans. If not, alternative infrastructure providers might carry out the projects at the regulated terms.

4) A consistent market design that clearly attributes responsibilities to the different participants, creates the necessary interfaces between them and defines products (for the different components) that can be traded.

In the European context this would imply: European network planning, a single European market design for all aspects, a European system operator and a European regulator.

### International experience

The United States’ transmission systems are operated through a wide spectrum of regional schemes. Some have sophisticated wholesale markets and independent system operators (ISOs), while others possess neither. However, motivations for transmission investment are largely the same as those in Europe: deployment of intermittent renewables (47 GW of wind in 2010), historic investment backlog and regional integration within the US. However, the way the investment needs have been addressed, and the levels of success in addressing them, differs markedly in the US, which has been more successful. In the period 2007-11 a total of 16,000 km of new lines were installed and the volume of investment shows an increasing trend.

California ISO (CAISO) is one example of a successful US model. CAISO is responsible for the operation and extension of a large portion of the California grid but the grid hardware itself is owned by the transmission owners (TOs).

**Funding:** CAISO collects a regulator-approved transmission charge from all consumers connected to the CAISO grid. It retains a grid management charge, and redistributes revenues from the transmission access charge to participating TOs. The tariffs of TOs joining the CAISO grid are transitioned into a grid-wide transmission charge over a 10-year period. CAISO revenues are determined by the regulator.

**Operating:** CAISO optimises the entire electricity system centrally by setting higher prices in import constrained parts of the network and lower prices in export-constrained parts.

**Planning:** CAISO has developed a formalised 23-month transmission planning process, TEAM, which attempts to incorporate five main principles into their planning studies: benefit framework, full network representation, market prices, explicit uncertainty analysis and interactions with other resources. TEAM includes a cost-benefit analysis of investment proposals which uses flexible weighting of the different welfare components, allowing for the assessment of a proposal from the perspectives of different stakeholder groups (Wu et al, 2006). The result is a project submission window in which transmission element proposals (both economically driven and policy-driven) are evaluated, and project sponsors are selected to construct and own the approved elements.
The process has been very successful in incentivising the construction of approved transmission lines. An impressive 87 per cent of the transmission lines approved in 2005 had been completed by 2009. Since 1999, transmission investment has increased by 84 per cent. A ratepayer organisation claims that this ‘success’ essentially represents excess transmission being funded through increasing tariffs (since 1999 load has only grown by 9 per cent in that time). The organisation asserts that reasonable, and perhaps economic, alternatives (some non-infrastructure) are not being considered. Indeed, the US Department of Energy has begun to look at non-transmission alternatives. From a European perspective the possibility of the oversupply of transmission, and the developing discussion about how to encourage non-transmission alternatives, are a testament to the success of models like CAISO that allow the discourse to be elevated a higher level.

2. Political challenges

A first-best market design is likely to be politically unfeasible in the European context for three reasons. First, the necessary changes compared to the current situation are dramatic and would produce significant redistributive effects (see 2.1). Second, a European solution would deprive member states of the possibility to manage their energy systems nationally (see 2.2). And third, a single European solution might fall short of being well-tailored to the consumers’ preferences, which differ substantially across the EU (see 2.3).

2.1. Redistributive effects

A single European market design would result in significant redistributive effects. If, to give an illustrative example, Europe were to introduce the US standard market design, all stakeholders would be affected. The national power exchanges would lose their role of traders for physical products and hence a major share of their current business. The transmission system operators would be reduced to mere owners of the physical infrastructure, while network extension planning and system operation would be transferred to an independent agency. The support for newly installed renewables would need to be reorganised, possibly in a way that is beneficial for some regions with favourable resources and less beneficial for other regions. Consumers in zones with low prices might be faced with increasing prices when better operation of the network allows the exporting more of ‘their’ cheap energy to other zones. And flexible generators might lose some of their value when demand response reduces prices in situations of scarcity. Such redistributive effects for stakeholders translates into redistributive effects between member states – as each has a different electricity sector to start with. A quantification of these effects is strongly dependent on the details of the final market design and can only be conducted based on substantial modelling. But to give an example of the order of magnitude, we evaluate the impact of a hypothetical European capacity mechanism. If every member state would have to ensure that the remaining margin over the reliable available capacity reaches the European average of 10% (see Figure 18) by exchanging
capacity credits, some member states would be significantly better off, while others would have to pay.

**Figure 18: Remaining margin over the reliable available capacity for 2013**

![Graph showing remaining margin over the reliable available capacity for 2013.](source: ENTSO-E 2013)

At a price of 100 Euro/MW-day\(^4\), the existing French overcapacities could generate – in our purely illustrative example – capacity credits worth EUR 140 million per year while Germany would have to buy credits worth EUR 306 million (see Figure 19).

**Figure 19: Gains losses of a simple (zero-sum) European capacity mechanism in million Euro**

![Graph showing gains and losses of a simple European capacity mechanism in million Euro.](source: own calculation based on ENTSO-E figures on system adequacy)

\(^4\) This is the order of magnitude observed in the JM Base Residual Auctions in 2013.
Finally, institutions will also oppose the loss of powers they are entitled to in the current system. National and sometimes even subnational regulators, power exchanges and even the corresponding mainly national advisory, supervisory and research institutions might perceive themselves vulnerable to such dramatic system change.

2.2. Perceived loss of sovereignty

In a truly single energy market the scope for national energy policies is significantly reduced. When economic signals in harmonised markets are driving investment decisions, member states will find it difficult to ensure that a certain – politically desirable – fuel mix materialises in their country. For example, a harmonised renewables scheme might reduce the number of new solar panels in the north of Europe, while a pure market framework for conventional investments might make new nuclear units un-investable in Europe\textsuperscript{45}.

Furthermore, using national market design choices to favour certain market participants for industrial or social policy reasons is not possible in a single market. For example, artificially low network tariffs for customers connected to the high-voltage network – typically energy-intensive customers – at the expense of other domestic consumer groups would then only be possible in a harmonised way at the European level. Likewise, supporting solar panels through preferential network access and exemption from obligations to provide system stabilising services could only be agreed jointly. Finally, subsidising customers in supply-constrained areas by enforcing a unique electricity price per country would be incompatible with the first-best market design.

2.3. Different preferences

Harmonising market designs might not only create winners and losers (see 2.1) but it might also ignore significant differences in the preference of national consumers. One illustrative example is security of supply. Some countries attach significantly higher value to an uninterrupted electricity supply than others. One indication is that rich countries in particular develop electricity systems with significantly lower interruptions than the other EU countries. Hence, hard-wiring a one-size-fits-all level of security of supply risks not being appropriate for any country.

\textsuperscript{45}See Lévêque (2013).
3. Properties of a feasible solution

The integrated first-best solution - a single European system operator, regulated by a single regulator, which develops the network in coordination with generators and consumers – appears politically infeasible because of the redistributive effects, the loss of sovereignty of member states over “their” electricity systems, the disregard of certain national preferences and the institutional changes it would involve.\textsuperscript{46}

To nevertheless reap significant benefits from an integrated European electricity market, we propose a bold blueprint for a European system to fund and incentivise infrastructure development. The approach is fourfold: (1) implement vertical unbundling; (2) add a European system-management layer; (3) establish a stringent planning process; and (4) phase-in European cost-sharing.

3.1. Implement vertical unbundling

Léautier and Thelen (2009) find that vertical separation is one key-requirement (the other being a well-designed incentive scheme) for reducing network congestion. It is important that transmission system operators should not be concerned with the interests of affiliated generators. The legal basis for this has already been adopted in the third EU

\textsuperscript{46} This section largely draws on Zachmann (2013).
energy sector liberalisation package of 2009. Implementation of the unbundling requirements should have been done by 3 March 2012. The European Commission acknowledges that in most member states the unbundling provisions are not yet fully transposed.

3.2. **Add a European system management layer**

National system operation has major spill-overs onto neighbouring countries, but also affects network investment incentives. Uncoordinated system operation increases the incentives for national operators to close their borders in order to ensure system stability. The straightforward way out of this dilemma is to add a European system-management layer, in other words, centralising and monitoring electricity system information in real-time. This would enable throughput of electricity through national and international lines to be safely increased without any major investments in infrastructure. This would neither require TSOs to merge nor to be expropriated, nor would it substantively infringe on national sovereignty over the security of national electricity systems. A European control centre would complement national operation centres and help them to better exchange information about the status of the system, expected changes and planned modifications. The ultimate aim should be to transfer the day-to-day responsibility for the safe operation of the system to the European control centre. To further increase efficiency, electricity prices should be allowed to differ between all network points across and within countries. That is, electricity in Hamburg might be cheaper than in Munich on the wholesale market if there is a lot of wind in the North Sea, while the sun is not shining on Bavarian solar panels. This would provide the correct incentives for switching off coal-fired power plants in the north and switching on gas turbines in the south in order not to overcharge the network. In addition, investors in generation (or load) will base their location decisions on these locational price signals. This will reduce congestion over time, by creating an incentive for generation/load to move to net electricity deficit/surplus areas.

3.3. **Establish a stringent planning process**

Current approaches to network planning suffer from a number of shortcomings: they essentially reflect the interests of TSOs, which make planning decisions without full information about cross-border impacts; the plans are non-binding, meaning stakeholders are not obliged to comply, and so do not provide the necessary synchronisation of investments in the energy system; the planning process is non-transparent as far as the modelling is concerned; and the planning process is ‘technocratic’ in the sense that it does not *a priori* take the concerns of residents into account.

Harmonising national network planning rules is administratively difficult and would take many years. To avoid this, the European approach is to use the ten-year network development plan (TYNDP) to ensure the consistency of the results of national planning with European objectives. To achieve this, ACER must provide opinions on the
consistency of the individual national ten-year plans with the TYNDP. However, the consistency of national plans with European objectives cannot be enforced by ACER or any EU institution (Commission, Parliament and Council) – Regulation 714/2009 explicitly refers to the “non-binding Community-wide ten-year network development plan”. Hence, to ensure the consistency of individual national network plans and to ensure that they contribute to providing the infrastructure for a functioning single market, the role of the TYNDP needs to be upgraded. This could be enacted by obliging national regulators to only approve projects planned at European level unless they can prove that deviations are beneficial.

The boosted role of the TYNDP that this would entail would need to be underpinned by resolving the issues of conflicting interests and information asymmetry. Two approaches to this are conceivable: first, relying on thorough cross-checking of ENTSO-E proposals by the regulator, or, second, shifting the entire planning process to an independent body. In the first case, ACER should be requested and authorised to thoroughly check that the TYNDP maximises the welfare of current and future European citizens and that national plans are consistent with the TYNDP. This implies that ACER would not only rely on the modelling results that TSOs use to justify their plans, but would have tools of its own for impartial evaluations. ACER should not resort to consulting proprietary models that are not fully disclosed and that have to be repeatedly procured. Instead, ACER – or another public body – should invest in the capabilities to build, manage and use a European open-source energy model. Based on a substantial upfront investment in a suitable model, ACER would structure a process in which all relevant stakeholders can support ACER by updating the assumptions and the modelling. Individual stakeholders will still have better information on their parts of the electricity system. TSOs will know the network better than any independent network modeller, generators will have a clearer view of their individual plans, large consumers (including distribution system operators) will have more information on their future load, and residents will best be able to evaluate the acceptability of proposed lines. Thereby, ACER’s power to approve the TYNDP based on its own modelling results would shift the burden of proof to the stakeholders (including ENTSO-E) in case they disagree with ACER’s conclusions. This would give the stakeholders an incentive to disclose private information. In addition, the open-source nature of the model would allow inconsistencies to be identified, and improvements to be proposed. Of course, state-of-the-art could only be ensured by continued investment in the model’s capabilities.

In the second case, resolving the issues of conflicting interests and information asymmetry in network planning could also be achieved by building on the significant effort that ENTSO-E has made in developing the TYNDPs. Using the TYNDP expertise would require that its governance structure be made independent from the interests of TSOs. Hence, a dedicated TYNDP governance structure should be developed that is representative of all electricity sector stakeholders (in a membership committee). An executive board that is independent from industry interest should have full operational control. Finally, the by-laws of the institution governing the TYNDP would need to ensure that the model used for planning is made fully transparent and open source.
Irrespective of the model chosen (‘cross-checking’ or ‘independent planning’), it is essential to make both the input from stakeholders and the final plan binding in order to improve the synchronisation of investment. That is, stakeholders that, for strategic or other reasons, deviate ex post from their predictions (e.g. building a power plant or consuming electricity at a certain point of the network) will be liable to claims for damages from other stakeholders.

Finally, planning will not be able to make all stakeholders equally happy. And certain choices that do not affect overall welfare might have substantial redistributive effects. To rectify the distributional consequences, an ultimate political decision by the European Parliament on the entire plan could open a negotiation process around selecting alternatives and agreeing compensation. This need for democratic approval ensures that all stakeholders have an interest in ensuring a maximum degree of balance of interest in the earlier stages. In fact, transparent planning, early stakeholder involvement and democratic legitimisation are well suited for minimising as much as possible local opposition to new lines.

The delivery of the plan would then be left to the TSOs or any other investor willing to deliver individual lines according to the regulated conditions. In case of multiple interests, the national regulator might choose the best value offer.

3.4. Phase in European cost-benefit sharing

Cost and benefit sharing is a critical element in the discussions about EU electricity networks. Different stakeholders have diverging interests, and it sounds unnatural to require stakeholders to pay for a transmission line that actually reduces their profits. On the other hand, stakeholders that are the major beneficiaries of a new line should not be able to pass all the cost onto society. Hence, all easily attributable cost should be levied on the responsible party. If new generation requires grid reinforcements, the reinforcements should be largely paid for by the generator (deep connection charges). In this way, the investor has the right incentives to trade-off high locational prices in one place (e.g. close to consumption centres), with cheap network access in another place (e.g. in a zone where an old power plant has recently been shut down), and good access to resources in a third place (e.g. for a wind turbine, a zone with high constant wind).

For all remaining network extensions the question is how to share the cost between network users in different regions. Having all line extensions in Sweden being equally financed by Bulgarian network users seems difficult. Having a Belgian line that is

47 It would be sensible to harmonise the allocation of network cost to different types of network users (consumer, generator, storage) across countries. According to Billette de Villemeur and Pineau (2012), trade between different regimes can increase inefficiency. For example, if in some countries only consumers have to pay the entire network cost while in another all costs are borne by the generators, more generators will move to the first country and more (industrial) consumers to the second country. Hence, more electricity will have to flow between countries and congestion is likely to increase.
required to accommodate loop-flows caused by inner-German imbalances being paid for only by Belgian network users is not reasonable either.

Based on the assumption that the outlined network development plan delivers an efficient proposal, and that new generators have to pay deep connection charges, we suggest that some redistribution is unavoidable. The reason is that, so far, even the most sophisticated cost-benefit analysis models have been unable to identify the individual long-term net benefit in an uncertain environment. For all infrastructure (e.g. rail and road), there is some socialisation of the costs of individual projects within the different regions of a country. Hence, we propose that consumers in all nodes that are expected to receive more imports through a line extension should be obliged to pay a certain share (e.g. half) of the line extension through their network charges, while the rest of the cost is socialised to all consumers\textsuperscript{48}. Such a cost-distribution scheme will involve some intra-European redistribution from the well-developed countries (infrastructure-wise) to the laggards. However, such a scheme would perform this redistribution in a much more efficient way than ad-hoc disbursements by the Connecting Europe Facility to politically chosen projects, because it would provide the infrastructure that is really needed.

\section*{4. Conclusion}

Implementation of this proposal will deliver the infrastructure needed to achieve the European energy policy targets in the field of electricity. It will increase the reliability of the network, enable a truly borderless European electricity market, and facilitate the integration of renewables. If the EU decides to wait for the results of the non-binding plan to materialise in the 2020s, valuable time will have been lost. All approaches involving throwing money at the problem to achieve flagship projects will fail to resolve the complex underlying issues. After three energy sector packages and 20 years of work, the EU possesses many of the key institutions and laws necessary for achieving the single electricity market. In the past, the benefits of a more coordinated system have not been great enough to outweigh the significant political and transaction costs required to achieve such a system. However, recent developments (unbundling, renewables, more trade) have substantially increased the value of greater coordination. It is the right time for the EU to take a bold step towards a borderless electricity infrastructure.

\textsuperscript{48} If a harmonisation of network tariffs were to be envisaged this fraction (‘half’) might also be made time-variant. For example, one might start with 100 percent in the first year and go to 90 percent in the second year and end with zero percent in the tenth year.
References

2. ACER Press Release (2012): “Progress made and challenges ahead for EU gas and electricity market integration” reported by ACER/CEER, Brussels, 29 November 2012
17. ECF (2011): “Power Perspectives 2030 – On the road to a decarbonised power sector in Europe”
22. Heddenhausen, M. (2007): “Privatisations in Europe’s liberalized electricity markets – the cases of the United Kingdom, Sweden, Germany and France”, Research Unit EU Integration, German Institute for International and Security Affairs
Appendix

Table 12: Literature Survey

<table>
<thead>
<tr>
<th>COMPETITION</th>
<th>Dep var: ln(employment)</th>
<th>Indep var: divestiture % effect= -42.4% **</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jennifer K. Shanefelter (2008): Restructuring electricity generation industry has improved productive efficiency. In particular, divestitures of generation assets have reduced employment and aggregate payroll expenses.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kira R. Fabrizio, Nancy L. Rose and Catherine D. Wolfram (2007): Restructuring electricity generation industry has reduced costs and input use. All IOU (Investor Owned Utilities) plants improved their efficiency relative to Municipal and Federal plants during the late 1980s and early 1990s.</td>
<td>% change in costs per MWh from 90 to 96: -13.5 in Restructuring States, -5.1 in Non- Restructuring States.</td>
<td></td>
</tr>
<tr>
<td>Lucas W. Davis and Catherine Wolfram (2012): Deregulating and consolidating electricity markets have led to an increase in operating efficiency, achieved primarily by reducing the frequency and duration of reactor outages. At average wholesale prices the value of this increased efficiency is approximately USD 2.5 billion annually and implies an annual decrease of 38 million metric tons of carbon dioxide emissions.</td>
<td>Dep var: Nuclear Operating Efficiency</td>
<td>Indep var: divestiture % effect= 10.4% **</td>
</tr>
<tr>
<td>Hiebert (2002): Plant efficiencies are associated with capacity utilization of the plant and the number of plants under utility management. Moreover, regulatory restructuring activity in certain states is associated with improvements in plant operating performance.</td>
<td>Dep var: Mean Plant Inefficiency</td>
<td>Indep var:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>capacity utilization of the plant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>coefficient (coal)= -1.57***</td>
</tr>
<tr>
<td></td>
<td></td>
<td>coefficient (gas)= - 5.65***</td>
</tr>
<tr>
<td></td>
<td></td>
<td>number of plants under mgnt of the utility</td>
</tr>
<tr>
<td></td>
<td></td>
<td>coefficient(coal)= - 0.07***</td>
</tr>
<tr>
<td></td>
<td></td>
<td>coefficient (gas)=  -0.06***</td>
</tr>
</tbody>
</table>
**Zarnic (2010):** European electricity market reforms have induced improvements in firm efficiency either through productive, allocative or dynamic efficiencies. However these are not uniformly distributed; the closest are the firms to the frontier, the more they are able to improve productivity in response to liberalization efforts stimulating competition.

<table>
<thead>
<tr>
<th>Dep var: Solow Residuals</th>
<th>Indep var:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>- Effect of liberalization coefficient = -0.077**</td>
</tr>
<tr>
<td></td>
<td>- Liberalization*Gap to leader coefficient = - 0.004 ***</td>
</tr>
<tr>
<td></td>
<td>- Liberalization*Dummy for catch-up firms (Above median) coefficient = 0.01 *</td>
</tr>
<tr>
<td></td>
<td>- Liberalization*Dummy for catch-up firms (Above 80th percentile) coefficient = 0.015 **</td>
</tr>
</tbody>
</table>

**Knittel (2002):** Programs tied directly to generator performance and those that modify traditional fuel cost pass-through programs are associated with greater efficiency levels.

<table>
<thead>
<tr>
<th>Dep var: Efficiency level</th>
<th>Indep var:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>- Equivalent Availability Factor program coefficient (coal)= 3.210*** coefficient (gas)= 0.0928**</td>
</tr>
<tr>
<td></td>
<td>- Heat Rate program coefficient(coal)= 2.578*** coefficient (gas)= 0.0928**</td>
</tr>
<tr>
<td></td>
<td>- Fuel cost pass-through program coefficient(coal)= 2.476*** coefficient (gas)= 0.0667*</td>
</tr>
</tbody>
</table>

**INTEGRATION**

**Lars Bergman (2003):** During the 1990s the electricity markets in Norway, Sweden, Finland and Denmark were deregulated and integrated into a single Nordic market for electricity. This paper shows that the electricity market reform has led to quite significant productivity increases.

Suitable data for systematic productivity analysis are not available.

**Zarnic (2010):** European electricity market reforms have reduced mark-ups of firms, especially those with subsidiaries. Price-cost margins are negatively associated with better functioning of wholesale and retail markets. The annual decrease in vertical integration negatively affects the mark-ups of consolidated firms.

<table>
<thead>
<tr>
<th>Dep var: mark-up (for consolidated firms with subsidiaries)</th>
<th>Indep var:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>- Effect of liberalisation coefficient = - 0.018 **</td>
</tr>
<tr>
<td></td>
<td>- Effect of cross-border arbitrage Coefficient = - 0.019 ***</td>
</tr>
</tbody>
</table>
### Clemens Gerbauleta, et al (2012): The paper examines four scenarios of different tertiary reserve market cooperation; results are promising to lower overall system costs by about 10% in the case of one unified tertiary reserve market called „Germalpina“, which seems to be preferable over the bilateral coalitions. In the scenario of full integration re-dispatch costs decrease by more than 50% compared to the National Scenario.

<table>
<thead>
<tr>
<th>Total System Cost per month (approximations):</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. National: EUR 85 million</td>
</tr>
<tr>
<td>2. Bilateral (Germany and Austria): EUR 79 million</td>
</tr>
<tr>
<td>3. Bilateral (Germany and Switzerland): EUR 77 million</td>
</tr>
<tr>
<td>4. Germalpina: EUR 75 million</td>
</tr>
</tbody>
</table>

Cost of re-dispatch per month (approximations):
- From National to Germalpina

### Alireza Abbasy, Reinier A. C. van der Veen, Rudi A. Hakvoort (2009): Integration of regulating power markets of different balancing regions has a potential to reduce the costs of balancing within multinational power markets. This paper investigates this potential by studying the case study of Northern Europe; the Netherlands, the Nordic region and Germany.

<table>
<thead>
<tr>
<th>Total Balancing Costs (approximations):</th>
</tr>
</thead>
<tbody>
<tr>
<td>- 0% Total Interconnection Capacity: EUR180 million/Year</td>
</tr>
<tr>
<td>- 5% Total Interconnection Capacity: EUR 125 million/Year</td>
</tr>
<tr>
<td>- 10% Total Interconnection Capacity: EUR 100 million/Year</td>
</tr>
<tr>
<td>- 15% Total Interconnection Capacity: EUR 90 million/Year</td>
</tr>
</tbody>
</table>

### Justus Haucap, Ulrich Heimeshoff and Dragan Jovanovic (2012): In recent years, a new market design was created by synchronization and interconnection of the four control areas of German reserve power market. The paper finds that reforms were jointly successful in decreasing MRP prices leading to substantial cost savings for the transmission system operators.

<table>
<thead>
<tr>
<th>Savings for 46 month:</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Market for incremental MRP</td>
</tr>
<tr>
<td>- EUR 1948 million</td>
</tr>
<tr>
<td>- Market for decremental MRP</td>
</tr>
<tr>
<td>- EUR 1400 million</td>
</tr>
</tbody>
</table>

### Erin T. Mansur and Matthew W. White (2008):
Electricity markets exhibit two forms of organization: decentralized bilateral trading and centralized auction markets. The empirical evidence indicates that employing an organized market design substantially improved overall market efficiency, and that these efficiency gains far exceeded implementation costs.

<table>
<thead>
<tr>
<th>Gains from trade (USD million/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Bilateral market post 10/2004 (counterfactual) = 150.1</td>
</tr>
<tr>
<td>- Organized market post 10/2004 (estimate) = 312.9</td>
</tr>
<tr>
<td>- Change in Gains from Trade (USD million/year) = 162.8</td>
</tr>
</tbody>
</table>

Implementation costs (one-time)
- USD 40 million