FONDAZIONE ENI ENRICO MATTEI

NOTA DI LAVORO

3.2014

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Energy: Resources and Markets
Series Editor: Giuseppe Sammarco

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Summary

This paper analyses a set of model-based decarbonization scenarios in order to quantify the long-term economic benefits that arise from an increasing integration of the pan-European electricity system. It thereby focuses on the interplay between transmission infrastructure and renewable generation capacity expansion. We confirm earlier findings that, on aggregate, pan-European transmission capacity expansion constitutes a no-regret option for integrating increasing shares of variable renewables in mitigation scenarios with positive social returns on investment. However, it turns out that the change in total discounted system costs that occurs as transmission capacity expansion increases is modest in magnitude, with a maximum of 3.5% for a case with no expansion compared to one with massive expansion. In technical terms this means that the optimum is rather flat and that taking into account regional and local benefits and distributional aspects, could alter the evaluation of the economic benefits considerably. A crucial finding in this context is that the configuration of pan-European transmission infrastructure and the importance of specific country-connections, i.e. a "Southern" versus a "Northern" solution, crucially hinges on the relative development of specific investment costs for solar and wind technologies over the next decades.

Keywords: Transmission Infrastructure Planning, European Energy Policy Targets, Mitigation

JEL Classification: Q42, Q48, Q54

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Quantifying the Long-Term Economic Benefits of European Electricity System Integration

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Abstract

This paper analyses a set of model-based decarbonization scenarios in order to quantify the long-term economic benefits that arise from an increasing integration of the pan-European electricity system. It thereby focuses on the interplay between transmission infrastructure and renewable generation capacity expansion. We confirm earlier findings that, on aggregate, pan-European transmission capacity expansion constitutes a no-regret option for integrating increasing shares of variable renewables in mitigation scenarios with positive social returns on investment. However, it turns out that the change in total discounted system costs that occurs as transmission capacity expansion increases is modest in magnitude, with a maximum of 3.5% for a case with no expansion compared to one with massive expansion. In technical terms this means that the optimum is rather flat and that taking into account regional and local benefits and distributional aspects, could alter the evaluation of the economic benefits considerably. A crucial finding in this context is that the configuration of pan-European transmission infrastructure and the importance of specific country-connections, i.e. a "Southern" versus a "Northern" solution, crucially hinges on the relative development of specific investment costs for solar and wind technologies over the next decades.

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1. Introduction

European integration of the electricity system by means of expanding pan-European transmission infrastructure capacities is argued to be an economically beneficial means for achieving four key long-term energy and climate policy targets (European Parliament and the European Council, 2009; European Commission, 2010; European Union, 2010; European Council, 2011): it constitutes a pivotal option to (i) integrate high shares of renewables, leading to a reduction in greenhouse gas emissions through substituting fossil-based electricity generation. Also, it (ii) increases competition in the internal market for electricity, leading to lower prices. Further, it (iii) increases security of supply in the European Union through integrating remote areas in the European periphery, enabling a more diversified energy mix and reduced congestion. And, finally, progress in attaining these three climate and energy policy ends jointly contributes to the long-term European policy target of (iv) transitioning to a competitive low carbon economy. "Energy infrastructure" and its development is also a key word in the contributions to the consultation of the EU Commission for a 2030 framework for climate and energy policies (European Commission, 2013). Despite these bold political statements, the respective arguments are given without any quantification, so the question is: How great are the long-term economic benefits of European electricity system integration and what are crucial variables influencing the result?

In order to come up with a comprehensive quantitative answer based on a numerical model, one ideally needs to account for the full sets of system effects inherent to the future development of the European electricity system. Since computational limitations have inhibited such complexity to date, no comprehensive assessment has been performed yet. Nevertheless, the literature provides a few contributions that quantify the economic effects of a system-cost optimal transmission capacity expansion in Europe: Fürsch et al (2013) find that average system costs in 2050 can be reduced by 3.5% if pan-European transmission capacity expansion is pursued optimally from a system cost perspective as opposed to a restricted scenario, i.e. one that does not allow for those transmission lines that are being significantly delayed as specified in the TYNDP (ENTSO-E, 2012). Tröster et al. (2011) calculate that, if the European electricity transmission grid is configured in an optimal manner given a specific feed-in structure of renewables providing a share of 97%, curtailment can be cut by two thirds from 12% to 4%, thereby reducing the need for investments into renewable generation capacities. Schaber et al. (2012b) find in a parametric study that for a European electricity system with 60% renewables, an optimal grid configuration in combination with an optimal mix between wind and solar capacities can even reduce curtailment to less than 1% as well as dampen the need for additional back-up capacities. These system effects lower the average cost of electricity by 7% as compared to a scenario with no grid extensions; and by 11% in a variant that assumes lower specific investment costs for the renewable technologies solar photovoltaic, wind onshore and offshore. A literature review by Booz&Company et al. (2013) finds that the benefits from improved integration lie broadly in the range of 1-10% of system costs, with the majority in the lower area of this range. Hence, current model results indicate that pan-European grid expansion is a no-regret option, despite that the quantitative effects are rather small in magnitude.

The aim of this paper is on the one hand to add a quantitative estimate of the economic benefits of European electricity system integration to the sparsely covered field of literature, applying the European electricity system model LIMES-EU+ (Haller et al., 2012). Secondly, we expand the focus of previous work by further investigating the magnitude and the structural pattern of system effects that result from the interplay between transmission infrastructure and renewable generation capacity expansion. This is achieved by comparing model results from a set of scenarios that are characterized by different assumptions on the expansion rate of pan-European net transfer capacity (NTC) and the development of specific investment costs for the variable renewable (vRES) technologies, wind onshore and offshore, solar photovoltaic and concentrated solar power. The analysis is pursued given ceteris paribus assumptions on the future development of other influential system drivers and exogenously enforced CO_2 emission reductions in the electricity sector in line with numbers in the "Roadmap for moving to a competitive low carbon economy in 2050" (European Commission, 2011b).

The outline is as follows. Section 2 briefly introduces the electricity system model LIMES-EU+ (Haller et al., 2012) and outlines important scenario assumptions. Section 3 presents the model results. Section 3.1 focuses on the impact of transmission capacity expansion on total system costs. Sections 3.2 and 3.3 analyze structural patterns emerging in the configuration of pan-European transmission infrastructure and the technology mix. Section 3.4 explores the electricity price distributions that result in the different scenarios. Section 4 discusses the model-based findings in the context of the political claims outlined above. It focuses on policy implications and model limitations that are particularly relevant for estimating economic benefits of the European electricity system integration. Section 5 concludes.

2. Model and Scenarios

The partial electricity system model LIMES-EU+ (Haller et al., 2012) is designed to generate quantitative scenarios that represent a consistent, system-cost optimal transition towards a decarbonized European electricity system in 2050. Endowed with perfect foresight, LIMES-EU+ iteratively yields a social planner solution that specifies in time steps of 5 years for each model region the optimal (i) dispatch and curtailment of installed electricity generation technologies, (ii) electricity import balance from neighboring model regions, (iii) investments into installed capacities of electricity generation technologies[2] and (iv) investments into net-transfer capacities[3] (NTCs) between model regions. The model is calibrated[4] to the ENTSO-E region and additionally covers the Middle East and North Africa (MENA). However, the focus of this analysis is the ENTSO-E region and the possibility to import electricity from the MENA regions is disabled in all scenarios. Specified as a linear optimization model, the objective function of LIMES-EU+ is to minimize the total sum of discounted[5] electricity system costs (comprised of fuel, investment, fixed and variable operation and maintenance costs) jointly for all model regions between 2010 and 2050, given a number of boundary conditions. Climate policy is simulated by constraining annual CO_2 emissions as suggested by the "Roadmap for moving to a competitive low

[2] To prevent excessive annual capacity additions that are not reconcilable with likely developments, they are restricted for wind onshore, offshore and biomass to 3, 1.5 and 1 GW, respectively.

[3] Electricity transmission is represented as a transport problem by specifying NTCs between all neighboring model regions. For the calibration year 2010 each model region is endowed with initial installed capacities (Kjärstad and Johnsson (2007); IEA (2010a), IEA (2010b) and NTC Summer Values 2009 (ENTSO-E, 2010a). Investment costs for NTC expansions are 0.38€/kW km, for more details consult Haller et al. (2012).

[4] For details on the model calibration consult Haller et al. (2012) and particularly the supplementary material.

[5] We apply a social discount rate of 5%.

carbon economy in 2050" (European Commission, 2011b), leading to a near decarbonization of the electricity system in 2050. In order to represent fluctuating feed-in of vRES and differences in electricity demand occurring on sub-annual time scales, LIMES-EU+ uses a time-slice approach (cp. Ludig et al., 2011). A total of 48 six-hourly time slices represent three representative vRES feed-in days with corresponding demand levels[6] for each season of the year and each model region individually.

The scenarios for this analysis are specified so as to represent both different conceivable degrees of European electricity system integration and developments of vRES technologies' specific investment costs. Other influential system drivers, e.g. electricity demand, CO_2 emission reduction targets, primary energy prices and the like are kept constant across scenarios and are either retrieved from literature estimates[3] or based on the definition of the scenario 80%DEF defined in the European Stanford Energy Modeling Forum (EMF) model intercomparison exercise EMF28 (Knopf et al., 2013b). The scenario 80%DEF is characterized by 80% greenhouse gas emission reduction by 2050 relative to 1990, leading to 93% CO_2 emission reduction in the electricity sector, the availability of the carbon capture and storage (CCS) technology and a reference development for energy efficiency, nuclear energy and renewable energies. It is constructed in a similar way than the scenarios in the "Energy Roadmap 2050" (European Commission, 2011a).

Different degrees of European electricity system integration are implemented in the model via restricting NTC expansion between neighboring model regions from one five-year time step to the following one (ΔNTC). As a reference case we set ΔNTC = 0 GW/a, i.e. in the reference scenarios current transfer capacities between countries persist and as a lower extreme cannot be expanded at all. In order to proxy different speeds of integration of the European electricity system, we consider three scenarios with ΔNTC $\leq$ 0.25, 0.5 and 1 GW/a. Considering that currently 40 GW of NTC are installed between the ENTSO-E regions (ENTSO-E, 2010a) in 33 country-connections, the scenarios with ΔNTC $\leq$ 1 GW/a could theoretically exhibit almost a doubling of European NTC per year, serving as an upper extreme.

The second scenario dimension in this analysis regards the development of vRES technologies' specific investment costs, a highly uncertain but at the same time very decisive parameter that directly influences the technology mix in optimization models (Nemet, 2009; Junginger et al., 2010). In energy system modeling, it is common practice to assume substantial long-term reductions in specific investment costs for vRES technologies (cp. Pahle et al., 2012; Schmid et al., 2013). They are generally justified by technology learning and more specifically by the empirically derived concept of learning-by-doing, which postulates a negative log-linear relationship between cumulative installed capacities and specific investment costs: the learning or experience curve (Junginger et al., 2010). It especially holds for modular technologies that allow for large economies of scale, e.g. solar photovoltaic (Junginger et al., 2010). Complementary to such top-down econometric approaches, bottom-up engineering-type of estimates examine cost reduction potentials for each step in the manufacturing and deployment chain of immature technologies. They generally confirm the trends postulated by top-down estimates (Neij, 2008).

[6] Demand projections are based on Capros et al. (2010) and IEA (2010a, 2010b).

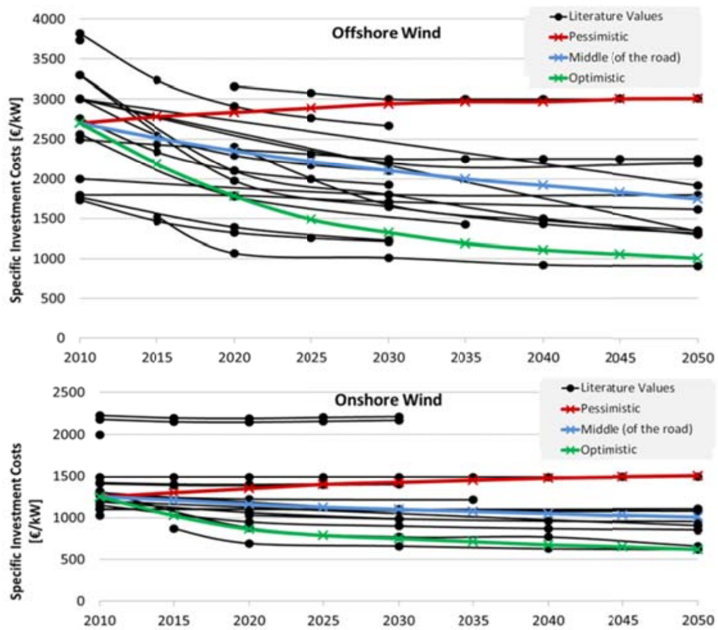

Figure 1. Specific Investment costs in €/kW for Wind technologies from the literature and the Pessimistic, Moderate and Optimistic trajectory chosen for this analysis. Literature data is from Schröder et al. (2013).

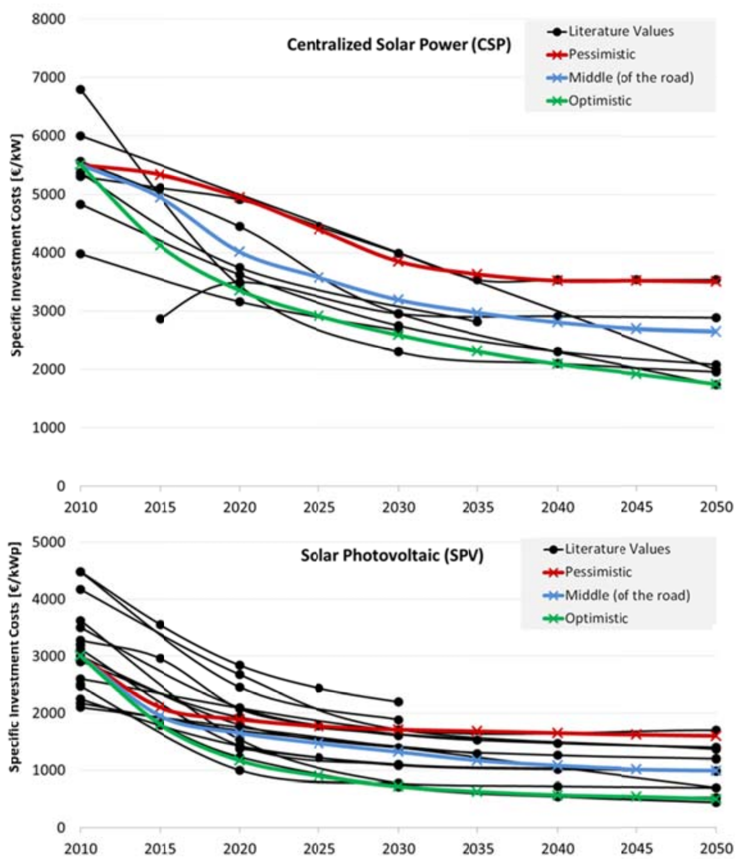

Figure 2. Specific Investment costs in €/kW for Solar technologies from the literature and the Pessimistic, Moderate and Optimistic trajectory chosen for this analysis. Literature data is from Schröder et al. (2013).

However, it is not a universal law that specific investment costs have to decrease log-linearly with cumulative installed capacities. There is a growing strand of literature that identifies significant uncertainties regarding the specification and identification of the log-linear learning curve model (Nemet, 2009; Nordhaus, 2009; Yeh and Rubin, 2012). Particularly for wind technologies, specific investment costs did increase in the recent years – despite continuously increasing installed capacities (Heptonstall et al., 2012). Rising steel and concrete prices had a significant effect on wind technologies' investment costs in the recent years (Panzer, 2012), and may do so in the future. Dinica (2011) suggests that also institutional factors are an increasingly important cost factor for vRES, e.g. project permitting costs caused by the financial interest of the regulator. Figures 1 and 2 plot literature values, mainly from bottom-up estimations, (compiled in Schröder et al. (2013)) for the development of specific investment costs of the vRES technologies solar photovoltaic (SPV), concentrated solar power (CSP) with storage and onshore and offshore wind (Wind-ON, Wind-OFF) in black. Interpreting the band of projections as a conceivable range for future developments, we consider four combinations of vRES investment cost developments: In three scenarios all four technologies develop similarly (either optimistic, pessimistic or medium), and in fourth scenario we consider the solar technologies to be on the optimistic trajectory and the wind technologies on the pessimistic one, i.e. a mixed scenario.

3. Results

In order to quantify economic benefits of European electricity system integration and drivers thereof, this Section analyzes selected model results. Conceptually, benefits are determined by comparing model results between scenarios that allow for an expansion of NTCs with respective reference scenarios that are bound to a pan-European transmission infrastructure as is today (keeping all other parameters constant).

3.1. Total discounted electricity system costs

An obvious indicator for the quantification of economic benefits of pan-European transmission capacity expansion to analyze is the total discounted electricity system costs over the time horizon 2010-2050, the minimization of which is the objective function of LIMES-EU+. Comparatively lower total system costs incurred by the European electricity system are economically beneficial as the cost differential may be directed to value-creating activities in other sectors of the economy. On the left axis, Figure 3 displays the savings in terms of this indicator for the different NTC expansion scenarios, relative to the respective reference vRES investment cost scenario in which NTCs remain at today's level. On the right axis, the blue dots indicate the social return of investment in NTC capacity expansion beyond the reference level in terms of system cost savings.

A first finding is that total system costs decrease upon allowing for NTC capacity expansion under all settings of specific investment costs for vRES technologies. Social returns on investments in NTC capacity expansion beyond the respective reference levels amounts to 180-340%. Hence, pan-European transmission capacity expansion presents itself as a means to increase the cost-efficiency of decarbonizing the European electricity sector, confirming the conclusion of previous work that it is a no-regret option. Moving from the low to high NTC expansion scenarios, the effect becomes less pronounced, revealing decreasing returns to incremental NTC deployment. Also, both indicators decrease when moving from the pessimistic over the middle-of-the road to the optimistic scenarios, indicating that the added value of NTC expansion is higher if vRES technologies remain more expensive to install. In the latter case vRES generation sites with better potential in the European periphery are comparatively more valuable to connect to central Europe, leading to comparatively higher social returns on NTC investment.

A second finding that is robust across all scenarios is that the percentage change in total system costs that occur as NTC expansion increases from low to high rates is quite modest in magnitude. It ranges between 2-3.5% in all cases. This is also valid for other combinations of vRES investment costs not illustrated in this paper but analyzed by the authors. This result is in line with the quantitative estimates provided in other studies min the Introduction. In technical language this implies a flat optimum of the objective function with respect to the parameter "transmission capacity expansion rate" (ΔNTC).

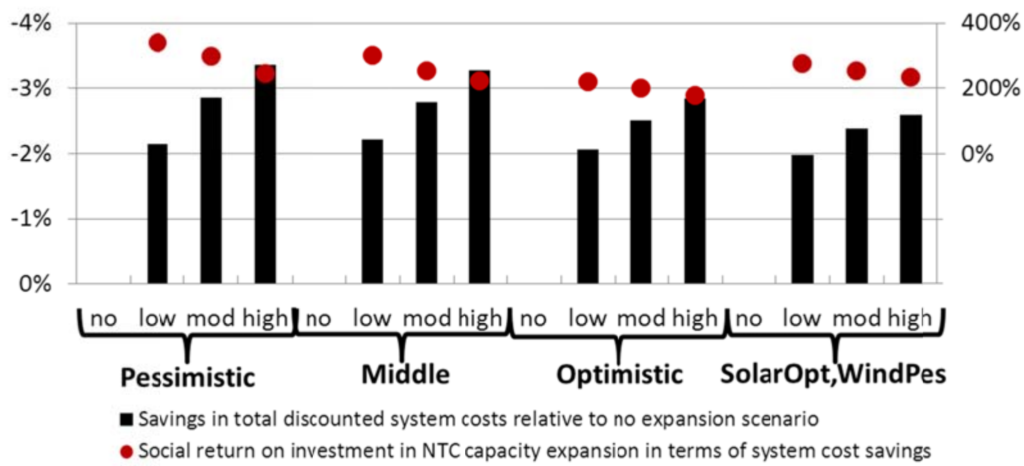

Figure 3. On the left axis percentage change in total discounted system costs over the time horizon 2010-2050 for different vRES investment cost scenarios with low, moderate and high expansion rates of transmission capacity relative to the respective reference scenario with no transmission capacity expansion (ΔNTC=0). On the right axis social returns on investment in NTC capacity expansion in terms of system cost savings.

3.2. Structural pattern and bottlenecks of pan-European transmission infrastructure

Having found that on aggregate the optimum is not very much affected does not yet imply that the scenarios are similar in terms of the configuration of NTC and generation capacities across Europe. Moving from the reference case with NTCs restricted to today's values to the high capacity expansion scenario, LIMES-EU+ deploys more and more NTC capacities in order to transport electricity between model regions to achieve a system-cost-optimal solution (Figure 4). All displayed scenarios have the investment costs of vRES set to the middle (of the road) values. In the low transmission expansion scenarios the constraint on ΔNTC is binding (illustrated in red) for four transmission corridors: (1) the east-west connection between the islands of Ireland and Great Britain with the mainland in France and

Benelux, (2) the north-south connection between Sweden, Norway, Denmark and Germany, (3) the west-east connection between the Baltic states, Poland and Germany, and (4) the south-north connection between the Iberian Peninsula and France. All these transmission corridors connect the European periphery to central Europe. They serve to transport electricity produced by vRES capacities in the northern, western and eastern (and southern) European periphery, endowed with comparatively more favorable wind (solar) potential, to agglomerations in central Europe. In the moderate transmission expansion scenario only corridors (1)-(3) are subject to restrictions. In the high expansion scenario the constraint is non-binding for all country connections except for Great Britain and Benelux and between Denmark and Germany.

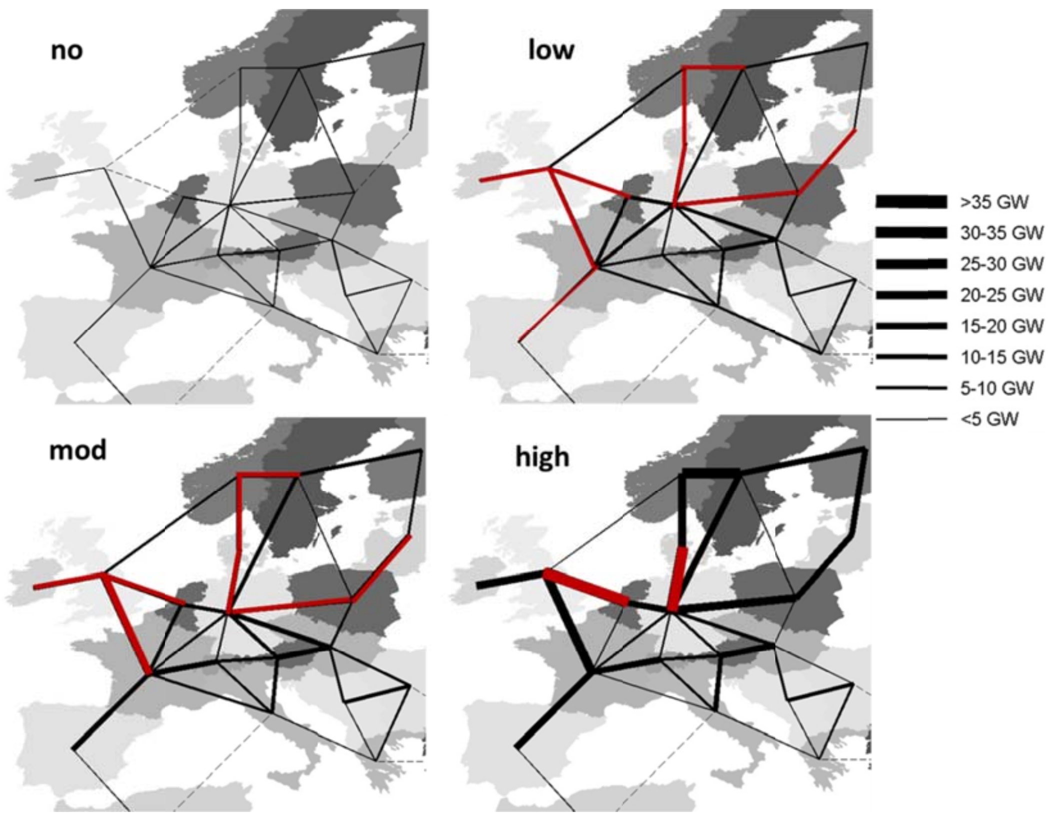

Figure 4. Net transfer capacities (NTC) between ENTSO-E model regions in GW in the year 2050, for the different transmission capacity expansion scenarios with investment costs of vRES set to the middle (of the road) values. Red color coding indicates for which connections the constraint on the transmission capacity expansion parameter ΔNTC = 0 (no), 0.25(low), 0.5 (moderate) and 1(high) GW/a is binding.

In general terms this implies that the possibility of a faster transmission capacity expansion is important particularly for those country connections that serve to transport electricity generated by variable renewables from the European periphery to central Europe. A more specific finding is that the model results indicate that, in the long-term, a pan-European transmission capacity expansion focusing on the integration of high-quality wind sites in Northern Europe, the Baltic countries, Ireland and Great Britain is the system-cost-optimal strategy. Are these findings robust?

In fact, in the pessimistic and optimistic scenarios the deployment of NTC capacities follows a very similar pattern to that in the middle (of the road) scenarios. Likewise, the integration of wind sites in the northern periphery is the dominant driver, confirming both the general and the more specific finding. However, the picture changes in the scenario that assumes solar technologies to follow the optimistic trajectory and wind technologies the pessimistic one. Figure 5 illustrates the average annual power flows in 2050 for two scenarios with high transmission capacity expansion (ΔNTC=1GW/a), the one with middle (of the road) assumptions on vRES investment costs on the left and the mixed scenario on the right. In the latter, LIMES-EU+ taps into the abundant solar potential of Southern Europe, particularly on the Iberian Peninsula. NTC capacity expansion primarily occurs in the south-north corridor between the Iberian Peninsula, France and Benelux countries. Also the transmission corridor South-Eastern Europe to central Europe is strengthened, drawing on the solar resources in these regions. In this case the high-quality wind sites on and around Ireland and Great Britain are only exploited for domestic supply, and not for exports to central Europe. The high-quality wind resources of northern Europe and the Baltic states are still relied upon, but to a much lower extent.

Hence, the general finding identified above, that the cost-optimal configuration of the pan-European transmission infrastructure is driven by the integration of high-quality renewable resource sites in the periphery is robust for the different vRES investment cost scenarios. However, answering the question of which country-connections are especially important crucially hinges on the relative development of specific investment costs of vRES technologies. If solar PV will continue its strong price decreasing trend of the past decades (BSW Solar, 2013), CSP starts to exploit its learning-by-doing potential and wind technologies specific investment costs stagnate or even increase, then the cost-optimal strategy would be quite different from the one identified in the pessimistic, middle (of the road) and optimistic scenarios. This leads to the conclusion that the interplay between the relative cost developments for wind and solar technologies and the choice of which transmission corridors to expand matters a lot for reaping the economic benefits of pan-European transmission capacity expansion .

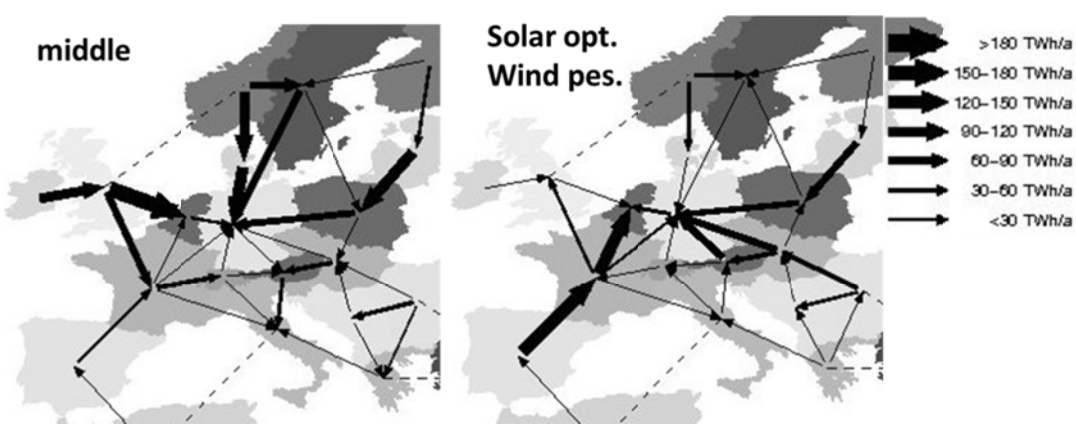

Figure 5. Average annual net electricity flows between model regions in the year 2050. Displayed are scenarios with different vRES investment costs, all have ΔNTC set to 1 GWkm.

3.3. Implications for the electricity mix

Figure 6 illustrates for the ENTSO-E region the aggregate installed generation capacities as well as intra-day storage[7] for all scenarios in the year 2040 (left axis) and the corresponding share of vRES in total net electricity production (right axis). It is not surprising that the share of vRES is substantially higher in the optimistic scenarios than in the moderate and especially the pessimistic scenarios, accruing to 30-40%, 40-50% and 55-60%, respectively. As can be expected, in the mixed scenarios the magnitude of solar PV capacity is substantially higher due to its relatively more favorable investment cost development. Interestingly, in this case the option to deploy offshore wind capacities is not pursued at all.

The influence of the different constraints on the speed of transmission capacity expansion on the aggregate technology mix is visible, but not very pronounced. With increasing NTC expansion, there is a tendency for (i) absolute installed capacities to decrease, (iii) solar PV capacities to decrease and (iii) onshore wind capacities to increase. Particularly in the no transmission capacity expansion scenarios, more solar PV capacities along with slightly higher intra-day storage capacities are deployed. As an option to increase the temporal flexibility of vRES production, however, storage is not the preferred option in LIMES-EU+. Rather, flexible back-up capacities are used for balancing fluctuations. One needs to acknowledge, however, that across scenarios the allocation of capacities to model regions differs as it is an endogenous model decision. Particularly in the no expansion scenario each region has to be almost self-sufficient in its supply of electricity. Further, the curtailment of electricity generated with vRES capacities decreases with more NTC in place. This effect is strongest in the pessimistic scenarios.

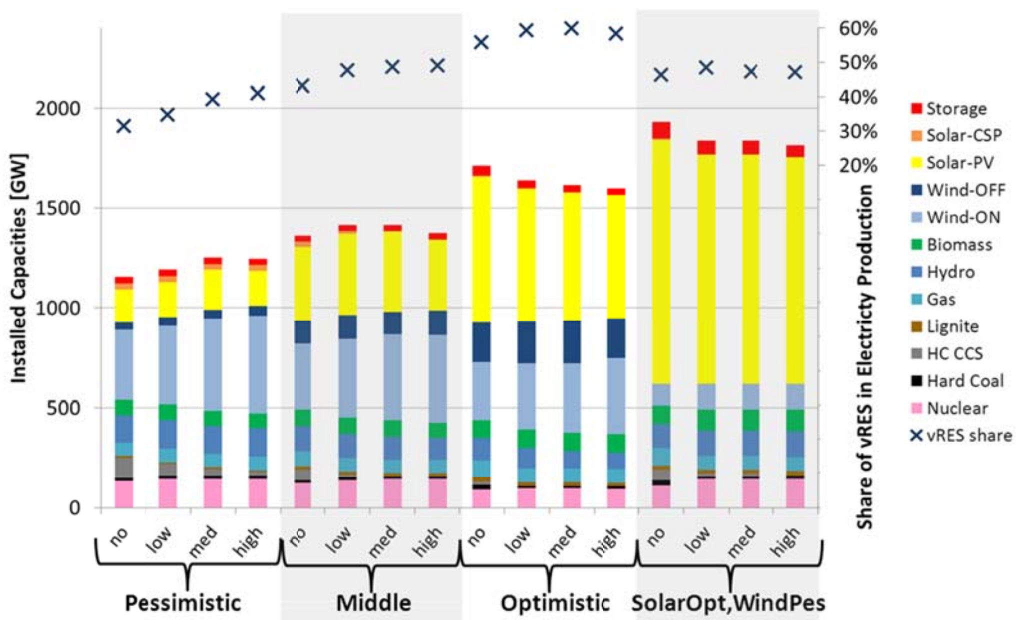

Figure 6. Installed capacities of electricity generation and generic intra-day storage in GW (left axis) and shares of vRES generation in net electricity production (right axis) in the ENTSO-E region for the year 2040 and aggregated across all ENTSO-E countries.

[7] Calibrated to pumped hydro storage with region-specific potential. Generic day-to-day and inter-seasonal storage technologies exist in LIMES-EU+ (see Haller et al., 2012); however, they are not deployed in the scenarios.

As regards non-renewable technologies, in the scenarios following a pessimistic trajectory for investment costs for vRES technologies, nuclear and especially CCS capacities are cost-optimal to deploy. The share of nuclear power in electricity production accrues to 20-25% in the pessimistic and middle (of the road) scenarios, but only reaches 15% in the optimistic ones. Likewise, CCS plays a visible role mainly in the pessimistic scenarios with the highest share of 18% of electricity production in the no grid expansion scenario. It is also deployed in the no grid expansion scenarios facing middle (of the road) and optimistic developments of vRES investment costs, but in these cases contributes less than 2% to total electricity production. Natural gas turbines are installed in all scenarios to supply electricity in those time slices that are characterized by low renewable feed-in and high demand.

3.4. Electricity price distributions

In order to investigate the argument that pan-European transmission capacity expansion is economically beneficial through lowering electricity prices, Figure 7 presents box plots of their distributions in the year 2040 for the ENTSO-E region. Electricity prices are a model result and differ for each region and time slice, leading to a sample of 600 prices per time step (48 time slices in 15 ENTSO-E model regions). Comparing the 50% percentile line across investment costs scenarios reveals that average electricity prices are highest in the pessimistic scenarios and lowest in the optimistic scenarios. The price-dampening effect of NTC expansion reaches up to 2-6% in the middle (of the road) and 5-9% in the optimistic scenarios. These findings are in line with the model results of Schaber et al. (2012b), who calculate that optimal grid extension leads to 7-11% lower average electricity prices. However, one needs to acknowledge that the average electricity prices differ much more across investment cost scenarios. In other words, following an optimal development pathway of the vRES technologies' investment costs has a much stronger price-dampening effect on average electricity prices than transmission capacity expansion. Nevertheless, NTC expansion again presents itself as a no-regret option as electricity prices do decrease – albeit little.

A much more pronounced pattern is visible in terms of the variance of the electricity price distributions across scenarios. The no transmission capacity expansion scenarios have a significantly larger variance than those allowing for NTC expansion, albeit in the middle (of the road) and optimistic scenarios this is only the case for the moderate and high expansion scenarios. This effect can be explained the following way: In all scenarios with $\Delta NTC=0$, fluctuations in vRES feed-in need to be balanced within each region, individually. This requires some back-up capacities that have very low full-load hours, since they are only dispatched during the few time periods that are characterized by very low vRES feed-in and high demand (which mainly occur during winter). During these times, electricity prices are high. If NTC expansion is permitted, model regions can balance their fluctuations through exchanging electricity with other countries or share back-up capacities in case vRES feed-in is low in the respective moment in all regions. In the pessimistic scenarios, in which the share of vRES in electricity production stays below 40% (cp. Figure 6), this effect reduces the variance of the distribution already significantly in the scenarios with $\Delta NTC \leq 0.25$. Due to the dominance of dispatchable generation technologies in the pessimistic scenarios' technology mix, the added value of NTC expansion is low beyond that threshold (dispatchable capacities generate electricity within individual model regions and do not require the transport of electricity between regions). However, in the middle (of the road) and optimistic scenarios, the share of vRES in electricity production amounts to 50-60%. Here, relatively more NTC expansion is required to induce the effect described above and the variance decreases only in scenarios with ΔNTC≤0.5 and 1. Schaber et al. (2012a) also find that the standard deviation of electricity prices across the European region increases with increasing vRES capacity and can be lowered with grid extensions.

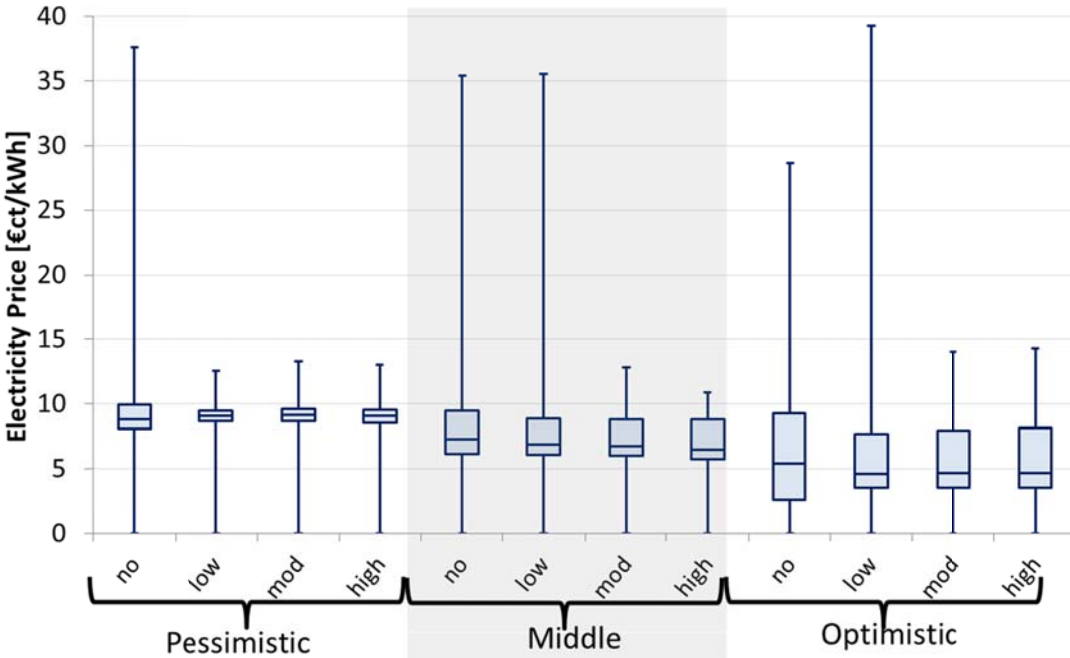

Figure 7. Box plots of the electricity price distributions in 2040 for the ENTSO-E region for all scenarios.

4. Policy implications and modeling limitations

This Section discusses the model results in the context of the political claims introduced at the outset, namely that expanding pan-European transmission infrastructure capacities is an economically beneficial means for achieving four key long-term energy and climate policy targets, including (i) the integration of high shares of renewables to substitute fossil-based generation, (ii) increasing pan-European competition in electricity supply to lower electricity prices, (iii) increasing security of supply and (iv) a cost-efficient transitioning to a competitive low carbon economy. We thereby focus on the policy implications and the model limitations that are particularly relevant for estimating the economic benefits from European electricity system integration that may be incurred with respect to each policy objective. The discussion reveals a number of issues that deserve further attention in future research that aims at refining quantitative estimates of the economic benefits of European electricity system integration.

The model results have shown that depending on whether the specific investment costs of solar or wind technologies will be relatively lower, either a “Northern solution”, tapping into wind resources in Northern Europe, the Baltic countries and the islands of Ireland and Great Britain, or a “Southern solution”, tapping into solar resources in the Iberian Peninsula and South-Eastern Europe, is the dominant strategy. For both strategies it is the case that, if a timely, large-scale expansion of the necessary transmission corridors to central Europe is pursued, then the share of renewables in the electricity system is higher as compared to the scenarios without grid expansion. Hence, for both strategies the policy target of integrating high shares of renewables is fulfilled to a greater extent in the high grid expansion scenarios, which are at the same time the more economically beneficial ones as they entail system cost savings. However, this holds for the renewable share and system costs *on aggregate across Europe*. On the level of individual Member States, the distribution of system costs follows distinct patterns with increasing integration of the domestic electricity systems. The countries in the European periphery endowed with more favorable wind and solar potential bear higher investment costs in the high NTC expansion scenarios as compared to the low NTC expansion scenarios and become exporting countries. Central European countries such as Germany in turn become heavy importers and need to install comparably less generation capacity. Hence, future research should address the distributional aspect between Member States and question *who* incurs the economic benefits of pan-European transmission capacity expansion and under which circumstances in more detail. Also, such considerations ideally go beyond the level of analysis of Member States in order take into account the regional or even local effects of increasing renewable capacity deployment. This would allow for obtaining a more holistic accounting of the economic benefits arising from the integration of the European electricity system. Such effects can either come in the form of economic co-benefits (e.g. regional employment effects, local land rents) or negative externalities (e.g. locally unacceptable changes in land-use, devaluation of property), compare Edenhofer et al. (2013a; 2013b; 2013c). If it turns out that the distribution of economic benefits is highly skewed both across the different levels of governance, i.e. the European, national, federal and local scale, the resistance by those who bear the costs but do not harvest the benefits of system integration could prove to be a significant impediment for reaching the overall economically beneficial solution. A transparent effort sharing is therefore crucial for the transition towards a low carbon Europe.

Regarding the second policy objective of low electricity prices, the model results have shown that the electricity price distribution in scenarios without transmission capacity expansion differ more between regions and time slices than in case with high transmission capacity expansion, that is they are more volatile. Electricity prices are particularly high in winter times that are characterized by high demand and low renewable feed-in across Europe. In the logic of the model, they would decrease ceteris paribus if either demand would be lower or renewable feed-in higher in a specific point in time. As both electricity demand and feed-in structure of renewables across Europe are exogenous model input in each time-slice, changes in assumptions would influence the resulting electricity price. Thus, the electricity prices determined by the model would be different under differently assumed temporal and regional demand and feed-in patterns. While a more diverse set of feed-in patterns for wind and solar electricity generation could be considered in future modeling exercise through implementing a refined set of time slices based on higher-resolution weather data, extreme events such as long periods of calm and clouds are more challenging to represent in energy system models. However, it is particularly in such periods that large-area pooling of spatially anticorrelated renewable feed-in could lead to substantial economic benefits through mediating the need for regional back-up capacities. Thus, with regard to unusual weather, energy system models are likely to underestimate the true economic benefits of pan-European electricity system integration. With regard to aggregate demand patterns it is even more challenging to determine sensible assumptions on their long-term evolution. The usual practice in energy system models is to scale empirical demand curves up or down depending on whether aggregate electricity demand is assumed to increase or decrease. However, by means of information-technology-based solutions like smart grids as well as energy efficiency and sufficiency considerations the aggregate load is likely to alter its temporal pattern considerably in the future. Also, these technologies could lead to a higher price elasticity of demand, altering the interplay between feed-in and load. All these phenomena are likely to have an impact on real-world electricity prices, but are currently not considered in electricity system models. Hence it would be important to better understand how distinct demand patterns, including elastic demand, and differently anti-correlated feed-in patterns of wind and solar capacities impact the quantitative estimates of economic benefits in terms of lowering electricity prices in a more integrated European electricity system.

In energy system models like LIMES-EU+, the pivotal energy policy objective of security of supply is given implicitly, i.e. by definition, through imposing mathematical balancing constraints. Also, model regions are assumed to be copper plates. Thus, by construction little can be concluded from such model results with regard to the economic benefits of pan-European transmission capacity expansion with respect to increasing security of supply, if it is defined as the uninterrupted provision of electricity. For such analyses it is necessary to employ line-sharp transmission infrastructure models that allows for a representation of the Kirchhoff laws which determine the power flow in meshed electricity grids. Such dedicated models could be intertwined with electricity system models to on the one hand validate their results with respect to whether they are feasible from a security of supply perspective and on the other hand provide a more detailed account of the transmission infrastructure that would be necessary for ensuring stability of the electricity grid at all times and in all locations. A line-sharp analysis taking into account electro technical specificities like loop flows, active and reactive power, voltage angles and the like is likely to determine higher total costs for transmission capacity expansion and a different regional distribution thereof – as compared to a NTC-based analysis. Future research should therefore attempt to couple energy system models that optimize capacity deployment over Europe as a whole with line-sharp infrastructure models, at best in a sequential way, in order to incorporate a more accurate estimate of infrastructure investment costs in the energy system cost optimization procedure.

Finally, with regard to the European policy target of a cost-efficient transitioning to a competitive low carbon economy in the long-term future, the model results indicate that for target attainment, a substantial restructuring of the European electricity system as a whole is necessary in all scenarios. Since the model reveals the cost-optimal solution from the perspective of a benevolent social planner endowed with perfect foresight, an implicit assumption is perfect coordination between individual countries throughout the transition. However, by legal rule the technology mix is a sovereign decision of European Member States (§194 in European Union (2010)) and to date a pan-European cooperation to jointly endeavor towards a systemically optimal transition pathway cannot be observed. From this perspective, the question of how to govern an economically beneficial European energy transition becomes central. Future research should hence explore institutional arrangements that are capable of ensuring a credible commitment to cooperation on a European scale. Also transfer mechanisms should be explored considering that the economic benefits and costs of European electricity system integration are not likely to coincide across jurisdictions, as discussed above. Doing so requires taking into account both vertical and horizontal interactions between the different governance levels, i.e. the European Union, Federal Governments, State Governments and local authorities (see Knopf et al., 2013a).

5. Conclusion

For quantifying the long-term economic benefits that arise from an increasing integration of the pan-European electricity system, this paper analyzed a set of decarbonization scenarios calculated with the European electricity system model LIMES-EU+ (Haller et al., 2012). We confirm earlier findings that, on aggregate, pan-European transmission capacity expansions constitute a no-regret option with positive social returns on investment. More NTC capacities lead to economically beneficial effects in terms of total discounted system costs and average electricity prices - albeit the magnitude of the effect is rather modest for both variables. With high pan-European NTC capacity expansion, total system costs decrease by not more than 3.5% over the period 2010-2050, as compared to a scenario without NTC expansion, and electricity prices by not more than 9% for the year 2040. It turns out that this result is robust across decarbonization scenarios with varying vRES investment cost pathways. In technical terms, this can be interpreted as a flat optimum of total energy system costs with respect to NTC capacity expansion.

In this respect we expanded the focus of previous work by identifying system effects that result from the interplay between transmission infrastructure and renewable generation capacity expansion. In particular the model results indicate that the cost-optimal configuration of the pan-European transmission infrastructure is driven by the integration of high-quality renewable resource sites in the periphery. This finding is robust for the different vRES investment cost scenarios. Yet, the question of which country-connections are especially important crucially hinges on the relative development of specific investment costs of vRES technologies. If prices of solar PV will continue its strong decreasing trend of the past decades, CSP starts to exploit its learning-by-doing potential and wind technologies specific investment costs stagnate or even increase, - then the cost-optimal strategy would be a “Southern solution” that taps into the abundant solar potential of Southern Europe, particularly on the Iberian Peninsula and South-Eastern Europe. This would require a strengthening of the transmission corridors from these areas to central Europe. However, in case wind technologies’ specific investment costs develop comparatively favorably, a “Northern solution” focusing on the integration of high-quality wind sites in Northern Europe, the Baltic countries and the islands of Ireland and Great Britain is the system-cost-optimal strategy. In both cases the capacity of the European transmission grid would need to be expanded substantially; by factor 3 to 5 – which constitutes an immense infrastructure investment requirement and in places also to visible altering of the natural landscape.

A discussion of the policy implications and the limitations of the model analysis with respect to achieving four key European long-term energy and climate policy targets revealed a number of issues that deserve further attention in future research aiming at refining quantitative estimates of the economic benefits of European electricity system integration that may be incurred with respect to each policy objective. First, the question arises regarding *who* incurs the economic benefits from integrating more renewable electricity generated in the European periphery in the European electricity system as a whole. As second question is how distinct demand patterns, including elastic demand, and differently anticorrelated feed-in patterns of wind and solar capacities impact the quantitative estimates of economic benefits from an integrated approach? Thirdly, in order to further investigate security of supply issues energy system models should at best be sequentially coupled to line-sharp infrastructure models. And, fourthly, how to govern a pan-European energy transition on different levels in order to ensure a cost-efficient pathway?

An important implication of the finding that pan-European transmission capacity expansion is both a no-regret option and crucial for integrating high-quality renewable potential in the European periphery is that the speed of transmission capacity expansion needs to accelerate. Compared to the growth rate of recent year's transmission infrastructure deployment transmission capacities, the high expansion scenario analyzed in this model seem rather implausible. Planning procedures of up to 10 years involving a multitude of actors makes transmission infrastructure projects vulnerable to local resistance and is faced with longer than initially expected permitting procedures (ENTSO-E, 2010b; ENTSO-E, 2012)(REF). Usually social resistance arises in situations where the distribution of economic costs and benefits is unevenly distributed across Europe. In fact, currently, the main concern for Transmission System Operators (TSOs) considering grid development is "the lack of social acceptance that severely delays or jeopardizes the realization of transmission projects" (ENTSO-E, 2010b, p.10). A growing body of research on the determinants of social acceptance of infrastructure projects identifies transparency of the planning process and participation opportunities as important success factors. In case of transmission infrastructure particularly the discussion whether individual transmission line are really needed is a controversial issue between TSOs, non-governmental organizations and local abutters – how much transmission capacity is actually needed and for what purpose. A transparent assessment that quantifies the economic benefits of transmission capacity expansion could play an important facilitating role in justifying grid development at the local level, and could also be a basis for determining eventual financial remunerations for those that experience local negative externalities of grid expansion. Such measures could help to accelerate pan-European transmission capacity deployment and open the window of opportunity for reaping the economic benefits thereof.

Acknowledgments

The authors would like to thank Ottmar Edenhofer, Michael Pahle, Lion Hirth, Paul Nahmmacher, Sylvie Ludig, Oliver Tietjen, Robert Pietzcker and Jan-Christoph Goldschmidt for fruitful discussions.

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