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Planning the Offshore North and Baltic Sea Grid: A Study on Design Drivers, Welfare Aspects, and the Impact on the National Electricity Markets

Jonas Egerer, Christian von Hirschhausen, and Friedrich Kunz

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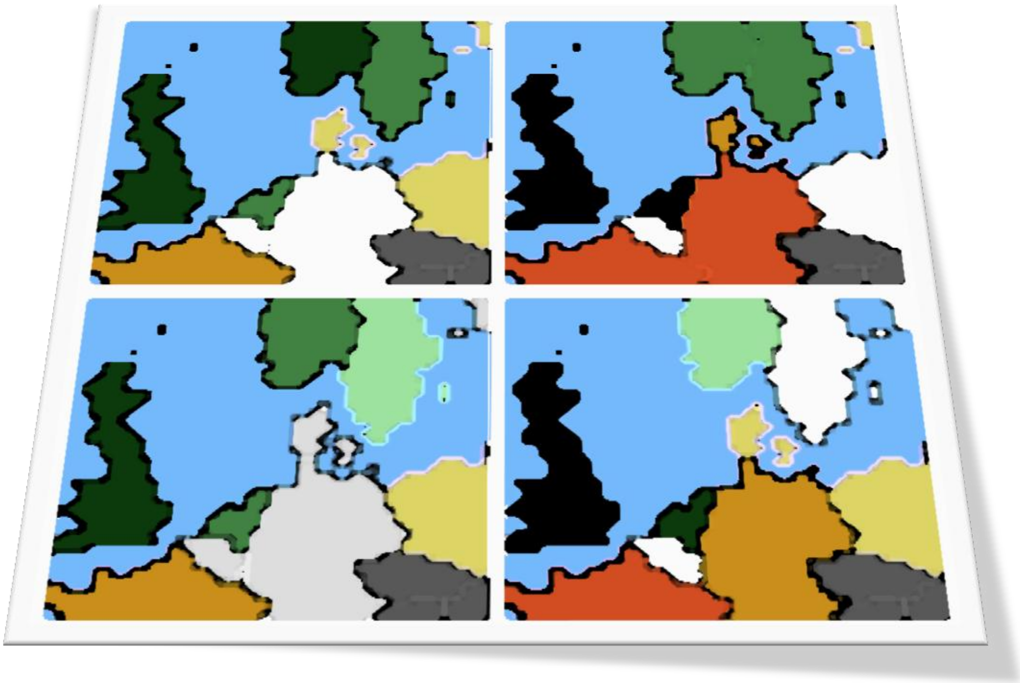

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This study is a “draft for public consultation”, pre-published in this preliminary form. The authors invite comments, suggestions, and proposals for additional analysis. The best way to respond is to write directly into the document, in “track change” mode; other comments are also welcome, please e-mail to je@wip.tu-berlin.de

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The consultation lasts until September 10, 2011, the final version of the study will be published by September 30, 2011.

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Executive Summary

A truly transnational challenge

1. The North and Baltic Sea Grid (NBSG) is one of the largest pan-European infrastructure projects raising high hopes regarding the potential of harnessing large amounts of renewable electricity, but also serious concerns about the implementation in largely nationally dominated regulatory regimes. Several studies have highlighted the technical potential and challenges and the financial needs of the North and Baltic Sea Grid. However, little is known about the design drivers of a potential North and Baltic Sea Grid, its impact on the overall welfare, and the costs and benefits of specific stakeholders (electricity generators and consumers), neither on the impact on the specific national electricity markets. Yet, these factors contribute significantly to the attitude that specific stakeholders will develop vis-à-vis the project, and are thus of utmost importance for the project.
2. This study addresses the perspectives of the North and Baltic Sea Grid from a technical-socioeconomic perspective: we identify drivers for different design configurations for a potential North and Baltic Sea Grid, and derive the implications of these designs for different types of stakeholders. The two designs are: i) a trade-oriented, bilateral scenario, and ii) a meshed grid scenario. In a second step, we identify the overall welfare effects of different configurations of the North and Baltic Sea Grid. Additionally, we analyze the distributional effects, both in terms of nation-wide effects, and the distribution of benefits between electricity generators and consumers. We also identify trade flows and the impact of the North and Baltic Sea Grid on each of the participating national electricity markets in terms of prices, internal congestion, etc. The study also derives estimates on the congestion rents that specific cables in the region, existing or planned, generate.
3. In doing so, the study should fulfill three purposes: i) it relates more technically oriented question to the socioeconomic effects; ii) it allows to assess both overall welfare effects and the impact of each of the stakeholders; and iii) it provides background information regarding the questions of planning, regulating, and financing pan-European energy infrastructures. The study should therefore inform the policy debate about the European Infrastructure Priorities launched by the European Commission, and confirmed by the February 2011 European Council.

Design options of the North and Baltic Sea Grid are endogenous: “bilateral trade” or “multilateral meshed”

4. The technical design of the future cables in the North and the Baltic Sea Grid are not exogenous to the institutional and regulatory framework neither does it (or should it) correspond to an “optimal” technical design. Instead, the design of the North and Baltic Sea Grid is endogenously driven by the rules governing regulation and financing. The current institutional setting has favored the emergence of point-to-point cables, often high voltage direct current (HVDC),

driven by bilateral trade considerations, hence its name “Trade” scenario. These cables are currently financed based on a merchant model, and have led to the NorNed, the Skagerak, the Kontek, and other cables. On the other hand, a truly “Meshed” scenario stands for an integrated approach of interconnected cables both in the North Sea and the Baltic Sea, and a truly pan-European energy infrastructure.

5. In terms of overall welfare, the meshed solution is clearly superior: with a meshed network extension, system welfare in the base scenario (2009) increases by about € 210 mn. per year, as compared with € 100 mn. for the Trade scenario. Both values decrease by about 20% in a scenario with higher near-shore wind integration (Wind+ scenario). However, as long as the institutional and regulatory environment does not change self-financing of the infrastructure is required, no cross-border cooperation exists on regulation, and no European (or other) instruments favor the integration, the Trade scenario will remain the default for any network development in the North and the Baltic Seas. Trade links are easier to build, have lower implementation costs in financing and regulation, and benefit from strong short-term oriented support by stakeholders standing to benefit from investing in these lines. On the contrary, the meshed scenario suffers from the absence of an established technology (e.g. multi-terminal connections with voltage source conversion (VSC) in the short term (though innovations in this field are likely) and of a well-defined business model.

Distributional issues matter

6. While most studies on the offshore grid developments focus only on the aggregate system benefits and investment costs, our focus is on the distributional issues of different design scenarios. This is justified by the strong impact that distributional issues have on political decisions. We analyze the effect of the North and Baltic Sea Grid on the national welfare of the participating countries (Belgium, Germany, Denmark, France, Great Britain, Netherlands, Norway, Finland, Poland, and Sweden) as well as on the producers and the consumers of electricity. In addition, we calculate the congestion rent occurring in the different scenarios, and which is an indicator for potential bottlenecks in the infrastructure.
7. The distribution of overall welfare indicates that countries with a traditional trade surplus and modest generation costs suffer a loss, mainly France and Germany, whereas net importing countries stand to benefit, such as Great Britain and the Netherlands. Both effects are significantly stronger in the meshed scenario. Some countries realize similar gains and losses in individual welfare positions, such that their net effect is close to zero. In addition to “small” countries such as Belgium, Denmark, Finland, and Poland, this is also the case for Norway and Sweden, where one might have expected a stronger positive effect.
8. When considering producers and consumers, one observes that consumers in high-price regions greatly benefit from the grid development, such as German, French, Great Britain and Polish electricity consumers. This is due to cheaper sources of electricity that these countries now obtain from the North and Baltic Sea region. By contrast, producers that benefit from the

increased interconnection are Norway and Sweden, whereas German, French, Belgian, Dutch, and Polish producers suffer losses.

Limited potential for merchant transmission investment

9. The study also highlights the limits of merchant financing on the way to an integrated North and Baltic Sea Grid: Transmission investment is (only) a lucrative business if it generates sufficient rents from the difference between buying and selling electricity at different ends of a merchant transmission line; the difference between locational marginal prices (LMPs) therefore determines the incentives to invest into a specific transmission line. On the other hand, in the (traditional) “regulated” approach the network operator is subject to a price revenue cap or a cost-based mechanism, where one objective of the regulator is to provide incentives for efficient expansion and/or management of the grid. The more meshed a networks gets, the more indirect becomes the link between the transmission investment and potential electricity flowing precisely between these two nodes.
10. In the Base 2009 scenario, the congestion rents in the North Sea lines sum up to about € 50 mn. per year, and for the Baltic Sea about € 30 mn. However, these congestion rents vanish with the introduction of both, the Trade and the Meshed scenario. Except for the NorNed cable, none of the existing cables is able to finance itself. A similar situation will prevail for new lines as well.
11. Our analysis thus indicates the limits of merchant transmission in the case of the North and Baltic Sea Grid. Whereas the first cable in the North Sea, such as the NorNed interconnector between Norway and the Netherlands, proved to be highly lucrative, this will be less the case for subsequent lines. While one or two additional lines could still be profitable with the buildup of the Grid, much of the investment will have to be regulated in order to come about. Merchant investment alone will not provide sufficient trade capacities.

Do not forget the “Hinterland“ integration

12. We find a strong interdependence between offshore grid expansion and the subsequent onshore network. In some cases, the construction of new offshore lines pushes the network bottleneck to the onshore grid. Thus, different transmission expansion plans can have very different effects in terms of electricity flows, and welfare distribution. These interdependencies need to be taken into account in the planning of the North and Baltic Sea Grid.
13. One indirect explanation for the difficult progress of the North and Baltic Sea Grid may be found in the analysis of the “Hinterland” infrastructure bottlenecks that all contributing regions are suffering from. Indeed, whereas it is relatively easy to build offshore generation facilities and to lay cables in the North and the Baltic Seas, it seems to be more difficult to transport the electricity to the centers of demand, or from the large storage and generation sites, onshore. Thus, the onshore transmission lines in Norway between the coast and the large storage sites are underdeveloped and only gradually emerging; Sweden is facing a similar situation. In both the Baltic onshore coast (Germany) and the North Sea coast in Germany, the Netherlands,

and Belgium, large take-away transmission projects are behind schedule. It is difficult to assess the importance of onshore transmission bottlenecks on the North and Baltic Sea Grid development, but it is reasonable to assume that it is a major determinant.

Conclusions

14. Some progress has been made in the installation of wind electricity generation offshore, and the electrical interconnection between Scandinavia, Great Britain, and mainland Central Europe; some larger projects are currently under way. However, we are still far away from the vision of the North and Baltic Sea as electricity hubs of Europe, with almost infinite capacities. With respect to the broad vision, progress has been modest overall.

15. There is clearly a distinction between the overall benefits of the NBSG-project, and the individual national perspectives. While the gains in social welfare are significant, the benefits that each individual country obtains vary with the network design, the regulatory approach, and the assumptions on supply and demand. Thus, there is a high variance in the expected benefits for each country, which will limit their enthusiasm to engage in such a multilateral project.

16. The study shows for the case of the offshore North and Baltic Sea Grid that different designs create different beneficiaries and losers on national level but also within the countries. While exporting countries suffer losses through additional competition combined with strong rent shifting from producers to consumers, lower flexibility of the chosen offshore design limits this development but also creates lower overall welfare gains. Balancing the interests of different participating parties is a critical element of any transmission expansion strategy. In this case, the exporters of low-cost electricity, i.e. Norway and Great Britain, are winners of a grid expansion, since they obtain higher prices in the region they export to, Continental Europe, than in their respective domestic markets. Continental European consumers also gain from the developments due to the price decrease they enjoy. On the other hand, electricity producers in the more expensive region, Continental Europe, lose market share and producer rent, while the consumers in the lower-price region also loose (consumer) rent: after the installation of the infrastructure, they may have to pay a higher price than before.

17. There is a complex issue of timing that drives a wedge between the public policy perspective and the interests of private investors. Even though the long-term effects of an integrated, meshed grid turn out to be the highest, they also occur after the longest project duration of all the different network designs. For a risk-averse, short-term profit oriented investor, a small investment into a point-to-point extension with predictable outcome will be more attractive than an engagement into a longer-term investment with less predictable outcome, albeit a high social welfare gain.

18. However, the potential for merchant transmission is reduced the further the infrastructure investment proceeds and prices converge. Congestion rents in the offshore grids are rather sensitive to additional transmission capacity, increasing the risk for merchant investments. More flexible and meshed offshore grids connected to several onshore nodes generate higher welfare gains and less onshore congestion, indicating that onshore transmission expansion

and offshore grid designs have to be decided on together. In the case of the NBSG, the opportunities for lucrative transmission investment are rapidly exhausted: perhaps one or two cables will still attract private merchant transmission, but for the remaining transmission expansion projects, there is too little congestion rent to pay for the infrastructure investment.

19. The NBSG therefore is a good example for the need of a balanced approach between the European level and the Member States, and merits further analysis into regulatory and financial issues. Independently of the scenario that will emerge, there is a rationale for coordination between the participating countries, but also with second-tier countries that are still affected by the transmission projects. Welfare and distributional issues are likely to play an important role in the debate on the future of the offshore North and Baltic Sea Grid.

1 Introduction: The Offshore Grid Challenge

The North and Baltic Sea Grid (NBSG) features very prominently on the agenda for European energy infrastructure development, both by the European Union and its Member States, and by the energy industry itself. The North Sea Grid is the No. 1 priority of the “European energy infrastructures for 2020 and beyond”, which defines the objective to develop an “Offshore Grid in the Northern Seas and a connection to Northern as well as Central Europe” (EC, 2010, p. 10). The objective is “to integrate and connect energy production capacities in the Northern Seas, including the North Sea and North-Western Seas, with consumption centres in Northern and Central Europe and hydro storage facilities in the Alpine region and in Nordic countries” (idem, p. 10). This project is of strategic importance since it enables Continental Europe to accommodate large volumes of wind and water surplus electricity generation in and around the Northern and Baltic Seas, while connecting these new generation hubs, as well as major storage capacities in Northern Countries and the Alps with the major consumption centres in Central Europe (EC, 2010, p. 12). The NBSG therefore stands for a series of cross-national grid connections that are supposed to lead the way to the large-scale integration of renewable energies, sometimes referred to as “Supergrids” (Hirschhausen, 2010).

The economic benefits of offshore grids, such as the NBSG, are relatively easy to demonstrate. The economic benefits result from a better use of existing electricity generation resources, higher security of supply and reserve power, and a higher share of renewable energy generation, mainly wind and hydropower. Thus, the OffshoreGrid study (Woyte et al., 2010) concludes that the connection costs of offshore wind farms could be reduced by 20% by 2030 if a meshed network design was used instead of radial connections. In fact, the NBSG plays a crucial role for attaining the EU 2020 renewable targets and 2030 outlook, with a particularly strong increase in wind power generation, especially offshore wind: most of the additional wind generation is expected in the North and Baltic Seas and the neighbouring countries.

However, besides the discussion on technical aspects of the NBSG, and the general agreement on overall positive welfare effects, little is known on the more specific effects of the project on each of the participating countries, or on potential investors, incumbent energy companies, and consumers. Yet it is precisely these agents, Member States and companies, who are expected to be the main drivers of the NBSG, with political, regulatory, and eventually some financial support from the European level. But so far there is a lack of understanding how stronger market interconnection and different offshore grid designs change the market situation in the affected countries, and that these results are important if one wanted to avoid a lock-in situation where suboptimal solutions are realized due to the missing willingness to cooperate of individual Member States and market players. Indeed one observes somewhat less enthusiasm about the perspectives of the NBSG at the level of individual actors, or even outright resistance of a few stakeholders that fear to lose economic ground in the process. This study therefore proposes a methodology to assess the micro-impacts of different scenarios for the NBSG, and applies it to a small set of representative developments. Our objective is to provide more detailed insights into the economic effects of offshore grids on the different groups of stakeholders, and thus to increase the transparency of the process; by doing so, we want to support a consensual decisionmaking on a project of vital European importance.

The study therefore provides a welfare economic analysis for market participants, Member States, electricity producers, and consumers, based on the engineering-economic analysis of development scenarios in the region over the next two decades or so. We do calculate overall welfare effects, too, but the main focus is an improved understanding of system effects of offshore grids and wind integration. By doing so, the study also provides insights into more general questions of planning, financing, and regulating multinational infrastructure developments; thus it also serves as a benchmark for other offshore energy projects within the European energy infrastructure priorities.

The study is structured in the following way: the next section summarizes existing knowledge on the NBSG, mainly from technical studies and feasibility analyses. We observe a wide variety of technical designs for the NBSG, although a majority of the studies has a focus on bilateral connections, whereas meshed grids are rather the exception. All studies point out the technical and/or the economic superiority of the NBSG, but none of them provides more specific results at the stakeholder level. We then summarize the economic approach chosen to highlight these specific effects (Section 3): it consists of a welfare maximization applied to a hypothetical competitive market with locational marginal prices (“nodal prices”). In addition to calculating overall welfare effects, the methodology identifies the effects of network extensions on electricity flows, prices, and the benefits of electricity producers and consumers called “producer surplus” and “consumer surplus”, respectively.

We then apply an engineering-economic model of the European electricity market to calculate the effects of the NBSG on the different actors involved. The ELectricity MODel ELMOD (Leuthold, Weigt, von Hirschhausen, 2011) provides a realistic representation of physical characteristics of electricity networks including Kirchhoff’s laws. The transmission network consists of three non-synchronized AC control zones (UCTE, Great Britain and Scandinavia) which are connected by offshore HVDC links in the North and Baltic Sea (Section 4). Section 5 provides results and an interpretation, focusing on the effects of the NBSG on welfare, producer and consumer surplus, the electricity flows resulting from different network designs, and the congestion rents emerging on concrete network connections. Section 6 concludes.

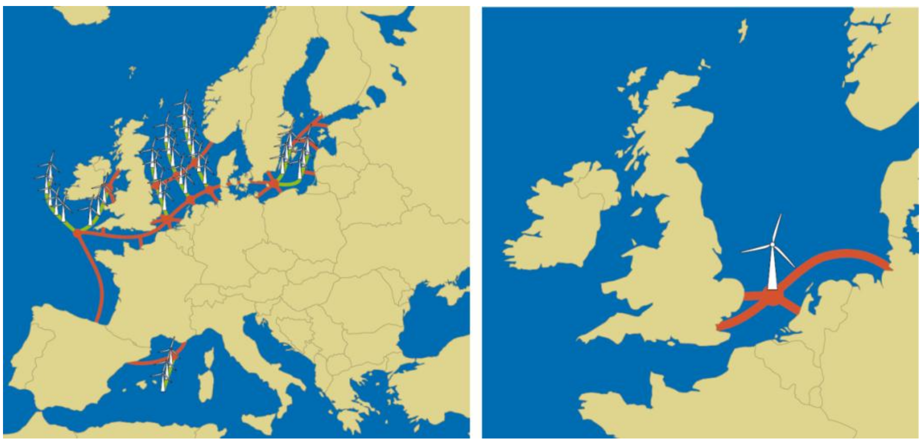
2 Previous Studies on the North and Baltic Sea Grid

Several studies and proposals have been published addressing the designs and implementation issues for offshore networks in the North and Baltic Sea region. Most of them are qualitative design studies or cost-benefit analyses, and difficult to compare with each other. Compared to meshed onshore systems with an existing network and obvious transmission scarcity and congestion, the North and Baltic Sea Grid does not yet exist except for a hand full of point-to-point interconnectors. Therefore, discussing possible offshore grid scenarios allows for many free dimensions in applied technology, regulation and design. Some of these proposals and studies are presented in the following.

The **European Offshore Supergrid Proposal** (Airtricity, 2006) points out that combining offshore grids with wind integration raises line utilization. Offshore wind parks in the North and Baltic Seas could be connected to several countries to increase trade and the flexibility of wind feed in (Figure 1). Airtricity discusses a pilot project with 10 GW of wind generation in the North Sea which is connected to Great Britain, Germany and the Netherlands. The major project risks are not considered to be technical issues, but the size of the project, its regulatory complexity and the issue of different regimes for wind feed-in. The different schemes present in the three connected countries cause difficulties in planning and operating such an offshore wind farm.

In the long run, the pilot project could be the first element of a meshed network with several offshore wind clusters in the Atlantic Ocean, the North Sea and the Baltic Sea. These offshore hubs can be connected to each other and create an offshore grid from Finland all the way to northern Spain. This additional grid is supposed to overcome the barriers of cross border trade and establishes a single internal European market for electricity. A major advantage of the project is that all the cables are deployed offshore, thus avoiding controversial discussions and delay which is an issue for onshore infrastructure development.

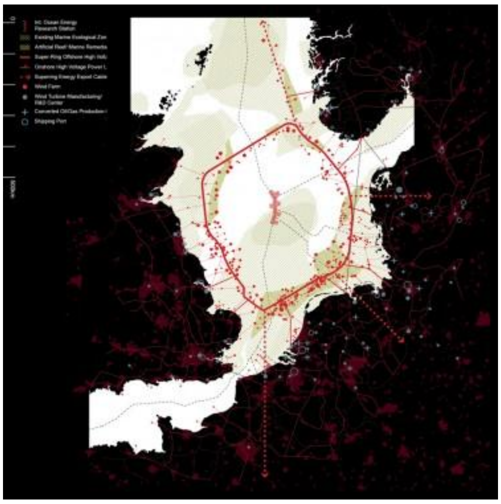
Figure 1: Offshore Grid Proposal by Airtricity



Source: Airtricity (2006).

A different conceptual approach is the **Zeekracht Masterplan** (OMA, 2009) with the North Sea offshore energy super ring (Figure 2). Published by the Office for Metropolitan Architecture (OMA), the basic idea is an offshore transmission circle with submarine cables linked to offshore wind farms. It allows for balancing of wind generation within the circle and its distribution to several onshore nodes surrounding the offshore ring. Additional trade capacity between the adjacent countries is included in the meshed design. The Zeekracht Masterplan is a conceptual study and does not evaluate system nor market implications of the design.

Figure 2: Offshore Energy Super Ring for the North Sea

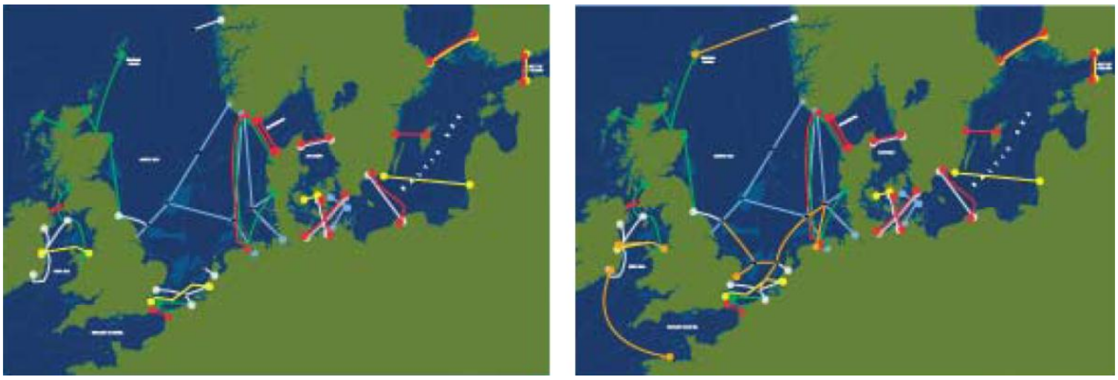


Source: OMA (2009).

In its **Oceans of Opportunity** study (EWEA, 2009a), the European Wind Energy Association (EWEA) investigates the the integration of 40 GW offshore wind generation capacity into the European electricity network by 2020 and 150 GW by 2030. The elements of an offshore grid are considered to be undersea transmission cables, offshore nodes on platforms with HVDC conversion equipment and onshore connection points to the AC networks.

The recommended projects (Figure 3) allow for the implementation of all planned offshore wind farms and increase electricity trading opportunities, as well as European energy security. The scenarios include the suggestions of the TradeWind study (EWEA, 2009b) and plans of the European TSOs. In 2020, most of the additional cables are point-to-point links with one meshed element between the connections towards Norway. Only in 2030, the study assumes the realization of a really meshed offshore grid with offshore connectors parallel to the British east coast connecting to offshore hubs at the Belgium, the Dutch and finally the German part of the North Sea. From there several onshore connections allow for flexible trade flows between the onshore AC grid and the meshed offshore network. The offshore links relief the onshore network in the Benelux which is already suffering scarcity in cross-border capacity today and will have to deal with a lot of additional on- and offshore wind capacity in the next two decades.

Figure 3: Offshore Connectors of the Oceans of Opportunity Study in 2020 and 2030



Source: EWEA (2009a).

The **TradeWind** study (EWEA, 2009b) is the first analysis of the proposed offshore grid designs with a flow based model applying the objective of minimizing system costs. With detailed wind generation data, a zonal system is implemented for 2020 and 2030 (Figure 4) and the impact of different offshore grid designs on total system costs in Europe is discussed. The grid is simplified to inter-zonal capacities by downscaling individual tie-line capacities and NTC values to zonal values.

Methodologically, this is the first study on the economic effects of large-scale cross-border integration of wind electricity at a European level. The objective function of the model is to minimize the total operating costs of the system. In the high wind scenario, annual cost reduction for generation amount to € 326 mn. The offshore grid design is similar to Figure 3 with additional meshed connection along the continental European coastline. The annual investment costs are estimated in the range of € 300-400 mn. per year. Regarding the transmission design, meshed offshore grids are seen as economic optimum, while the main proposed onshore grid expansions are not considered specific to additional wind capacity, but mostly motivated by already existing bottlenecks in the system.

Figure 4: TradeWind Results for Change in Net Energy Flow and Production for 2030

Source: EWEA (2009b).

One contribution to the discussion by Greenpeace and 3E is the study **A North Sea Electricity [r]evolution** (Woyte et al., 2008), which wants to identify the priorities for an efficient integration of large scale offshore wind generation and focuses on an offshore grid in the North Sea. Two main drivers of the development are the availability and the variability of wind power. By comparing different types of connections (radial integration, trade links, etc.), the study develops a layout for an offshore grid. Thereby, an assumed offshore wind power capacity of 68.4 GW with an annual output of 247 TWh is realized in the time frame between 2020 and 2030.

The impact the offshore grid has on the variability of wind output is analyzed with hourly time series. Serving as trade connections between the different North Sea wind generation areas offshore connectors could lower the wind variability. The offshore links have a total length of 6,200 km, a capacity of 1 GW and estimated investment costs of € 15-20 bn. The layout consists of mostly direct HVDC connections with few offshore substations (Figure 5). The study points out that the load duration curves for wind power in the North Sea depend on the analyzed scope and a higher capacity credit is present for larger combined areas. To harvest this benefit, trade capacity for balancing offshore wind variability is necessary.

Figure 5: Offshore Grid of the Greenpeace and 3E Study

Source: Woyte et al. (2008).

Based on the TradeWind study, the techno-economic **OffshoreGrid** project aims at a scientifically based view on offshore grids in northern Europe with a suited regulatory framework (Woyte et al., 2010). The study compares cost and benefits for several offshore grid design options with focus on wind integration (radial or through offshore clusters), integration of wind farms in HVDC trade links, and the beginning of a meshed offshore network with offshore wind hubs.

For the integration of offshore wind farms in interconnection projects the results indicate 70-80% cheaper infrastructure cost compared to a separated approach with direct lines. The benefits of the integrated solution depend on the savings in cable length. The main parameters deciding on the optimal dimensioning of the different elements of the offshore wind integration are the rating of the hub connection to shore, already existing or planned interconnectors, and the incremental benefit of additional connection capacity.

Figure 6: Offshore Grid - Case Study: Direct versus Meshed Interconnection

Source: Decker and Woyte (2010).

3 The Basic Metrics for Evaluation: Welfare, Producer and Consumer Surplus, and Congestion Rents

This section of the study introduces the basic metrics that will be used to assess the social welfare impact of the North and Baltic Sea Grid. We begin with a simple one-zone example to demonstrate the basic concepts, and then move deeper into the welfare analysis of a nodal approach.

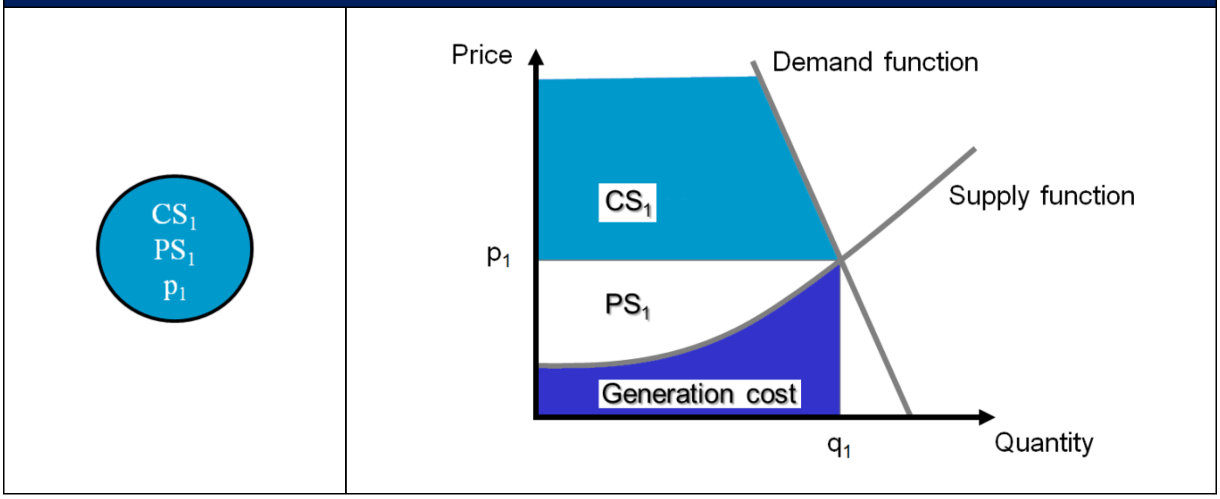
3.1 Welfare measures in a zonal approach

Market coupling in Western Europe and market splitting in the Nordic market are currently the predominant market designs in the European electricity markets. Thereby, one price for electricity is derived in the market settling process for each country or price zone.

The **one zone** example addresses a single price zone for all nodes of the network with an aggregated supply and demand function including all market bids of generators and consumers (Figure 7). The market is settled where the supply and the demand function intersect resulting in the traded quantity (q_1) and the market price (p_1). The zonal welfare includes consumer surplus (CS_1) and producer surplus (PS_1) and is defined by the area below the demand function minus the generation cost. Assuming a given demand function, the market result can only be altered by changes on the supply side. With additional competitive generation capacity p_1 decreases. The welfare gains due to the increase of q_1 with lower p_1 go in hand with a redistribution of PS_1 towards CS_1. Reductions in available generation capacity which is often discussed in regard to market power issues increases p_1. The results are welfare losses through lower q_1 and a redistribution of CS_1 to PS_1.

The market dispatch of example (1) is only valid as long as no internal link in the transmission system is congested. In case of internal congestion a technically infeasible market outcome results, as only the price and not the location of generation and demand within the network is considered in the process of market settling (Ehrenmann and Smeers, 2005).

Figure 7: Welfare and Surpluses for the One Zone Example



The **two zone** example illustrates the case with two separated price zones. We assume that there is a congested line, so that there is insufficient transmission capacity for dispatching the least cost generation in the system between the two zones (Figure 8). In this case, an optimal dispatch would want to replace more expansive generation in zone 2 with cheaper generation from zone 1, but lack sufficient transmission capacity; this results in two different zonal prices p_1 and p_2. A separation ("splitting") between zone 1 and zone 2 is a logical result to maintain a feasible market dispatch that respects the transmission constraint. This would avoid cheaper generation of zone 1 to bid into the market although there is insufficient transmission capacity for transport to the demand in zone 2.

Compared to one zone with one price for electricity, separate zones will therefore have deviating market prices in case of inter-zonal congestion. The difference in prices between zones is a good indicator where upgrading the network might be beneficial. However, additional transmission capacity causes price convergence and thereby alters the market result as it allows for more trade flows. In zone 1, the additional exports raise overall demand and therefore cause a higher p_1 redistributing CS_1 to PS_1 and further decreasing CS_1 by lower zonal consumer demand (q_1). PS_1 benefits from the higher p_1 and the additional exports. In zone 2, the additional imports decrease p_2. CS_2 gains by redistribution from PS_2 and higher consumer demand (q_2). For producers in zone 2 (PS_2) the additional competition from zone 1 implicates lower generation volumes and surplus.

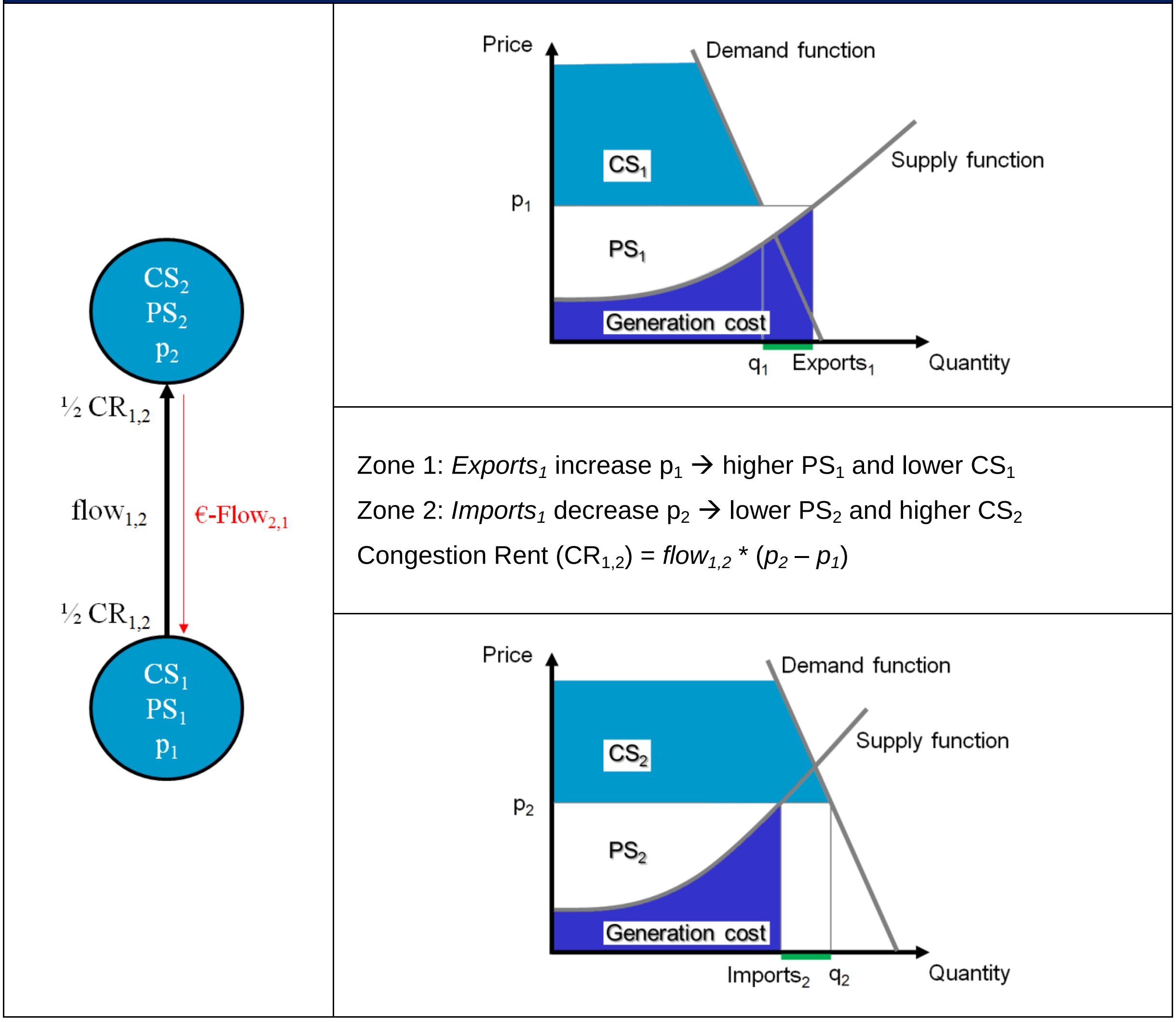
In the one zone example (1) welfare has the two components of CS and PS. Introducing trade requires financial compensation for the physical electricity flows between the two zones. Its value is the electricity flow multiplied with the market price of the exporting zone. If the transmission capacity between the two zones is congested a scarcity rent is charged for the transport of electricity. This rent is referred to as **congestion rent** (CR), in the following. It reflects the rent of the line between the two zones and is quantified by the price difference between the starting and the ending node of the line (price difference of the two zones) multiplied with the line flow. Depending on the regulatory scheme these rents might be used for compensating a merchant investor, or to drive down electricity prices in the two zones through redistribution.

For the welfare calculation the congestion rent is allocated evenly between the two zones for each inter-zonal line. The overall net impact on zonal welfare depends on the specific characteristics of the demand and supply function in the zone and the congestion rent. Therefore, losses in CS by a higher zonal price might be lower or higher than the additional income for producers with exports.

The situation described in the two zone example is a good representation of the current European market design where only certain network constraints are integrated in the process of market settling.[1] If internal congestion is present within one price zone, re-dispatch and counter-trading are deployed to establish a secure transmission system including line flow limitations and n-1 security. Starting out from the determined infeasible market outcome the responsible TSO has to compensate generation which is re-dispatched out of the market and pays other suitable generation for replacement.

[1] In Continental Europe with countries as price zones cross-border lines are considered in the market dispatch. In the Nordic market with several price zones in Norway (five), Sweden (six at the end of 2011) and Denmark (two) also scarcity on lines within the countries is considered if the line connects internal price zones.

Figure 8: Welfare and Surpluses for the Two Zone Example



3.2 Welfare measures in a system of locational marginal prices

While the evaluation is rather simple for two price zones its complexity increases with more zones and cross-border lines influencing each other in the market dispatch. All zonal approaches result in an in-feasible dispatch in case of internal congestion. One way to avoid this dilemma is to create additional price zones with all possibly congested lines in between separate zones. In a system where every link is considered a possible bottleneck, every single node has to become its own price zone; this is called a system with locational marginal prices (LMP), or “nodal prices”.[2] With renewable generation, and their increasing share of fluctuating electricity output defining larger price zones without internal con-gestion becomes very challenging and locational marginal prices instead of zonal pricing is considered a reasonable alternative (Neuhoff et al., 2011). In this study we apply the LMP approach to have all nodes with all network links and therefore all possible network constraints in the market dispatch. The

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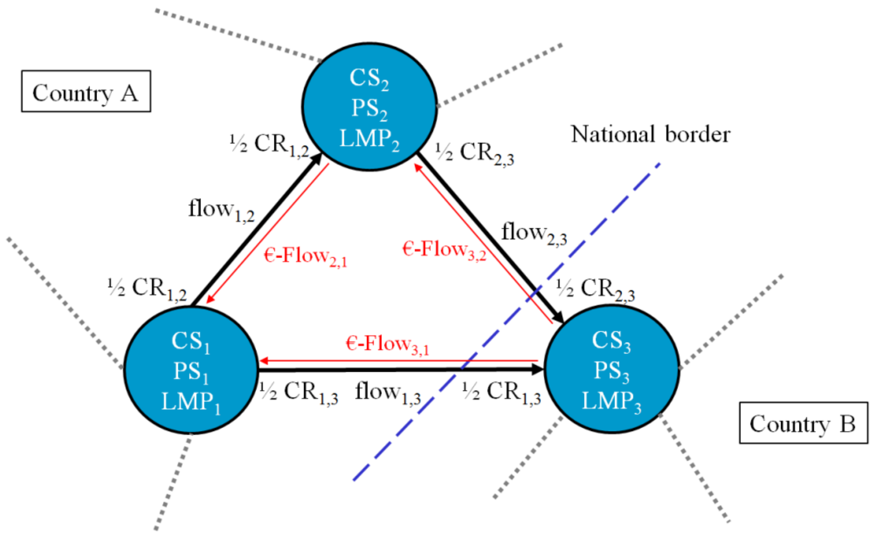
[2] LMP is currently employed in several electricity markets in the US (e.g. PJM, NYISO) and its implementation is planned for Poland within the next years.

resulting nodal prices reflect the change in total production costs for an additional incremental load at the particular node. As all internal network restrictions are considered re-dispatch is not required.

Figure 9 provides a representation of the welfare and surplus measures in an LMP-system, the principles of which are similar to the zonal approach.[3] CS is determined by the LMP as well as the demand function and PS by the dispatch data on nodal generation. The nodal PS is calculated by the amount of nodal generation times the LMP minus nodal generation cost. It implicitly includes the net financial trade flows. For the welfare calculation the cross border rent between two nodes is shared evenly between the two. All in all, the welfare of one zone comprises of CS, PS and half of the congestion rent on all related transmission lines.

Figure 9: Welfare and Surpluses in the LMP Scheme



3.3 The methodology used in this study

In this study, we are interested in the welfare as well as producer and consumer surplus at a national level. We assume that the objective of transmission expansion is to maximize the overall welfare for the participating countries, including all countries i and their consumer surplus (CS_i), producer surplus (PS_i) and congestion rents in the network (CR_i). CS_i and PS_i of one country are only discussed on national but not on nodal level. The welfare and surplus values can be calculated by the sum over all nodes within its borders. The national congestion rent is distinguished in internal CR_i on all lines within the country and in cross-border CR_i for all lines connecting it to other countries. The cross-border rent is shared evenly between the two involved countries. We thus are able to obtain welfare values, CS, PS and internal and external congestion rents of the transmission system, analyzed at the national level for all countries adjacent to the North and Baltic Sea.

[3] The nodes are the transformer stations in the meshed high voltage electricity network. For the European electricity network high voltage lines with 380kV to 150kV are usually included in the meshed network topology.

The complexity of the issue lies in the fact that different technical designs of the North and Baltic Sea Grid have very different welfare implications. The main reasons are that transmission investment influences the market outcome by decongesting the network and alters the flow pattern which depends on Kirchhoff's laws. These two factors require the detailed network with all transmission lines included. The LMP approach allows a good assessment of the impact transmission investment has on various market participants. The LMP in a node goes down with the availability of additional competitive generation capacity. A decreasing LMP increases CS as the lower nodal price creates additional demand and redistributes surpluses from producers to consumers. For producers, the additional competition causes losses as they get paid less and some generators might be pushed out of the market. Vice versa if additional markets become available for exporting generation the LMP in that node rises, leading to higher PS and lower CS. For every node, the net welfare change depends on the specific characteristics of nodal generation, demand and congestion rent.

In a highly meshed network as the European electricity transmission system the expansion of transmission capacity can relief congestion in one place but is likely to increase congestion on other links in the network moving congestion rents towards different lines. Therefore, the effects of transmission expansion on national welfare and surpluses are not obvious and subject to a scenario based evaluation.

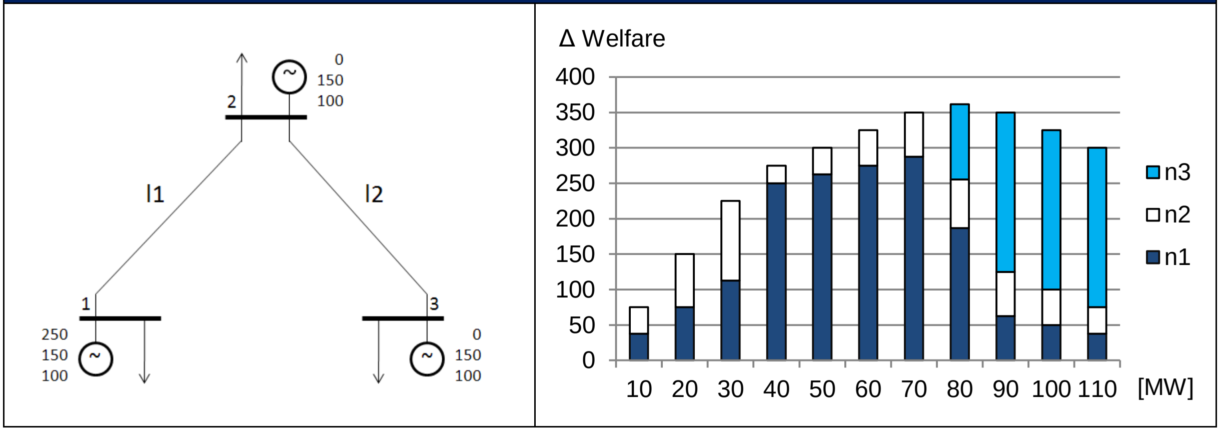
The change in distribution of welfare and surpluses resulting from line extensions is difficult to predict as it depends on many factors. The following simple example illustrates the implications resulting from transmission upgrades in a nodal network which represents a typical transit scenario (Figure 10).[4] In the example node 1 (n_1) wants to export to node 2 (n_2) and 3 (n_3). However, no direct flows to n_3 are possible as all exports are directed to n_2. Under the assumption of non-cooperative strategic behavior and the absence of a compensation mechanism, the three nodes decide on the expansion off their adjacent lines maximizing their own welfare. For line upgrades the nodes next to it have to pay half of the investment cost. In this case, this means that n_1 and n_2 decide on the extension of the constrained line 1 (l_1) and both pay half the cost. N_3 has no influence on the investment decision for l_1 but is affected in its welfare as well.

The results lead to a system optimal line upgrade of 80 MW with € 360 in additional welfare. On nodal level, n_1 gains € 190, n_2 about € 70 and n_3 which is not investing itself gets € 100. However, if n_1 and n_2 have decision power on the line investment n_2 limits the additional capacity of l_1 to 30 MW to increase its own welfare gains from € 70 to € 110. N_1 would like to increase capacity to 70 MW but agrees on 30 MW and takes away € 110 in welfare gains before not investing at all. N_3 does not see any welfare gains for this extension capacity. The system welfare gains decrease from € 360 to € 220. Including a third line (n_1 to n_3) complicate the scenario as loop flow are present in meshed networks. The possibility of coalitions (e.g. n_1 and n_2) and side payments allow for different results.[5]

[4] Nodal demand 200 MW, demand function with reference price of 25 €/MWh and point elasticity of -0.25. Three generation types with capacity of the numbers in Figure 10. Cheap generation 20 €/MWh, middle one 25 €/MWh and lower one 30 €/MWh. Line 2 unconstraint and initial capacity of l_1 10 MW. Expansion cost 2.5 €/MW.

[5] Gately (1974), Nylund (2009) and Buijs (2011) have discussed cross-border transmission expansion with game theoretic approaches and two-stage models with multiple countries deciding on line upgrades.

Figure 10: Nodal Welfare Implications from Transmission Investment



4 Model, Data, and Scenario Specification

4.1 Introduction to the applied electricity market model

This work applies the ELectricity MODel ELMOD (Leuthold, Weigt and von Hirschhausen, 2011), an engineering-economic optimization model for the European electricity market at a nodal level. Based on the DC load flow low approach (Schweppe et al., 1988) it allows a realistic representation of physical characteristics of electricity networks including Kirchhoff's laws, and contains a line sharp representation of the high-voltage transmission network.

For the scope of this study, the ELMOD model has been extended to the electricity markets of Great Britain and Scandinavia. To represent markets dominated by hydro power generation we also implement seasonal hydro reservoirs. The transmission network consists of three non-synchronized AC control zones (Continental Europe, Great Britain and Scandinavia) which are connected by offshore HVDC connectors in the North and Baltic Sea. The mathematical formulation of the model is presented in the consecutive Equations 1 to 7:

The objective function in Equation 1 maximizes the annual system welfare consisting of all nodes (n) in the three control zones and of all representative hours (t). As explained in the previous section for a simple example, each node has a characteristic linear demand function and a merit order of different generation technologies (s). Each technology has a specific marginal generation cost (MC). Total welfare can then be expressed as follows:

$$\max_{\substack{g_{n,s,t} \\ q_{n,t}}} W = \sum_{n,t}\left[\left(A_{n,t} * q_{n,t} + 0.5 * M_{n,t} * {q_{n,t}}^2\right) - \sum_s\left(g_{n,s,t} * MC_{n,s}\right)\right] \qquad (1)$$

For the implementation of the DC network an additional set (dc) is introduced to the model and refers to the HVDC lines. With regard to the maximal power flow, which can be bi-directional, the DC grid is modeled in the same way as its AC counterpart (Equation 2). The transmission limit is set by a maximum on the absolute flow value for every HVDC line in Equation 4. With the assumption of directed electricity flows in the DC grid, no voltage angle (Equation 3) is required.

$$|flow\_ac_{ac,t}| \leq Flow\_AC\_max_{ac} \qquad \forall\ ac, t \qquad (2)$$

$$flow\_ac_{ac,t} = \sum_n (H_{ac,n} * delta_{n,t}) \qquad \forall\ ac, t \qquad (3)$$

$$|flow\_dc_{dc,t}| \leq Flow\_DC\_max_{dc} \qquad \forall\ dc, t \qquad (4)$$

The upper limit for generation is defined in Equation 5 by the maximal generation of every technology and for each node ($G\_max_{n,s}$). The additional factor $Availability_{n,s,t}$ defines the percentage of installed capacity which can be used in the optimization. It refers to revision time of conventional power plants and the dependency of renewable electricity sources on physical restrictions.

$$g_{n,s,t} \leq G\_max_{n,s} * Availability_{n,s,t} \qquad \forall\ n, s, t \qquad (5)$$

Seasonal hydro reservoirs are modeled in a more sophisticated way than the other generation technologies. They own a total generation budget for all hours of one model run (Equation 6) which allows them to allocate a certain average amount of generation to the m different hours. As the upper limit of generation for every single hour is set to the installed generation capacity in Equation 5, reservoirs can increase their output for some hours to 100%. However, they must not violate the average generation restriction in Equation 6 over all combined modeled hours. If they are generating in some hours above the value of the average constraint they do so by reducing their generation level in other hours below the average constraint. The factor Res_n determines the allowed average output of the reservoirs for each node.

The model formulation assumes perfect competition and the absence of market power as conventional generators have to bid all their capacity into the market at marginal cost. For hydro reservoirs this issue is more complicated as the marginal generation cost is zero and the binding constraints are the maximum generation output and the limited yearly generation volume. Contrary to inter-temporal profit maximization, the objective of welfare optimization also forces the inter-temporal production of hydro reservoirs to serve the welfare purpose.

$$\sum_{t=1}^{m} (g_{n,s,t}) \leq Res_n * G\_max_{n,s} * m \qquad \forall\ n, s \in \{reservoir\} \qquad (6)$$

The energy balance (Equation 7) includes demand, generation and transmission in- and output. Its sum has to be zero for every node and in all hours meaning that generation and imports of electricity has to equal the demand and exports. The marginal value of the energy balance is the cost of an additional incremental unit of electricity at the node and reflects the locational marginal price.

$$\sum_s g_{n,s,t} - demand_{n,t} - ac\_input_{n,t} - dc\_input_{n,t} = 0 \qquad \forall\, n,t \qquad (7)$$

The described model is a quadratic constrained problem. It is implemented in the General Algebraic Modeling System (GAMS) and solved with CPLEX.

Box 1: Model Assumptions

Due to the large scope of the model, some simplifying assumptions had to be made, which could be relaxed in later work:

- The modeled time resolution does not include consecutive hours. The entire year is represented by 80 characteristic hours with different demand levels and generation outputs for renewable energy sources. Therefore, we do not consider ramping constraints and ramping costs for thermal power plants and consequently less flexible generation is used.
- We consider four different wind levels for the analysis; however, the missing temporal deviation of wind generation in different locations and the lack of extreme wind situations may underestimate the benefits of additional trade capacities;
- Combined heat and power plants are not separately implemented as must run or with lower generation costs in the winter months. Consequently, they are less competitive and some markets see lower generation levels and more imports (e.g. the Netherlands);
- The seasonal hydro reservoirs in Scandinavia and the Alps are forced to follow the welfare maximizing objective function. Thus, they are restrained from using their inter-temporal decision power. Having an annual generation limit the profit maximizing use of seasonal reservoirs is generating electricity whenever prices are the highest. As this objective is not always in line with the welfare objective in the model approach seasonal hydro reservoirs could possibly increase their own profit and the overall welfare of their country if allowed to act in a profit maximizing way.
- The additional wind generation is added to the already existing capacity leading to a market with even more surplus generation capacity than today. Too much base load generation tends to decrease the prices due to the missing flexibility constraints.
- The assumptions for natural gas prices (BP, 2011) with a separate prices for Great Britain might overestimate its competitive export potential for the British electricity market;
- The trade flows in the network are somewhat higher than the stated values for 2009 as the implemented network does not limit the cross-border flows to the current NTCs, but determines them by individual line constraints in the DCLF approach.
- Simplified n-1 security is included with an 80% limitation for all lines of the three AC networks;
- The modeling approach is not suited to conduct a cost-benefit analysis; thus, investment costs are not considered in the welfare analysis.

4.2 Parameters and input data

The base model runs are conducted with European electricity market data for 2009. We only alter two parameters: i) the offshore network topology, and ii) the amount of electricity from wind farms integrated through local lines; all other parameters, such as generation characteristics, marginal generation costs, demand, etc. are held constant in the model runs.

The time resolution represents one entire year by 80 representative hours. They are distinguished in 40 summer and winter hours for ten different demand levels and four different wind generation levels (Figure 11).[6]

- Summer and winter hours have different availability factors for hydro run of river and for wind generation in every country.
- For wind power an additional separation in four different generation levels is included for the ten different demand levels.[7]

The 80 model hours describe different situations in the network with a focus on renewable generation and demand levels. The increasing importance of seasonal storage with market integration of Scandinavia and therefore their representation in the model is a key factor for the trade flows in the North and Baltic Sea Grid. However, not having consecutive hours in the hourly time frame does not allow for an inter-temporal implementation of short term pump storage plants and ramping constraints for conventional generators.

The underlying transmission network reflects the ENTSO-E (2009) grid map resulting in the basic network topology of Figure 12 with 2069 nodes, 2877 AC lines and eight DC lines for the model scope. The AC grid consists of three separate AC high voltage transmission systems with lines of 380kV, 300kV, 220kV and 150kV. Countries neighboring the North and Baltic Sea are implemented line sharp while their neighbors are referred to by one main node and their cross-border lines without the national transmission network.[8] The line characteristics are calculated based on Fischer and Kießling (1989).

Figure 11: Representative Hours (t) for one Model Year

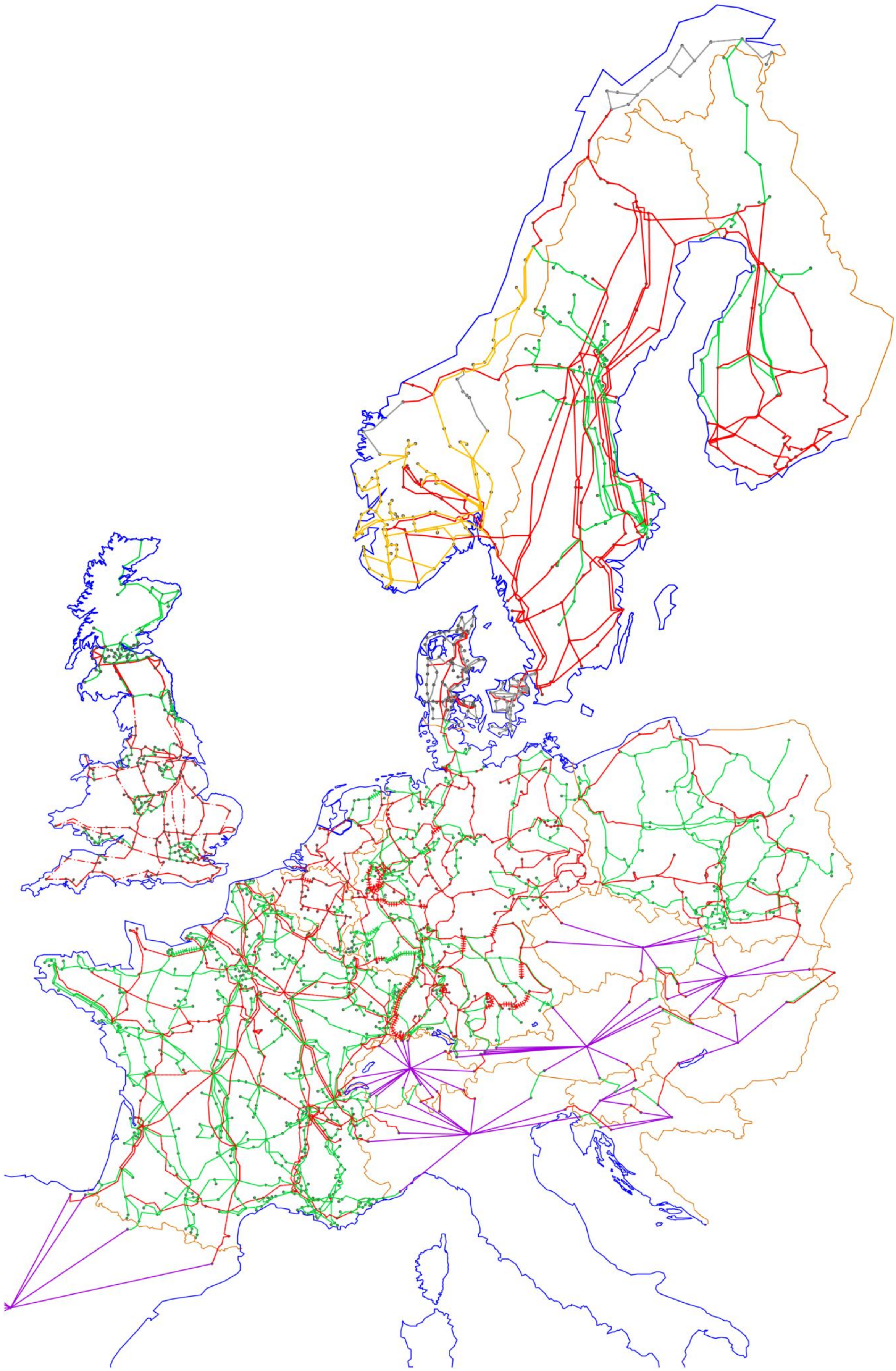
<table>
<tr><td>Season</td><td colspan="40">Summer / Winter</td></tr>
<tr><td>Demand</td><td colspan="4">1</td><td colspan="4">2</td><td colspan="4">3</td><td colspan="4">4</td><td colspan="4">5</td><td colspan="4">6</td><td colspan="4">7</td><td colspan="4">8</td><td colspan="4">9</td><td colspan="4">10</td></tr>
<tr><td>Wind</td><td>1</td><td>2</td><td>3</td><td>4</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

[6] The first of the ten different demand cases for both seasons reflects the average of the highest 10% of all winter/summer hours in the model scope for 2009, the second case the average of the second highest 10% and so on. With this approach the highest/lowest case is closer to the extreme peak/off-peak hour than in case of using one or two days with 24 consecutive hours.

[7] For the four different wind cases the seasonal capacity factor for wind in each node (onshore and offshore) is multiplied with the onshore factors (0.2 – 0,8 – 1,2 – 1,8) and the offshore factors (0.4 – 0.9 – 1.1 – 1.6).

[8] Thus, BE, DE, DK, FI, FR, GB, LU, NL, NO, PL and SE are represented with their nodal network while AT, CH, CZ, ES, HR, HU, IT, PT, SI and SK are only represented by one main node with all domestic generation and demand.

Figure 12: Implemented AC Electricity Network for 2009



The nodal demand is derived from hourly national demand data which are publicly available.[9] However a nodal allocation of the national demand values is necessary as this data is not publicly available. Using NUTS3[10] data for GDP and population (EU, 2010a/b) the nodal demand is assumed to be proportional to these figures and derived as percentage of the national demand value.

The model uses generation data for 16 different technologies of electricity generation (Meller et al., 2009 / NVE, 2010 / DECC, 2010). While renewable wind and hydro generation is implemented with zero marginal generation cost, conventional generation plants face costs for fuel and CO_2 allowances. For the natural gas price in Great Britain, we use an average deviation of the Heren NBP Index from the Continental European prices, in order to correct for the very low 2009 natural gas price in Great Britain (BP, 2011). Table 1 shows the resulting marginal generation costs for different gas technologies in Great Britain and Continental Europe. Note that gas fired combined cycle turbines (CCGT) will provide base load in GB, being cheaper than hard coal power plants. This will be an important driver of the results in the next section.

Table 1: Generation Cost of Coal and Gas Plants in GB and Continental Europe

Great Britain	Type	Cost [€/MWh]	Continental Europe	Type	Cost [€/MWh]
Natural Gas	CCGT	33.22	Natural Gas	CCGT	42.72
Natural Gas	Steam Turbine	48.07	Natural Gas	Steam Turbine	61.82
Natural Gas	Gas Turbine	52.26	Natural Gas	Gas Turbine	67.19
Hard Coal	Steam Turbine	34.65	Hard Coal	Steam Turbine	34.65

Source: BP (2011), EEX (2010), IRS (2011), Gampe (2004) and own calculation.

4.3 Scenario specification

We use the existing electricity system in 2009 as the **Base-2009** case, and then add scenarios in two dimensions:

- With respect to the grid design that is emerging, we distinguish between a **Trade** scenario and a **Meshed** scenario;
- With respect to the local level of wind park integration, we add a **Wind+** scenario where additional connections of new parks are added to the closest shore.

4.3.1 Design scenarios: Trade vs. Meshed network structures

The Trade scenario is characterized by point-to-point trade cables that connect two countries, respectively. This corresponds to the traditional setting that has dominated the developments in the North and Baltic Seas so far, e.g. the NorNed, Baltic, or Kontek cables; this is also the structure foreseen by

[9] The sources are ENTSO-E (2010a) for Continental Europe, Nordpoolspot (2010) for Scandinavia and National Grid (2010) for Great Britain.

[10] Nomenclature des unités territoriales statistiques (NUTS) is a European standard for statistical purposes.

the ten-year network development plan (ENTSO-E, 2010b). The Trade scenario thus extends the Base-2009 scenario by four new connectors and the expansion of the already existing offshore links in the North Sea; in the Baltic Sea the transmission capacity of all existing connectors is extended. In addition to the radial lines for offshore wind integration, an equivalent of 5,300 km of 1 GW in transmission capacity is built. The trade scenario is a state of the art offshore grid design of point-to-point HVDC cables without multi-terminal solutions. The Trade scenario thus maintains a bilateral integration offshore.

On the contrary, the **Meshed** grid design stands for an integrated approach for wind feed-in and trade links for the future offshore grid expansions. The concept is derived from the meshed offshore grid proposal in the TradeWind study (EWEA, 2009b) and the offshore energy super-ring suggested in the Zeekrach Masterplan (OMA, 2009). Thereby, the hubs of the main offshore wind generation fields in the North Sea are connected with each other by additional connectors. In the Baltic Sea Kriegers Flak is realized. Existing trade links are not extended so that the overall exchange capacity between the three non-synchronized electricity networks (Great Britain, Scandinavia and Continental Europe) almost equals the Trade scenario. Due to the existing wind integration the meshed system is embedded in, the overall expansion is only slightly higher (5,500 km * 1 GW) but has to share some of its trade capacity with wind integration. Note that some technology development is necessary to realize the Meshed design, notably multi-terminal connections that the current HVDC technology does not deliver. However, gradual technological innovations are expected to make such a Meshed scenario feasible within the considered time span.

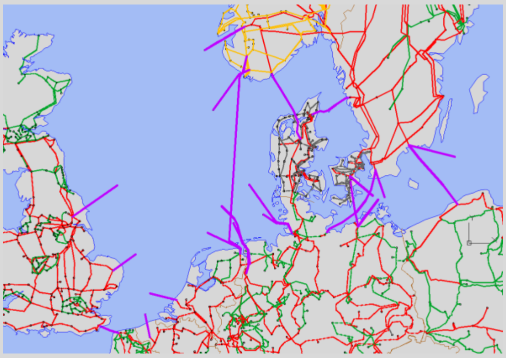
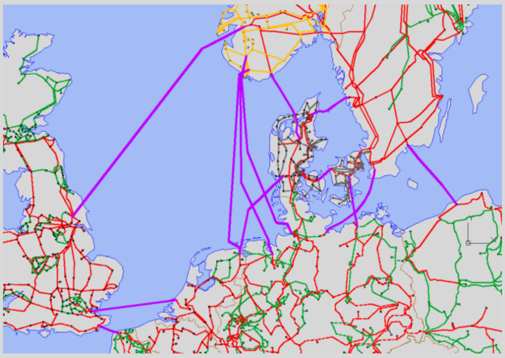
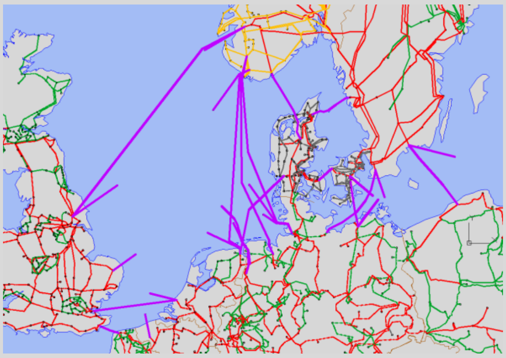
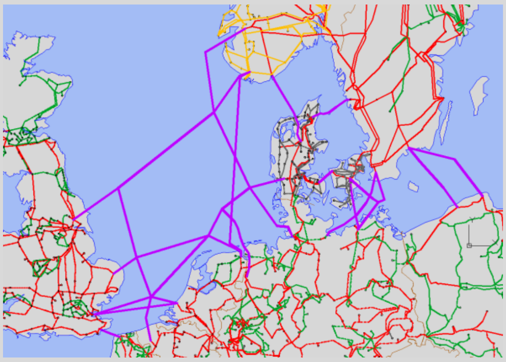
4.3.2 Local wind park integration: Base 2009 and Wind+

In the **Base** case of 2009, there are no large offshore wind parks that are connected to the shore. Yet, such integration has started in the meantime in the North and the Baltic Seas, and this trend is likely to accelerate. The **Wind+** scenario therefore reflects a situation where additional offshore wind generation close to shore (and assumedly to be connected by AC cables) is added to the nearest onshore node. The offshore wind parks more than 80km from shore are connected with HVDC cables to the country the wind farm is located. The values for wind generation in the Wind+ scenario are taken from the regional 2020 installation figures of the OffshoreGrid (2010) project for on- and offshore wind generation. This implies additional cables of 2,600 km * 1 GW transmission capacity, most of it installed in the North Sea.

Figure 13 shows the network implications of the Base case 2009 and the scenarios developed thereupon.[11] One clearly distinguishes the point-to-point connections in the Trade scenario from the intensive interconnection in the Meshed scenario. Also, the Wind+ scenarios are combined with the Base and the two design scenarios (Trade, Meshed), by adding the near-shore wind park capacities.

[11] The BritNed connector and the Great Belt cable in Denmark are not included for the 2009 model runs. For 2009 the two offshore grid designs are compared to the existing network including all operating HVDC connectors at that time.

Figure 13: Offshore Grid and Wind Scenarios

	2009	**Wind+**
Base		
Trade		
Meshed		
Onshore Wind	**73.6 GW**	**177.2 GW**
Offshore Wind	**0.3 GW**	**47.2 GW**

5 Results and Interpretation

5.1 Implications on welfare and surpluses

5.1.1 Overall system welfare effects

Before providing the analysis at the level of the participating countries and stakeholders, we provide the overall system benefits to society, i.e. the sum of national welfare gains. In the Meshed scenario using the 2009 assumption, total social welfare increases by € 210 mn. per year more than double the increase in the Trade scenario (~ € 100 mn.). In the Wind+ scenarios, these values decrease by about 20%, respectively, due to the fact that more local wind feed-in reduces the inter-regional price differences.

The welfare gains results mainly from a cheaper electricity generation dispatch. In the Wind+ scenario new wind generation enters the markets with all other generation still available, allowing for a cheaper generation dispatch with less expensive generation and lower LMPs. Therefore, the potential for savings in generation cost and welfare gains through price convergence is lower than in the 2009 scenarios.

5.1.2 National welfare effects

We now assess the welfare effects at the level of the participating countries. The national welfare changes are illustrated for the two network scenarios in 2009 and for Wind+ compared to no additional network extensions. Figure 14 presents the results; in each figure, overall welfare improvements are shown in green, whereas decreasing welfare is shown in red; the more intense colors depict stronger effects.

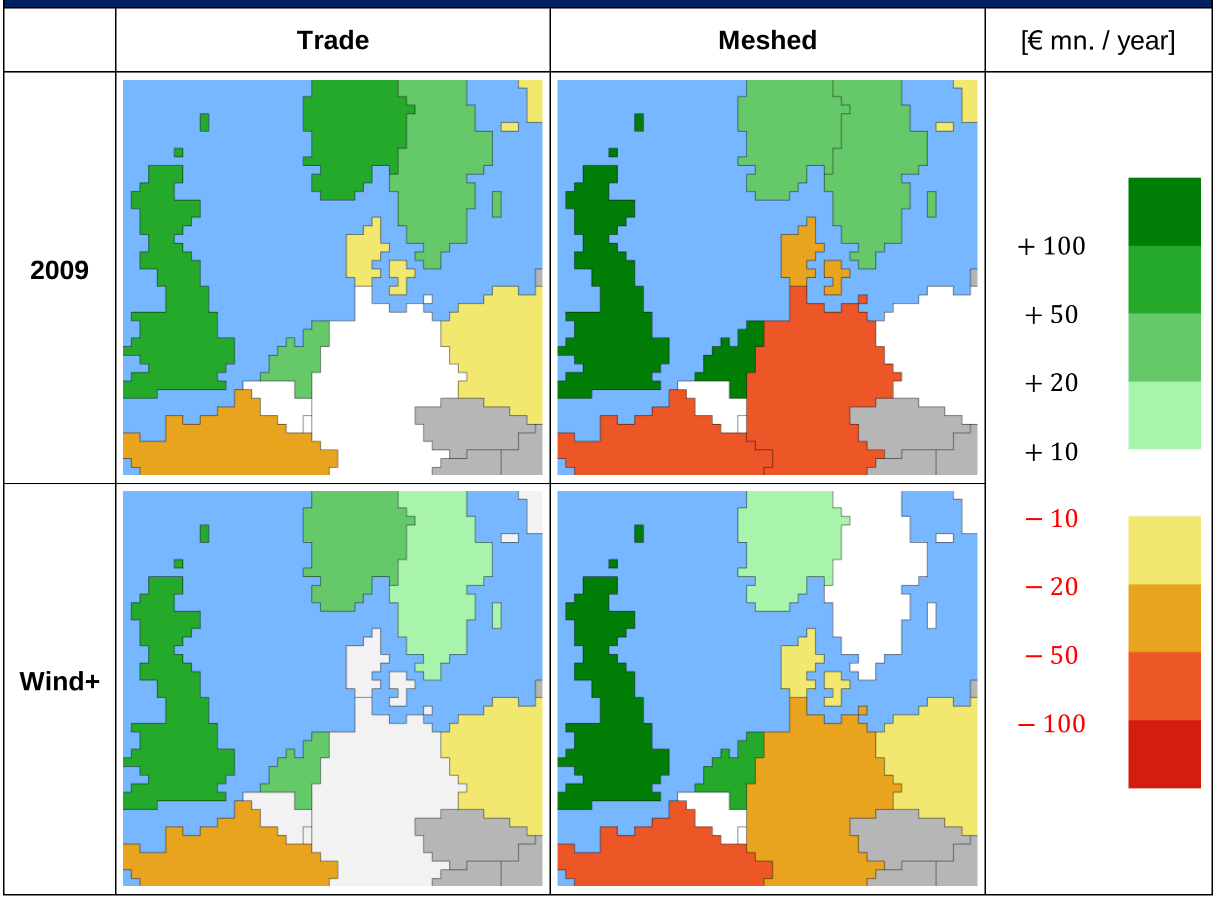
We find that smaller isolated markets can increase their welfare when they are better integrated in the internal European electricity market. This is the case for Great Britain which has trade connectors to the Netherlands and Norway in both expansion scenarios. Compared to the 2009 network where only trade with the low price zone of France is possible the new export markets allow for an increase in national welfare. The welfare gains are larger in the Meshed scenario where north-south onshore congestion in the British transmission network is bypassed by the additional offshore connectors alongside the British east coast. On the contrary, traditional exporting countries suffer losses from the North and Baltic Sea Grid, either by exports or by lower prices. The main countries in this category are Germany and France. This effect increases in the Meshed scenario when even more competition arises from Great Britain and Scandinavia by more flexible distribution of their exports in the continental onshore transmission system.

Importing countries benefit from lower market prices through the additional competition by new suppliers. That happens mainly to the Netherlands, where a large share of the consumption is imported from Germany and France in the base case. As some imports become available at lower prices from Great Britain and Scandinavia and consumers benefit from lower prices high welfare gains are realized. The loss in producer rent due to decreasing market prices in the Netherlands is significantly lower, as national production does not cover all domestic demand. This development is stronger in the Meshed scenario with more flexible import opportunities.

Countries with significant levels of seasonal hydro reservoir capacity can create more national welfare without increasing the net exports; this is notably the case for Norway and Sweden. Hours with high levels of wind generation in the markets connected by the North and Baltic Sea Grid allow for buying cheap electricity to replace domestic hydro reservoir generation. In hours with low wind generation the higher price for electricity allows for additional export profits by increased hydro reservoir generation. Competing with the transmission capacity of the North and Baltic Sea Grid, transit countries lose welfare by the decrease in congestion rents on their national transmission lines. For Denmark this causes lower welfare values, especially in the Meshed scenario.

When considering the national welfare results, some countries might be exporters for low demand and become importers for high demand. The same happens with different levels of wind output. Therefore, the results are driven not only by the change in prices and trade flows but also by their change in the various system states. In most countries the benefits and losses created by the North and Baltic Sea Grid in the Trade scenario increase when moving to the Meshed design. Except for France, all directly connected countries see welfare gains (GB, NO, SE, NL), are indifferent (BE, DE) or only suffer small losses (DK) in the Trade scenario. This statement does not hold for the Meshed scenario as Germany and Denmark suffer higher losses. However the results from the Wind+ scenario could increase the willingness to cooperate in the realization of the Meshed design, thanks to the overall welfare increase.

Figure 14: Development of National Welfare Compared to no Offshore Extensions



5.1.3 Consumer and producer surpluses

Not only national welfare but also the distribution of consumer and producer surpluses within one country can become an important issue. Figure 15 therefore focuses on the decomposition of the overall welfare effects (marked in yellow) into consumer surplus, producer surplus, and congestion rent. Even if the national welfare balance is positive for a certain network expansion scenario, higher electricity prices can raise public and political opposition. Candidates for this argument are mainly the Scandinavian countries. Thus the overall welfare gain in Norway and Sweden is positive (several millon € per year), but consumers have to pay an additional € 100-150 mn. for their electricity.

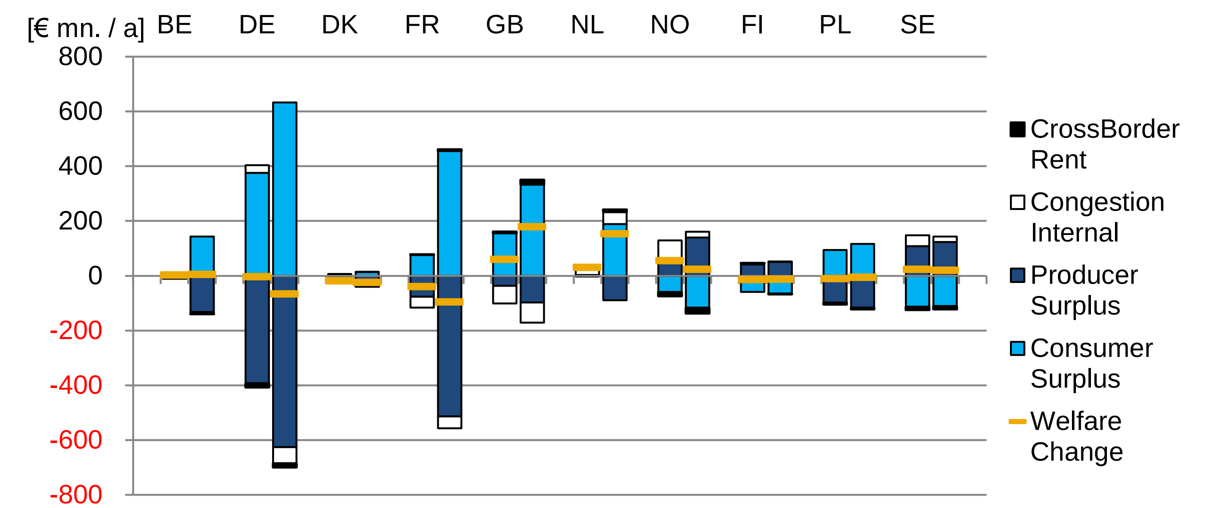
Consumers in continental Europe generally benefit due to lower electricity prices. These benefits can be substantial, such as in the case of Germany and France, with € 600 and 400 mn., respectively. On the other hand, producer surplus in these countries decreases, in sizeable sums.

With increasing shares of renewable generation capacity, market prices become more sensitive to its hourly output causing low prices in high wind hours with excessive generation being exported, and high prices in low wind hours with deficit generation being imported. Countries with more flexible generation benefit from the subsidized renewable generation of other countries by providing wind balancing generation.

The internal congestion rents decrease in some countries while increasing in others. This effect would look different in the current European market design with price zones. Internal congestions could be utilized to limit NTCs and the network assessment becomes less transparent than with LMPs. The decrease in cross border rents for Denmark confirms the idea of lower national congestion rent with additional competition in transmission. Norway and Sweden are faced with higher internal congestion.

The most significant result is that distributional impacts of consumer and producer rent are higher than the welfare gains. Therefore, overall system benefits in the traditional cost-benefit analysis, national welfare evaluation but also the strong distributional challenges have to be considered in the approach to build the North and Baltic Sea Grid.

Figure 15: Rent Shifting with Trade (left) and Meshed (right) Network Design for 2009



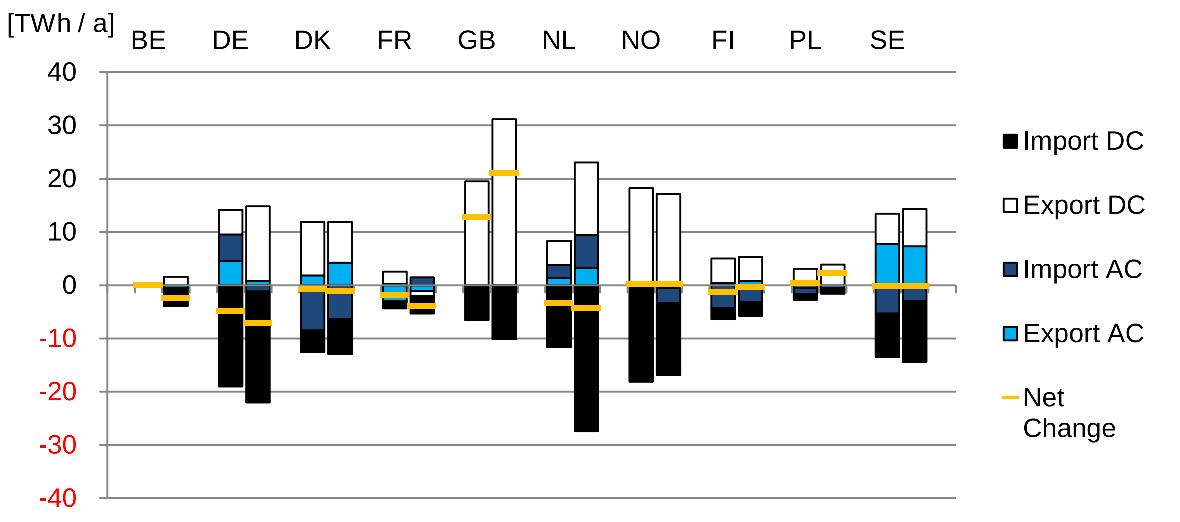
5.2 Change in trade flows and volumes

The international cross-border trade flow increases with additional offshore connectors even for the AC grid, by about 5%. In the North and Baltic Sea Grid, cross-border flow increases from 40 TWh/year in the 2009 base scenario to 110 TWh/year in the Trade scenario and to 140 TWh/year in the Meshed design. Thereby, the annual electricity flow increases in both directions for all countries as the North and Baltic Sea Grid allows for a more efficient usage of generation capacities regarding the specific hourly demand needs and fluctuating wind output (Figure 16).

Note that the results are mainly driven by a better integration of Great Britain, which even dominates the effect of additional transmission capacity to Scandinavia. Both, lower gas prices and an increase in offshore wind expansion plans in Great Britain account for this. The electricity mainly replaces generation from Germany, France and the Netherlands where the net trade balance decreases. Scandinavia might have cheap hydro generation but the current annual generation output is calibrated to supply the domestic markets and can even be insufficient in dry years. Therefore the supply curve of generation starts at low prices, but becomes very steep for additional capacity. The flexibility of the seasonal hydro reservoirs is used in the welfare maximization to increase production and exports in hours with high prices (low wind, high demand). This exported energy has to be imported back in hours with sufficient generation so that exports as well as imports increase significantly for Norway and Sweden.

The Meshed design does not lead to increased trade between Scandinavia and Continental Europe. Its design allows for more flexible distribution of imports to the Netherlands mainly from Great Britain. One could argue that the model underestimates the North-South bottleneck in the British system which is relieved in the Meshed system, and that the meshed analysis allows for a better understanding for the real needs of connectors in the trade design. The comparison of the Trade and Meshed design indicates a strong interrelation between on- and offshore network congestions and leads to the assumption that transmission expansion planning for offshore connectors and onshore projects should go hand in hand.

Figure 16: Change in Trade Flows with Trade (left) and Meshed (right) Scenario for 2009



5.3 Congestion rents in the North and Baltic Sea Grid

5.3.1 Interdependence between on- and offshore congestion

The national congestion rent is an indicator for internal transmission scarcity within the country. Figure 15 shows that the onshore congestion is affected by the offshore grid design. Some countries see more severe internal congestion as a consequence of the offshore connectors (NL, NO and SE) indicating an increasing need for onshore AC extensions. Others have internal congestion relieved with the offshore links (DE, FR and GB). In the Trade scenario the internal congestion rent of all countries together increases by about € 75 mn. per year. In comparison, the Meshed scenario causes lower internal congestion rents in the AC grid for all countries than the Trade design, with an overall decrease of € 175 mn. per year. Comparing these values to the overall annual welfare benefits from the North and Baltic Sea Grid, the importance of the onshore network becomes obvious.

The congestion rent in the onshore systems is highly interdependent with the offshore congestion. Depending on where the bottlenecks are located in the system, a strong expansion of offshore connectors without onshore investment moves the congestion to the onshore links. Vice versa, a good hinterland connection of the offshore connectors can result in the offshore cable as bottleneck in the system. The analysis of the offshore congestion rent should be considered in this context.

5.3.2 Change in congestion rents for existing connectors

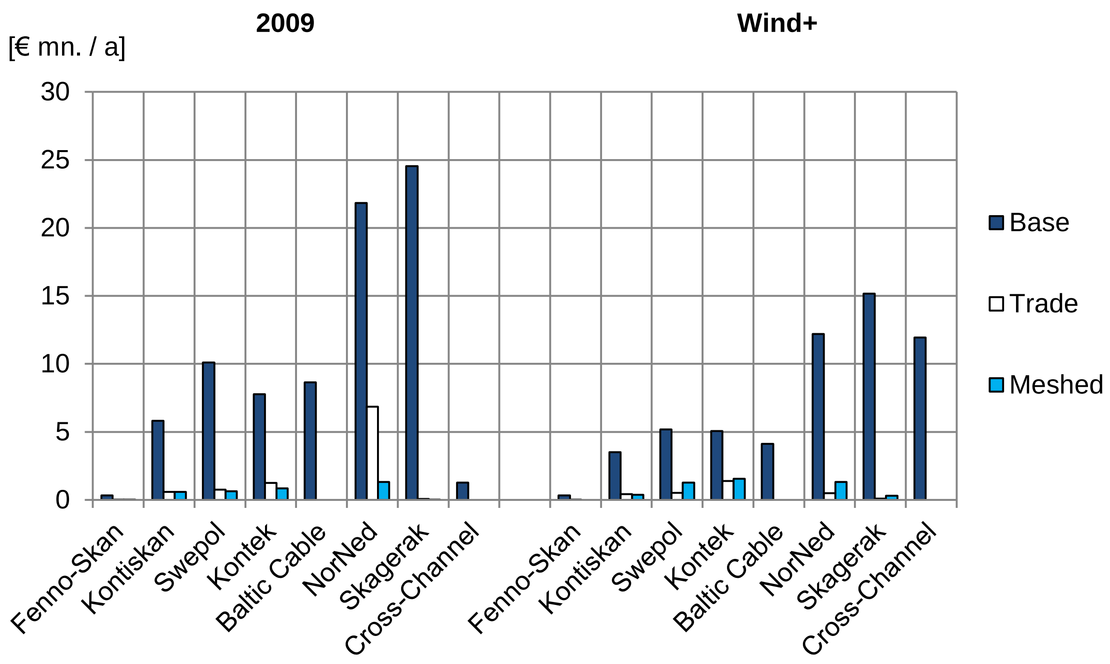
In this study the focus is on the offshore network and its congestion rent which is measured by the trade flows on each connector multiplied with the price difference between the starting and the ending node. For the 2009 base scenario three offshore connectors in the North Sea and five connectors in the Baltic Sea exist. The sensitivity of their congestion rent with increasing offshore transmission capacity is illustrated in Figure 17 for the different scenarios.

The congestion rent on the three connectors in the North Sea sums up to € 48 mn. per year for the base scenario in 2009. Thereby, the Skagerak cable between Denmark and Norway (€ 24.5 mn. per year) and the NorNed cable between Norway and the Netherlands (€ 21.8 mn. per year) collect high congestion rents while the Cross-Channel connector experiences only low congestion (€ 1.2 mn. per year). With the additional offshore cables of the Trade and Meshed scenario these values collapse, indicating that with additional trade connectors, the effect of price convergence outweighs the additional trade flows. The Skagerak and Cross-Channel cable are not congested anymore and only for the NorNed cable some congestion rent remains: In the Trade scenario € 6.8 mn. per year and in the Meshed scenario € 1.3 mn. per year.

In the Baltic Sea the four connections between Scandinavia and Continental Europe have an annual congestion rent of € 5-10 mn. each in the 2009 scenario. This value equally goes down dramatically by more than 90% with the additional transmission capacity in the Trade and Meshed design.

For the Wind+ scenario the congestion rents start from lower initial values without additional offshore transmission. As wind generation with no marginal generation costs is added to the markets the model sees lower LMPs and also price convergence compared to the 2009 scenario causing the lower congestion rents. Still, the intense impact of additional offshore capacity remains. Although this congestion rents might be higher in reality the sensitivity of the congestion rent to additional transmission capacity modeled for the North and Baltic Seas suggests that merchant investments relying on these returns face high risks by consecutive network extensions.

Figure 17: Congestion Rent for the Existing Offshore Links in Trade / Meshed Design



5.3.3 Congestion rent in the Trade and Meshed scenarios

We now consider the aggregate of the offshore congestion rents in the North and Baltic Sea Grid, respectively. Clearly additional network expansion causes a reduction of the rent (Table 2).

The Trade scenario, initially conceived to rely on merchant investment in point-to-point trade connectors, shows a high sensitivity of congestion rent to additional capacity. Here, missing onshore AC extensions could move the bottleneck out of the merchant lines into the onshore network. Without additional onshore investments the assumed connector upgrades will not be realized by merchant investment.

The Meshed scenario benefits from its flexible allocation of input and output capacity to several onshore nodes and its congestion rent is more robust for line expansion in the North Sea. However, it was never intended to generate additional congestion rents as its multi-national complexity depends on regulated investments. Its high congestion rents in the North Sea can be explained by its alternative to onshore transmission where congestion in the AC network is relieved. Therefore, the welfare optimal design of the North and Baltic Sea Grid could include additional lines in the North Sea for regulated investment. All in all, the results indicate congestion rents in the North Sea are higher during the winter months; the Baltic Sea Grid sees similar congestion rents during winter and summer.

Table 2: Seasonal Congestion Rent in the North and Baltic Sea for P2P and Hubs

[€ mn. / a] [12]			Base			Trade			Meshed		
			W	S	∑	W	S	∑	W	S	∑
North Sea	2009	P2P	25.7	21.9	47.6	18	15.2	33.2	4.5	2	6.5
		Hubs	-	-	-	-	-	-	21.5	12.5	34
	Wind+	P2P	24.7	14.7	39.4	3.6	1.8	5.4	2.9	1.4	4.3
		Hubs	-	-	-	-	-	-	45.9	20.9	66.8
Baltic Sea	2009	P2P	15.8	16.9	32.7	2.2	4.4	6.6	1.5	1.6	3.1
		Hubs	-	-	-	-	-	-	0.65	0.15	0.8
	Wind+	P2P	9.8	8.4	18.2	1.9	4.2	6.1	1.4	2.5	3.9
		Hubs	-	-	-	-	-	-	0.4	0.5	0.9

Box 2: Merchant and Regulated Transmission Investment

The way the market design is set up has a direct impact on the transmission network and its welfare effects. In this box, we consider different forms of financing the infrastructure, and the welfare effects. There are two stylized ways to finance transmission investment: One depends on regulated investment by a transmission company (Transco) investing according to network extension plans which are approved by a national regulatory authority. The planning should rely on welfare maximization with the objective of realizing investment which has higher welfare benefits than investment costs. Thereby, the Transco is compensated for its investment by regulated incentives. The second approach depends on merchant investment refinanced by long-term financial transmission rights where no regulated Transco is required as transmission projects can be realized on a project basis. The value of an investment is determined by the rent generated by transporting electricity through the transmission line.

In the following the merchant and regulated approach and their characteristics within the framework of electricity transmission investment is discussed (Figure 18). We assume a system with two isolated nodes of different linear generation cost functions and fixed demand. On node has rather cheap generation while the other one is more expensive. In the initial market dispatch a price difference between the two nodes exists.

With additional transmission capacity the least cost generation dispatch becomes cheaper for the system as some more expensive generation in one node is replaced with imports from the second node. Therefore, the exporting node increases generation output causing the nodal price to go up along the linear supply function. At the other node the generation output decreases leading to a

[12] The abbreviations in the table are winter (W), summer (S), point-to-point connectors (P2P) and elements of the meshed offshore network (Hubs).

lower nodal price. Through the additional transmission capacity, the prices of the two nodes converge. Again, the nodal price is defined by the cost of providing an additional marginal unit of electricity. The congestion rent for transmission equals the flow multiplied the price difference. Additional transmission capacity increases the flow one the one side but causes price convergence on the other side. The congestion rent increases of the additional trade flow outweighs the price convergence. The value of this rent is of importance for the investment decision of merchant investment. It stands for the total revenue and has to pay for the transmission line. To optimize the trade capacity of merchant lines the marginal cost for additional capacity should be equal to the marginal revenue. However, in welfare terms this expansion path is not satisfying. Knowing the welfare optimal expansion capacity, regulated investment should be invited to increase the line capacity to the intersection of total revenue and total cost (Figure 18). Though the total revenue is lower the system welfare is higher than for merchant investment.

Figure 18: Merchant and Regulated Transmission Investment

Objective for <u>Merchant</u>

Marginal Revenue

=

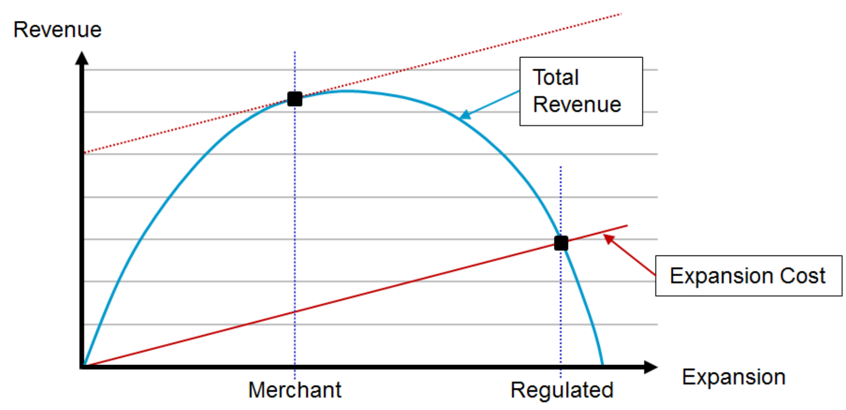
Marginal Cost

Objective for <u>Regulated</u>

Total Revenue

=

Total Cost



Based on: Kirschen and Strbac (2004), p.237.

5.3.4 Investment opportunities in new offshore connectors

Additional information is provided on financing perspectives of the offshore grid. Box 2 provides a distinction between the two basic mechanisms of financing, merchant and regulated investment. In general, one has to analyze three design options for **new** offshore lines:

- Point-to-point trade connectors mainly existing in the Trade scenario and financed by merchant investors. Only two countries are involved and benefits can be allocated to the individual line. However in the scenarios the new point-to-point offshore connectors do not generate sufficient congestion rent to be financed by merchant investment. Even if some merchant investments could be profitable, the risk of consecutive transmission expansion makes investments unlikely. One can assume that 1-2 merchant project might still be profitable in the North Sea depending on the future progress of the offshore transmission capacity.
- Radial wind integration with the purpose to connect offshore wind hubs to the national AC transmission network. The current development foresees regulated investment to guarantee the

offshore wind farms the possibility to feed in their electricity into the onshore system.[13] Merchant wind integration cables are also an option.

- Meshed offshore cables either connect two offshore hubs or an offshore hub to the onshore transmission system. As the benefit of an individual line is difficult to measure in a meshed system and the design includes several nations in the planning process, merchant investment of meshed grids is unlikely. The investment for this type of offshore grid design could be incentivized by a multi-national regulatory institution. The model results indicate that meshed offshore topologies are a suitable approach for relieving onshore congestion.

6 Conclusions

The North and Baltic Sea grid is a complex project which highlights the necessity for a coordinated approach to realize cross-border transmission investments. The project is of high importance for energy network infrastructure development in Europe, but the assessment of its benefits and costs is quite at the beginnings. The purpose of this study is to provide a methodology to assess the future potential welfare and distributional issues, and to apply this methodology to a set of concrete scenarios. While traditional network planning is based on purely technical considerations, this study also puts forward the need of an engineering-economic approach.

We find a strong relation between the regulatory rules and the emerging grid design: the grid development is not exogenous to the institutional setting. The current institutional setting would favor bilateral point-to-point connections, whereas the meshed grid yields higher welfare but is more difficult to bring about. In particular, we state that the technical design of the grid is endogenous, and that strong regulatory cooperation would be required to generate an integrated North and Baltic meshed grid design.

The main focus of the study is on the welfare implications of different grid designs, in particular the effects on producers and consumers; this is a main driver for political support of, or resistance to, the project. There is clearly a distinction between the overall benefits of the NBSG-project, and the individual national perspectives. While the gains in social welfare are significant and certain, the benefits that each individual country obtains vary with the network design, the regulatory approach, and the assumptions on supply and demand. Thus, there is a high variance in the expected benefits for each country, which may limit their enthusiasm to engage in such a multilateral project.

The study shows for the case of the North and Baltic Sea Offshore Grid that different designs create different beneficiaries and losers on national level but also within the countries. While exporting countries suffer losses through additional competition combined with strong rent shifting from producers to consumers, lower flexibility of the chosen offshore design limits this development but also creates lower overall welfare gains. Balancing the interests of different participating parties is a critical element of any transmission expansion strategy. In this case, the exporters of low-cost electricity, i.e. Norway and Great Britain, are winners of a grid expansion, since they obtain higher prices in the region they export

[13] In Germany Tennet is currently planning four major offshore hubs in the North Sea - each one for the integration of two offshore wind farms with a single capacity of about 400 MW. They are connected by HVDC cables either to an onshore nodes close to Hamburg or another one close to the Dutch border (Tennet, 2011).

to, Continental Europe, than in their respective domestic markets. Continental European consumers also gain from the developments due to the price decrease. On the other hand, electricity producers in the more expensive region, Continental Europe, lose market share and producer rent, while the consumers in the lower-price region also loose (consumer) rent: after the installation of the infrastructure, they may have to pay a higher price than before.

There is a complex issue of timing that drives a wedge between the public policy perspective and the interests of private investors. Even though the long-term effects of an integrated, meshed grid turn out to be the highest, they also occur after the longest project duration of all the different network designs. For a risk-averse, short-term profit oriented investor, a small investment into a point-to-point extension with predictable outcome will be more attractive than an engagement into a longer-term investment with less predictable outcome, albeit a high social welfare gain.

The NBSG is also an important test case for different institutional options for financing high-voltage transmission lines, in particular the two extreme cases: private merchant transmission, and regulated investment. The potential for merchant transmission is reduced the further the infrastructure investment proceeds and prices converge. Congestion rents in the offshore grids are rather sensitive to additional transmission capacity, increasing the risk for merchant investments. More flexible and meshed offshore grids connected to several onshore nodes generate higher welfare gains and less onshore congestion, indicating that onshore transmission expansion and offshore grid designs have to be decided upon together. In the case of the NBSG, the opportunities for lucrative transmission investment are rapidly exhausted: perhaps one or two cables will still attract private merchant transmission, but for the remaining transmission expansion projects, there is too little congestion rent to pay for the infrastructure investment.

Far from being a panacea for the large-scale integration of renewable, the North and Baltic Sea Grid highlights the challenges of the “Supergrid”-approach to connecting electricity supply and demand in a renewable-based system. While it is relatively easy to show the overall welfare gains of such a project, “the devil is in the details”, and the study highlights important interdependencies between planning, regulating, financing, and pricing offshore transmission infrastructure. This is also a challenging field for multi-national and European policy.

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8 Annexes: Lists of Offshore Cables Analyzed

Annex 1: List of Offshore Cables in the North Seas

[MW]	Name	From	To	2009			Wind+		
				Base-2009	Trade	Meshed	Base-Wind	Trade	Meshed
Wind	NEW	Sweden	SE Kriegers Flak	0	0	700	750	750	750
	NEW	Denmark East	DK Kriegers Flak	0	0	700	700	700	700
	NEW	Germany	DE Kriegers Flak	0	0	700	600	600	600
	NEW	Sweden	Sweden OFF	0	0	600	750	750	750
Trade	Fennoskan	Sweden	Finland	400	1350	1350	400	1350	1350
	Kontiskan	Denmark West	Sweden	300	845	845	300	845	845
	Kontek	Germany	Denmark East	400	1100	400	400	1100	400
	Baltic Cable	Germany	Sweden	450	1150	1150	450	1150	1150
	SwePol	Poland	Sweden	600	1200	600	600	1200	600
	Storebælt	Denmark West	Denmark East	0	600	600	0	600	600
Meshed	NEW	Sweden OFF	Poland	0	0	600	0	0	600
	NEW	DK Kriegers Flak	DE Kriegers Flak	0	0	700	0	0	700
	NEW	DE Kriegers Flak	SE Kriegers Flak	0	0	700	0	0	700

Annex 2: List of Offshore Cables in the Baltic Sea

[MW]	Name	From	To	2009			Wind+		
				Base-2009	Trade	Meshed	Base-Wind	Trade	Meshed
Wind	NEW	Norway	Norway OFF West	0	0	2000	200	200	2200
	NEW	Norway	Norway OFF South	0	0	3500	200	200	3700
	NEW	Great Britain	GB OFF Middle	0	0	2000	4000	4000	4000
	NEW	Great Britain	GB OFF South	0	0	1000	4000	4000	4000
	NEW	Belgium	Belgium OFF	0	0	1000	2000	2000	2000
	NEW	Netherlands	NL OFF West	0	0	1000	1500	1500	1500
	NEW	Netherlands	NL OFF North	0	0	1400	1500	1500	1500
	NEW	Germany	DE OFF West	0	0	1400	2100	2100	2100
	NEW	Germany	DE OFF East	0	0	1400	2100	2100	2100
	NEW	Germany	DE OFF Wind 1	0	0	0	2100	2100	2100
	NEW	Germany	DE OFF Wind 2	0	0	0	2100	2100	2100
Trade	Cross-Channel	Great Britain	France	2000	4000	4000	2000	4000	4000
	Skagerak	Denmark	Norway	1040	2050	2050	1040	2050	2050
	NorNed	Norway	Netherlands	700	1400	700	700	1400	700
	BritNed	Great Britain	Netherlands	0	1700	700	0	1700	700
	NorGer	Norway	Germany	0	1400	0	0	1400	0
	Nord.Link	Norway	Germany	0	1400	0	0	1400	0
	Cobra Cable	Denmark	Netherlands	0	700	0	0	700	0
	Norway–UK	Great Britain	Norway	0	2000	0	0	2000	0
	Cross-Channel	Great Britain	France	2000	4000	4000	2000	4000	4000

Continuing Annex 2:

[MW]	Name	From	To	2009			Wind+		
				Base-2009	Trade	Meshed	Base-Wind	Trade	Meshed
Meshed	NEW	Norway OFF West	Norway OFF South	0	0	2000	0	0	2000
	NEW	Norway OFF South	GB OFF Middle	0	0	2000	0	0	2000
	NEW	GB OFF Middle	GB OFF South	0	0	1000	0	0	1000
	NEW	GB OFF South	NL OFF West	0	0	1000	0	0	1000
	NEW	Great Britain	NL OFF West	0	0	1000	0	0	1000
	NEW	NL OFF West	Belgium OFF	0	0	1000	0	0	1000
	NEW	NL OFF West	NL OFF North	0	0	1000	0	0	1000
	NEW	GB OFF South	NL OFF North	0	0	1000	0	0	1000
	NEW	NL OFF North	DE OFF West	0	0	1400	0	0	1400
	NEW	DE OFF West	DE OFF East	0	0	2800	0	0	2800
	NEW	Denmark	DE OFF East	0	0	700	0	0	700
	NEW	Norway OFF South	DE OFF East	0	0	3500	0	0	3500
	NEW	Norway OFF West	Norway OFF South	0	0	2000	0	0	2000
	NEW	Norway OFF South	GB OFF Middle	0	0	2000	0	0	2000
	NEW	GB OFF Middle	GB OFF South	0	0	1000	0	0	1000