# Scenarios for a North Sea Super Grid: Technical Feasibility of HVDC Connections and their Economic Impact on the Riparian Power Markets

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**This paper is motivated by the ongoing discussion about a super grid in the North Sea, which aims at incorporating the future large-scale offshore wind power plants and connecting the riparian states of the North Sea. By means of such a network, a further exploitation of efficiency potential due to geographical differences in the cost structure of the power plant mix may be achieved. The possible grid expansion scenarios are compared regarding their effects on trade flows, capacity investments, marginal cost of production as well as overall system costs in selected European electricity markets. Thereby, the analysis has to explicitly account for the technical feasibility of the grid expansion. Hence the Institute of Energy Economics at the University of Cologne (EWI) and the Institute of Power Systems and Power Economics (IAEW) of RWTH Aachen University combine their technical and economic modeling approaches in order to provide an integrated analysis of the topic.**

***Index Terms*—Transmission expansion planning, security of power supply, HVDC transmission, electricity market modeling, cost-benefit-analysis**

## I. Introduction

In January 2010, nine European countries approved a multinational plan to develop a North Sea Super Grid that can address the fluctuating nature of renewable energy sources (RES) by connecting tidal power projects, offshore wind farms, hydroelectric plants and other renewable energy sources in Europe. Although various transmission technologies might be technically feasible for such a grid, high voltage direct current (HVDC) technology is the most promising as it provides attractive features especially for transmission of bulk power via long submarine cables.

While politically discussed proposals of North Sea HVDC network structures offer a visionary character, the presented approaches have remained tentative. Consequently, the academic assessment of this issue is still owed. Thus, the focus of this study is on the technical feasibility of HVDC grid structures, its impact on connected power systems and the evaluation of its economic benefits.

Therefore, various North Sea point-to-point connections are analyzed under consideration of existing alternating current (AC) transmission systems in the riparian states of the North Sea and beyond. A technical evaluation and a determination of overall connection costs in combination with a simulation of the economic impact of links between the national power systems provide a basis for an economic assessment.

This paper explores a methodology which allows for the development of a technically feasible and economically beneficial HVDC North Sea network structure. In Section III, the methodology of the technical evaluation of HVDC North Sea connections is presented. Section IV discusses a methodology of a market based economic assessment of technically feasible HVDC links. In Section V the results of the integrated evaluation are displayed and discussed by means of a cost-benefit-analysis. We conclude with a brief summary of our findings and an outlook.

## II. Approach and Methodology

A combination of technical and economic modeling approaches provides an integrated analysis of a North Sea Super Grid. The objective of the technical analysis is the estimation of maximum HVDC transmission capacities subject to network security calculations. HVDC North Sea links cause a coupling of former UCTE and NORDEL AC systems. Hence, the impact of power flows via the HVCD cables on the AC systems has to be investigated. The AC systems are therefore examined regarding the (n-1)-security criteria. The basis of the network security calculations is a network model consisting of approximately 2,500 nodes and 4,500 branches. The results of the technical evaluation are overall investment costs for optional HVDC links consisting of HDVC terminal costs, HVDC cable costs and costs for the reinforcement of affected AC networks.

In a second step, a detailed modeling of generation and storage capacities enables an analysis of generation dispatch, use of storage capacity and cross-border power exchange as well as capacity development with regard to the development of infeed from RES. The costs of the transmission capacity expansion associated with the previously derived point-to-point connections are contrasted with the efficiency gains in the power markets, thus enabling us to estimate the effect on overall system costs.

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For this reason the most efficient of several optional HVDC point-to-point connections can be identified.

An iterative loop including an assessment of HVDC point-to-point connections under consideration of their investment costs and their impact on the connected power market provides a starting point for a reasonable development of an economically efficient and technically feasible HVDC North Sea network structure.

## III. Technical Evaluation of North Sea HVDC Point-to-Point Connections

The objective of this paper is to analyze the effect of HVDC links on the European power system. In order to do so, optional HVDC links are investigated and thus resulting overall investment costs can be compared. These costs comprise the expenses associated with the HVDC system on the one hand and the conventional system on the other hand. This section deals with how the HVDC system costs are derived and the applied methodology to calculate the conventional system costs.

The costs for each HVDC link can be subdivided into two major costs terms. The first term represents the investment costs of the HVDC system. These costs are basically determined by the power and length of the HVDC link which are assumed to increase approximately linearly with power and length.

The second cost term represents necessary network reinforcements in the conventional AC system to integrate the HVDC link. These reinforcements may become a necessity, as a secure operation of the network in technical terms has to be always guaranteed [1]. The amount of necessary reinforcements strongly depends on the transmission capacity of the HVDC link and the selected connection nodes in the extra high voltage grid. In case of a HVDC connection to a network node, which is bounded with slender transmission capacities, the required reinforcement measures and consequently the reinforcement costs are expected to increase compared to a connection to a strong network node. Then again, the distance between two HVDC terminals might increase if technical optimal network nodes are selected. Therefore, the first step of the applied methodology aims at identifying possible network nodes for the connection of the HVDC terminals.

### *A. Reinforcement of the underlying AC network structure*

After having defined appropriate network connection nodes for HVDC terminals, overall HVDC investment costs are determined. The first cost term can be calculated for given HVDC systems, the second cost term requires a network analysis as the costs strongly correlate with the number of overloaded elements in the system.

The general approach to determine the overloaded network elements is based on a three-staged process.

At first, a power plant scenario is being defined in which installed generation capacities for each primary energy type are assigned to the different market zones. In a next step a market simulation is conducted in order to obtain the hourly dispatch of each generation unit. The third step is dedicated to the identification of one or several critical hours, conducting contingency analyses for each of them. Thereby, load and generation values for each considered node of the extra high voltage network are taken into account.

The basic results from this process are the overloaded network elements in the system. The monetary effort to mitigate these overloaded network elements can be determined and compared for each HVDC link.

The power plant scenario is based on a published study conducted for the European Commission in 2007 [2]. Starting from the year 2005, a market simulation of the electricity system until 2030 was carried out in order to determine the power plant development. The underlying assumptions were nuclear phase-outs in Germany and Belgium and the EU's climate protection goals did not have to be met. Under these assumptions, the study predicts increasing installed capacities of renewable energy sources, decreasing capacities of coal power plants and increasing capacities of natural gas power plants.

Based on this study, aggregate values of installed capacities were transformed into generation units of power plant types. Each power plant type represents a generation technology with representative technical parameters. After the generation of a power plant mix based on aggregate installed capacities, a market simulation on power plant level was performed to determine the dispatch of each generation unit. The objective function of the market simulation is the minimization of total generation costs summed up for one year. The main degree of freedom of the market simulation is the power generation of each power plant in every hour. The relevant boundaries are the maximum transfer capacities between the market zones and the technical boundaries of the power plants as for example maximum power, minimal down time of the units or minimal and maximal fill levels of pump storage basins.

The economic dispatch of each generation unit has an impact on the transmission network, which has to be analyzed. The basis of the network analysis is a network model. The network model used for these analyses covers the extra high voltage grids of the UCTE and NORDEL regions and consists of approx. 2,500 network nodes, 4,500 transmission lines and 900 conventional power plants. This model represents the situation in 2007 and was generated by using solely publicly available data [3]. Published data such as cross border load flows verify the network model.

The model described in the paragraph above is amended with published grid reinforcements [4] to represent the grid topology for 2030. Concerning the connection of conventional generation units to the grid two approaches are applied. In case grid connection nodes for power plants are available these nodes are used, while a reasonable network node for this power plant is created based on primary energy prices and existing stations if this is not the case. Renewable generation units are placed according to renewable potential maps and the allocation of already installed generation units.

After having set up the economic and technical system, the economic dispatch of each generation unit is determined. Subsequently overloaded network elements are identified for a strong-wind strong-load scenario. This scenario has been chosen as it can be expected to constitute a critical situation for the system as the wind feed-in is high and the transmission lines on the other hand are already highly stressed.

This process is repeated for the case without any HVDC reinforcement in the system (Base Case) and various scenarios with HVDC reinforcement measures.

The associated costs in the conventional grid for a given HVDC link and HVDC power are defined as the difference of the length of overloaded lines in the situation with the respective reinforcement measures compared to the Base Case multiplied with the specific costs of new AC single circuit lines. This estimation can be regarded as conservative since probably not every overloaded line has to be reinforced with a new AC single circuit line to reduce the overloaded elements. Table I shows the assumed cost parameters for the HVDC system and the costs for a single circuit line.

TABLE I
ASSUMED ECONOMIC DATA OF HVDC LINKS AND AC REINFORCEMENTS

| Component | Costs |
|---|---|
| HVDC terminal (€/GW) | $120 \cdot 10^6$ |
| HVDC underground cable, 3 GW (€/km) | $1.2 \cdot 10^6$ |
| AC single circuit line (€/km) | $0.65 \cdot 10^6$ |

### *B. Results of the HVDC cost analysis*

In this section we conduct an analysis of the costs associated with HVDC reinforcement measures. HVDC links between Germany, the Netherlands, Norway and France are considered. The capacity of each link is varied from 2,500 MW to 7,500 MW. In order to identify optimal connection nodes of the HVDC terminal to the conventional grid, multiple network nodes per country are analyzed.

This section concentrates on optional HVDC links between Norway, with a high amount of hydroelectric plants, and Germany, the Netherlands and France, with a large amount of installed capacity of renewable energies.

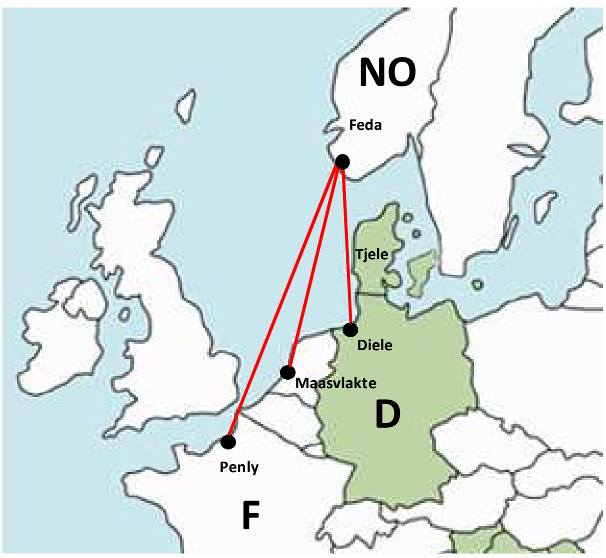


Fig. 1.Geographical Position of Potential HVDC Connection Nodes.

The assumed grid connections for those links are at node Feda in Norway, at node Maasvlakte in the Netherlands, at node Penly in France and at node Diele in Germany. Fig. 1 shows the geographical position of the nodes named above.

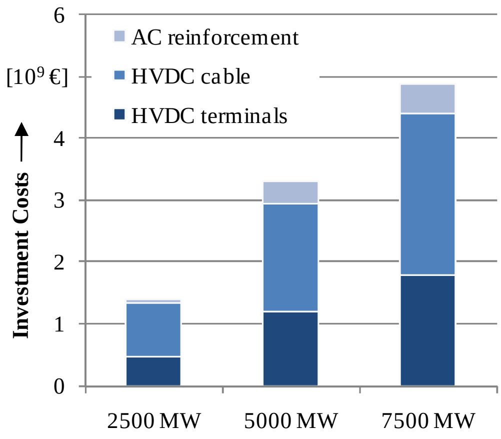


Fig. 2. Analysis of the Cost Structure for HVDC Connections between Norway (Feda) and the Netherlands (Maasvlakte).

In order to analyze the HVDC link costs, the costs for an HVDC link from Norway (Feda) to the Netherlands (Maasvlakte) is exemplarily considered for different HVDC transmission capacities (Fig. 2). One can see that the cost of reinforcement measures within the underlying AC system are negligible compared to the investment costs of the HVDC terminal and the HVDC line. It can therefore be concluded that the cost of the HVDC link is determined by the investment costs of the HVDC link.

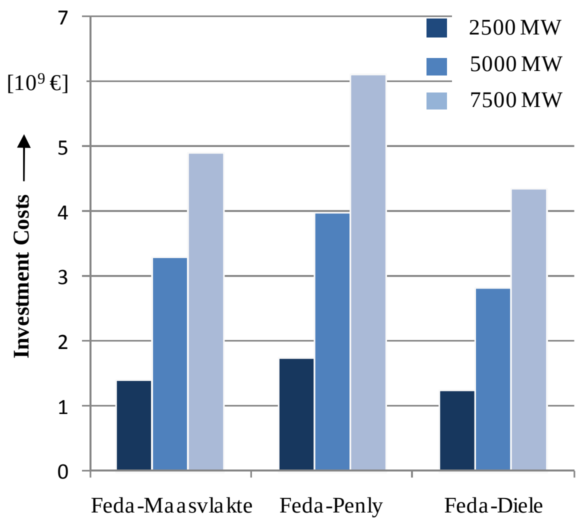


Fig. 3. Analysis of HVDC Costs for Different Links.

For each possible connection, the HVDC overall investment costs are calculated. Fig. 3 shows the overall investment costs for each of the three potential configurations. Due to the longest distance, the point-to-point connection between Feda (NO) and Penly (FR) requires the highest investment costs. The overall investment costs and the technical configuration as NTC values of the proposed connections present the input data for the economic evaluation. The impact of each point-to-point connection on the national power markets can be simulated and thus enable us to identify the most efficient link. Based on the conducted analysis, it is possible to investigate further development steps of the North Sea Super Grid through consideration of the most efficient point-to-point-connection.

## IV. The Effects of HVDC Connections on the European Electricity Markets

Based on the mainly technical analysis described in the previous sections, we carry out an economic evaluation of the costs and benefits of the proposed HVDC transmission lines. First, in order to assess their impact on overall welfare, scenario-based market simulations are conducted and analyzed with respect to changes in total system costs and trade flows. Thus, the identified efficiency gains can be contrasted with the investment costs associated to the grid expansion in the next step (section V).

### *A. The Model DIME*

The Dispatch and Investment Model for Electricity Markets in Europe (DIME) was developed at the EWI as a linear optimization model of the conventional European electricity market [5], [6]. It simulates dispatch as well as investment decisions on the supply side and minimizes total discounted costs based on the assumption of a competitive generation market. In this analysis 16 regions are modeled in detail and cover Central and South Western Europe as well as Great Britain, Scandinavia and Finland. A $17^{th}$ so-called satellite region which constitutes Eastern Europe is represented by an exogenous price curve and an upper limit on power imports.

The model input includes demand side parameters, supply side parameters and political parameters. The residual demand which has to be met by conventional generation is derived by subtracting exogenous infeed of RES-E and other must-run technologies such as CHP from total demand. Regarding the supply side, input parameters cover the cost of generation (e. g. investment costs, O&M costs, prices of fuels and $CO_2$-certificates), technical parameters of conventional generation technologies (such as ramp rates and minimum loads) as well as the amount of conventional capacities already existing within a country. Furthermore, the NTC values of international interconnector capacities and political parameters such as nuclear policies are incorporated in the model.

As an output of the cost minimization, the structure of generation and capacities is identified for each country. The resulting fixed and variable costs of generation, investment costs as well as the magnitude and value of power imports and exports form the basis for the comparative cost-benefit analysis of investments in HVDC capacities.

### *B. Scenario Description*

In this analysis comparative statics indicate the value of additional transmission line capacities. The base case scenario (BC) comprises all relevant technical and economic parameters and the best guess for their future development. Thus, the BC assumptions concerning the European grid are based on public information on existing capacities and planned extensions provided by ENTSO-E [4]. The other scenarios differ from the BC *only* in the addition of one HVDC connection to the original grid configuration respectively. This is incorporated into the model by altering the NTC values equivalently to the physical capacities of the newly built transmission lines. At first, we concentrate on the analysis of the lowest (2,500 MW) and highest (7,500 MW) configurations of the proposed HVDC connections. The resulting scenarios are displayed in Table II.

TABLE II
SCENARIOS OF HVDC CAPACITY EXPANSIONS

| | 2,500 MW | 7,500 MW |
|---|---|---|
| Base Case | no variation | |
| Scenario I (NO - DE) | √ | √ |
| Scenario II (NO - NL) | √ | √ |
| Scenario III (NO - FR) | √ | √ |

The following paragraphs give an overview of the basic assumptions which hold for all scenarios.

Total demand (plus network losses) is aligned to the forecast in [7]. The overall trend is positive until 2020, while in some countries, e. g. Germany, it declines afterwards due to efficiency gains.

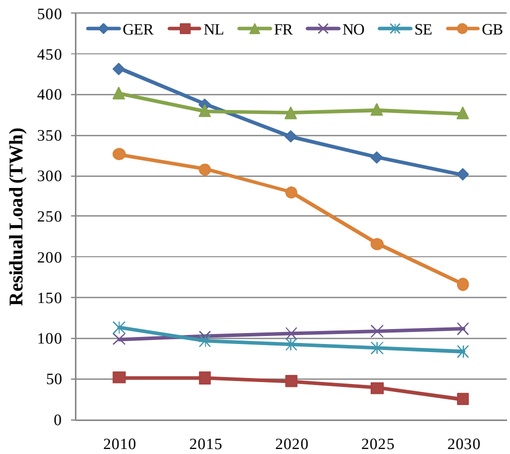


Fig. 4. Residual Load (TWh) per Year in Selected Countries.

Then again, the overall residual load of Europe (i. e. total demand minus RES infeed and generation from CHP technologies) exhibits a strictly decreasing trend over the years. Fig. 4 gives an overview of its development in selected countries. The negative trend of the residual load is due to an increasing production from RES. The underlying infeed from RES is modeled according to [8]. Thus, the corresponding capacities result from a cost-minimizing RES expansion throughout Europe. Thereby, present national support schemes such as quotas or feed-in-tariffs are assumed to prevail. The production resulting from the given capacities is calculated under consideration of technology and region specific full load hours as well as hourly generation structures.

The fuel costs and prices of $CO_2$-certificates are chosen on the basis of [8] and constitute an almost constant spread in variable costs of coal- and gas-fired power plants (Table III). Regarding the conventional supply side, the initial values of installed capacities are based on EWI's data base which includes roughly 46,000 power plants and their technical characteristics all over Europe.

TABLE III
DEVELOPMENT OF FUEL COSTS AND PRICES OF $CO_2$-CERTIFICATES

| | 2010 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|
| Lignite (€$_{2008}$/MWh$_{th}$) | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Hard Coal (€$_{2008}$/MWh$_{th}$) | 9.9 | 10.5 | 11.1 | 11.5 | 11.9 |
| Nuclear (€$_{2008}$/MWh$_{th}$) | 3.6 | 3.5 | 3.3 | 3.3 | 3.3 |
| Gas (€$_{2008}$/MWh$_{th}$) | 20.1 | 22.2 | 24.2 | 26.8 | 29.4 |
| Oil (€$_{2008}$/MWh$_{th}$) | 20.8 | 23.1 | 25.5 | 27.8 | 30.1 |
| $CO_2$ (€$_{2008}$/t $CO_2$) | 13.0 | 15.0 | 20.0 | 25.0 | 30.0 |

The scenarios are computed from 2010 up to 2040 for seven reference years (every 5$^{th}$ year). Each modeled year is represented by three types of day (Weekday, Saturday and Sunday/Holiday) with up to 24 hours for each of the four seasons respectively. Investment decisions are made once per year of reference while the hourly dispatch and the resulting costs are scaled up to one year using the frequency of occurrence of each day.

The time horizon is limited by the availability of computational capacities. Nonetheless, the final year of 2040 allows for the analysis of the impact of the cross-border grid extensions in 2020 on the investment decisions concerning conventional generation capacities. Still we have to account for possible biases in the investment decisions resulting from the definition a final year of reference in a model with complete information and perfect foresight.

### *C. Scenario Analysis*

The basic insights which motivate our economic analysis of investments in cross-border transmission capacities concern the welfare gains by loosening constraints on transnational trade. The differences in wholesale electricity prices which persist despite the progress made in integrating the European markets in recent years indicate that efficiency gains may still be realized. By increasing transmission capacities and thus allowing for higher imports from low price to high price regions the overall costs of satisfying total electricity demand will be decreased, even though production costs in the exporting regions may rise.

But since an increase in transmission capacities is not for free, a complete price alignment is not desirable from an economic point of view. This is why for each possible grid extension the investment costs have to be contrasted with the efficiency gains in order to identify the limit of the economically beneficial transmission capacities. In order to do so, we analyze the change in total and regional costs and trace it back to variations in power exchange and regional generation. This step lays the groundwork for the final cost-benefit-analysis described in section V.

The Base Case to which the scenarios are compared indicates the total costs of satisfying demand in all model regions in due consideration of the basic grid configuration (i. e. without the additional HVDC capacities of the miscellaneous scenarios). Hereby, the total costs include investment costs, fixed and variable costs of generation and indicate the value of imports as well as the costs due to transmission losses in the course of transnational electricity exchange. Fig. 5 displays an ascend in total costs over the reference years.

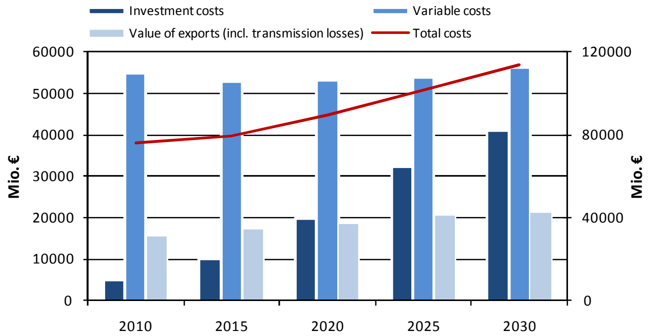


Fig. 5. Development of Cost Components in the Base Case.

This development is driven by (re-)investments in generation capacities and the restructuring of the power plant mix. It can be observed that falling residual load does not necessarily come along with decreasing conventional capacities since a minimum of capacities is required out of security of supply considerations. This minimum is calculated by subtracting the secure capacities of wind power plants from the maximum hourly load of a given year.[1]

Furthermore, the increase in the value of imports corresponds to rising trade volumes. Accordingly, the cost of transmission losses of cross-border trade flows increases. The major net-exporting countries are France and Germany, although the German surplus in exports declines over time. On the other side, the Netherlands and Belgium are the biggest net-importers. While the Dutch surplus in imports decreases, Norway's surplus steadily grows over the years of reference. The national imports and exports finally result in trade flows which reach their highest volumes on the connections between Germany and the Netherlands, Germany and France (both directions), France and Great Britain as well as between Norway and Sweden (both directions).

Table IV summarizes the cost variations realized in the given scenarios between 2020 and 2040. First of all, the given values are negative and therefore confirm the theoretical storyline of reducing generation costs by loosening the trade constraint. Accordingly, a higher HVDC capacity addition leads to greater cost savings. Nonetheless, the efficiency gains differ between scenarios, i. e. with the geographical allocation of the transmission lines. This is due to the fact, that the lines connect different markets with individual cost structures. While the connected markets have direct access to the new line and therefore contribute the

[1] The assumed capacity credits for wind power plants are 8% for onshore and 15% for offshore capacities. The capacity credits for other RES are zero, which reflects a conservative point of view concerning system security issues.

biggest share of trade flows, electricity transfers from other regions via the HVDC connection are limited due to upstream transmission restrictions. Furthermore, as can be seen in Table IV, the ranking of the scenarios by cost savings does not change with respect to the capacity of the HVDC connection.

TABLE IV
PERCENT COST REDUCTIONS IN COMPARISON TO THE BASE CASE

| | 2,500 MW | 7,500 MW |
|---|---|---|
| Scenario I (NO-DE) | -0.24 % | -0.41 % |
| Scenario II (NO-NL) | -0.24 % | -0.42 % |
| Scenario III (NO-FR) | -0.25 % | -0.43 % |

Our scenario analyses show that additional transmission capacities to Continental Europe are in particular beneficial to Norway. This may be explained by the increase in the Norwegian ratio of residual demand to production over the reference years considered in our analysis. Hence, Norway would have to augment domestic production, eventually accompanied by additional investment in production capacities, or rely on electricity imports. By considering investment and development of electricity trade in the model, we may conclude that relying on additional imports is more efficient.

The first scenario we present in greater detail describes the impact of additional transmission line capacities between Norway and Germany (Sc. I). It constitutes the lowest cost reductions in comparison to the Base Case which amount to 0.24% in the 2,500 MW case and to 0.41% in the 7,500 MW case. One major change between the BC and the scenario lies in the exchange between Germany and Norway, i. e. in the direct effect of the additional HVDC connection. In the 2,500 MW case, the yearly trade flows in the reference years between 2020 and 2030 are on average by 122% (DE to NO) and even 167% (NO to DE) higher than in the BC. Not surprisingly, these numbers rise even higher when assuming a 7,500 MW capacity addition, namely up to 265% and 382% respectively. Since transmission in opposite directions does not occur simultaneously, the merit orders in both countries indicate that, on the one hand, in off-peak hours cheap base-load generation from Norway (hydro) substitutes more expensive base-load generation in Continental Europe. On the other hand, Norway avoids production from expensive gas-fired power plants by importing Continental European electricity in peak-times. As a result of both effects, Norway achieves a constant and nearly exclusive employment of its Hydro capacities despite an increase in domestic residual load. At the same time, due to the rising imports from Germany, the Norwegian imports from the Netherlands, Denmark and Sweden are substituted accordingly. Overall, the total Norwegian costs of power supply decrease on average by 15% (2,500 MW) and 33% (7,500 MW) in the reference years between 2020 and 2030. On the contrary, the German costs remain almost unchanged. This may be explained by the already good link-up of Germany with other European countries.

Scenario II describes the effects of additional HVDC capacities between Norway and the Netherlands. In analogy to Scenario I, the direct effect of the additional HVDC line on the trade flows between Norway and the Netherlands is the most striking. Here, the average percent rise in the trade flows from Norway to the Netherlands amounts to 293% and to 267% in the opposite direction. Imports as well as exports virtually rise simultaneously in Norway and the Netherlands, thus leaving the national net export in the reference years almost unchanged. Concerning the Netherlands this change is mainly a redirection of trade with Germany. Due to the fact, that a significant part of the Dutch electricity generation is hard coal based, the basic idea of what drives the trade flows between Norway and the Netherlands is the same as in Scenario I – importing cheap hydro production from Norway and exporting base/mid load production in peak hours to Norway. This can be endorsed for example by considering the reference year 2020, which is the year, the new cross-border transmission capacity is assumed to be available. We observe an increase in Dutch hard coal production of 4%. Alike is true for subsequent years, although changes in the power plant mix might alter the origin of the Norwegian imports.

Total costs of meeting demand in Norway are reduced in respect to the Base Case. The decrease amounts to about 15% on average in the reference years 2020 till 2030 in the scenario with 2,500MW of capacity and to almost 43% in the scenario with 7,500MW. Overall costs increase in all reference years in Sweden. This effect may be explained by a decrease in Norwegian “Hydro-Exports”.

Scenario III exhibits some of the already know patterns of the previous two scenarios. System costs in Norway decrease. In the case of a HVDC capacity of 2,500 MW the average reduction in the reference years 2020-2030 amounts to 20%, while it reaches over 50% when assuming a capacity of 7,500 MW. Furthermore France, analogously to the Netherlands before, profits from the direct link to Northern Europe. In this case, the redirection of trade flows via the French links to Germany and Great Britain is most striking. In comparison to the BC the French exports to both countries decrease, while the imports from both nations augment. For Example, the French exports to Germany shrink on average by more than 50% in the case of a 7,500 MW line. At the same time the exports from France to Norway add up to more than 10 TWh per reference year in the 2,500 MW case and to over 25 TWh in case of a 7,500 MW link. These exports substitute former Dutch and German trade flows to Norway.

## V. COST-BENEFIT-ANALYSIS

Having identified the efficiency gains due to the additional HVDC capacities, we now contrast these benefits with the investment cost calculated in section III. Although we have shown that cost reductions can be achieved by extending the grid, the savings may not be sufficient to justify the investment. Furthermore, the most beneficial scenario identified in section V is not necessarily the most preferable overall option since a rise in benefits may be overcompensated by a corresponding increase in investment costs.

The calculation of the welfare effects requires the comparison of a one-time payment for the capacities in 2020 with savings realized in succeeding years. Therefore, the present value (PV) of the cost reduction is calculated using a discount rate of 6%. Hereby, the benefits of the years 2020 to 2040 are taken into account by scaling the results of the reference years accordingly. The range of 20 years is chosen according to the minimal life time of transmission lines. Finally, the respective balance of savings and investment costs gives the net welfare effect per scenario.

Table V displays the results of the cost-benefit analysis. First, all 2,500 MW cases prove to be economically profitable. Thereby, on the one hand, the present values of the cost reductions increase with the length of the HVDC connection, such that the link between Norway and Germany (Sc. I) results in the smallest savings, while the transmission line between Norway and France (Sc. III) achieves the highest reduction. This is due to the fact, that the shortcut between two geographically distant markets enables exchange that was previously strongly restrained by the transmission restrictions in the various transit countries. Consequently, the idle efficiency potential may be greater than between two geographically close countries.

TABLE V
NET WELFARE EFFECTS OF HVDC CAPACITY EXPANSIONS

| mio. € | PV of Benefits | Invest. Costs | Net Welfare Effect |
|---|---|---|---|
| Scenario I (2,500 MW) | 2,448 | 1,354 | 1,094 |
| Scenario I (7,500 MW) | 4,749 | 4,363 | 387 |
| Scenario II (2,500 MW) | 2,535 | 1,534 | 1,001 |
| Scenario II (7,500 MW) | 4,840 | 4,902 | -62 |
| Scenario III (2,500 MW) | 2,873 | 1,854 | 1,019 |
| Scenario III (7,500 MW) | 5,372 | 6,110 | -737 |

On the other hand, the longer HVDC lines come along with higher costs, too. Therefore, concerning the 2,500 MW lines, not the scenario with the highest cost reduction (Sc. III, NO-FR) is the overall most efficient one, but Scenario I which has shown to achieve the smallest savings. The total reduction in system costs due to the capacity expansion between Norway and Germany amounts to 1,094 mio. € and is therefore 9.3% higher than in Scenario II and 7,4% higher than in Scenario III.

With regard to the 7,500 MW links, the ranking of the scenarios according to the present value of their benefits exhibits the same pattern as the ranking of the 2,500 MW cases. Nonetheless, the additional savings realized by adding another 5,000 MW of capacity are lower than those achieved by the first 2,500 MW. This decreasing marginal utility stems from the fact, that the optimal decision rule is to exploit the biggest efficiency potentials that can be realized by one additional unit of trade first. Consequently, every further capacity addition is left with smaller gains.

On the contrary, the investment costs increase disproportionately strong to the capacity expansion. While the investment costs rise linearly with the length of the line and the capacity of the DC terminal, the costs caused in the adjoining AC grids, while negligible compared to the HVDC costs, increase faster than the capacity of the lines. Furthermore, the absolute values of the grid enforcement costs and their development differ between the connecting nodes in Continental Europe.

Consequently, the resulting change in total system costs is no longer positive in all 7,500 MW cases. Especially Scenario III (NO-FR) exhibits a significant negative welfare effect of -737 mio. € due to the line length and AC grid costs. Similarly, the net effect in Scenario II (NO-NL) is negative, too, but to a lesser extent. Thus, the capacity expansion is not justified by a sufficient rise in trade gains in neither case. In contrast, Scenario I (NO-DE) proves to have a positive net welfare effect in both cases.

The results are illustrated in Fig. 6 which displays the average costs and benefits per additional capacity. Thereby, an intersection of two lines marks the critical point at which the net welfare effect switches from positive to negative. Furthermore it shows that the explicit analysis of all 5,000 MW cases would have yielded positive, though (compared to 2,500 MW) smaller welfare gains, since the intersections are on the right hand side of the corresponding mark on the abscissa.

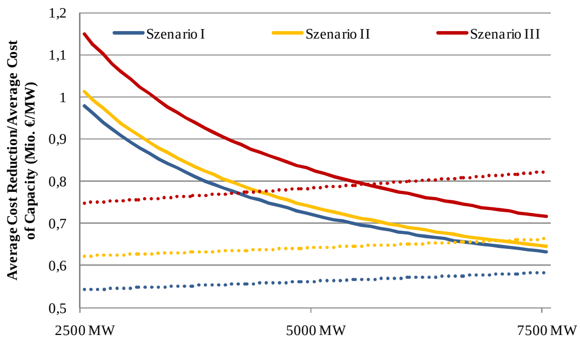


Fig. 6. Average Costs (dotted lines) and Benefits (solid lines) of capacity additions.

One crucial aspect of the analysis is that it gives no indication for the optimal choice of capacity. For this kind of assessment an analysis of the marginal costs and benefits of the HVDC lines would be necessary. Accordingly, no conclusion concerning the optimal combination of the given option can be drawn. Again, this would require a new set of market simulations in order to consider the effects of the simultaneous linkage of diverse markets on transnational trade flows and costs of electricity supply.

## VI. CONCLUSION AND FURTHER RESEARCH

In our paper we investigated the economic effects of several HVDC point-to-point connections, coupling Scandinavia, in particular Norway, with Continental Europe more closely. In contrast to other recently publishes studies we incorporate the technical feasibility of the additional transmission capacities. By contrasting the cost reduction in meeting the European electricity demand with the investment costs associated with the installation of the HVDC lines, we are able to derive conclusions regarding the net welfare effects of the various point-to-point connections. This allows us to rank the considered combinations with reference to their social advantageousness.

A HVDC link between power systems requires reinforcement measures in underlying AC systems. We can show that the required AC reinforcement measures to secure system operation are insignificant compared to HVDC cable and terminal costs.

Our analysis underlines the notion that the effect of additional cross-border transmission capacities is anything but obvious. This is due to the complex interaction of trade flows and the corresponding shifts in electricity generation, investments and system costs. We demonstrate that there are significant efficiency gains to be exploited. Because of its Merit Order, Norway proves to be the main beneficiary of the additional HVDC lines. The effect on the costs of meeting demand in the Continental European countries which are connected to Norway is ambiguous. While the Netherlands and France profit from the additional connection to Northern Europe, German system costs remain nearly unchanged. Regarding the net welfare effect, the connection Norway-Germany proved to be the most efficient.

While we investigate the net welfare effects of single point-to-point connections, no marginal benefit analysis of additional cross-border transmission capacity was carried out. Hence, our analysis does not allow us to derive an optimal capacity addition for the connections considered. This analysis is left for future research. Additional research ideas based on our analysis include, for instance, a detailed assessment of the impact of the additional HVDC capacities on national redispatch costs.

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## VIII. Biographies

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