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Integrated North Sea grids: the costs, the benefits and their distribution between countries

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Abstract

A large number of offshore wind farms and interconnectors are expected to be constructed in the North Sea region over the coming decades, creating substantial opportunities for the deployment of integrated network solutions. Creating interconnected offshore grids that combine cross-border links and connections of offshore plants to shore offers multiple economic and environmental advantages for Europe's energy system. However, despite the growing consensus among key stakeholders that integrated solutions can be more beneficial than traditional radial connection practices, no such projects have been deployed yet. In this paper we quantify costs and benefits of integrated projects and investigate to which extent the cost-benefit sharing mechanism between participating countries can impede or encourage the development of integrated projects. Three concrete interconnection case studies in the North Sea area are analyzed in detail using a national-level power system model. Model outputs are used to compute the net benefit of all involved stakeholders under different allocation schemes. Given the asymmetric distribution of costs and benefits, we recommend to consistently apply the Positive Net Benefit Differential mechanism as a starting point for negotiations on the financial closure of investments in integrated offshore infrastructure.

Keywords

Cross-Border Interconnection; Onshore and Offshore Transmission Investment; Offshore Coordination; Net Benefit Allocation.

Highlights

- Three North Sea offshore gird case studies are analysed.
- They are shown to have substantial net benefit over non-integrated network designs.
- Asymmetric net benefit sharing between countries is shown to be a barrier.
- Positive Net Benefit Differential method alleviates asymmetric benefits.

1 Introduction

Offshore wind power is envisaged to play a key role in the future European energy system, constituting one of the principal low-carbon alternatives to conventional generation plants. Although currently installed capacity of offshore wind in the region is about 5GW, deployment is expected to reach several hundred GW in the coming decades. By 2030, up to 150 GW are envisaged to be deployed in Europe, with almost half of this capacity concentrated in the North Sea region. In light of Europe's goal of increased market integration and ambitious offshore wind deployment goals, there is an ongoing debate regarding the future development of offshore grids. Given the large capital investment requirements to enhance cross-border energy transfers as well as accommodate imports from large offshore clusters, there is a significant opportunity for these activities to be combined. The economies of scale of accommodating offshore wind export capability and cross-border trade through a common meshed transmission network promises for substantial cost savings. North Sea is particularly suited to the role of a pilot test-bed for such innovative projects due to the area's large offshore development potential as well as the growing need for interconnection between neighboring countries via undersea cables. However, the business-as-usual approach to the development of transmission infrastructure is currently characterized by limited coordination. Alternative arrangements are required to facilitate the coordinated connection of wind farms to shore and their meshing with cross-border interconnectors.

The European Commission has in the past recognized the potential for developing a meshed North Sea offshore grid and set it as one of the main infrastructure priorities for Europe [1]. In a similar vein and recognizing the large offshore wind potential in Britain, the UK regulator has launched a series of consultations on the design of a novel regulatory framework to facilitate the planning and delivery of coordinated projects [2]. The potential for integrating offshore wind farms within interconnection projects between Scotland, the Republic of Ireland and Northern Ireland have also been extensively investigated in the ISLES project [3]. Coordination at the local cluster and multi-jurisdictional level are shown to entail significant cost savings, while the uncertainty related to the allocation of benefits is recognized as one of the primary barriers to coordinated development. In addition, several independent studies have been carried out in order to quantify the potential benefit of such integration projects at the national and EU level. For example, in [4] the authors demonstrate that the annual techno-economic, environmental and strategic benefits enabled through coordinated network development in 2030 will be in the order of EUR 1.5 to 5.1 billion, depending on the eventual level of offshore wind deployment. In a similar vein, a recent study covering all North Seas Countries' Offshore Grid Initiative (NSCOGI) countries has quantified the benefits stemming from coordination at various levels to be between 8 and 40 billion euros, with offshore-onshore connection coordination being a primary source of capital cost savings [5]. In addition, the strategic flexibility of offshore-offshore links was shown to be substantial due to the ability for reducing the impact of asset stranding in the case of unfavorable deployment scenarios [6]. Finally, the OffshoreGrid report published in 2011 confirmed the substantial benefits of integrated solutions. The project results showed that a meshed offshore grid that integrates offshore wind energy and interconnection in a hub-to-hub, tee-in or split arrangement increases social welfare due to reduced investment costs that arise from asset sharing [7]. The importance of coordinating offshore network development across Europe was also highlighted as key in delivering future-proof energy infrastructure a recent report for the UK's National Infrastructure Commission [8].

Today most industry, research and policy-makers agree that an integrated offshore electricity grid brings both financial and technical benefits to the European power system, probably outweighing the costs of investment. This was clearly expressed in the Memorandum of Understanding signed by the North Sea Countries' Offshore Grid Initiative (NSCOGI), in which all coastal states of the North Sea region declared their will to support the implementation of such an offshore grid. NSCOGI performed a cost-benefit analysis of an offshore grid with more updated scenarios reconfirming and further detailing certain aspects of the OffshoreGrid study [9]. However, despite the growing evidence that an integrated offshore grid in the North Sea offers significant benefits, such projects are not commercially pursued. In practice, only direct offshore interconnectors are built and planned, and, apart from the three-leg Kriegers Flak project, initially interconnecting Denmark, Sweden and

Germany via a 600 MW offshore wind farm, there are currently no integrated projects under consideration. In light of the potentially substantial benefits of interconnected projects in the North Sea area, the European IEE project NorthSeaGrid [10][11] was conducted. The principle aim of the present paper is to explore the underlying reasons for the observed lack of commercial interest in integration and propose suitable mitigation measures. In particular, we aim to answer a number of topical questions:

- How substantial is the benefit of integrated solutions?
- Is it riskier to build integrated networks compared to conventional radial connections?
- What are the regulatory issues that may be currently prohibiting the development of offshore integrated networks?
- To what extent is asymmetric cost/benefit allocation a barrier to the development of integrated projects?
- What modifications can be made to national and EU regulatory practices to enable the emergence of cost-efficient integrated solutions?

These questions are addressed with the aid of concrete case studies focusing on three particular projects that could be potentially developed in the near future. For this purpose, a techno-economic tool modelling North Europe electricity system operation has been developed. The undertaken analysis offers a two-fold contribution on the topic of integrated offshore projects in the North Sea:

- We investigate the costs and benefits of three specific case studies, chosen for their development potential. Focusing on a concrete project enables us to compute an accurate estimate of social welfare benefits, analyse economic impact and commercial viability, and delve into the specific regulatory arrangements that apply to uncover potential gaps and barriers.
- We demonstrate that asymmetric cost-benefit allocation is a problematic issue under the current regulatory regime; although integrated connection architectures are shown to increase social welfare, specific players are found to be in a substantially worse off position, leading to severe difficulties in achieving consensus across all involved parties. The Positive Net Benefit Differential method is proposed as an alternative arrangement that alleviates these effects.

The paper is structured as follows. In section 2 we present the details of reduced EU system and three interconnection case studies and showcase the cost-benefit calculation and allocation methodologies considered. In section 3 we present the main study results and examine the materiality of different regulatory barriers identified. In section 4 we summarize and discuss policy recommendations stemming from the presented analysis.

2 Methods

In this section we outline the model and case studies used to explore integrated connections in the North Sea. We first introduce the EU electricity system model used and proceed with presenting the three case studies in detail. We subsequently showcase the methodology employed for calculating the costs and benefits of each project, identify the regulatory and accounting rules that apply in each case study and finally discuss the different cost-benefit allocation methodologies that were examined.

2.1 Case Study Definitions

Three specific case studies have been developed to examine the benefits and costs of integrating interconnectors with offshore wind farms. These particular case studies were chosen in consultation with NSCOGI to ensure that they would be of interest to regulators, network operators, and private investors, exhibiting high learning and generalization potential. The selected case studies cover a total of six North Sea countries. This diversity enables us to examine a wide array of possible cross-country interactions at the investment, operation, regulation and commercial level, identify potential conflicts or adverse effects and propose some applicable mitigation measures. For each case study, two system architectures are studied; (i) a base case which involves direct connections of offshore wind farms to shore and separate cross-border interconnectors; (ii) an integrated case where connections of offshore wind farms to shore are combined with interconnections. By comparing the two alternatives, the benefit of integration can be derived. A detailed technical design was developed for each network to obtain an accurate estimation of costs as well as enable an in-depth technical risk assessment. Single-line diagrams are presented for all cases in the following sections; black and red lines represent

HVDC and HVAC link respectively. Note that although all wind farms/interconnectors analyzed refer to actual sites, their names are not disclosed for commercial privacy reasons.

2.1.1 Case 1: German Bight

The base case of the first case study, shown in Figure 1, involves two German wind farms radially connected to shore via two direct 1400 MW HVDC connections. In addition, a separate HVDC cable is built to link Denmark and the Netherlands. The integrated case, shown in Figure 2, constitutes an NL-DK-DE interconnection via a split hub-hub. One wind farm connects to Germany and the Netherlands via a 700 MW and an 1100 MW connection respectively. The second wind farm connects to Denmark with a 1000 MW connection. A 700 MW HVDC connection links the two offshore wind hubs, creating an integrated network between the three countries.

2.1.2 Case 2: UK-Benelux

The base case for the UK-Benelux study involves two wind farms radially connecting to Belgium and a third wind farm connecting directly to the Netherlands. Due to their proximity to shore, these three connections are via HVAC links. A separate UK-Belgium HVDC connection is also built to enable energy trading between the two countries; the single-line diagram is shown in Figure 3. The alternative integrated network, shown in Figure 4, involves the interconnection of Belgium, the Netherlands and UK via a split hub-hub connection. In particular, a super-cluster is created by connecting the 1400 MW Dutch and the 1400 MW Belgian wind farm to a common HVDC platform. An HVDC link connects this platform to the Netherlands, while an HVAC cable connects the platform to Belgium. Furthermore, instead of having a direct UK-Belgium link, the UK connects to Belgium via the HVDC platform of the 900 MW wind farm. The latter connects Belgium via AC cable. Finally, integration between all three countries is achieved by connecting the two wind farms via an AC hub-hub connection. Case 3:

2.1.3 UK-Norway

The base case connection diagram is shown in Figure 5, where 7200 MW of offshore wind power is connected to the UK via six dedicated links. Normally-open AC cables are used to pair every two wind farms in order to improve system reliability in the event of a line fault; each dotted red line represents a normally-open AC cable connection of 600 MVA. In addition, a 680km HVDC interconnector between UK and Norway is built to facilitate energy transfers between the two countries. The alternative case, shown in Figure 6, is to integrate the UK-NO interconnector with two multi-terminal HVDC converter stations and use an AC super-node to export wind power from the six wind farms. One benefit of this arrangement is the removal of two onshore converter stations.

2.2 Cost and Benefit Calculation

In this section we outline the calculation of costs and benefits for the base and integrated arrangement of all three case studies.

2.2.1 Estimation of Capital Costs

In this section we present cost calculations for all network arrangements, including HVDC and HVAC cables, transformers; note that the cost off the offshore wind farms are not included. Capital expenditure (CAPEX) costs are divided over 6 years, an assumption based on experience with previous cable construction projects. The base case discount rate used throughout the analysis is 4%, as suggested by ACER and adopted by ENTSO-E in the context of cost-benefit analyses for transmission planning [12]. In addition, although we have assumed the same rate across projects, it is imperative to highlight that integrated networks will probably face higher financing risks due to the anticipatory elements they entail (i.e. assets that are not immediately necessary but are included in the design for later use). Finally, project lifetime has been assumed to be 20 years, in line with the assumptions utilized by Tennet [13], National Grid [14] and other European TSOs. Overall, it has been assumed that investments will be made between 2024 and 2029, while operation will occur between 2030 and 2049.

Capital costs of electricity projects depend on a number of exogenous factors which may change from their present state at the time of investment. In order to increase the robustness of the undertaken analysis and investigate the degree to which the proposed integrated projects remain beneficial, three uncertainty factors have been considered as the main drivers of variability in CAPEX.

- Uncertainty on market conditions includes a variety of sources such as foreign exchange rates, inflation, prices for engineering consultants and suppliers as well as cost of maintenance labor. Historical experience with past transmission projects has been used to characterize this source of uncertainty.
- Uncertainty in copper price is characterized based on the volatility observed in historical commodity price fluctuations over the past years.
- Uncertainty in steel price is characterized based on the volatility observed in historical commodity price fluctuations over the past years.

Historical data were employed to characterize the probability distribution of each cost element. As a result, instead of a single cost estimate, a distribution of probable costing was constructed for each network configuration. It is important to note that technology-specific operational expenditures related to periodic cable maintenance and other equipment are also included in the CAPEX computation. In addition, a reliability analysis has been performed for each arrangement and the expected cost of outage restoration has also been factored, subject to market uncertainties. Further details on the methodology and the assumptions employed can be found in [15]. The costs for the German Bight case study are shown in Table 1. Note that P15 and P85 denote the 15^{th} and 85^{th} percentile of the cost distribution. As expected, the integrated network has a reduced cost by €345M due to the lower number of transmission assets employed.

Costs for the UK-Benelux case study are shown in Table 2. For this particular case, the integrated case has an increased cost by 23%, mainly due to higher platform costs and extra HVDC converter stations.

Finally, capital costs for the UK-Norway case study are shown in Table 3. The integrated network arrangement entails capital cost reduced by 6% due to the lower number of onshore AC/DC converter stations and reduced number of cables used. Of course, the integrated arrangement results in overall reduced transfer capability, so the net benefit will be highly sensitive on whether a smaller number of assets can be used effectively so as to reduce system operation costs.

An important aspect of network integration is that the ability to combine wind export capability with cross-border trade, so as to exploit economies of scale. Table 4 presents the cross-border capacity made available under the base case and integrated network designs. It is clear that although the expected cost of all three integrated projects is 3% lower than the radial design, the former results in more than double interconnection capacity. For example, the German Bight case study, despite the integrated network having a 12% lower capital cost, results in triple cross border export capacity due to the multi-purposing of assets. Of course, the fact that some assets have to accommodate two different functions, wind energy transfer and energy arbitrage, could lead to some increased wind curtailment or foregoing of trading opportunities. An operational model has been used to determine the balance between benefits of extra cross-border capacity and potential limitations due to asset sharing.

2.2.2 Estimation of Operational Costs

One of the project's key objectives is to identify and quantify the system benefits of the proposed integrated grid developments in the North Sea. This is carried out by evaluating how European social welfare changes under the different network arrangements; architectures that lead to higher social welfare should be pursued. It is important to note that under the assumption of inelastic demand, maximization of social welfare is equivalent to minimizing operational costs of the system. In order to carry out the analysis, a mathematical optimization model has been developed to minimize system operation cost for a given network arrangement by deciding on the most economical way to meet demand while respecting all applicable constraints. The model's objective is the minimization of system cost across Europe which consists of investment costs in peaking generation capacity and generation operating costs. The optimization process is subject to reliability constraints to ensure that adequate generation is available for each hour of a year while considering the effect of forced outages; the maximum loss of load expectation (LOLE) is set to 4 hours per year. If this is not feasible, new peaking capacity generation has to be added until the system has sufficient capacity to meet the security requirement. A Direct Current Optimal Power Flow (DC OPF) formulation is used to determine how power is distributed throughout the network, whilst optimizing generation dispatch to minimize the total costs. The seasonal availability of hydro power (as well as the variability of ‘run of river’ and hydro with reservoir), dispatch of concentrated solar power (CSP) production considering thermal reservoir capacities thermal storage losses, and the stochastic contribution from renewable generation and the associated short and long-term correlations with demand are also considered. The system operation horizon comprises of one calendar year; demand, wind and irradiance time series for all modelled system nodes capture the main system operating points as well as locational variability and seasonal characteristics of demand and intermittent generation sources.

The studies are carried out on the zonal model of pan European Grid system, shown in Figure 7. The model considers only the European main transmission corridors and interconnectors. In order to capture the major cross-border flow patterns as well as local congestion bottlenecks which may impact trading possibilities, the capacity of each corridor and interconnection is based on the capacity given by the ENTSO-E latest development plan [16]. The model takes into account the characteristics of power generation and electricity demand in all European countries. As can be seen in Figure 7, some countries consist of several nodes (e.g. Germany and UK comprise of 4 and 3 nodes respectively) while others have been aggregated to a single node (e.g. Sweden and France). Although the focus of the different case studies is on the NorthSeaGrid, as the power systems in Europe are highly interconnected, modelling the whole of Europe allows the system interactions across Europe to be simulated. Overall, the base case system comprises of 48 buses and 118 lines. Additional buses and lines are added in each study to represent the offshore project under investigation.

In order to simulate a system with a significant level of renewable power generation, a future generation background with 50% of energy consumption being supplied by renewables is used. The total installed capacity of renewable power generation including hydro power and storage is 980 GW. Total installed generating capacity is 1739 GW and the system peak demand is 874 GW. The share of capacity for each generation technology in the generation mix is depicted in Table 5. The generation fuel costs and carbon prices used in these studies are presented in Table 6.

In addition to the above, a range of sensitivity studies has been carried out in order to identify and analyse the robustness of the results against different assumption regarding the future European generation mix, uptake of demand-side participation schemes as well as carbon and fuel prices. In total, four scenarios have been developed for analysis, as follows:

- Base case scenario with renewables covering 50% of the European electricity demand;
- High renewables scenario, with increased installed capacity of photovoltaic, wind and solar- based generation, whose output totals about 60% of total European electricity consumption.
- Low fuel cost scenario, where fuel prices are set at 60% of the original levels shown in Table 6, while the carbon price is reduced by 50%. This scenario substantially reduces the cost of constraints, essentially depressing the value of cross-border trade.
- Demand-side response (DSR) scenario, where peak demand levels have been reduced through consumer participation schemes. This is particularly relevant as DSR is increasingly being regarded as one of the solutions that need to be adopted in the future to enable high renewable penetration in Europe.

The operation model produces a range of time and locational specific market prices including prices based on wholesale electricity marginal fuel costs, including the effect of plant maintenance and carbon emission pricing. Note that operation is deterministic, resembling a market with perfect competition and information. Prices vary with time and location to reflect the changing cost of supplying energy to different parts of the system at different times due to variable resource availability and network constraints. These prices are used in the computation of payment and revenues that apply to the different system participants such as energy producers and consumers. Of course, the exact accounting method depends on the respective regulatory framework of each country. For example, wind generators may receive additional revenue support above market price from government in some countries. These effects are taken into account when computing costs and revenues of different countries and players.

2.3 Cost and benefit allocation methods

Cost/benefit allocation for electricity transmission infrastructure is a challenging topic of great significance, which greatly impacts the long-term development of an electricity system. Following the unbundling of electricity markets in Europe, cross-border transmission investment projects are taken on the basis of commercial profitability, following a regulatory test that confirms positive contribution to social welfare. The case of integrated offshore networks is more complex since more stakeholders are involved; the wind farm owners will also require some increase in profit to participate in this venture. Similarly, consensus at the political level for such an ambitious cross-border energy exchange may be stalled if consumer prices in the exporting country increases. It follows that asymmetric cost/benefits can lead to market inefficiencies and ultimately fail to induce investment in attractive projects due to effects such as free-riding; this can apply to non-hosting countries which benefit from a transmission asset while not participating in its funding. However, if a project increases overall social welfare, then it is possible to design an allocation scheme where benefits and costs can be shared or traded to ensure that all stakeholders are better off.

The possible criteria to consider when evaluating the efficiency of a cost/benefit allocation method are numerous. In principle, efficiency reflects the extent to which the chosen method can induce private decisions that promote social welfare. One of the most important considerations is that of cost reflectivity; users that benefit from a network asset should share the costs. It is important to highlight that the ‘beneficiary pays’ principle has been recently incorporated in national legislation in the US (FERC [17]) and in the EU (ACER [18]) as a necessary feature of cost/benefit allocation mechanisms. This is coupled with an allocation scheme’s ability to send efficient economic signals to generation and load entities regarding their short term (operational) as well as long-term (planning) decisions. Another important consideration is predictability; prospective network users must be able to calculate ex-ante their cost of using the network. A final practical consideration is the implementation effort required.

Historically, the norm has largely been the adoption of cost socialization schemes where cost allocation is independent to the distribution of benefits. Although this is a straightforward approach with good predictability, it cannot induce complex investments such as the integrated networks examined. For this reason, one major aim of the present paper is to identify the allocation scheme that best facilitates the development of integrated offshore projects. In general, there are three basic approaches that can be adopted as a basis for an allocation scheme and are being considered by NSCOGI [19]. More information about the different mechanisms can be found in [20].

- **Postage stamp allocation methods:** The first approach is a uniform allocation structure, where no differentiation is made between stakeholders regarding their use of an asset or the benefit extracted therefrom. A specific form of this approach is cost socialization. Although this approach possesses the advantages of administrative ease and long-term tariff stability, it fails to induce investment decisions that may have winners and losers. As a result, such a scheme is more suited to security-driven investments, recognizing the fact that a reliable electricity system is a public good enjoyed by all network users, rather than an economically-motivated investment.
- **Flow-based allocation methods:** Network costs are allocated pro-rata to each user, according to their network flows. A 50/50 split rule is usually applied to distribute costs at each location between consumers and producers. Flow-based allocation methods are widely applied in New Zealand, Central America, and Australia.
- **Benefit-based allocation methods:** Network costs are allocated to the users benefitting from the reinforcement. Regarding ease of implementation, although application of the 'beneficiary pays' principle can be straightforward in some cases, e.g. in the case of dedicated connections to a new generation plant, it can become complicated when applied to a large multi-purpose project that involves stakeholders across different countries. As a result, there are numerous variants of the exact methodology to be followed. A thorough explanation of the different cross-border allocation methodologies examined in the NorthSeaGrid project can be found in van der Welle [20]. In this paper , the following three cross-border cost/benefit allocation schemes are investigated in detail:

- **Conventional:** Allocation of infrastructure costs and congestion revenues between countries is drawn on the basis of the ‘equal share’ principle. Allocation of infrastructure costs and congestion revenues between countries is on the basis of equal sharing, while allocation within countries is based on the respective national rules for congestion rents, network tarification and support schemes.
- **Louderback:** Infrastructure costs are divided between countries depending on their direct costs and a share of the common costs, based on the difference between stand-alone infrastructure cost and attributable cost. As before, intra-country allocation between stakeholders follows the applicable rules of each jurisdiction.
- **Positive net benefit differential (PNBD):** The basic idea of this method is that parties that face negative net benefits are compensated by parties accruing positive net benefits according to some pre-determined rule. Schemes based on the PNBD concept are fully consistent with the ‘beneficiary pays’ principle suggested by Hogan [21]. Two variants of the PNBD methods have been considered:
    - The first variant, denoted PNBDvar1, follows the ACER recommendations [18] and applies to both hosting and third countries. All countries extracting a positive net benefit (NB) from the project compensate countries suffering a negative NB until their NB level increases to zero. The share payable by each country is proportionate to their share in the sum of positive NB.
    - The second variant, denoted PNBDvar2, aims to further reduce complexity of the re-allocation scheme by limiting compensation payments solely to hosting countries.

3 Results and Discussion

In this section, the operational model presented in section 2.2.2 has been used to compute the net benefit of radial and integrated network designs across the three case studies. Drawing comparisons between two network setups is essential for determining the impact of network integration on social welfare. In addition, we focus on the impact of asset coordination on certain attributes of interest such as electricity prices and utilization of transmission assets. Subsequently, having computed all relevant state variables such as production levels, power flows and locational prices, the allocation of costs and revenues among stakeholders within each country is determined according to the three benefit-based allocation methods discussed in 2.3. A central aim of this analysis is to identify allocation methods which could induce private-driven investment in projects which increase social welfare while mitigating adverse effects such as free-riding which could prevent such projects from materializing in practice.

3.1 Value of network integration

3.1.1 Calculation of savings

The savings resulting from integration of offshore wind farms and cross-border links with respect to the base case for each case study are presented in Figure 8. In addition to the three cases, a 'Combined' case study, where all three projects are built, has also been carried out. This study enables the exploration of the level of inter-dependence between the three projects by examining if the majority of benefits persist when all three projects are built.

The savings shown in Figure 8 are attributed to different sources. In all cases, with the exception of the UK-Norway case, the integrated configurations lead to positive savings in terms of generation investment (i.e. reduced need for building back-up generators for security purposes), and operational cost, (indicating the capability to meet demand using less expensive resources). This is because the integrated configurations increase the interconnection capacity amongst the respective NSCOGI countries from 3.1 GW to 7 GW as shown in Table 4. With higher interconnection capacity, the generation dispatch in the respective countries can be optimized to allow better resource sharing and access to lower cost generators. Furthermore, this also allows sharing of generating capacity across Member States and reduces the need for investment in extra plants. Naturally, this leads to the reduction in operating cost and the capital cost of generation system with reference to the base case.

The magnitude of savings in OPEX is relatively modest in comparison with the projected whole energy market value (€200 bn/year) but not insignificant in absolute terms. For the German Bight case, the savings in the operating cost and generation CAPEX are circa 35 M€/year and 11 M€/year respectively. Note that these savings are in addition to the capital savings due to the network architecture itself presented in section 2.2.1. In contrast, in the UK-Benelux case the savings are obtained by improving the interconnection between the UK, BE, and NL at the expense of higher network investment costs. The full net benefit calculation is performed in section 3.1.7. However, the implementation of integrated network configurations does not always lead to lower operating costs; in the case of UK-Norway, the operating cost increases by a small amount. This is due to the fact that the integrated architecture does not result in an increase of cross-border capacity. Instead, in the integrated case the same assets are used to perform two functions and thus some constraints do arise. However, as we later show in section 3.1.7, this small penalty in terms of operational cost is far outweighed by the significant savings in the project's cost. Finally, the fact that the savings in the 'Combined' case are approximately the sum of savings from all individual cases indicates that the three studies cases are relatively independent. This clearly indicates that the development of one North Sea grid proposition does not compete with other developments and the system benefits offered do not overlap.

3.1.2 Sensitivity analysis of savings

In addition to the main scenario presented in the preceding sections, three further studies have also been carried out to analyse the sensitivity of the results against different system backgrounds and cost assumptions (scenarios presented in 2.2.2). This enables us to identify the drivers of the benefits and the possible range of system benefits given the uncertainty of how the system will be developed in the future. Results of the sensitivity analysis are shown in Figure 9.

The results demonstrate that in the scenario with higher RES penetration, the savings for the integrated approach are higher due to the expanded opportunities for arbitrage created by the increased levels of available low-cost energy; enhancing the capacity of interconnectors presents substantial benefits under this scenario. In the German Bight case, the benefit increases from 46 M€/year to 64 M€/year. The largest increase is found in the UK-Benelux case, where the benefit jumps from 47 M€/year to 141 M€/year. This is particularly driven by the distribution of renewables in the UK and continental Europe which increases significantly the demand for interconnection between UK and continental Europe especially via NL and BE. In the UK-Norway case, the system benefits do not change since there is no large change to the cross-border capability between base case and integrated networks.

In the scenario with lower fuel and carbon prices, the benefits of the integrated approach are reduced due to the supressed differential between energy prices. The increased cross-border capacity made available in the integrated designs leads to reduced benefits since arbitrage opportunities are less valuable. As a result, reduced differentials have a moderate impact on all case studies, with the exception of UK-Norway, where savings remain unchanged due to the integrated network not having extra cross-border capacity.

Finally, in the DSR scenario, the savings in generation capacity investment are negligible since flexibility in demand greatly reduces peaking capacity requirements. Savings in terms of operational cost are also reduced in this scenario. Increased system flexibility leads to a reduction in the curtailment of renewable output; as demand can follow the output of renewable power generation, there are fewer instances that require engagement of out-of-merit high-cost generators. This effect is substantial in both the German Bight and UK-Benelux cases, where presence of DSR resulted in a 26% and 36% decrease in annual savings respectively. In the UK-Norway case, the annual savings slightly increase due to the fact that cross-border trading becomes marginally less attractive following the deployment of DSR.

3.1.3 NPV calculation

In this section we calculate the net present value (NPV) of network integration, when compared to the base case. For each case study, the expected net benefit accrued over a 20-year project lifetime is calculated by combining the operational benefits presented in the preceding section along with the capital cost data presented in section 2.2.1. Results for all four sensitivity scenarios are shown in Table 7; all studied integrated networks present substantial savings.

In the case of German Bight, the expected NPV of the net benefit under the main scenario is 1,213M€, with a 70% confidence that this number will be between 1,082M€ and 1,338 M€ in the case of increased steel, copper and market prices. Even an extreme 50% reduction in copper prices (which renders the radial network considerably lower cost and is the most important uncertainty source for this specific case), was found to marginally reduce NPV to 1,000M€. The undertaken sensitivity analysis indicates that the operational benefits are robust to changes in the most influential cost parameters. In terms of the other examined scenarios, it is evident that the NPV is larger under the HRES scenario, due to increased cross-border trade made available through the integrated network. The NPV of integration drops by 17% and 20% in the case of LFC and DSR scenarios respectively, since there is less scope for cross-border trade due to reduced price differentials and increased operational flexibility.

The NPV of net benefit for the UK-Benelux case study is 659M€. As before, the NPV was found to be robust against different steel, copper and market prices. In particular, the NPV was found to be almost insensitive to copper prices, while market has the largest impact. However, even if market prices increase by 25%, the expected benefit value does not drop below 550M€. When examined under the HRES scenario, the NPV almost triples due to the increased attractiveness of cross-border trade, which is highly facilitated by the integrated UK - BENELUX grid. As before, the LFC and DSR scenarios lead to modest decreases of NPV benefit.

The UK-Norway case study presents an expected net benefit of 336M€. As shown earlier, although the integrated arrangement does not provide operational savings, it does result in a substantially positive NPV due to the reduced capital cost. The NPV is considerably robust against changes in the scenario considered. In contrast to the previous case studies, the HRES scenario results in lower NPV. This is because in the radial network there is a dedicated UK-Norway link which makes fuller use of available arbitrage opportunities. For the same reason, NPV increases under the DSR scenario by about 12%, since there are fewer attractive cross-border arbitrage trades in the base case due to the peak shaving carried out by DSR. In terms of different steel, copper and market prices, as shown in the Table 7, NPV of the UK-Norway integrated project is between 220M€ and 400M€ with a probability of 70%.

In the case of the 'Combined' case study, the expected NPV of the net benefit is 2,292M€ with a 70% probability that it will lie between approximately 2,000M€ and 2,500M€. The relative standard deviation in this case is lower than when individual cases were considered in the preceding sections. This is because the correlations between uncertainties largely cancel out when all cases are considered together. This means that a decision to build all the cases would be beneficial, with a higher certainty. We proceed by analyzing impact of network integration on other system attributes.

3.1.4 Impact on electricity prices

Figure 10 shows the impact of the integrated projects on the Load Weighted Average Electricity Prices (LWAEP), which have been calculated using the following formula:

$$LWAEP_i = \frac{\sum_r \pi_{i,t} \cdot L_{i,t}}{\sum_t L_{i,t}}$$

Where $\pi_{i,t}$ is the electricity price at zone i at time t, based on the Locational Marginal Pricing method, and $L_{i,t}$ is the electric load at zone i at time t. In Figure 10, we are plotting the percent change of LWAEP when comparing between the base case and integrated case studies. A positive change means that price at a specific node is on average higher under the integrated case study, while a negative change indicates price depression.

The results demonstrate that for regions that have a significant level of renewable power generation capacity (e.g. DE_NW, UK_N) and are likely to be constrained-off due to transmission congestion, the integrated solutions that help to relieve congestion lead to higher LWAEP. This can be explained as follows: as the amount of renewable power generation increases in a zone, the electricity price of that zone will tend to be lower since zero marginal cost renewables reduce the need to run expensive peaking plants. When the output of renewables is curtailed due to network constraints, the zonal electricity price will be low; this is an economic signal to increase demand in those conditions. With significant penetration of renewables, it can be expected that the level of congestion will increase and the electricity prices will be depressed further although the price volatility will increase. Increasing the amount of transmission capacity will allow the low marginal cost electricity output from renewables to be accessed by other zones which have higher electricity prices and this will increase the electricity prices in the exporting zones. For example a 3.9% increase in LWAEP of UK_N is observed as a result of adding the UK-Norway interconnector. This highlights the importance of this cross-border link and the large impact it can have on electricity prices.

3.1.5 Impact on market revenue of wind farm

Looking specifically at the average market price of offshore wind farms (OWF) output, the results of the studies demonstrate that the integration of wind with cross-border interconnection exposes the respective OWF to the zone with lower electricity prices (when price differentials arise due to link congestion). This is because the low-cost OWF is always on the exporting side of the network constraint, since power flows from regions with low electricity prices to regions with higher electricity prices. Naturally this outcome is not attractive from an OWF investor's viewpoint; it is a substantial issue that will need to be addressed though the cost-benefit allocation scheme to ensure that wind farm owners are willing to pursue integrated projects. In Figure 11 we plot change in the average market price of the output of different OWFs (the average income per MWh of wind output) against the non-integrated base case; negative change means a reduction in value. These were obtained by dividing the difference between the average market value of the OWF output in the integrated and base case with the value in the base case.

The results show that the average market price of the DE_OWF1 and DE_OWF2 output drops by around 20% and 16% respectively. NL_OWF and UK_OWF also experience substantial decrease in their average market prices. The impact on the market value of BE_OWF (1 and 2) output is less pronounced. However, in the UK-Benelux case study, BE_OWF2 has a slight value increase in the integrated network arrangement. This case is driven particularly by the topology set up of the integrated case. It is important to note that decrease in average OWF market price does not automatically translate to a decrease in OWF revenue, since the integrated case may improve the utilization of wind output and reduce the amount of wind curtailment.

3.1.6 Impact on utilization of network assets

The integrated North Sea configurations also improve the utilisation of network assets, as shown in Figure 12. For example, the utilisation of the link connecting Belgium Wind Farm 1 to the onshore Belgian system increases from 40% to around 55% in the 'UK - Benelux' and the 'Combined' cases. The utilisation of other offshore networks such as DE-WF1 – North West Germany, UK-WF – North UK and BE-WF2 – BE also shows improvement. As shown in Figure 12, many sections of the integrated NSG networks have high utilization factors (above 60%). This is considerably higher than the base cases where some links are only used for wind power energy export resulting in utilization rates of around 40%, confirming the increased efficiency of the proposed integrated schemes. This is expected since the links connecting the offshore wind farms to the onshore network are not dedicated only to transfer power from the wind farms but also to transfer power across regions.

3.1.7 Impact on network revenue

As the integrated configurations facilitate better energy trading across different regions, this provides commercial opportunities to gain additional revenues taking advantages of differences in electricity prices across regions. The results of the studies are shown in Figure 13, where the revenue R_l for a link l has been computed as $R_l = \sum_t P_{l,t} \cdot |\pi_{i,t} - \pi_{j,t}|$, where $P_{l,t}$ is the power flow over the link at time t, $\pi_{i,t}$ and $\pi_{j,t}$ denote prices at the sending and receiving nodes of the link respectively.

It is important to note that, in the integrated cases, the topology of the North Sea Grid changes. Therefore, some links may disappear and these are modelled as links with zero capacity and consequently zero network revenue. High revenue is an indication of a capacity constraint, raising the business case for a reinforcement project between the two system nodes.

3.2 Cost/Benefit Allocation

In the previous section, we clearly demonstrated that integrated grids increase social welfare compared to their radial design counterparts; offshore wind has a prominent role to play in contributing to EU's decarbonisation goals. On this basis, regulators in the North Sea should ensure that private investment decisions on this type of solutions are pursued and a suitable cost-benefit allocation framework is in place to ensure that the benefits are shared by all stakeholders. In this case, the stakeholders of interest are the network users i.e. the consumers, the respective TSOs, the offshore wind farm owners (OWFOs) as well as other transmission-connected electricity producers. In this section, we compute the benefit experienced by different stakeholders in each country for different allocation methodologies and pinpoint problematic cases and potential solutions. The following framework assumptions have been adopted:

- Network users and generators ultimately pay for network cost. Each country employs a different sharing ratio; ENTSO-E figures for the countries of interest are, in terms of percentage of cost shouldered by generators (the remainder taken up by consumers), are as follows:
    - Belgium 7%
    - Denmark 4%
    - Germany 0%
    - UK 27%
    - Netherlands 0%
    - Norway 38%
- Given that energy markets alone cannot deliver the desired level of renewables in the EU, national support schemes have been deployed to spur investment in technologies such as large-scale offshore wind energy. The average level of support, normalized over 20 years, varies between countries as follows:
    - Belgium 70 €/MWh
    - Denmark 60 €/MWh
    - Germany 60 €/MWh
    - UK 90 €/MWh
    - Netherlands 90 €/MWh

3.2.1 German Bight

Net benefit differentials between the integrated and radial network arrangements of the German Bight case study are shown in Table 8, where they have been split into different categories:

- *Consumer surplus* is the benefit stemming from reduced prices under the integrated arrangement and is attributed to consumers.
- *Producer surplus* is tied to generators' revenue; positive differential indicates a revenue increase for the OWFO or owners of other plants.
- *Congestion rent* is the benefit accrued from cross-border trading when utilizing project-related cables or other existing links; positive differential indicates increase in TSO's revenue due to increased trading volume and/or price differentials.
- *Revenue support* refers to payment transfers from consumers to OWFOs and is subject to each country's individual renewable energy support scheme policy.
- *Customer Use of System (CUoS)* refers to the charges incurred by customers for using the electricity network to access energy from producers.
- *Generator Use of System (GUoS)* refers to the charges incurred by generators for using the electricity network to access their customers.

In Table 8, the conventional allocation methodology has been used to split benefits among different countries. Focusing on the distribution of benefits at the country level, Germany is projected as the big winner under the integrated network choice, accruing benefits totaling 6,746M€. Specifically, power generators will accumulate the majority of this benefit. OWFOs and other German generators have increased revenue under the integrated paradigm due to increased electricity prices in Germany; the increased cross-border capacity assists in the resolution of congestion and low-cost energy from German generators exported to the Danish and Dutch systems. Given that energy export activity is more intense under the integrated case, consumer surplus is considerably reduced since German consumers face increased prices. In addition, price differentials with neighbouring countries are naturally reduced, resulting in reduced congestion rent gathered by the German TSO across its cross-border links. The congestion rent accrued on project-related infrastructure increases considerably by

2,603M€ since the integrated arrangement provides high-volume access to areas with high price differentials. The German support to offshore renewables amounts to 2,110M€ transferred through consumer payments to the OWFOs. Finally, CUoS charges are reduced by 965M€ due to the integration capital cost savings.

On the other hand, Denmark stands to lose the most if the integrated project goes ahead, accruing losses of -5,333M€. Increased volumes of German offshore wind power and other low-cost generators directly feed into the Danish onshore transmission network, suppressing Danish wholesale electricity prices. As a result, although consumer surplus increases surplus of Danish generators is reduced disproportionately by 5,274M€. The integrated project reduces congestion within the Danish transmission system compared to the base case, resulting in reduced congestion rents. As far as the congestion rent applying specifically to project-related infrastructure this reduces slightly since price differentials drop due to increased trading volume. Use-of-System charges for both consumers and generators increase under the integrated paradigm since, instead of a single radial connection, more assets are installed to increase trade capacity.

The overall result for the Netherlands under a pro-integration choice is almost neutral at -28 M€. Dutch generators lose out from on-average lower prices and lower production volumes as a result of more competition created by German offshore-wind power (-3,423 M€). This is partially offset by a gain in Dutch consumer surplus of 2,589M€, since Dutch power consumers enjoy lower prices. A less dominant countervailing effect for Dutch consumers is that they have to pay for a higher use of transmission system charges as the Netherlands has to spend more on offshore grid costs if the integrated project is chosen. German wind power will cause more congestion in the Dutch transmission system should the integrated project be realised. This pushes up the congestion rent income received by the Dutch TSO.

Overall, non-hosting countries (referred to as ‘third countries’) are minimally affected by the network architecture choice; integrated solution results in a loss of just 3M€. However, individual stakeholders in these countries can face significant differences under the two design variants. In particular, consumers will gain due to the influx of cheaper energy from other countries, while local producers will naturally face decreasing revenue. Due to this increase of cross-border trade volume, income of TSOs of third countries will also increase.

From the preceding analysis, it is very clear that adopting a conventional allocation methodology raises severe issues. Most importantly, there is a substantially asymmetric distribution of project benefits between Germany and Denmark. Although Danish consumers benefit from importing cheap energy from Germany, this effect is far outweighed by the revenue losses faced by Danish generators. It is clear that Denmark is better off under a radial network and as such, achieving consensus on development of integrated projects is severely problematic. However, network integration does give a substantial overall benefit of 1,382M€ and should be pursued in the interest of all stakeholders. By compensating some stakeholders it is possible to achieve positive net benefit differentials across all three participating countries. In Table 9 below we showcase the effect that the four CBCA mechanisms examined have on the net benefit of different stakeholder groups in each participating country. Bracketed entries in italics are the difference with respect to the conventional method.

When the Louderback method is applied, the benefit accrued by German stakeholders is reduced by 765M€ and re-distributed equally between Denmark and the Netherlands. However, this is a modest modification and not sufficient to ensure that Denmark supports the integrated architecture. The application of the PNBD's first variant results in a more substantial benefit transfer, ensuring that the aggregate net effect on Danish and Dutch stakeholders is zero. Under this scenario, these countries would be essentially indifferent between radial and integrated network design. The second variant of PNBD involves even more substantial transfer payments and succeeds in ensuring that all three countries have a net positive benefit from pursuing the integrated solution. In the case of Germany, the application of one of the PNBD variants implies that a higher share of the total project cost bill has to be paid by German power consumers through higher use-of-system charges. Applying the PNBD method, German consumers face higher aggregate network charges ranging from 5,361M€ (variant 1) to 6,071M€ (variant 2). By contrast, applying Conventional and implementing the integrated solution instead of the stand-alone solution would give German consumers an aggregate advantage in terms of reduced network charges of 965M€. Compared to the Conventional method, Dutch consumers would be better off if the Netherlands received compensation from either one of the two variants of the PNBD method. Unlike their Danish counterparts, Dutch generators do not gain under non-conventional CBCA, since they are fully exempt from GUoS charges.

3.2.2 UK - Benelux

The net benefit differential of the integrated UK - Benelux case as compared to the radial connection base case is presented in Table 10, broken down into different categories. As before, the conventional allocation methodology has been applied. This case is particularly interesting because third countries (in this case France) are also benefiting substantially. Overall, the big winner is Belgium where substantial benefits are accrued by consumers and the TSO, by gaining further access to lower-cost generation in the Netherlands and France. On the other hand, the integrated project has a net negative impact on UK and Netherlands. Although Dutch generators benefit from increased trade, this is far outweighed by the loss of consumers' and TSO's welfare who are now seeing increased prices and lower price differentials in their network. In the opposite vein, UK consumers benefit from increased cross-border capacity to mainland Europe, but the ensuing losses of local generators and the TSO are greater. In third countries, and primarily France, wholesale prices are affected in an upward direction, leading to increased producer surplus and reduced consumers surplus. The overall effect to non-participating is positive, leading to a net benefit increase of 1019M€ due to substantial increase in the congestion rents of other network links. As in the German Bight case study, it is difficult to see how the integrated solution could reach consensus among the countries involved despite the increased welfare benefits at the European level; the Netherlands and UK are better off under the radial connection project, by 2,478M€ and 709M€ respectively.

In Table 11 the distributional effect of the four different allocation schemes are presented. As can be seen, the Louderback and PNBD schemes involve transfer payments from Belgium to Netherlands and the UK, in the form of increase customer charges. However, the hosting countries of the proposed UK-Benelux integrated project are poised to lose welfare under all four CBCA methods examined. This particular project requires also that non-hosting countries bridge the financing gap inhibiting the final investment decision by transferring some of their accrued benefits to UK and Netherlands.

Although projections suggest that the UK-Benelux integrated project should be implemented from a European perspective, it will not materialise unless third countries and/or additional EU funding (e.g. through the Connecting Europe facility) are forthcoming in providing such support. This highlights the level and scale of cooperation required between member countries at the regulation level to ensure that beneficial integrated solutions are commercially viable.

3.2.3 UK – Norway

The net benefit of the integrated UK-Norway case study as compared to the radial connection basecase is presented in Table 12 broken down into different categories under the conventional cost-benefit allocation methodology. As can be seen, the UK is projected to be the overall beneficiary of this integrated project, accruing 5,146M€ in net benefit increase, while Norwegian social welfare decreases by 4,468M€. The project's architecture choice has relatively minimal impact on third countries. The vast share of benefits is absorbed by the OWFOs and other plants to a lesser extent who see increased revenue due to uncongested access to the Norwegian market. OWF gain a total of 18,127M€ as the sum of 9,450M€ in producer surplus, 8,653M€ in support payments plus 23M€ in savings due to lower tariff charges. Other plants accrue gains of 1,921M€. UK consumers will have to pay for the increased renewables support and will face higher energy prices, resulting in a total welfare loss of 14,323M€. Per contra, Norwegian consumers and generators are worse off under the integrated network; more Norwegian hydro is exported to the UK pushing up prices, while the other plants are facing increased competition from the UK during dry seasons. The integrated network also impacts use of system charges, resulting in increased payments for consumers and generators. In order to promote an investment decision in the integrated network, major compensation concessions must be granted by the UK to Norway to balance the asymmetric benefit sharing.

The effects of different allocation mechanisms are presented in Table 13. The three alternative allocation mechanisms result in substantial benefit transfers from UK consumers to Norwegian energy producers. Under the Louderback methodology, despite the 2,198M€ transfer between the two countries, Norway would still not be incentivized to pursue North Sea integration. The first variant of the PNBD methodology results in Norway being neutral between radial and integrated designs, while a positive net benefit of 180M€ is achieved for Norway under the second variant. Note that the bulk of benefit transfers is in the form of increased or decreased CUoS and GUoS payments.

In order to meet 2030 and 2050 EU climate and energy headline targets cost effectively, offshore wind has a substantive role to play. To this end, the implementation of a properly planned, meshed offshore grid consisting of integrated infrastructures needs to take off early in the next decade; adoption of suitable cost-benefit appraisal and sharing mechanisms are critical to support such endeavours and induce private investments. The analysis undertaken in section 3.1.3, established the positive social welfare effect of all three integrated project proposals from a European perspective. The undertaken allocation study suggests that the PNBDvar2 method is successful in achieving positive net benefit figures for all participating countries in the interest of achieving an investment decision in integrated architectures. However, there is an exception in the case of the UK-Benelux where third countries will also have to participate in a cross-border benefit transfer scheme.

4 Conclusions and Policy Implications

In this paper we have addressed a number of topical questions regarding the costs, benefits and distributional effects of integrated network projects in the North Sea area. Three concrete cases studies were chosen for their generalizability potential and commercial/regulatory interest. One conventional and one integrated network design was developed for each case and analysed in depth. For each network, the investment costs were quantified in close consultation with equipment suppliers and engineers, while the corresponding operational costs were quantified with the aid of pan-European wholesale electricity market optimisation model. Possible variability in terms of capital costs were captured using historical volatility of related commodity and market prices, while extensive sensitivity analysis of operational costs were undertaken using four European development scenarios incorporating different assumptions in terms of new technology uptake and fuel cost evolution. The analysis has clearly demonstrated that in all three case studies, the integrated network is more beneficial than its conventional counterpart. In the German Bight and UK-Benelux cases, the integrated network enables increased cross-border electricity trade between participating countries, thus substantially increasing the benefit that can be extracted from some offshore assets. In the UK-Norway case, the integrated network presents significant economies of scale with a negligible penalisation on the ability to export wind. In addition, the benefits of all three projects were shown to be largely inter-independent. The extensive analyses undertaken present evidence on the benefits of integrated projects highlighting the need to ensure a harmonized regulatory framework which can induce such investment decisions in the interest of European social welfare.

In a second step, the net benefit impact of pursuing an integrated network architecture for stakeholders within countries was determined by applying different CBCA methods. The conventional cross-border benefit allocation methods were shown to result in significant imbalances leading to potential issues in achieving political consensus between the participating countries. The undertaken analysis clearly demonstrated that some countries may be better off in pursuing radial connection projects. In addition, the economic implications on non-participating third countries were shown to be substantial in some cases. Conventional benefit allocation methods are therefore less suited for inducing offshore infrastructure projects due to the asymmetric distribution of costs and benefits. Our main recommendation is to consistently apply the Positive Net Benefit Differential mechanism as a starting point for negotiations on the financial closure of investments in integrated offshore infrastructure. This method is fully consistent with the 'beneficiaries pay' principle and mitigates free riding. Compensation transfers between countries in line with the proposed mechanism can improve the European-wide political acceptance of such projects. The primary vehicle for implementing such redistributive measures is through network tarification adjustments. When applying the PNBD method, issues meriting due further attention include the choice of Base Case assumptions. The rule for compensation between stakeholders should also be investigated further; it needs to strike a delicate balance between theory and political feasibility. Overall, the analysis undertaken in this paper has brought the assessment of integrated offshore grids a significant step further by highlighting the hindering role of asymmetric benefit distribution towards development.

In addition to the above points, we highlight that the NorthSeaGrid project also analysed in detail the materiality of other regulatory barriers, summarised in [23]. In brief, the relevant regulations should level the playing field among potential hosting countries for investors in offshore wind farms. Beyond the necessary alignment of support schemes, the harmonization of congestion management and use-of-system charging as applied to wind farm operators is necessary. Electricity markets need to be virtually fully integrated, in both the intra-day and balancing time frames, whilst the planning of offshore wind and grid infrastructure needs to be closely coordinated. Finally, properly filling the legal voids that currently characterize the possibility for implementing integrated offshore infrastructures is a matter of high urgency.

Acknowledgements

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Figures

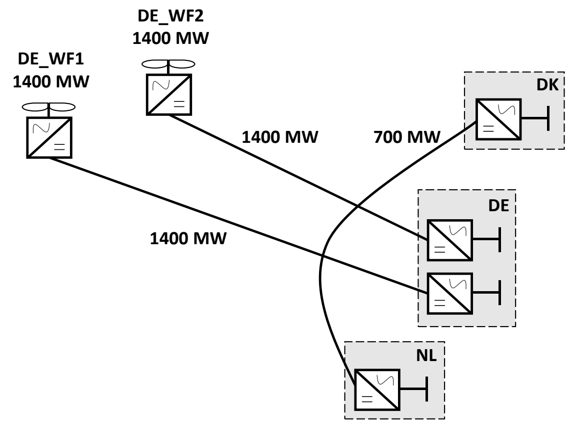

Figure 1: Single-line diagram of the radial connection base case in the German Bight case study.

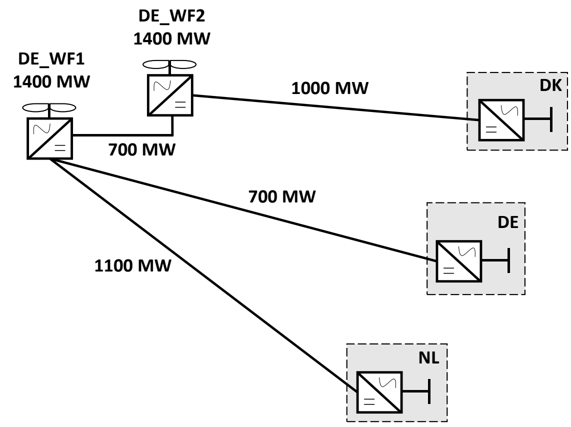

Figure 2: Single-line diagram of the integrated network in the German Bight case study.

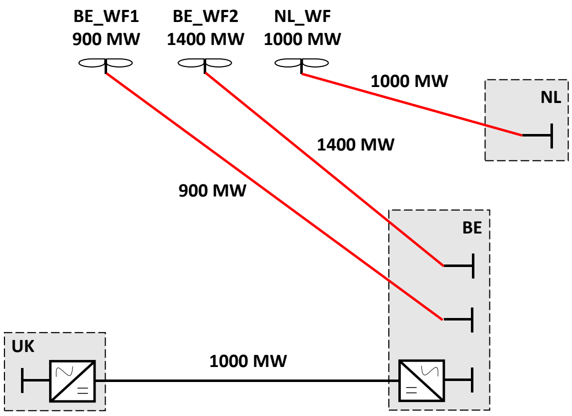

Figure 3: Single-line diagram of the radial connection base case in the UK-Benelux case study.

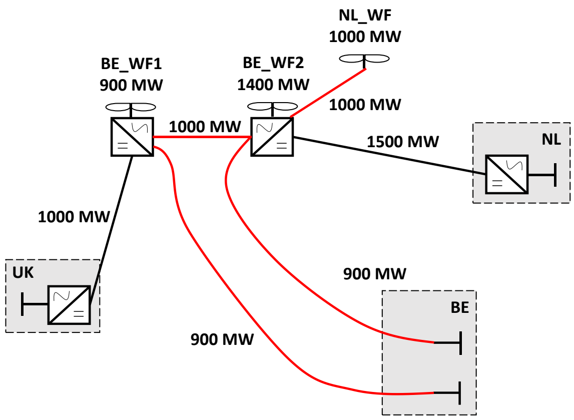

Figure 4: Single-line diagram of the integrated network in the UK-Benelux case study.

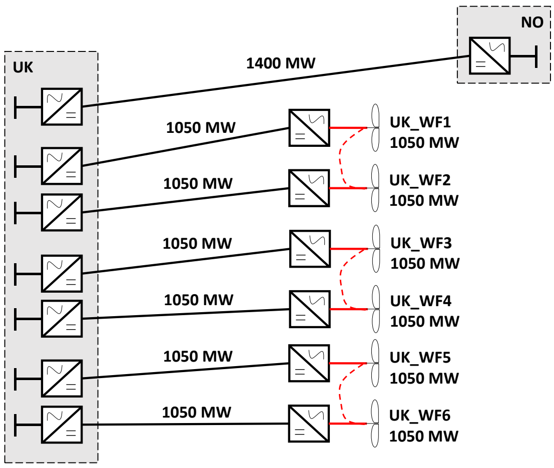

Figure 5: Single-line diagram of the radial connection base case in the UK-Norway case study.

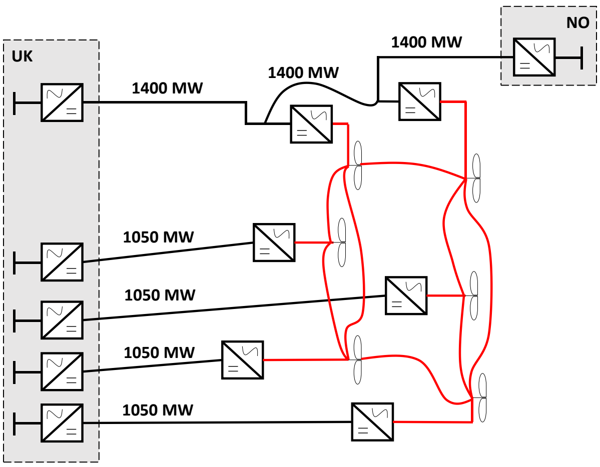

Figure 6: Single-line diagram of the integrated network in the UK-Norway case study.

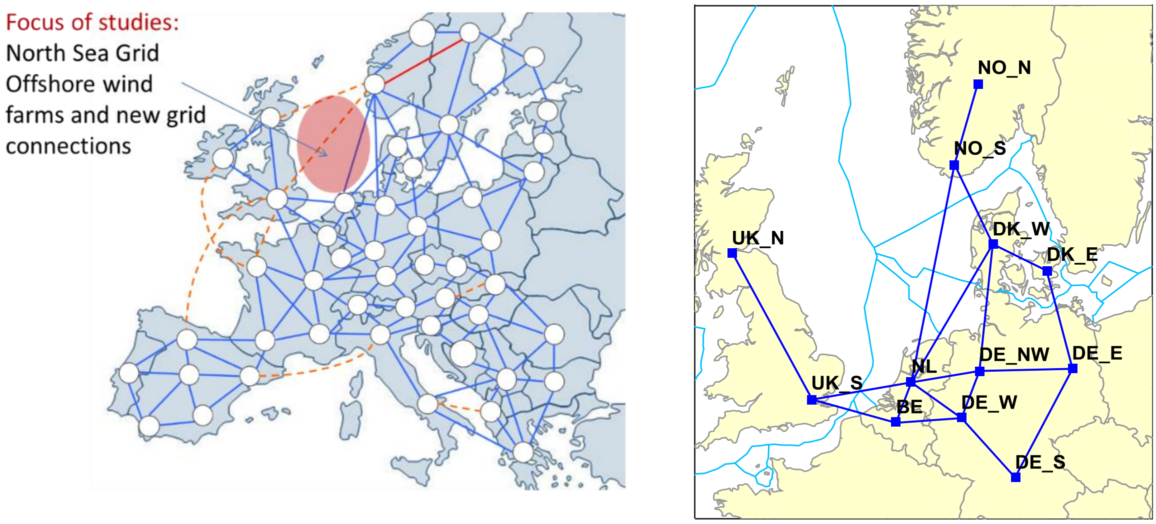

Figure 7: Topology of pan-European grid model used (left panel) and system nodes that are particularly relevant to the three case studies along with their interconnections (right panel).

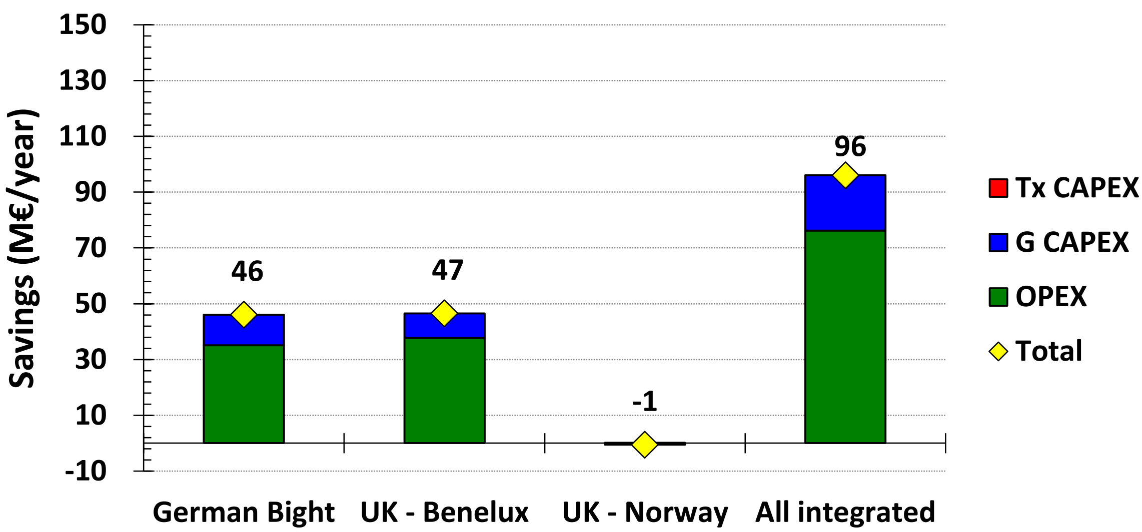

Figure 8: Annual system savings of integrated North Sea grid networks.

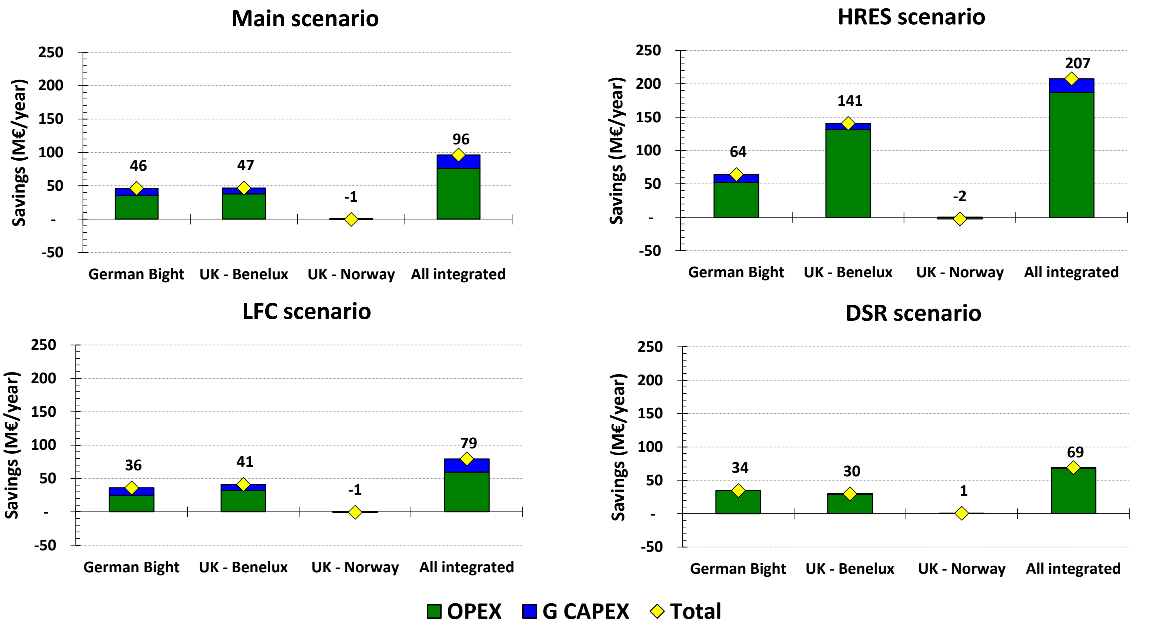

Figure 9: Savings of integrated solutions under different scenarios

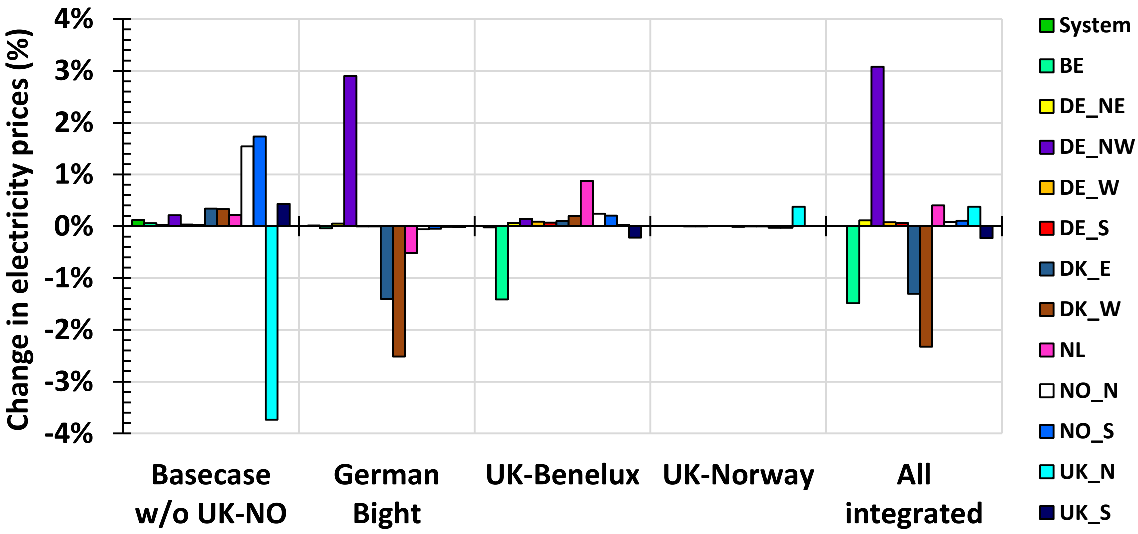

Figure 10: Impact of the proposed integrated network projects on average electricity prices.

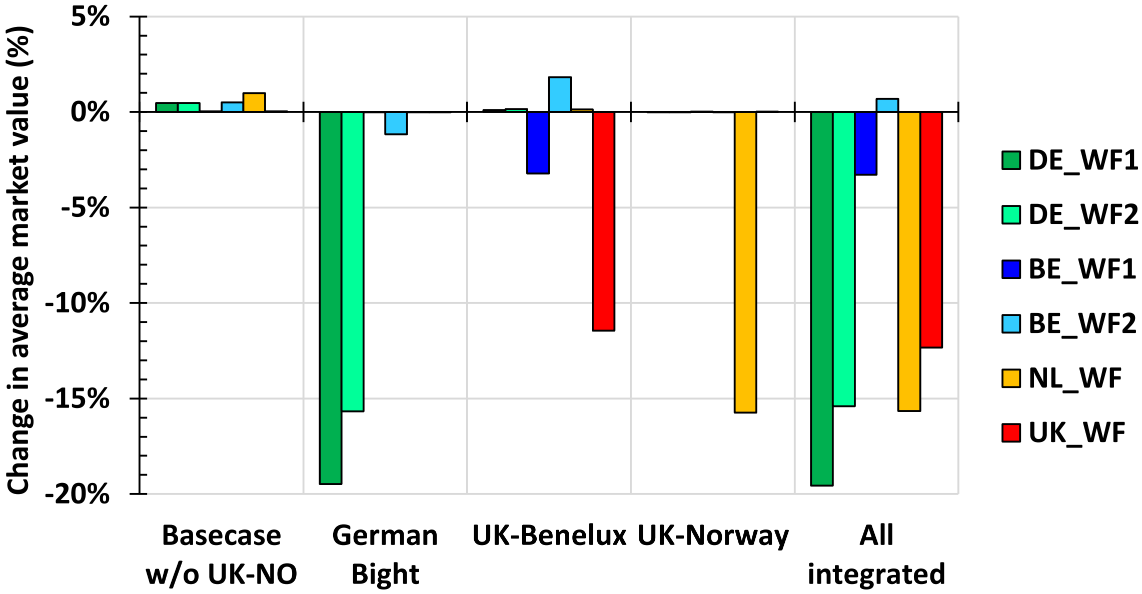

Figure 11: Change of average market value of offshore wind farms across case studies.

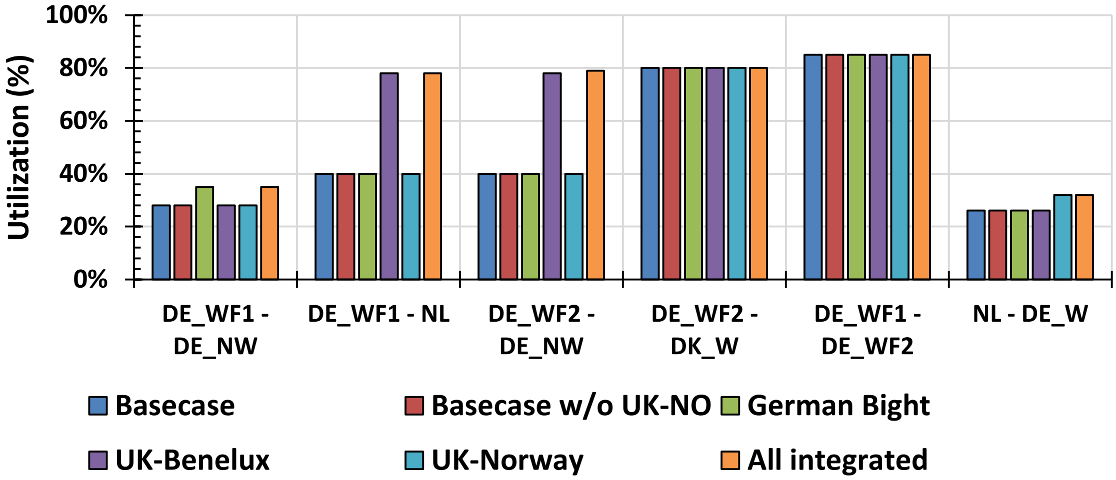

Figure 12: Utilization of different lines across case studies.

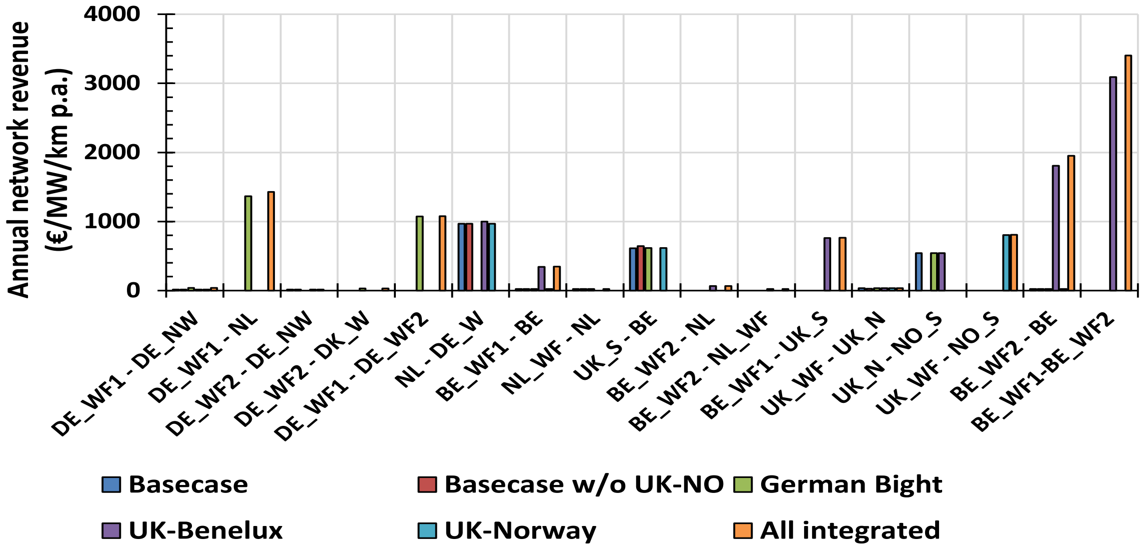

Figure 13: Annual network revenue of each link across different case studies.

Tables

Table 1: Estimated investment cost and associated metrics for the German Bight case study.

	Base case (M€)	Integrated (M€)
Offshore HVDC platforms	680	680
Single-core HVDC submarine cables	1407	1048
Single-core HVDC underground cables	111	49
Onshore AC/DC converter stations	475	330
Offshore AC/DC converter stations	290	210
Expected Cost	**2962**	**2608**
Standard Deviation	406	345
P15	2522	2236
P85	3394	2971

Table 2: Estimated investment cost and associated metrics for the UK-Benelux case study.

	Base case (M€)	Integrated (M€)
Offshore Transformer	60	17
Offshore HVAC platform	410	127
Offshore HVDC platform		630
HVAC and HVDC submarine cables	1012	891
HVAC and HVDC underground cables	19	13
Onshore Transformer	31	18
HVAC reactor	40	26
HVAC GIS Switchgear	100	99
Onshore AC/DC converter station	238	264
Offshore AC/DC converter station	-	264
Expected Cost	**1911**	**2348**
Standard Deviation	254	298
P15	1642	2027
P85	2183	2667

Table 3: Estimated investment cost and associated metrics for the UK-Norway case study.

	Basecase (M€)	Integrated (M€)
Offshore HVDC platform	1740	1740
Single-core HVDC submarine cable	5000	4536
Single-core HVDC underground cable	264	195
Onshore AC/DC converter station	1004	766
Offshore AC/DC converter station	714	714
HVDC Circuit Breaker	-	180
HVAC GIS Switchgear	73	119
Expected Cost	**8794**	**8249**
Standard Deviation	1117	1043
P15	7577	7117
P85	9980	9373

Table 4: Interconnection capacity between countries provided under base case and integrated network designs.

Scheme	Link	Capacity under Base case (MW)	Capacity under Integrated (MW)
German Bight	NL – DK	700	700
	NL – DE	0	700
	DE – DK	0	700
UK - Benelux	UK – BE	1000	1000
	UK – NL	0	1000
	BE – NL	0	1500
UK - Norway	UK – NO	1400	1400
Total		3100	7000

Table 5: Generation mix used in the studies.

Generation Type	Mix participation
Peaking Capacity	16%
Coal	5%
Gas	13%
Coal carbon Capture & storage	2%
Gas carbon Capture & storage	1%
Nuclear	6%
Oil	< 1%
Wind	23%
Photovoltaic	14%
Concentrated Solar Power	< 1%
Biomass	5%
Geothermal	< 1%
Hydro run-of-river	4%
Hydro Reservoir	7%
Storage	3%

Table 6: Fuel cost and carbon price assumptions.

Fuel type	Fuel price (€/GJ)
Coal	3.05
Gas	7.00
Oil	13.19
Uranium	2.15
Biomass	4.13
Carbon price (€/CO_2 ton)	74.00

Table 7: NPV of net benefit of integration across case studies.

	German Bight	BE – NL - UK	UK - Norway	Combined
Main scenario				
Expected NPV (M€)	1213	659	336	2292
Standard Deviation (M€)	123	83	87	210
P15 (M€)	1082	570	244	2077
P85 (M€)	1338	747	426	2508
HRES scenario				
Expected NPV (M€)	1591	2633	315	4623
Standard Deviation (M€)	132	170	87	278
P15 (M€)	1448	2458	222	4320
P85 (M€)	1724	2808	405	4905
LFC scenario				
Expected NPV (M€)	1003	533	336	1935
Standard Deviation (M€)	120	83	87	189
P15 (M€)	876	448	243	1731
P85 (M€)	1124	617	426	2124
DSR scenario				
Expected NPV (M€)	961	302	378	1725
Standard Deviation (M€)	119	77	87	184
P15 (M€)	834	224	285	1528
P85 (M€)	1081	381	469	1910

Table 8: German Bight case study - Breakdown of net benefit differentials (M€) per category per country using the conventional allocation methodology.

Benefit category	DE	DK	NL	Third countries	Total
Consumer surplus	-10687	2220	2589	841	-5036
OWF producer surplus	1506	0	0	0	1506
Other producers' surplus	14890	-5274	-3423	-911	5283
Congestion rent – project-related	2603	-42	-42	0	2519
Congestion rent – other links	-2531	-1885	1199	66	-3150
Consumers' support payments	-2110	0	0	0	-2110
OWF support revenue	2110	0	0	0	2110
Savings in CUoS charges	965	-338	-352	0	260
Savings in GUoS charges	0	-14	0	0	0
Total	**6746**	**-5333**	**-28**	**-3**	**1382**

Table 9: German Bight case study - Effect of different CBCA methods on net social welfare of different countries. All values in M€.

		Consumers	±	TSO	±	WFOs	±	Other producers	±	Total	±
Conventional	**DE**	-11832	-	72	-	3616	-	14890	-	6746	-
	DK	1882	-	-1927	-	0	-	-5288	-	-5333	-
	NL	2237	-	1157	-	0	-	-3423	-	-28	-
Louderback	**DE**	-12597	*(-765)*	72	*(0)*	3616	*(0)*	14890	*(0)*	5981	*(-765)*
	DK	2250	*(+368)*	-1927	*(0)*	0	*(0)*	-5273	*(+15)*	-4950	*(+383)*
	NL	2620	*(+383)*	1157	*(0)*	0	*(0)*	-3423	*(0)*	355	*(+383)*
PNBDvar1	**DE**	-17193	*(-5361)*	72	*(0)*	3616	*(0)*	14890	*(0)*	1385	*(-5361)*
	DK	7002	*(+5120)*	-1927	*(0)*	0	*(0)*	-5075	*(+213)*	0	*(+5333)*
	NL	2265	*(+28)*	1157	*(0)*	0	*(0)*	-3423	*(0)*	0	*(+28)*
PNBDvar2	**DE**	-17903	*(-6071)*	72	*(0)*	3616	*(0)*	14890	*0*	675	*(-6071)*
	DK	7343	*(+5461)*	-1927	*(0)*	0	*(0)*	-5061	*(+227)*	355	*(+5688)*
	NL	2620	*(+383)*	1157	*(0)*	0	*(0)*	-3423	*(0)*	355	*(+383)*

Table 10: UK-Benelux case study - Breakdown of net benefit differentials (M€) per category per country using the conventional allocation methodology.

Benefit category	BE	NL	UK	Third countries	Total
Consumer surplus	7077	-5102	3694	-2839	2830
OWF producer surplus	-2275	317	0	0	-1958
Other producers' surplus	-6976	5953	-3540	2508	-2055
Congestion rent – project-related	651	1970	702	0	3323
Congestion rent – other links	4016	-5449	-1183	1350	-1266
Consumers' support payments	0	-62	0	0	-62
OWF support revenue	0	62	0	0	62
Savings in CUoS charges	187	-167	-279	0	-259
Savings in GUoS charges	14	0	-103	0	-89
Total	**2694**	**-2478**	**-709**	**1019**	**526**

Table 11: UK-Benelux case study - Net social welfare effect of different allocation methods on stakeholders expressed as total cost (left columns) and net benefit differentials (right columns). All values in M€.

		Consumers	±	TSO	±	WFOs	±	Other producers	±	Total	±
Conventional	**BE**	7264	-	4667	-	-2274	-	-6963	-	2695	-
	NL	-5331	-	-3479	-	379	-	5953	-	-2478	-
	UK	3416	-	-481	-	0	-	-3643	-	-708	-
Louderback	**BE**	6895	*(-369)*	4667	*(0)*	-2276	*(-2)*	-6988	*(-25)*	2298	*(-397)*
	NL	-5269	*(+62)*	-3479	*(0)*	379	*(0)*	5953	*(0)*	-2415	*(+63)*
	UK	3660	*(+244)*	-481	*(0)*	0	*(0)*	-3553	*(+90)*	-374	*(+334)*
PNBDvar1	**BE**	5103	*(-2161)*	4667	*(0)*	-2288	*(-14)*	-7111	*(-148)*	371	*(-2324)*
	NL	-2961	*(+2370)*	-3479	*(0)*	379	*(0)*	5953	*(0)*	-107	*(+2371)*
	UK	3854	*(+438)*	-481	*(0)*	0	*(0)*	-3481	*(+162)*	-431	*(+277)*
PNBDvar2	**BE**	5103	*(-2161)*	4667	*(0)*	-2288	*(-14)*	-7111	*(-148)*	371	*-(2324)*
	NL	-3285	*(+2046)*	-3479	*(0)*	379	*(0)*	5953	*(0)*	-107	*(+2371)*
	UK	3618	*(+202)*	-481	*(0)*	0	*(0)*	-3568	*(+75)*	-431	*(+277)*

Table 12: UK–Norway case study - Breakdown of net benefit differentials (M€) per category per country using the conventional allocation methodology.

Benefit category	UK	NO	Third countries	Total
Consumer surplus	-7512	-1238	54	-8696
OWF producer surplus	9450	0	0	9450
Other producers' surplus	1262	-915	-10	337
Congestion rent – project-related	-57	-57	0	-114
Congestion rent – other links	-522	-108	-26	-656
Consumers' support payments	-8653	0	0	-8653
OWF support revenue	8653	0	0	8653
Savings in CUoS charges	1843	-1333	0	510
Savings in GUoS charges	23 + 659 = 682	-817	0	-135
Total	5146	-4468	18	696

Table 13: Net social welfare effect of different allocation methods on stakeholders expressed as total cost (left columns) and net benefit differentials (right columns). All values in M€.

		Consumers	±	TSO	±	WFOs	±	Other producers	±	Total	±
Conventional	**UK**	-14323	-	-579	-	18127	-	1921	-	5146	-
	NO	-2571	-	-165	-	0	-	-1732	-	-4468	-
Louderback	**UK**	-15927	*(-1604)*	-579	*(0)*	18107	*(-20)*	1347	*(-574)*	2948	*(-2198)*
	NO	-1208	*(+1363)*	-165	*(0)*	0	*(0)*	-897	*(+835)*	-2270	*(+2198)*
PNBDvar1	**UK**	-17584	*(-3261)*	-579	*(0)*	18086	*(-41)*	755	*(-1166)*	678	*(-4468)*
	NO	199	*(+2770)*	-165	*(0)*	0	*(0)*	-34	*(+1698)*	0	*(+4468)*
PNBDvar2	**UK**	-17715	*(-3392)*	-579	*(0)*	18085	*(-42)*	708	*(-1213)*	498	*(-4648)*
	NO	310	*(+2881)*	-165	*(0)*	0	*(0)*	34	*(+1766)*	180	*(+4648)*