Baltic InteGrid

Integrated Baltic Offshore Wind Electricity Grid Development

# COST-BENEFIT ANALYSIS of an integrated offshore grid in the baltic sea

## Comparison of different levels of grid integration based on case studies

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Interreg Baltic Sea Region

EUROPEAN UNION

EUROPEAN REGIONAL DEVELOPMENT FUND

# Cost-benefit Analysis of an Integrated Offshore Grid in the Baltic Sea

## Comparison of different levels of grid integration based on case studies

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General view of the wind farm, Aerial view, © EnBW

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# Executive Summary

In an effort to reduce the greenhouse gas emissions from electricity generation, most of the European countries in the North Sea and Baltic Sea Regions have established national targets to increase offshore wind power capacity. As the share of renewable energies rises, however, power fluctuations are expected to become more frequent. As a result, international electricity grid interconnections have been implemented or are in the planning phase, and there is growing interest in the prospect of evacuating the power produced by offshore wind farms (OWFs) into transnational grid infrastructure.

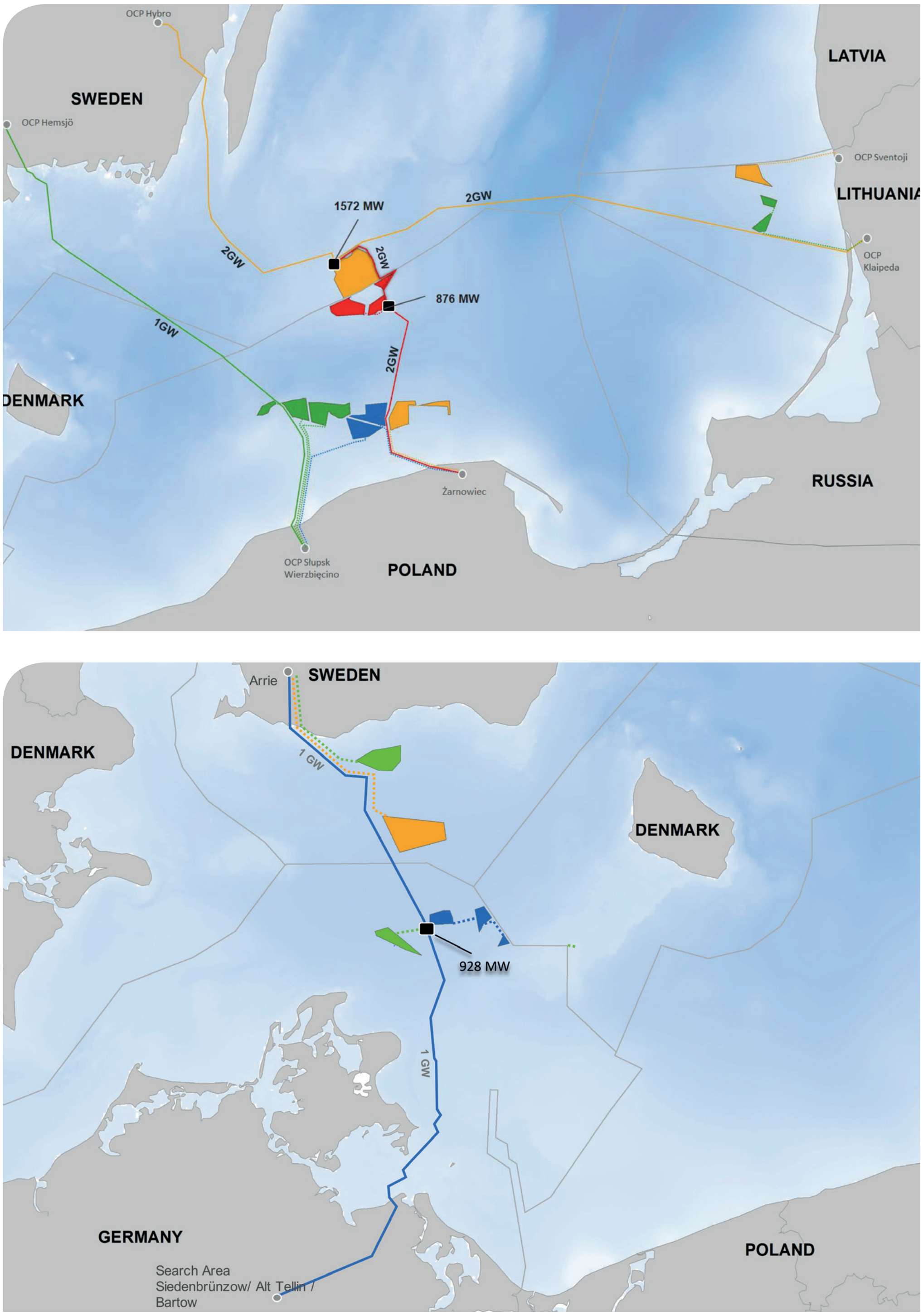
The challenges associated with such systems are the subject of various European research collaborations and initiatives, the majority of which are focused on OWFs in the North Sea Region (NSR). The INTERREG project Baltic InteGrid (Integrated Baltic Offshore Wind Electricity Grid Development) is the first to concentrate on potential offshore wind development in the Baltic Sea. The project is a collaboration between 14 partners from all eight EU Member States in the Baltic Sea Region (BSR). Project research addresses multiple issues, including policy and regulation, market and supply chain, technology and grid design, environment and society, spatial planning, and costs and benefits.

This report examines the costs and benefits of different design options for an integrated offshore grid. A systematic cost-benefit analysis (CBA) is conducted to allow for a direct comparison of the socio-economic effects of varying levels of wind farm integration. The CBA is based on ENTSO-E guidelines and adapted to fit the long-term horizon (2050) of potential projects. The aim of this CBA is not to provide a precise economic forecast, but to enable a comparison of specific infrastructure variants.

This report analyses two case studies, each of which contains six scenarios with two main variables: the level of wind farm integration and the extent of OWF development. The first case study examines the interconnections between the electricity grids of Sweden, Poland, and Finland. The second focuses on interconnections between Swedish and German electricity markets.

Cost-Benefit Analysis
Policy & Regulation
Market & Supply Chain
Technology & Grid Design
Spatial Planning
Environment & Society

*Figure 1*
*Case study 1 (top) and case study 2 (bottom), both showing high offshore wind installations and partial integration*




Commissioning year 2025 2030 2035 2040 2045

Connection technology HVDC cables HVAC cables Onshore connection point Converter station

For each case study, three levels of wind farm integration are analysed. The zero-integration case is the baseline and assumes that the development of HVDC interconnectors is completely independent of the OWFs that are connected to their respective electricity markets in a conventional, radial manner, using mostly HVAC technology. In the partial-integration case, some wind farms are connected to interconnectors, whilst others are connected radially. In addition, some direct connections of wind farms are assumed. In the maximum-integration scenario, all wind farms are part of a highly interconnected HVDC grid infrastructure. For the development of OWF installations, two different pathways are assumed. The high case assumes that most of the projects currently in planning stages will be realised. The low case only takes into account those projects with a high probability of realisation. The interconnecting capacity is held constant for the different levels of integration.

The potential benefits of greater OWF-interconnector integration are primarily expressed as differences in total system costs for electricity provision in Europe under given conditions. The dynamic investment and dispatch model dynELMOD is used to calculate system costs. The predefined scenario configurations and greenhouse gas emissions targets are set as boundary conditions. The model determines cost-effective investment in generation capacities, storage, and additional interconnectors through 2050 for the European electricity market as a whole. Non-monetarised results are also analysed.

For the cost evaluation, the linear model used assumes cost parameters for cables and nodes. Cable costs include costs of materials and construction. Node costs include the total costs of converters or transformers, including construction and the platform cost for offshore nodes. Operational costs, depreciation, and cost trends are also included. Because the scenarios have a long-term horizon and the development of innovative technology like HVDC breakers is anticipated, there is high uncertainty in cost assumptions. However, a sensitivity analysis shows that general results (i.e. the cost ranking for the different levels of integration) are quite robust to variations in cost assumptions.

Costs and benefits are expressed as net present values and are compared to evaluate relative benefits of increased integration. The following table indicates the integration levels that proved to be the most favourable in the different case studies and OWF installation assumptions.

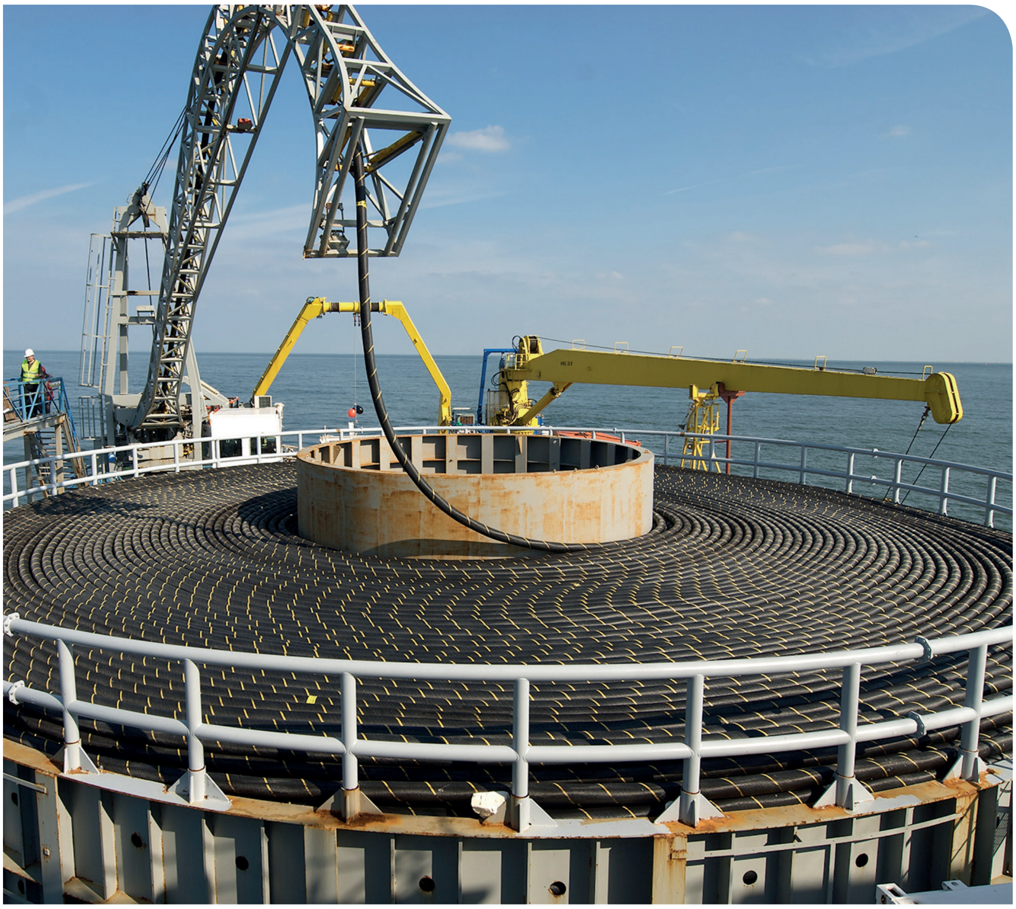
| | **Case Study 1 (SE / PO / LT)** | **Case Study 2 (DE / SE / DK)** |
|---|---|---|
| **High OWP** | Partial Integration | Maximum Integration |
| **Low OWP** | Maximum Integration | Zero Integration |

**Five central conclusions can be derived from the analysis:**

1. No general trend is observed as the level of integration increases. This is due to the specific characteristics of the different scenarios. For future infrastructure projects, potential wind farm integration should be evaluated carefully and on a case-by-case basis.
2. The interconnection of market areas can be expected to yield significant socio-economic benefits. This interconnection is already a feature of the zero-integration cases. Differences in benefits are relatively low for the various levels of wind farm integration. The analysis shows that the market benefits of additional integration are, at the very least, small or close to neutral. These include the benefits of an increased rate of adequacy, especially in cases of an overall low adequacy. Depending on the scenario, additional integration may produce significant benefits. This analysis captures only the additional benefits of higher levels of integration; benefits from investments in the base case are not represented, although they may be significant. Individual infrastructure projects should therefore be evaluated in greater detail.
3. Differences in costs between the three levels of integration are more significant. In each case, the CBA identifies the least expensive scenario as the most favourable. The cost structure varies significantly between zero-integration and maximum-integration scenarios. The results indicate that the replacement of HVAC infrastructure with HVDC technology in a meshed configuration could be economically competitive, but the level of integration has to be examined carefully. Although cost assumptions are highly uncertain, especially for HVDC technology, this finding is rather robust to cost variations.
4. A higher degree of integration appears to be more reasonable in scenarios with high offshore wind capacity, because in such cases the high share of fixed costs can be distributed among many projects.
5. A higher level of integration supports additional non-monetarised benefits. For example, in many cases, better market coupling and additional feed-in options for OWFs can increase the security of supply.

The CBA shows that the integration of OWFs and interconnectors can increase socio-economic welfare, but the optimal level of integration should be evaluated carefully.

Cost-Benefit Analysis



*Stiftung Offshore-Windenergie, Eon-Netz, Detlef Gehring 2008*

# 1. Introduction

The following report provides a cost-benefit analysis (CBA) of case studies in the Baltic Sea for different levels of grid integration between Baltic countries. The objective is to compare integration levels to determine the most favourable design for a meshed grid. The report was conducted as part of the Baltic InteGrid project (Integrated Baltic Offshore Wind Electricity Grid Development). Deutsche WindGuard was the leader of this group of activities and prepared the cost portion of the analysis. The benefit analysis was conducted by the Institute for Climate Protection, Energy and Mobility (IKEM), a Baltic InteGrid project partner. The results were then weighed against each other.

Sections 1.1 – 1.2 provide a brief introduction of the Baltic InteGrid project and the CBA summarised in this report. The current status of research on integrated offshore grids is then summarised (chapter 2), and the CBA methodology is explained (chapter 3). The scope of the investigation, including the design of the case studies, is outlined (chapter 4). The benefits of different integration levels are then analysed (chapter 5) and the corresponding cost analysis is presented (chapter 6). Costs and benefits are weighed against each other for the different cases and integration levels (chapter 7). Finally, conclusions are drawn regarding the relative benefits of specific integration levels (chapter 8).

## 1.1 Baltic InteGrid Project

The Baltic InteGrid project (Integrated Baltic Offshore Wind Electricity Grid Development) is co-financed within the framework of the INTERREG Programme for the Baltic Sea Region 2014 – 2020. It consists of 14 partners from all eight EU Member States in the Baltic Sea Region (BSR), which work in close cooperation with key stakeholders. The project duration is 2016 – 2019.

The project explores the potential for a meshed or integrated offshore grid in the BSR. It aims to promote sustainable electricity generation, advance the integration of regional electricity markets, and ensure security of supply in the BSR through an integrated grid approach that optimises the potential for, and efficiency of, offshore wind energy (OWE). There are three main output areas that are intended for use in strategic recommendations to support an integrated Baltic Offshore Grid:

- the Baltic Offshore Grid Forum: the conference and communication platform for the project
- a high-level concept for the Baltic Offshore Grid: the interdisciplinary research component of the project
- detailed case studies for two interconnection scenarios included in the Baltic Grid Concept

This analysis contributes to the high-level concept for the Baltic Offshore Grid by assessing potential costs and benefits. The analysis is performed on the basis of concrete design options, which are then applied in case studies for two interconnection scenarios.

## 1.2 Cost-benefit Analysis (CBA)

This purpose of this study is to analyse the relative costs and benefits of different design options for an integrated offshore grid. Costs and benefits are evaluated on the basis of case study scenarios, and the disaggregated data are then used in an overall CBA.

CBA is a systematic approach to estimating the economic advantages and disadvantages of alternative projects or investments. It can be used to assess whether the benefits of an investment option outweigh its costs and to evaluate the change in welfare attributable to it. Costs and benefits are expressed in monetary terms and adjusted for the time value of money. Because costs and benefits generally occur at different points in time, all flows of costs and benefits over time are expressed in a common unit of measurement, the ‘net present value’.[1]

CBA serves as a basis for comparing costs and benefits of different options under consideration. It is a particularly useful decision-making tool for projects can affect the public interest. For many reasons, it is challenging to perform a CBA for the development of an interconnected European electricity grid. For example, the analysis must account for the wide variation in policies (e.g. compensation systems) of participating states. In addition, implementation periods for grid planning projects often last as long as 10 – 20 years.

Very large projects with long time horizons introduce greater uncertainty about costs and benefits and therefore increase the complexity of CBA. In such cases, various assumptions must be made, including with regard to future energy-market development, resource availability, and political decisions. One major challenge is the monetarisation of benefits, which is possible only to a limited extent.

All results must be assessed carefully to prevent an underestimation of costs or overestimation of benefits. Sensitivity and risk analysis may be useful as supplementary methods of evaluating the insecurity of results.

The CBA should also consider social, ecological, and other non-monetary factors. For example, effects on CO2 emission or grid flexibility are also relevant to the analysis of an interconnected European electricity grid. The impact of the project on the overall welfare of states should also be considered, such as through an analysis of the effects on states and relevant stakeholders.

CBA is used in many contexts, including in policy-making and governmental processes, as well as in business activities of all kinds. CBAs for grid infrastructure projects are generally performed in accordance with the ENTSO-E[2] guidelines for assessing projects of common interest (PCIs). This analysis develops a result-oriented methodology that is based on ENTSO-E guidelines and adapted to the specific goals of the study. Given the specific challenges of CBA for long-term electricity projects and the relatively high uncertainty of many input parameters, the following CBA of an integrated Baltic Offshore Grid aims to compare different scenarios rather than provide an exact economic forecast for individual cases.

# 2. Status of evaluation of integrated offshore grids

Many recent studies have examined the potential for, and benefits of, integrated offshore grids in the North and Baltic Seas. The European Commission (EC) has a keen interest in advancing meshed concepts to the implementation stage; this is the objective, for instance, of the PROMOTiON project, which is currently underway in the North Sea. The first completed integrated solution is Kriegers Flak, a hybrid grid connection in the Baltic Sea that connects Germany and Denmark through the OWFs Baltic 2 (DE) and Kriegers Flak (DK). The following sections summarise recent research on the costs and benefits of integrated solutions. This is followed by an overview of political opinion formation at EU level.

## 2.1 Status of implementation of integrated offshore grids in the EU

This chapter reviews recent initiatives relevant to political opinion formation on the potential costs and benefits of integrated offshore grids. The initiatives are presented in chronological order.

### Baltic Sea Region Energy Cooperation (BASREC)

The Baltic Sea Region Energy Cooperation (BASREC) was initiated in 1998 by regional ministers for energy and the EC. The BASREC format was revised in 2015, and the group now has no regular meetings. Any of the BASREC countries can propose meetings of the GSEO (Group of Senior Energy Officials) as needed to discuss an energy issue of common interest. Under the revised format, BASREC has no budget to finance further projects. Projects conducted by the group before the revision include studies on the potential for offshore wind in the BSR and research for the report 'Electricity grid expansion in the context of renewables integration in the Baltic Sea Region'.[3]

### Baltic Energy Market Interconnection Plan (BEMIP)

The Baltic Energy Market Interconnection Plan (BEMIP) initiative was launched in 2009 with the signing of a Memorandum of Understanding (MoU). In 2015, a new MoU extended the scope of the initiative to incorporate issues regarding security of supply, energy efficiency, renewable energy, and the integration of the Baltic States' electricity network into the Continental European Network, including network synchronisation. The BEMIP enhances regional cooperation in the energy sector in the BSR to achieve its main objective: the creation of an open and integrated regional electricity and gas market between EU countries in the BSR. BEMIP has established dedicated working groups to develop measures, projects, and studies on specific topics (e.g. infrastructure, security of supply, and renewable energy).[4] The BEMIP Action Plan includes objectives for interconnection and for renewable energy generation. In addition to better integrating the electricity market, it aims to promote sustainable energy development, the integration of renewable energy in electricity systems and cross-border cooperation on renewable energy.[5]

### North Seas Countries Offshore Grid Initiative (NSCOGI)

In 2010, 10 European countries signed an MoU for a North Seas Countries Offshore Grid Initiative (NSCOGI). The objective was to establish a cooperative framework for grid infrastructure development in the North Sea in order to ensure energy security and a cost-efficient, low-carbon, sustainable energy solution for the region. Since then, NSCOGI has been responsible for evaluating and facilitating the coordinated development of a potential offshore grid in the North Sea. Three working groups were created to support research on grid implementation, market/regulation, and permissions/planning.

The working groups are chaired by representatives of the energy ministries of two participating countries. In 2013, the European Union (EU) identified the Northern Seas offshore grid (NSOG) as one of its four priority corridors for electricity infrastructure (Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure). The Northern Seas include the North Sea, the Irish Sea, the English Channel, the Baltic Sea, and neighbouring waters. The aim is 'to transport electricity from renewable offshore energy sources to centers of consumption and storage and to increase cross-border electricity exchange'.[6]

### Energy cooperation between the North Seas Countries

The NSCOGI gained new momentum in June 2016, when several EU member states (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden, and later also the UK) and the European Commission (EC) signed a political declaration on energy cooperation that included a joint work programme for the coming years. The initiative focuses on building additional electricity links, increasing energy trading and further energy market integration, and reinforcing regional cooperation with the goal of reducing greenhouse gas emissions and enhancing security of supply.[7] One explicit objective of the initiative is to advance the cost-effective development of wind energy in the region through voluntary cooperation. Further interconnection between the North Seas countries is to be enhanced using a step-by-step approach, with coordination in regional grid planning and development. By exchanging information on their offshore infrastructure planning, countries will support coordinated investment planning and mobilise capital.[8] The declaration expresses a political intent and has no binding effect.

### 'Northern Seas as the Power House of North-Western Europe'

In early 2016, 20 members of the European Parliament signed a manifesto titled 'Northern Seas as the Power House of North-Western Europe'. In this document, the signatories stated that cooperation in the NSR should focus on the large-scale deployment of OWFs and emerging marine renewables, along with the completion of a meshed electricity grid. The manifesto also proposed an action plan to implement a North Sea offshore grid to make the region's waters the 'power house' of Europe.[9]

### North Seas Energy Forum

The first North Seas Energy Forum was held in March 2017. The forum is organised by the European Commission and invites representatives from the public, private, and non-governmental sectors in the countries of the NSR (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden, and the United Kingdom) and from the EC.[10] The discussions are intended to advance the development of a regional offshore grid by addressing concrete questions and challenges.

### Baltic Sea Offshore Wind Forum (BaSOF)

The Baltic Sea Offshore Wind Forum (BaSOF) is a forum established to promote the development of offshore wind power in the Baltic Sea. The forum organises workshops, conferences, and seminars with stakeholders from the Baltic Sea Countries (BSC). BaSOF meetings are held biannually to formulate a common strategy for recommendations to BSC governments. Previous forum topics include cross-border support systems and grid interconnectors. On 15 June 2017, BaSOF members approved the Baltic Sea Declaration, which was developed to accelerate the use of offshore wind power in the Baltic Sea. The declaration, which addresses the political structures relevant to the Baltic Energy Market Interconnection Plan (BEMIP), aims to establish a legal framework for greater utilisation of offshore wind in the Baltic Sea and emphasises the need for further interconnection in the BSR.[11]

## 2.2 Status of research on CBA of integrated offshore grids

This chapter summarises key findings from recent studies on the costs and benefits of integrated offshore grids.

### WindConnector Concept (2017)

In a study commissioned by TenneT and The Crown Estate, Pöyry examined the feasibility of a 'WindConnector concept', a plan for offshore grid infrastructure that can both transmit electricity generated by OWFs and connect electricity markets.[12] This configuration would allow for the transmission of wind energy and facilitate international electricity exchange. The infrastructure would be utilised more efficiently, as it could be used for electricity exchange in less windy periods. The study was conducted from the perspective of a TSO seeking to increase the efficiency of its infrastructure. According to TenneT, the study indicated that combining infrastructure for OWE and interconnection significantly increased the occupancy rate and thus lowered consumer energy costs. The study identified potential capital savings of up to €1.8 billion from a 'WindConnector' between the Netherlands and the UK. The asset utilisation could increase from 45–50 %, up to 80 %. The modelling suggested that the value of potential market-to-market flows more than offset the investment required to install infrastructure linking the markets. However, the realisation of combined infrastructure projects of this kind would require further research and adjustments to regulatory frameworks.[13]

### NorthSea Grid (2015)

The NorthSeaGrid project investigated a meshed offshore grid to facilitate system integration of OWE based on a case-study approach. The study, published in 2015, was undertaken by 3E, Deutsche WindGuard, CEPS, DNV GL, ECN, and Imperial College Consultants. Instead of investigating the overall power system, it focused on three concrete case studies (embedded in modelling of the overall European power system). Based on the case-study analysis, the project identified and researched barriers to integrated solutions, with a focus on financial risks and regulatory issues. For each case, the costs and benefits were identified for all stakeholders. The cost and benefit calculations were based on sensitivities and risk assessments, and various approaches to cost-benefit allocation were examined. The net present value of the difference in net benefits of integrated and base options was calculated for the three cases. A sensitivity analysis was conducted for each case to ensure that the overall results were robust to changes in key variables. Benefits were expressed as savings in generation investment and operating costs. The case studies showed that the net present benefit of the integrated options fell between €350 million and €1,200 million or €2,300 million for all integrated cases combined. In the German Bight and UK-Benelux cases, benefits were primarily driven by the increased level of interconnection between the countries of the NorthSeaGrid. In the UK-Norway case, a small capacity reduction led to a marginal increase in system cost. In the integrated cases, the material requirements and related costs were generally lower, which was associated with decreased operating costs. Furthermore, the results for greater availability and utilisation of the infrastructure were positive. The technical risks were found to be largely similar for both isolated and integrated developments. Therefore, the additional net present benefit of integrated designs was higher. The study showed that uncertainties did not increase when integrated designs were implemented and that the major uncertainty drivers were the market and basic materials, such as copper and steel. The level of benefits of the integrated cases was, however, sensitive to the characteristics of the future European system. A higher penetration of renewables tended to increase the benefits. Lower fuel and carbon prices and increased system flexibility supported by demand-response tended to reduce benefits.

### Benefits of a meshed offshore grid in Northern Seas region (2014)

The 'Study on the benefits of a meshed offshore grid in Northern Seas region' was launched by the European Commission and conducted by Ecofys to assess the potential benefits of a meshed offshore grid in the North Sea, the Irish Sea, and the English Channel. The study compared a base case with a coordinated case (meshed grid). In the coordinated case, a larger number of offshore hubs were required, as were fewer cables with a higher rating. The study showed that the net infrastructure investment cost was €4.9–10.3 billion higher for the coordinated network development. However, this investment was associated with significant techno-economical, environmental, and strategic benefits. The annual savings from a coordinated offshore grid in 2030 (including costs of losses, $CO_2$ emissions and generation savings) were calculated as €1.5–5.1 billion. These monetarised benefits led to the conclusion that the coordinated offshore grid was profitable in all study scenarios.[15] The key drivers for these reductions of the total annual cost of electricity supply were the opportunities for energy trading; cross-border flows between Member State; and the resulting improvement in the integration of offshore wind capacity and different generation pools in the region. The study found that greater coordination of the national reserve capacities could reduce generation costs by another €3.4–7.8 billion.[16]

### Strategic Development of North Seas Grid Infrastructure (2014)

The study 'Strategic Development of North Seas Grid Infrastructure', conducted by Imperial College London and E3G and published in July 2014, used cutting-edge computer modelling to assess the risks and opportunities associated with different designs for a North Sea electricity grid. The study found that coordinated and strategic approaches to network planning in the North Sea could lead to lower infrastructure costs. By sharing resources and working together to plan and design the grid, by 2040 the North Sea countries could save €25–75 billion of the costs associated with a national approach. According to the study, coordinating the planning process for OWF locations could increase benefits to €30–80 billion. The authors also considered uncertainties regarding expected offshore wind deployment and determined that, even in the worst-case scenario (i.e. with offshore wind development assumed to be much lower than projected), the economic regret was limited to roughly €1 billion.[17]

### OffshoreGrid (2011)

The European project OffshoreGrid was one of the first major research studies on an integrated offshore grid in the North Sea. The project, which began in 2009 and was finalised in 2011, was coordinated by 3E.[18] In the study, a detailed cost-benefit analysis of offshore electricity infrastructure developments in the Northern European Seas was conducted for the first time on a large scale, taking into account technical, economic, and regulatory aspects. In the OffshoreGrid project, a European Power System model and tailor-made infrastructure cost model was used to assess the costs and benefits of different integrated design concepts (hubs, tee-in and hub-to-hub interconnectors). The main conclusion was that consistent use of hub connections where appropriate in the North Sea could reduce investment costs by €14 billion. Based on that determination, two interconnected grid designs were developed: the 'Direct Design' and 'Split Design'. The additional investments required for these options were €5.4–7.4 billion, depending on the specific design. The benefits were not calculated in monetary terms, but the additional investment was found to be negligible when spread over the long project lifetimes and referred to the kWh of offshore wind electricity produced. The study was the basis for further research, including the NorthSeaGrid project.

## 2.3 Summary of evaluation status

At EU level, the topic of integrated or meshed offshore grids has been of great importance for roughly a decade. The NSCOGI was a major step forward in research on a meshed offshore grid in the North Sea. The EC is currently promoting two large projects to advance it further (PROMOTiON and Baltic InteGrid). In addition, the North Seas Energy Forum brings together representatives from the public, private, and non-governmental sectors in NSR countries to solve challenges related to the implementation of a meshed grid in the North Sea.

Many scientific studies have also examined the potential benefits of an integrated offshore grid. Although the basic assumptions and case selection have varied, the overall evaluation of an integrated offshore grid has tended to be positive. The following table summarises the main assumptions and results of the different studies considered here.

| | WindConnector | NorthSea Grid |
|---|---|---|
| **Year of publication** | 2017 | 2017 |
| **Author** | Pöyry on behalf of Tennet | 3E, Deutsche WindGuard, CEPS, DNV GL, ECN, Imperial College on Subject analysed behalf of EC |
| **Subject analysed** | One hub-to-hub case between Netherlands and UK | 3 cases<br>German Bight: 2 OWF, 3 countries<br>UK-Benelux: 3 OWF, 4 countries<br>UK-Norway: 6 OWF, 2 countries |
| **Subject of comparison (base case)** | Hub OWF connections | Radial and hub OWF connections, point-to-point interconnectors |
| **Benefits** | More efficient infrastructure use (trading in less windy periods) – increased occupancy rate, lower consumer energy costs | Greater availability and utilisation of infrastructure, increased level of interconnection, increased network security |
| **Investment cost behaviour** | <1.8 bn €<br>(Value of market- to market flows 'more than offsets the investment required for the additional infrastructure') | German Bight: -0.35 bn €<br>UK-Benelux: +0.45 bn €<br>UK-Norway: -0.55 bn €<br>All: -0.45 bn € |
| **Overall benefit compared to base case** | 1.8 bn € | German Bight: 1.2 bn €<br>UK-Benelux: 0.65 bn €<br>UK-Norway: 0.35 bn €<br>All: 2.3 bn € |
| **Conclusion** | These studies are comparable with regard to the subject of analysis and comparison. The results tend to be in the same direction/can be explained by different case designs and slightly different methodologies with regard to the details of CBA calculations. | |

| Benefits of a meshed grid | Strategic Infrastr. Developm. | Offshore-Grid |
|---|---|---|
| 2014 | 2014 | 2011 |
| Ecofys on behalf of EC | Imperial College, E3G | 3E, dena, EWEA, ForWind, IEO, NTUA, Senergy, SINTEF on behalf of EC |
| Whole North Sea, Irish Sea, English Channel | Whole North Sea | Whole North Sea |
| Radial OWF connections, limited number of point-to-point interconnectors | Optimal radial solution, point-to-point interconnectors | Radial and hub OWF connections |
| Techno-economical, environmental, strategic; key benefits opportunities for trading and cross-border flows, better integration of offshore wind capacities, higher speed of construction | Savings in operation and network investment costs | Reduced cables, maritime space used, environmental impact; increased n-1 security, security of supply, security to wind farm operators due to reduced losses in cases of failure |
| Scenario 100 GW OWF: +7.8 bn €<br>Scenario 67 GW OWF: +4.9 bn €<br>Scenario 51 GW OWF: +10.3 bn € | -43 bn – -8 bn | -6 – +1 bn € compared to radial case<br>+5.4 – 7.4 bn € compared to radial/hub base case |
| Scenario 100 GW OWF: 5.1 bn €/a<br>Scenario 67 GW OWF: 1.5 bn €/a<br>Scenario 51 GW OWF: 3.4 bn €/a<br>(annual savings in 2030) | 25-75 bn € | Split design: 1.02 bn €/a<br>Direct design: 1.3 bn €/a<br>Net presentvalue benefit:<br>16 bn € (split) and 21 bn € (direct) across a lifetime of 25 y. |
| These studies are comparable with regard to the subject of analysis and comparison. The results for the overall benefit tend to be in the same direction. A difference can be observed with regard to the investment cost, which increased in the Ecofys study and decreased in the Imperial College/E3G study, whilst the OffshoreGrid study quoted both options, depending on the type of base case. As the case design plays a significant role here, the differences are explicable. | | |

***Table 1***
*Comparison of recent studies on benefits of meshed offshore grids.*

# 3. CBA Methodology

The following chapter outlines the main objectives and the general methodology for the CBA of an integrated offshore grid in the Baltic Sea.

## 3.1 Main objectives

This CBA is a comparative analysis that does not evaluate whether a certain scenario is beneficial or not. Instead, the analysis compares scenarios with different levels of grid integration to evaluate the costs and benefits associated with an increase in integration. Therefore, one assumption is that increased interconnection is beneficial and desirable. The question is which level of integration should be selected and how this can be assessed for different concrete scenarios.

**The objective is to produce the following outputs:**
- an overview of the disaggregated costs of integrated offshore grid scenarios
- an overview of the benefit difference between different levels of integration, primarily using system cost as a monetarised indicator
- a comparison of costs and benefits of different levels of integration
- conclusions for use in decision-making on the integration level of meshed offshore grids

The following section outlines the CBA methodology, which was developed on the basis of a result-oriented strategy.

## 3.2 Methodology

The methodology applied in the CBA of an integrated offshore grid in the Baltic Sea is based on the ENTSO-E CBA methodology contained in the July 2016 draft version[19], which provides criteria for the assessment of costs and benefits of European transmission projects. The ENTSO-E methodology is used in market and network development as a common framework for evaluating Ten-Year Network Development Plans (TYNDP), which in turn serve as the sole basis for the selection of candidate projects of common interest (PCIs).[20] The proposed set of indicators has been adapted to accommodate the reduced complexity of a result-oriented CBA.[21]

**ENTSO-E identifies the following main categories for project assessment[22]:**

**Benefits**
- socio-economic welfare (including RES integration and $CO_2$ variation)
- losses
- security of supply (indicators: adequacy and system stability)

**Residual impacts**
- environmental
- social
- other

**Costs**
- total project expendituresw

For simplicity, these categories have been narrowed down to a reduced list of the most relevant indicators, as is recommended for a result-oriented CBA analysis.[23] The following table presents the criteria used by ENTSO-E and the methodology used in this study. Residual impacts are excluded.

| | Criterion | Evaluation | This study | Remarks |
|---|---|---|---|---|
| Benefits | Socio-economic welfare | Central criterion for monetarised benefits | System costs<br><br>Electricity prices | The socio-economic welfare is analysed on the basis of overall system costs.<br>The sub-criteria RES integration and CO2 variation are integrated results of the system costs.<br>The electricity prices as an indicator of consumer surplus are analysed for the different cases. |
| | Losses | Technical criterion, considered within case study development | Not analysed | As similar network projects with comparable technologies are analysed, the losses will not be the limiting criteria to compare. |
| | Security of supply | Important criterion, no complete monetisation possible | Adequacy rate | Because the base case already includes interconnectors, the security of supply does not change significantly between the cases, as indicated by the adequacy rate.<br>Because the model does not simulate local congestion, the security of supply cannot be analysed directly. The model is run including the assumption of DC line failures to analyse the influence on the adequacy rate. |
| Residual Impacts | Environmental, social, etc. | Usually no monetisation possible | Not analysed | The residual impacts are partly analysed within other working packages of the Baltic InteGrid project. |
| Costs | Total costs | Only the rough total project costs are considered for far-future projects | Disaggregated investment costs | To develop profound results the cost assumptions are named in a disaggregated manner. As ENTSO-E recommends for far-future projects to consider the investment cost plus a complexity factor standing for the other cost parameters, this study also concentrates on the evaluation of investment cost associated with a component specific factor for O & M and other costs. |

*Table 2*
*Development of a list of key cost and benefit indicators based on ENTSO-E criteria*

Core indicators are the socio-economic welfare and the project expenditures. These indicators are fully monetised and weighed against each other. Additional indicators evaluate the security of supply of transmission systems. Costs and benefits are analysed in two separate models: a market model to evaluate the socio-economic welfare of the various scenarios and their individual security of supply, and a linear cost model (LCM) to calculate project capital (CAPEX) and operational expenditures (OPEX). All cash flows are discounted to the base year 2017 with a discount rate of 4 %, as suggested in the ENTSO-E guidelines.

**In this CBA, the following measurement indicators are used:**

**For benefits**
- system costs
- electricity prices
- adequacy rate (as an indicator for security of supply)

**For disaggregated investment costs (HVAC and HVDC)**
- cables (material and installation)
- onshore nodes (converters/transformers, installation)
- offshore nodes (converters/transformers, breaker, platform, installation)

The costs and benefits are analysed separately in different models. The following figure provides an overview of the general approach.

*Figure 2*
*Methodology*

| Benefits | | | Costs | | |
|---|---|---|---|---|---|
| System Costs | Adequacy rate | Electricity Prices | Cable (AC&DC) | Onshore Nodes | Offshore Nodes |
| Market Model | | | Linear Cost Model | | |

All benefits are calculated by applying a market model that simulates the European grid and the European energy market. The model uses defined input parameters and optimises the grid to determine the best solution from a socio-economic point of view. The costs are derived from recent scientific publications and market announcements and are analysed using a LCM. The analysis is conducted from a high-level perspective. Technical and financial details are not taken into account because the objective is to obtain a general overview of the preferable level of integration in concrete scenarios. The methodology and models used to calculate the costs and benefits of design options for integrated offshore grid cases in the Baltic Sea are explained in detail in the following chapters.

# 4. Investigation Scope – Pre-feasibility Studies

Two pre-feasibility studies were performed in the context of the Baltic InteGrid (BIG) project to assess two cases of OWF-interconnector integration.[24] The CBA evaluates the costs and benefits of different levels of wind farm integration in these concrete cases. Case study 1 (CS1) assumes a connection between Poland, Sweden and Lithuania; in case study 2 (CS2), a connection between Germany, Sweden, and potentially Denmark (the island of Bornholm) is foreseen.

The two cases used for the pre-feasibility studies are located in the South Baltic Region because, according to the BIG analysis of planned OWF projects, the majority of projects under development are located in this southern part of the basin. Case selection was based on on the following considerations: economic and spatial possibility of locating interconnection, potential OWF projects, projects identified in TYNDP, and consultation with TSOs. The following figure provides an overview of the locations of the two case studies.

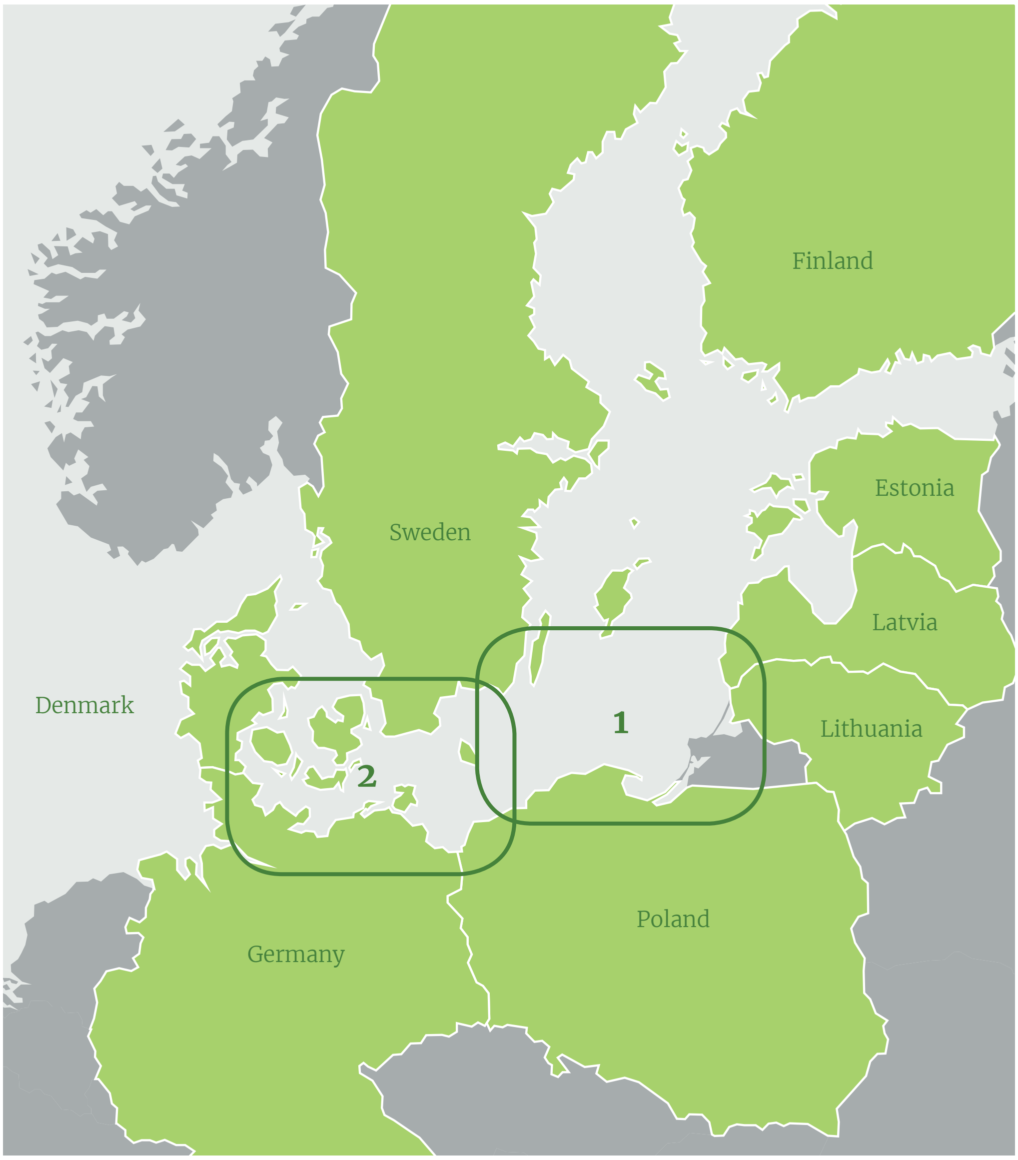



*Figure 3*
*Case study locations*

For each case study, a total of six scenarios were developed to test the influence of two variables:

**Level of integration and level of OWE development**

1. **Level of integration** is defined as the degree to which the OWF projects are integrated with the relevant interconnections or with each other. The CBA investigates the costs and benefits of different levels of integration. The following integration levels are assumed in both case studies:
   - **Zero integration/Baseline scenario:** no integration of OWFs with the planned interconnector; interconnectors are developed independently of the OWF export infrastructure.
   - **Partial integration:** partial integration of OWFs with the interconnector and development of remaining OWFs in a radial configuration.
   - **Maximum integration:** maximum integration of OWFs with interconnector and / or other OWFs.

2. **Level of offshore wind energy development** refers to the extent of OWE development in the study area. Due to high uncertainty regarding the level and speed of regional OWE development, the scenario assumes two OWE development rates. For each, a list of projects developed over time (in five-year intervals) was identified. The following scenarios are assumed in both case studies:
   - **High OWP:** assumes rapid development of offshore wind in the region; most of the projects planned and further projects with lower certainty are commenced within the PFS timeframe.
   - **Low OWP:** projects develop at a slower pace, and only projects that have higher certainty and are  more advanced stages of the development process are included.

The following table illustrates the systematic approach used to define case-study scenarios.

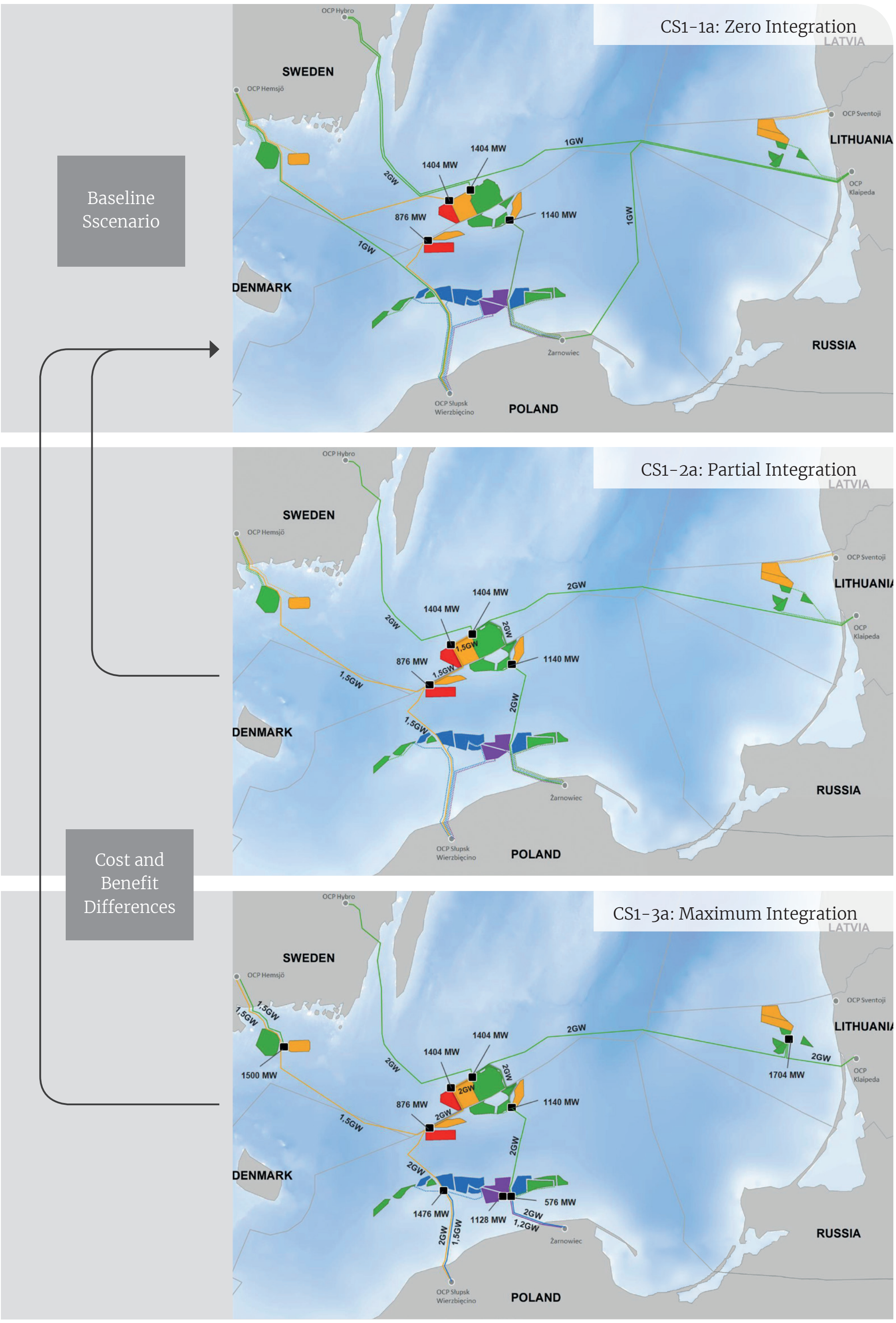
*Table 3*
*Overview of the six case-study scenarios.*

| | | Level of integration | | |
|---|---|---|---|---|
| | | zero | partial | maximum |
| Level of offshore wind development | High | 1a | 2a | 3a |
| | Low | 1b | 2b | 3b |

The pre-feasibility studies deliver expected snapshots of generation capacity by 2025, 2030, 2035, 2040, and 2045 (with greater uncertainty after 2030/2035). For each time step, a system-wide assessment was conducted for HVAC and HVDC grid components (multi-terminal to onshore connection point) and an inter-OWF component assessment was performed. A list of all components was developed for each case-study scenario and is used as an input for CBA. The list also includes component specifications (e.g. component type, ratings, voltage level, cable lengths).

Because the pre-feasibility studies serve as the main basis for the CBA analysis, it is important to describe their concrete design and outline the different scenarios included in each of the two case studies.

**Case study 1: Sweden – Poland – Lithuania**
The following figure illustrates the general layout and approach used in case study 1 with high offshore wind installation ('CS1-High').



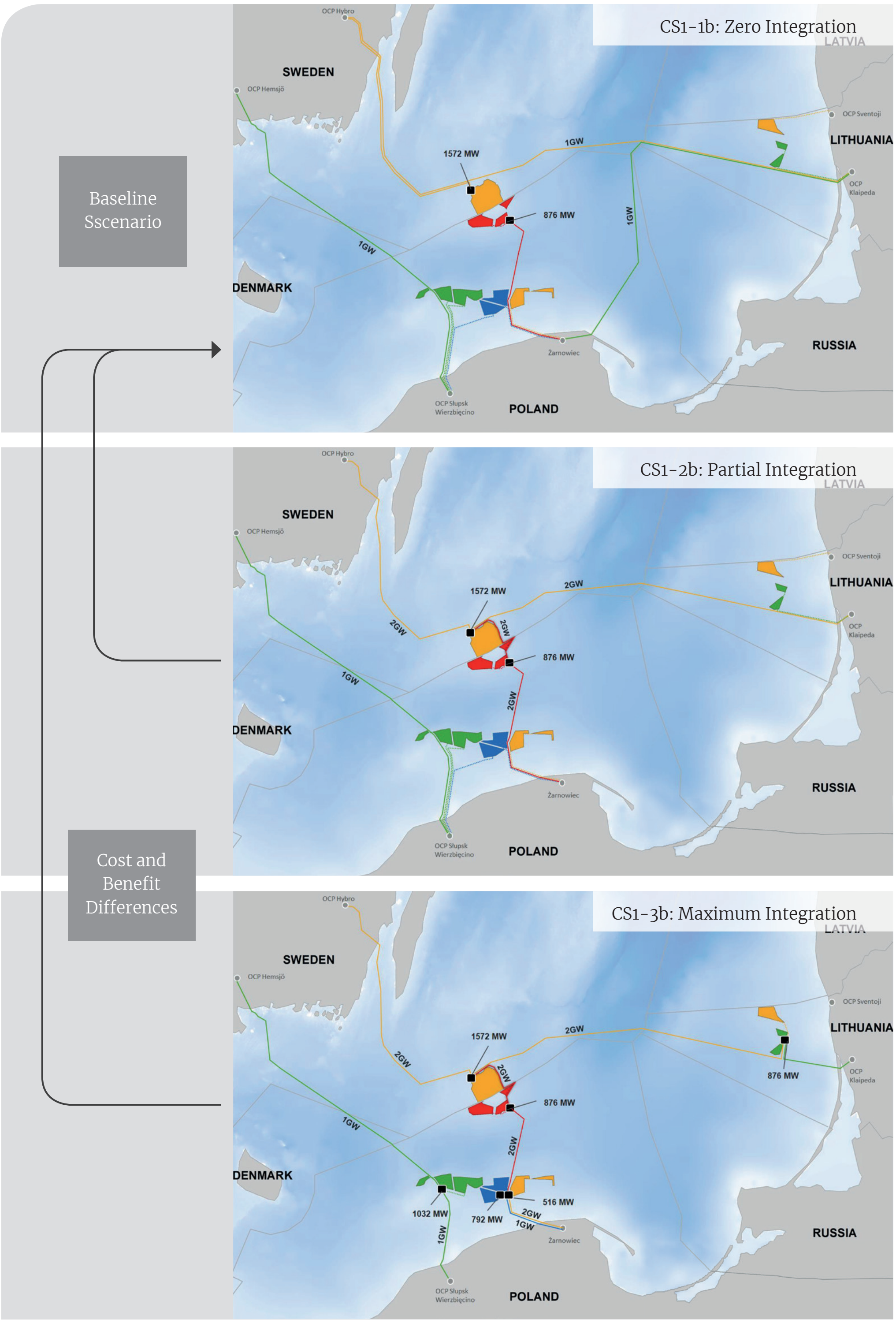

Commissioning year: 2025, 2030, 2035, 2040, 2045

Connection technology: HVDC cables, HVAC cables, Onshore connection point, Converter station

*Figure 4*
*Case study 1 with high offshore wind installation*

The following figure illustrates the general layout and approach used in CS1 with low off-shore wind installation (referred to as ‘CS1-Low’ in the text that follows).

*Figure 5*
*Case study 1 with low offshore wind installation*

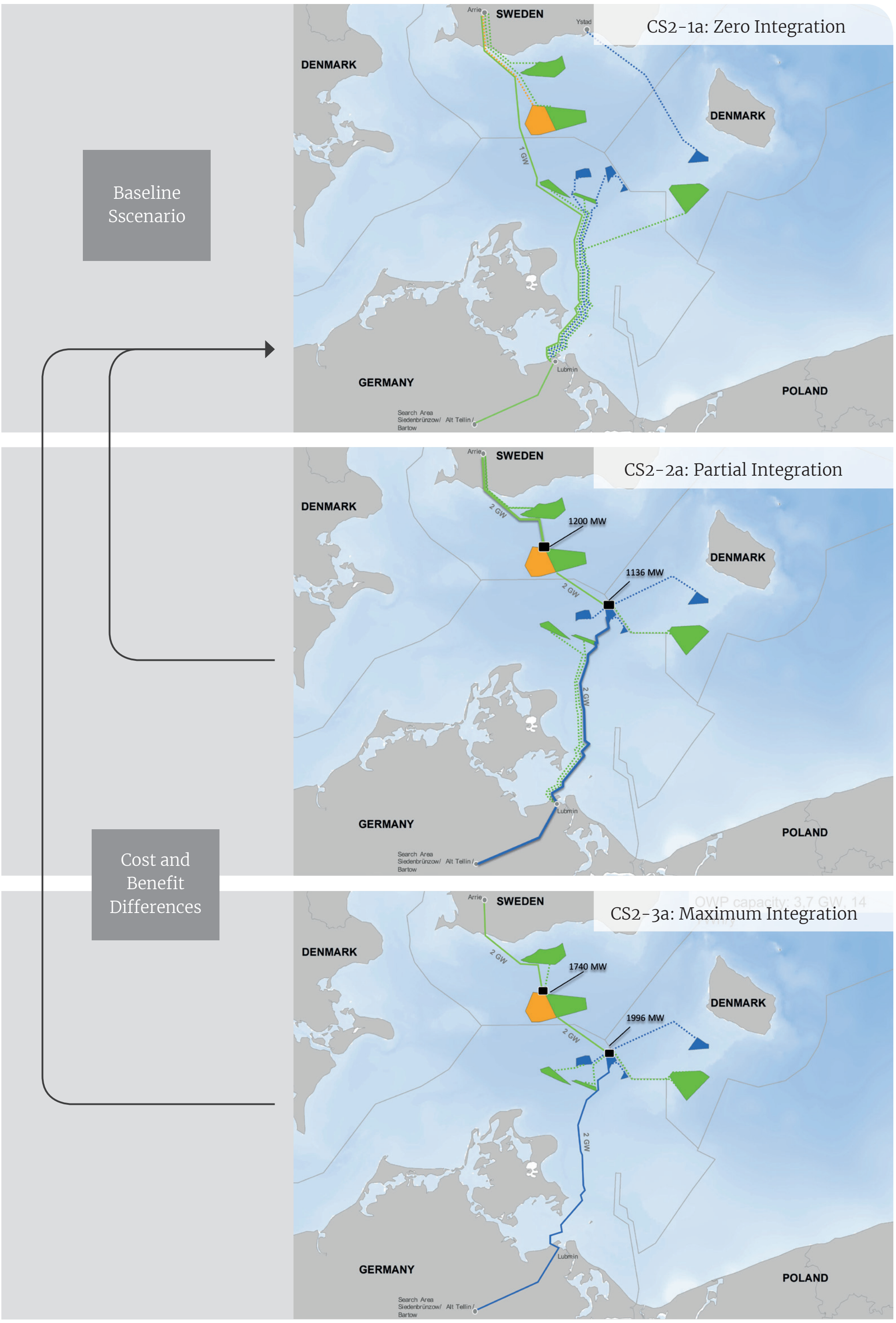



Commissioning year: 2025, 2030, 2035, 2040, 2045

Connection technology: HVDC cables, HVAC cables, Onshore connection point, Converter station

**Case Study 2: Germany – Sweden – Denmark**

The following figure illustrates the general layout and approach for CS2 with high offshore wind installation (‘CS2-High’).



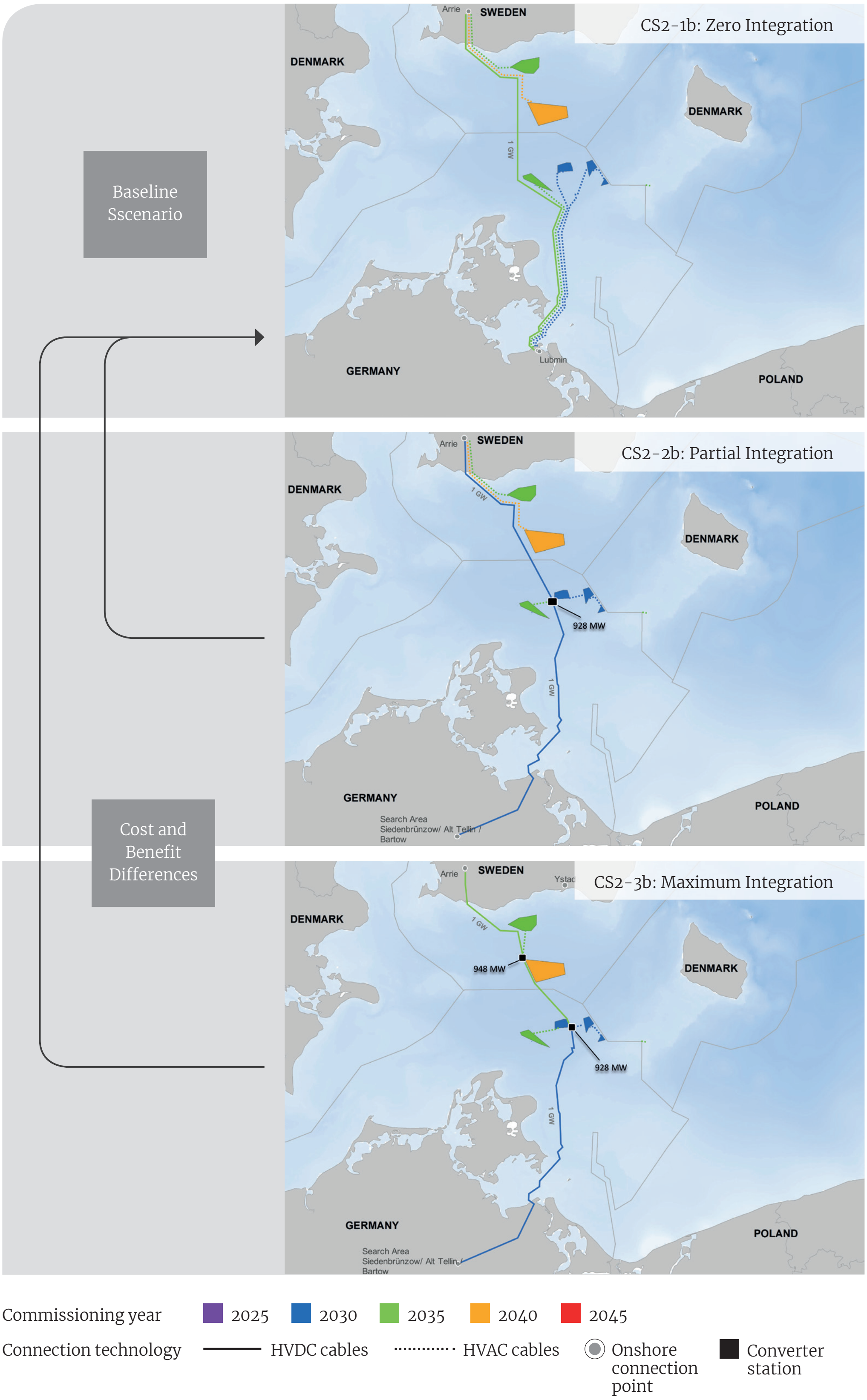

Commissioning year: 2025, 2030, 2035, 2040, 2045

Connection technology: HVDC cables, HVAC cables, Onshore connection point, Converter station

**Figure 6**
*Case study 2 with high offshore wind installation*

The following figure illustrates the general layout and approach used in CS2 with low off-shore wind installation ('CS2-Low').

*Figure 7*
*Case study 2 with low offshore wind installation*



For each of the four combinations of study region and offshore wind installation, the zero-integration variant is set as the baseline scenario. In the CBA, the scenarios that assume the integration of OWFs with interconnectors are compared to the baseline scenario. This makes it possible to compare the relative benefits of partial or maximum integration with those of a non-integrated interconnection design and to identify the optimal level of integration.

# 5. Analysis of Benefits

This chapter analyses the relative benefits of varying levels of integration, primarily using system cost as a monetarised indicator. The sections below describe the market model used, as well as the main input parameters and assumptions. The monetarised and non-monetarised results are presented with regard to potential benefit differences. The analysis of benefits includes the difference in total system costs, which the model shows for different levels of integration. The total system costs includes the costs of generation and investment in generation and transmission capacity in the scenarios, excluding the investment needed for the case-specific infrastructure. The benefit difference for the overall system can therefore be compared between the specific case and the base case; this result can be analysed and later compared to the case-specific cost. A subsidiary result of the model is the case-specific effect on electricity prices in the relevant markets. As non-monetarised results, the case-specific effects on the adequacy rate (indicating security of supply) are analysed, as is the ratio of $CO_2$ emissions reductions in different countries.

## 5.1 Market Model

The dynamic investment and dispatch model dynELMOD is used to determine the benefits of additional integration between OWFs and the interconnections between market areas. The model determines cost-effective investments into generation capacities, storages, and interconnectors for Europe through 2050. The model therefore represents the electricity market as a whole, and the resulting system costs reflect the total costs of providing electricity in Europe under given conditions, such as emissions targets. Under the assumption of an efficient market, the objective of a cost-minimising social planner is equivalent to welfare maximisation. Given that the merit-order market clearing leaves little potential to exert market power and a generally high level of regulation, this assumption is reasonable for the electricity sector. The socio-economic benefits in the model context mostly relate to efficient use of the given resources (e.g. available renewables).

By integrating the generation and investment decision, the model not only dispatches the given infrastructure to cover the electricity demand in a cost-minimising way, but also determines the infrastructure used. This yields the total system costs (including benefits), because each investment or generation decision is taken to minimise system cost. This indicates a cost-efficient infrastructure to provide electricity.

The starting point in the methodology is the current power plant portfolio installed in the European electricity system, which is phased out according to the technical lifetime. Investments in new capacities are made under the restrictions of $CO_2$ emissions pathways and assumptions on investment, emissions, and fuel costs. The modelling approach is intended to integrate this two-step process:

**Investment:** First, the model determines investments in generation capacity, including storage capacities, and interconnectors. It is important to note that the investments specific to certain cases (grid topology for different integration levels) are excluded from this determination, because the data on investment costs are collected in the cost analysis and later compared to the benefit results. To reduce computational complexity, and thus permit the representation of a large geographic region, a reduced set of hours is used in this step of the investment analysis. Instead of using the full 8760 hours, the model only uses certain hours, depending on model complexity. This time-frame reduction technique is described in Gerbaulet and Lorenz (2017).[25] The methodology ensures that the reduced set of hours accounts for the characteristics of seasonal and time-of-day variations in the input parameters.

**Dispatch:** Using this cost-efficient electricity-generation portfolio, the model is solved again with the entire time set of 8,760 hours, with the investment decisions fixed. This ensures the reliability of the power plant portfolio test for system adequacy in all cases. Combining both steps generates the model output.

The objective function of the model represents the total system cost, including costs of generation and investment in generation and transmission capacity. The market-area-sharp market clearing then balances local demand with flows to and from the respective market areas. Generation and transport variables are subject to upper bounds that are defined by the model inputs and endogenous calculated investments in capacity extension or new capacities. There are also constraints on the general behaviour of power plants (e.g. ramping and CHP constraints), storage-specific constraints (e.g. regarding reservoir level and turbine and pump capacities), and the implementation of European emissions targets. The model is written and solved in the General Algebraic Modeling System (GAMS) using the CPLEX solver, and the full formulation is available and documented in Gerbaulet and Lorenz (2017).

## 5.2 Main input parameters and assumptions

As for all large-scale electricity sector models, the data set plays a crucial role in the result and transparency of the model. Therefore, we use open-source data or our own calculations where possible, and the full dataset is part of the publicly available model documented in Gerbaulet and Lorenz (2017). The most important assumptions regarding the data set and future developments are listed below.

- Installed capacity: Apart from the offshore capacities in the scenario data, the data for current installed capacity and future generation capacity are drawn from the scenarios in TYNDP 2016[26] and the Scenario Outlook & Adequacy Forecast 2015.[27]
- Generation technologies: The model distinguishes between 31 renewable and conventional generation technologies, taking into account the technical and economic parameter assumptions described in Schröder et. al (2013).[28]
- Fuel prices: Prices for fuels are taken from the European Commission's Reference Scenario 2016, and projections are based on Schröder et. al (2013).
- Time series: The structure of availability of renewable generation is based on the year 2013. The demand data come from the ENTSO-E transparency platform,[29] and both raw and processed meteorological data are drawn from various sources.
- Grid: For the load flow constraints, a country-sharp power transfer distribution factor (PTDF) matrix for the European high voltage grid is used, representing the physical flows. The underlying high-voltage network topology consists of five non-synchronised high-voltage electricity grids (Continental Europe, Scandinavia, Great Britain, Ireland, and the Baltic countries) with operating voltages 150kV, 220kV, 300kV, and 380kV, respectively. These data are based on the documentation in Egerer et al. (2014).[30]
- CO2 pathway: The CO2 emission pathway is based on the scenario 'Diversified supply technologies' from the European Commission's Energy Roadmap 2050 (2011).[31] It uses the limits allocated to the electricity sector and is based on a 90 % emission reduction by 2050.
- The data specific to the case studies (i.e. the topology and OWF development (low, high) and the level of integration (zero, partial, maximum/high)) were derived in the course of the project and documented in chapter 4.

## 5.3 Monetarised Results

To achieve a meaningful comparison between the different scenario dimensions for each of the two case studies described in chapter 4, the model is run for the zero-integration scenario to determine the investments in generation capacities. The resulting investment decisions are then used in the partial- and high-integration scenarios to determine whether a higher level of integration corresponds to lower overall system costs, meaning a more cost-efficient dispatch or investment in interconnector capacity. While each scenario represents a social optimum, comparing the individual topologies yields the additional social benefit of specific topologies and wind farm developments. The results are classified as monetarised or non-monetarised to account for all aspects of the ENTSO-E CBA methodology. The monetarised results refer to those which are in some way quantified in the objective function of the model and therefore a direct result of the optimisation. Non-monetarised results are not quantified in the optimisation and are an indirect result of the model.

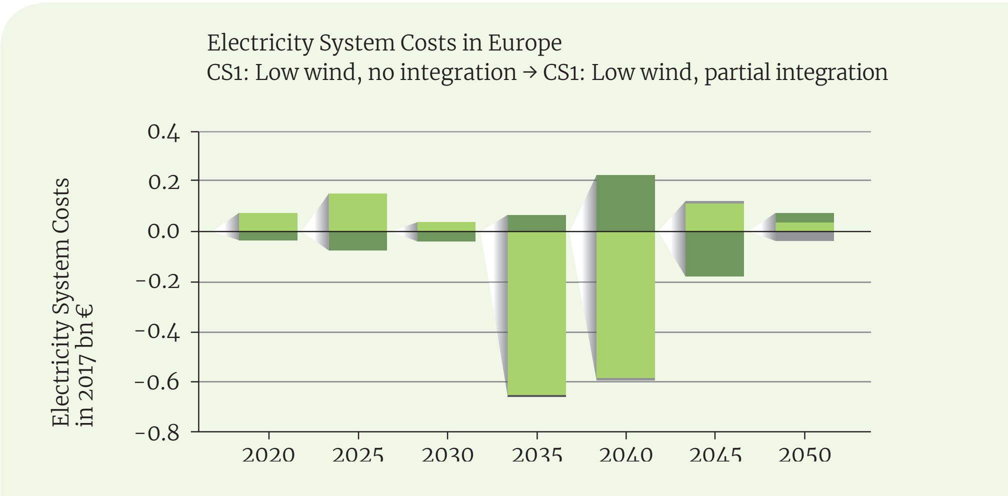
### 5.3.1 Main Results – Total System Cost

The main results are the differences between overall system costs for each scenario. These are shown in Table 4. As stated above, the total system costs reflect the cost-optimal investment and generation decision based on the scenario-specific data. The difference between the zero-integration and higher levels of integration is determined; this result is then used to assess whether variations in topology are associated with different outcomes that have lower total systems costs as a direct result of the specific change in topology and OWF development, therefore directly reflecting additional benefits. The comparison between the base case and a partial- or high-integration case also implies, however, that benefits of the infrastructure available in the base case (e.g. additional interconnector capacities) are not captured. Costs are classified as operation and maintenance costs (O & M); generation costs; and costs of investment in generation, storage, and grid infrastructure. All graphs show that there is no difference in investment in generation infrastructure. This is because the investment decision in the zero-integration base case is also assumed in the two cases with higher levels of integration.

***Table 4***
*Overall system cost differences in 2017 bn €*

| **CS1 (PL, SE, LT)** | | | |
|---|---|---|---|
| High Offshore Wind Power | | Low Offshore Wind Power | |
| Partial Integration | High Integration | Partial Integration | High Integration |
| CS1_2a - CS1_1a | CS1_3a - CS1_1a | CS1_2b - CS1_1b | CS1_3b - CS1_1b |
| 0.06 bn € | 0.09 bn € | 0.92 bn € | 0.99 bn € |
| **CS2 (DE, SE, DK)** | | | |
| High Offshore Wind Power | | Low Offshore Wind Power | |
| Partial Integration | High Integration | Partial Integration | High Integration |
| CS2_2a - CS2_1a | CS2_3a - CS2_1a | CS2_2b - CS2_1b | CS2_3b - CS2_1b |
| 1.83 bn € | 1.76 bn € | -0.03 bn € | -0.01 bn € |

Both case studies show little difference between partial and maximum integration scenarios. There is, however, a cost reduction in the low-wind scenario in case study 1 (CS1); in case study 2 (CS2), the cost difference occurs in the high-wind scenario. In CS2, there is even a small benefit in the low-wind scenario. The figures below show the disaggregated costs, allowing for a comparison of no integration and partial integration. A cumulative negative value indicates that the total system costs are lower in the scenario with partial or high integration. For the cases with significant benefits (i.e. low wind in CS1 and high wind in CS2), reduced investment in interconnectors leads to the overall cost decrease. The increased integration in those cases allows for greater flexibility in transport, which is why a lower interconnector capacity is needed. The scenarios with marginal benefits also show cost differences, although the overall impact is smaller, and the additional costs equalise the reduced costs.



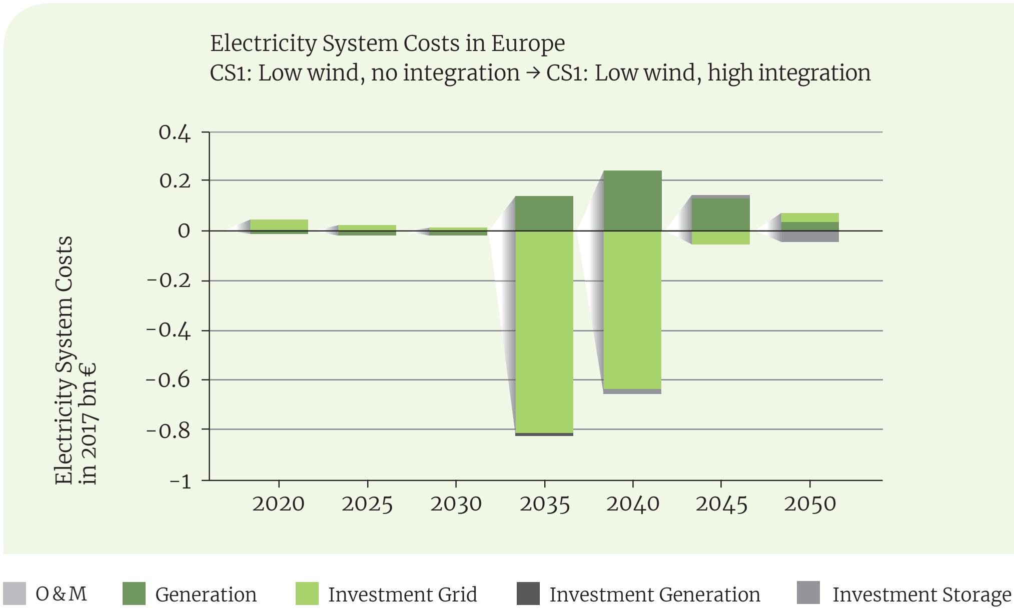
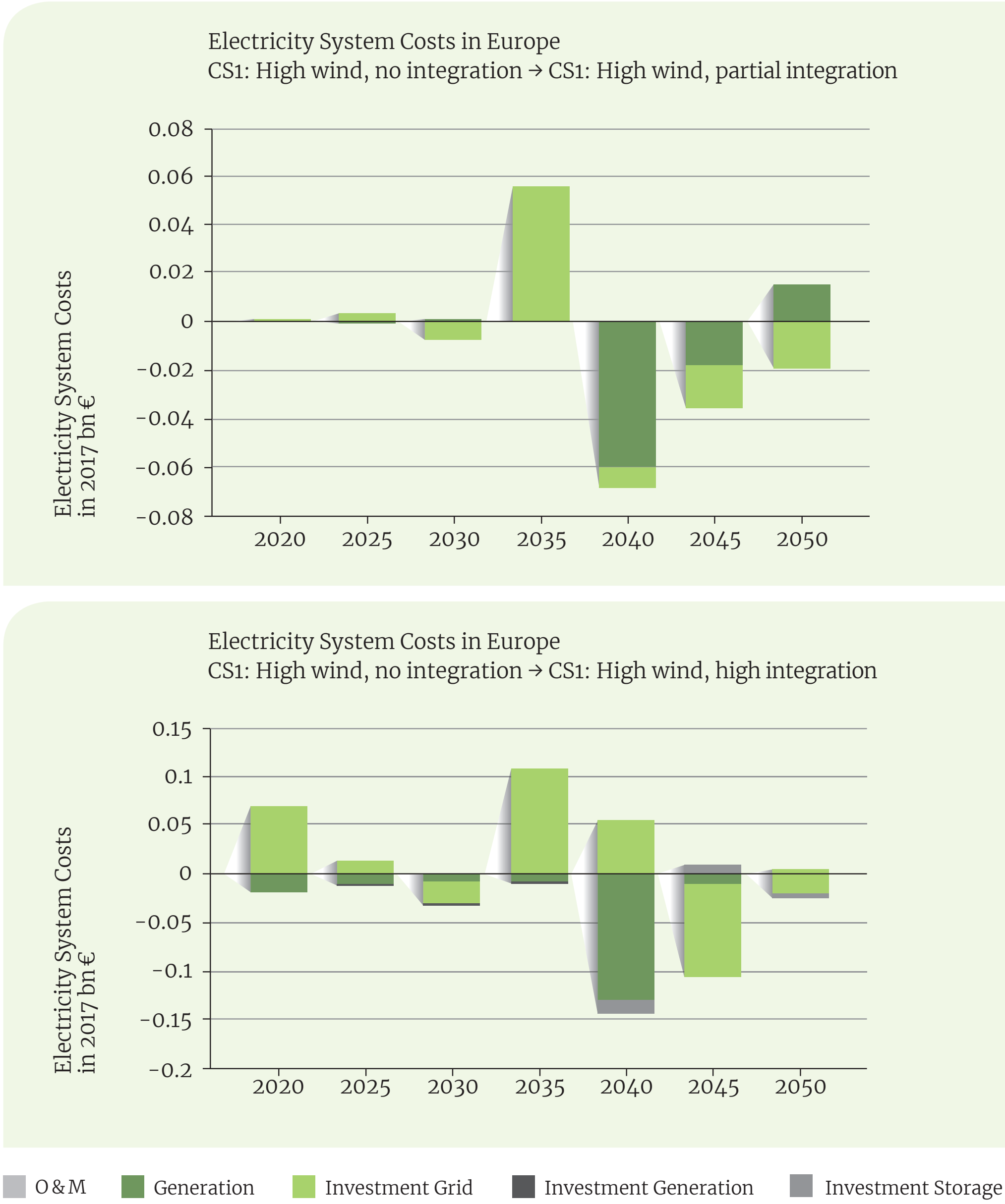




*Figure 8*
*Total system costs: case study 1 – low wind*

In general, CS1 shows a very high similarity between the benefits of partial and high integration. This is true for cost composition, temporal distribution, and absolute values. The significant benefits are in the low-wind scenario, where there is less investment in grid infrastructure than in the zero-integration case. In the high-wind scenario, the absolute values are much lower. The benefits are mainly due to additional generation from the offshore wind capacities in the scenario data. There is also a small difference in grid investment.

*Figure 9*
*Total system costs: case study 1 – high wind*



In CS2, the absolute values in the low- and high-wind scenarios are similar; however, the scenarios differ in terms of composition and temporal appearance. The low-wind case shows a small negative benefit for both levels of integration, but the composition is very different. While the partial integration allows for lower grid investments, the benefit in the high-integration case is dependent on the additional offshore wind capacities available.

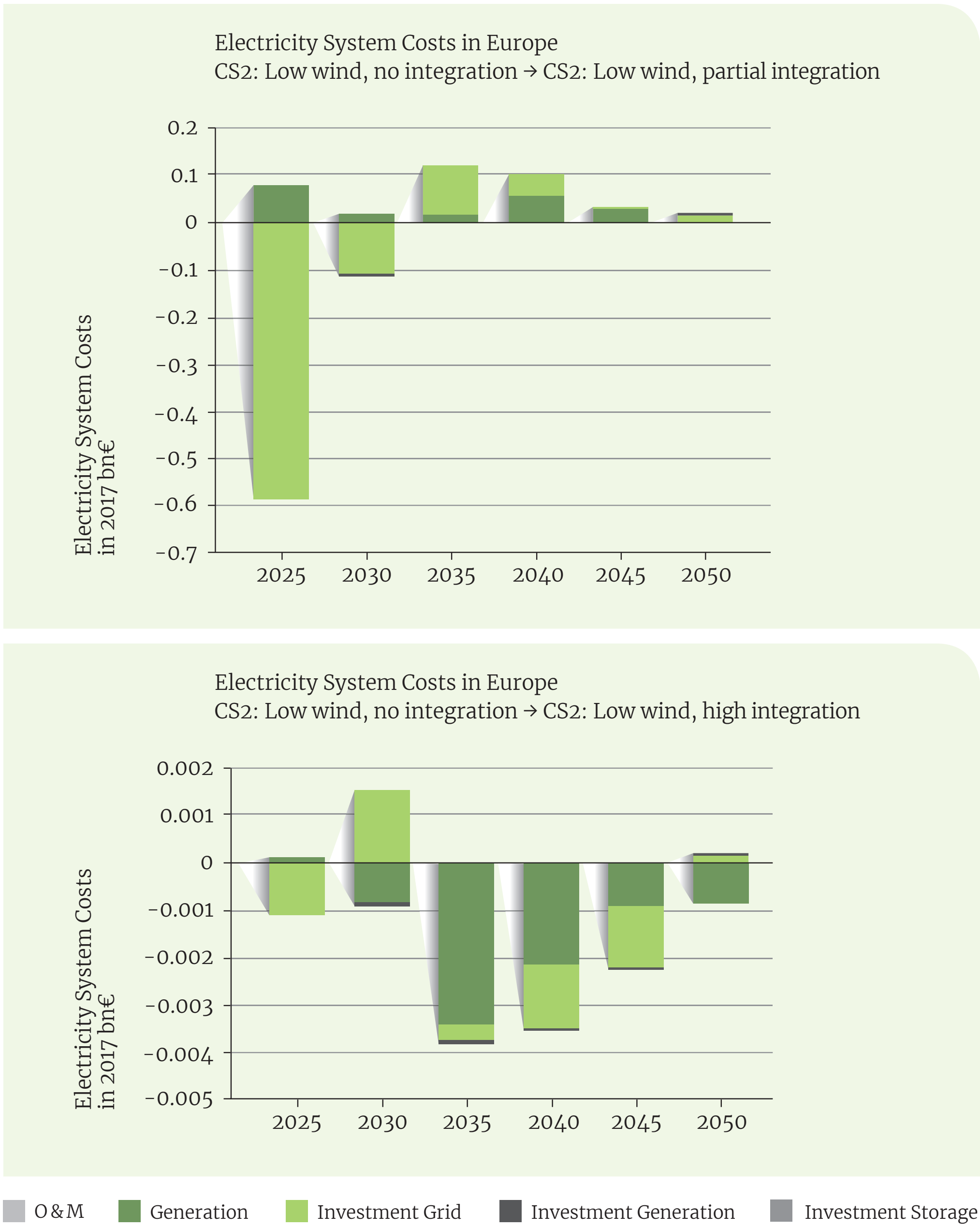
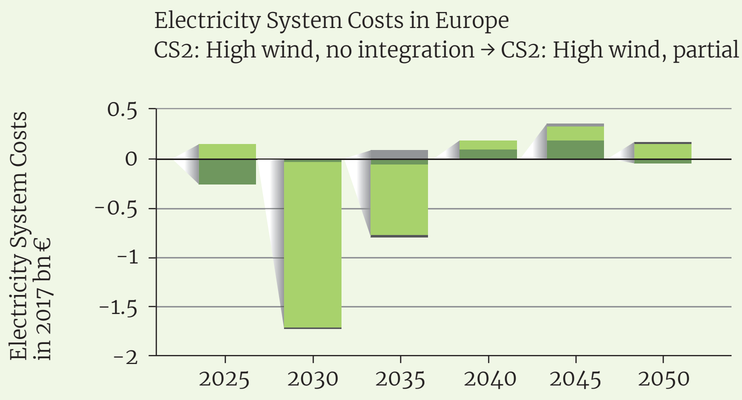
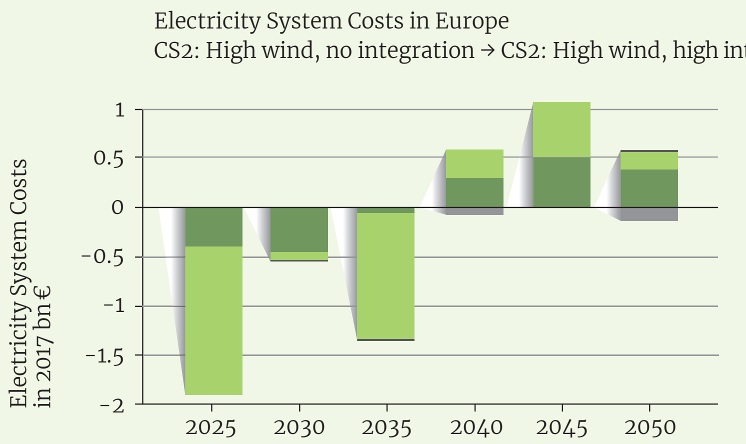



***Figure 10***
*Total system costs: case study 2 – low wind.*

The high-wind scenario shows a significant benefit over the zero-integration base case. The composition here is similar in the sense that most of the benefit is due to lower investment in grid infrastructure, but the absolute values and investment timing are different.

*Figure 11*
*Total system costs: case study 2 – high wind*




### 5.3.2 Electricity Prices

Market-area-sharp electricity prices are an endogenous result of the model. More specifically, the electricity price is defined as the cost of an additional unit of electricity per market area. This means that the price differences directly indicate the available generation capacity from the scenario data in the respective market areas and therefore gives an indication of how expensive electricity is in that area. However, because the modelling objective is to maximise total system costs (including investments in generation and transmission capacities), the prices will converge at the point where the investment in transmission capacities provides no additional cost reduction for the actual electricity dispatch. The resulting price differences between the base and integration scenarios can therefore be interpreted as the impact of the changed topology, which is not decided by the model, and the additional wind capacities, which provide cheap generation.

The resulting graphs therefore indicate regional benefits, depending on the scenario and topology. The first deviation in prices occurs in 2030, when the first projects are developed. The results again illustrate the similarities between the partial- and full integration scenarios. However, they are highly dependent on the chosen scenarios itself. One example is the price development in the 'low wind – partial integration' scenario for Lithuania, where the specific grid topology and wind farm development result in a constellation entirely different from that obtained in the corresponding 'high wind' scenario.

The results for CS1 are shown below.

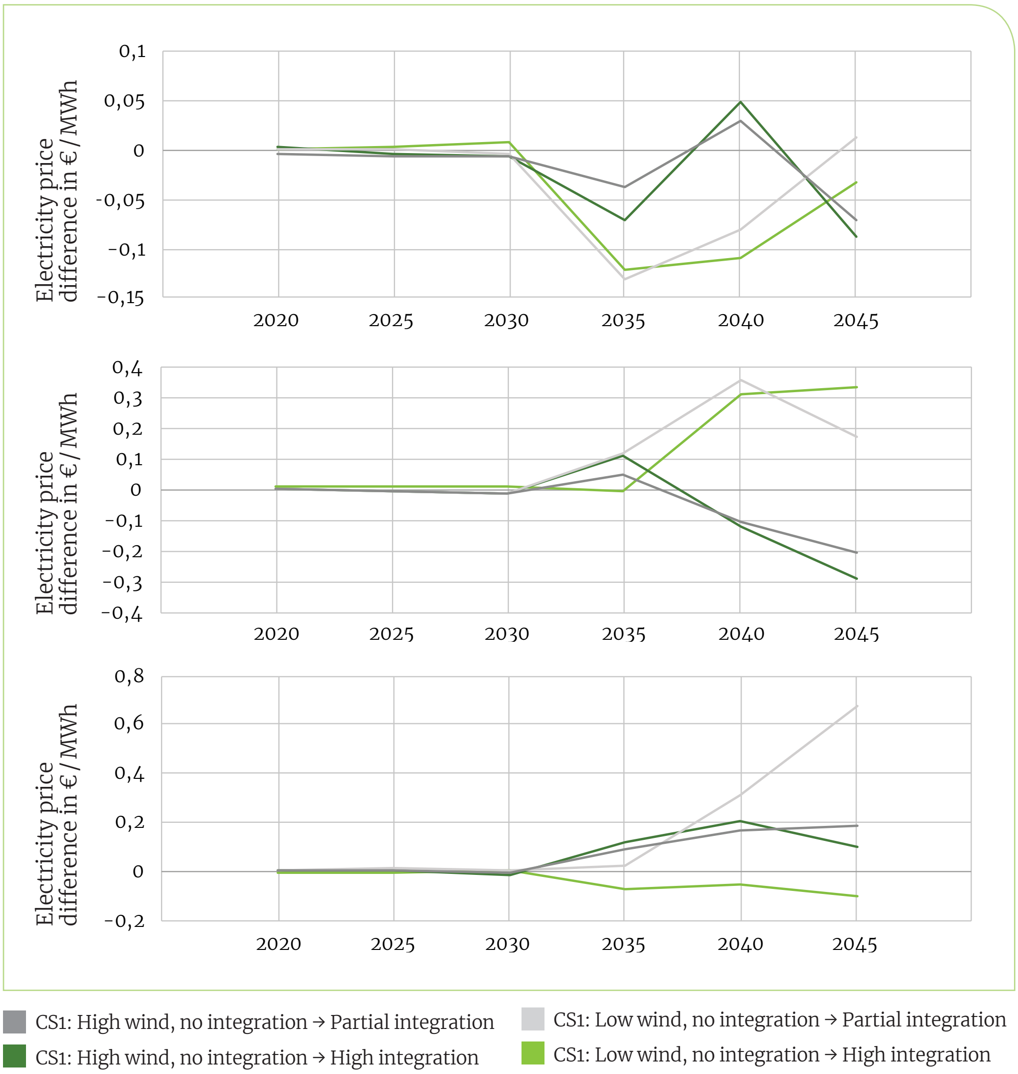



*Figure 12*
*Average electricity price difference for scenario variations. (Top: Poland, Middle: Sweden, Bottom: Lithuania)*

The results for CS2 show less scenario-specific behaviour. As in CS1, the overall impact of the different topologies is small; this is due to the relatively small increase in cheap generation capacities in both scenarios. The distribution of those capacities (and thus the distribution of additional cheap generation) between the relevant market areas appears to depend on the specific topology, rather than on the overall (more abstract) level of integration. Note that the prices in Germany and Denmark are equal in all scenarios, which shows that there is no congestion between those market areas.

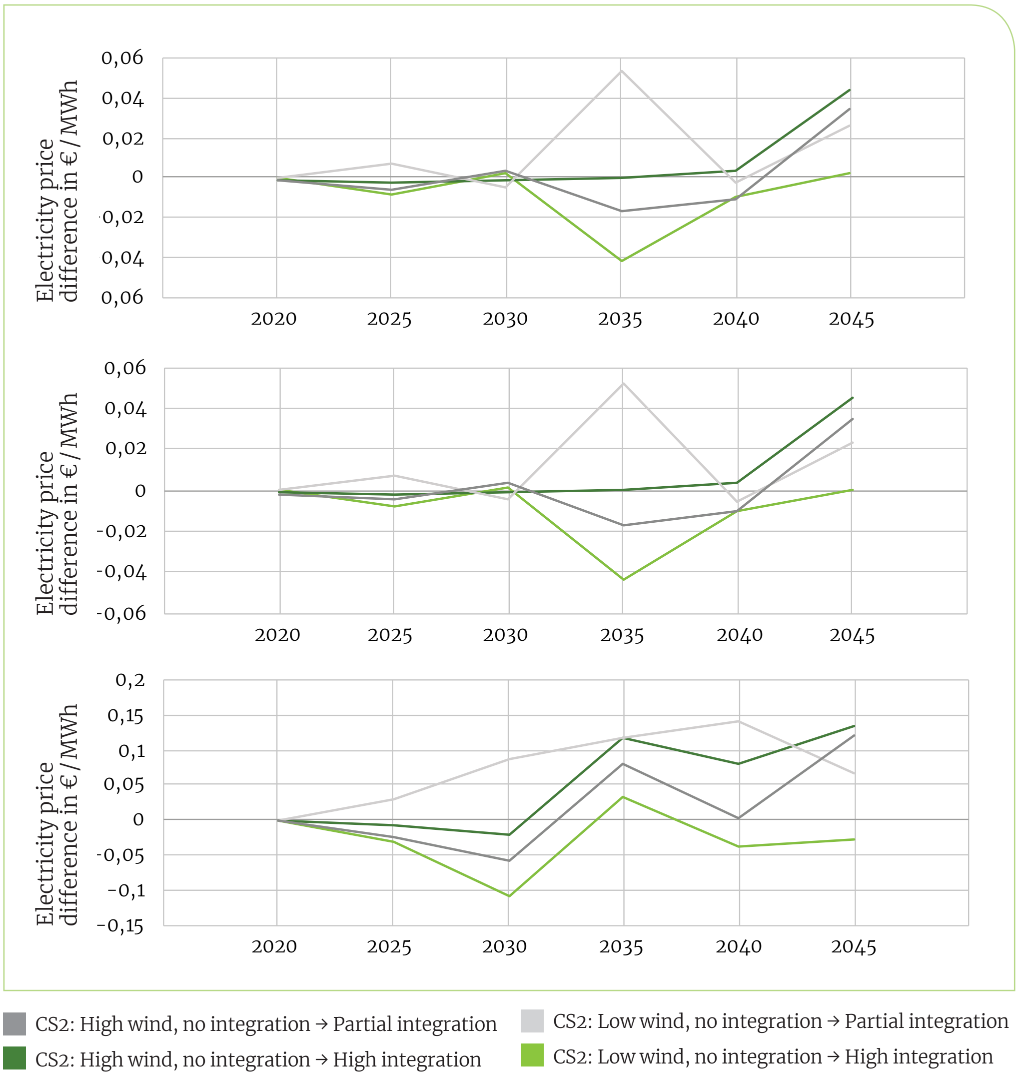



***Figure 13***
*Average electricity price difference for scenario variations. (Top: Germany, Middle: Denmark, Bottom: Sweden)*

Overall price differences are relatively small. This is in line with the model objective to reduce the overall system cost. The distribution of the scenario-specific capacities is reflected in price differences and therefore indicates regional benefits; however, the distribution is dependent on the specific topology rather than on the overall level of integration.

## 5.4 Overview of Non-monetarised Results

Some benefits of higher integration cannot easily be identified and/or quantified. For example, local congestion can be reduced as integration increases, but the model employed here cannot be used to analyse this relationship because it does take local grids into account. For the same reason, the higher security of supply cannot be analysed fully. The adequacy rate is used to provide at least a non-monetary indicator of security of supply in the different scenarios. The availability of cable lines to transmit electricity to the mainland will increase network security and reduce losses in wind farm generation, but this topic could not be evaluated using the model employed in this analysis. The losses in each scenario are also important to consider, but it was decided that, because the case study design included similar network projects with comparable technologies, the losses would not be the limiting criteria to compare. An integrated grid could also lead to a better integration of offshore wind capacities and faster construction. A combination of feed-in and trading will increase the efficiency of infrastructure use, but the resulting benefits will greatly depend on the regulatory requirements for hybrid assets of this kind. Furthermore, although environmental benefits are not analysed in this report, but these benefits could also be an important factor favouring meshed grids if the total cable length is reduced, decreasing the burden on the seabed. Likewise, potential social benefits are not readily quantifiable, but are indicated in the analysis of electricity prices in section 5.3.2.

The following sections provide a basic outline of non- or semi-monetary benefits. The security of supply will be analysed on the basis of case-specific changes in adequacy rate. In addition, the regionalisation of CO2 reduction in the relevant countries will be studied more closely. Although the 2050 overall reduction target of 90% is a predefined input parameter, each country approaches the target at a variable rate, as shown in the model.

### 5.4.1 Adequacy rate in cases of line failure

The benefits to the European electricity market are analysed further by comparing the adequacy of generation capacity per market area. In this analysis, ‘adequacy’ is defined as the available generation capacity per market area at a given time. Investments in capacity are determined for the zero-integration case and fixed for the scenarios with higher integration. These results are useful in assessing the security of supply in all scenarios. The comparison between different levels of integration helps quantify flexibility differences between the scenarios, because flexible infrastructure allows for greater availability.

The analysis is performed by calculating the aggregate available generation capacity in each region and its neighbours. Generation capacities from neighbouring countries are considered only if the respective interconnector capacities are sufficient. The result of this analysis for CS1 in Sweden (‘CS1-Sweden’) is displayed in Figure 14 as a residual load duration curve, which measures how often a certain capacity is available in a given market area. The offshore grid transmission lines are excluded to determine adequacy in the case of a line outage. The outage includes the main interconnectors in the base case, the lines to the central point in the partial-integration scenario, and the lines between wind farms in the high-integration scenario. The resulting adequacy rate is displayed in Figure 15 and the difference in adequacy is shown in Figure 16.

*Figure 14*
*Adequacy rate*
*CS1: Sweden*

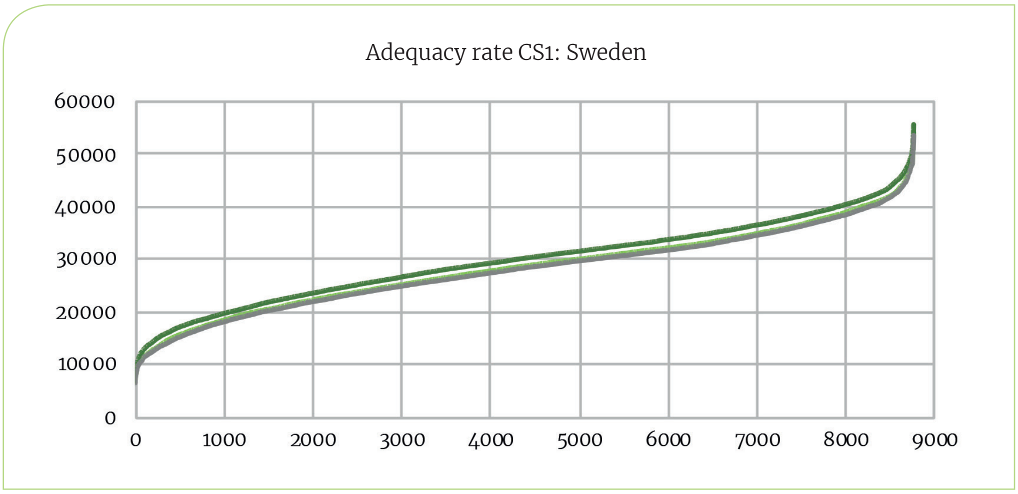



*Figure 15*
*Adequacy rate*
*CS1: Sweden*
*(including outages)*

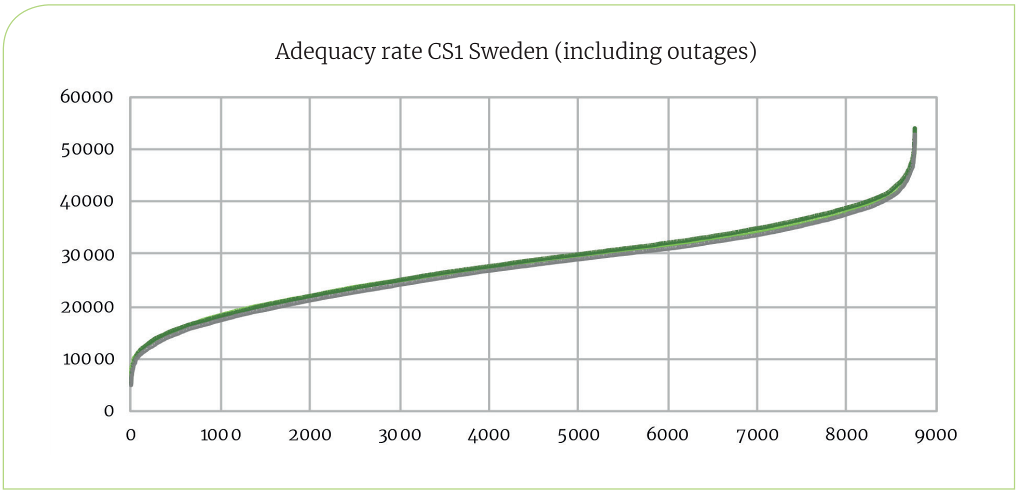
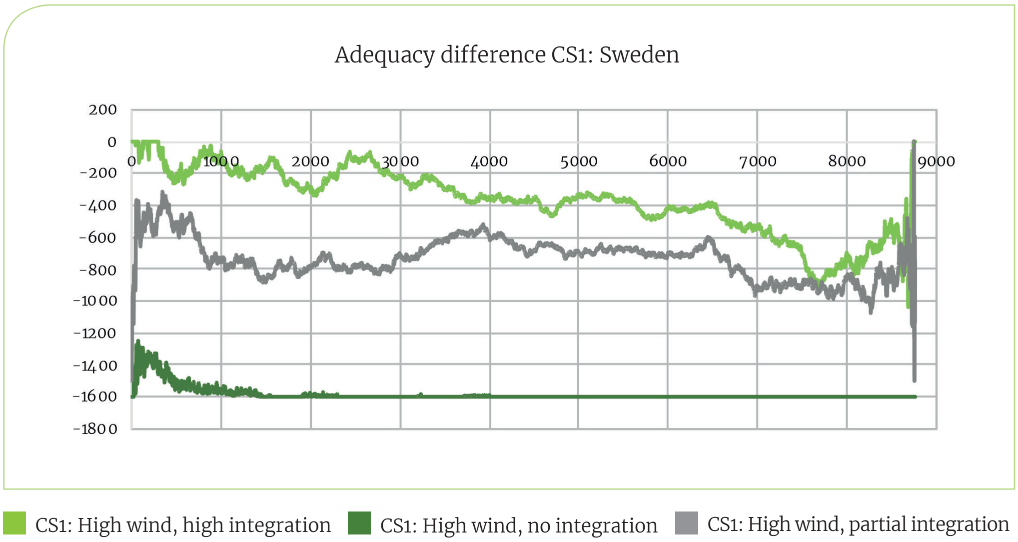



*Figure 16*
*Adequacy difference*
*CS1: Sweden*




The adequacy analysis for Sweden indicates that the adequacy rate is sufficient in all cases. With respect to the additional adequacy when outages occur, the partial- and full-integration scenarios show a smaller loss of adequacy over the full adequacy duration.

Cost-Benefit Analysis

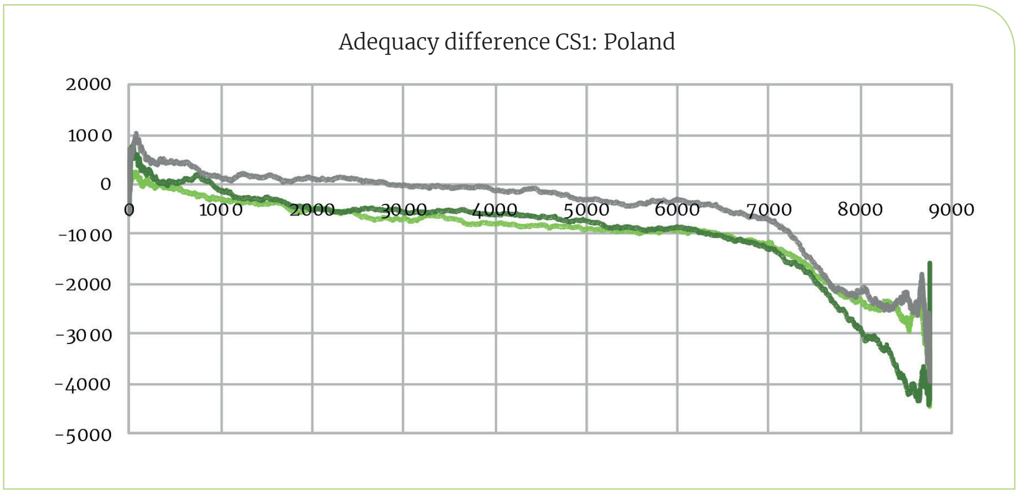



*Figure 17*
*Adequacy difference CS1: Poland*

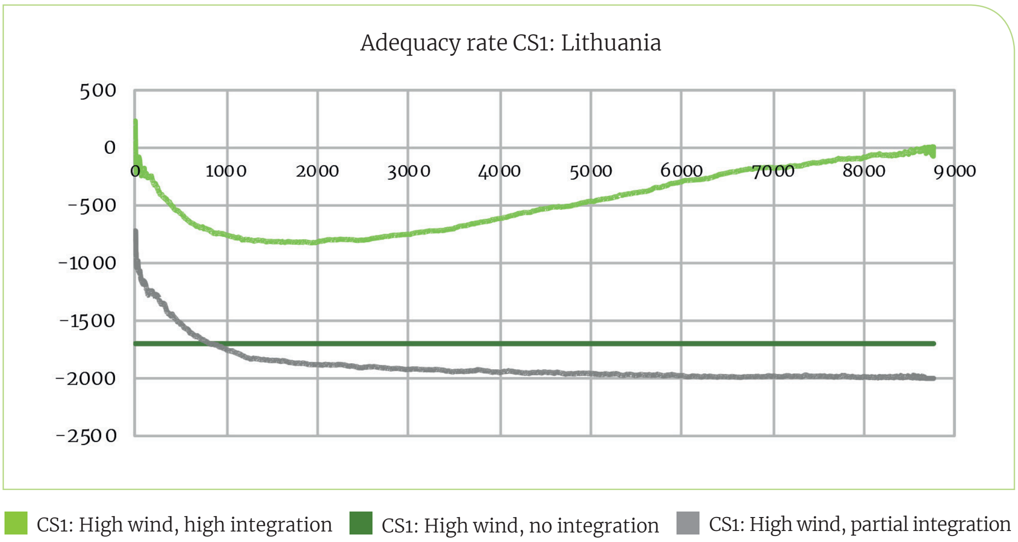



*Figure 18*
*Adequacy difference CS1: Lithuania*

Similar conclusions are drawn for Poland and Lithuania in CS1 and Germany and Sweden in CS2. For Poland, the overall differences in adequacy rate are small, but the adequacy rate proves the most robust in the partial-integration case. This is also is observed for CS2-Germany, where additional integration provides benefits only in hours of high adequacy. For CS1-Lithuania, the full-integration scenario provides the most robust adequacy rate; however, at times with low adequacy, both partial and full integration are similarly robust. The flat negative difference in adequacy in the zero-integration scenario shows that only one interconnection has implications for the adequacy rate. For CS2-Sweden, additional integration increases the overall adequacy rate, though not at all hours.

*Figure 19*
*Adequacy difference CS2: Germany*

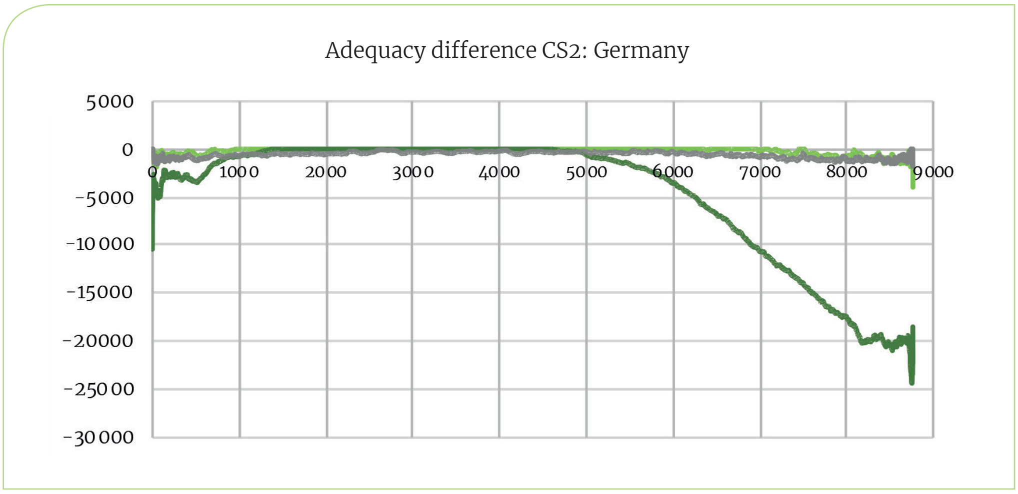
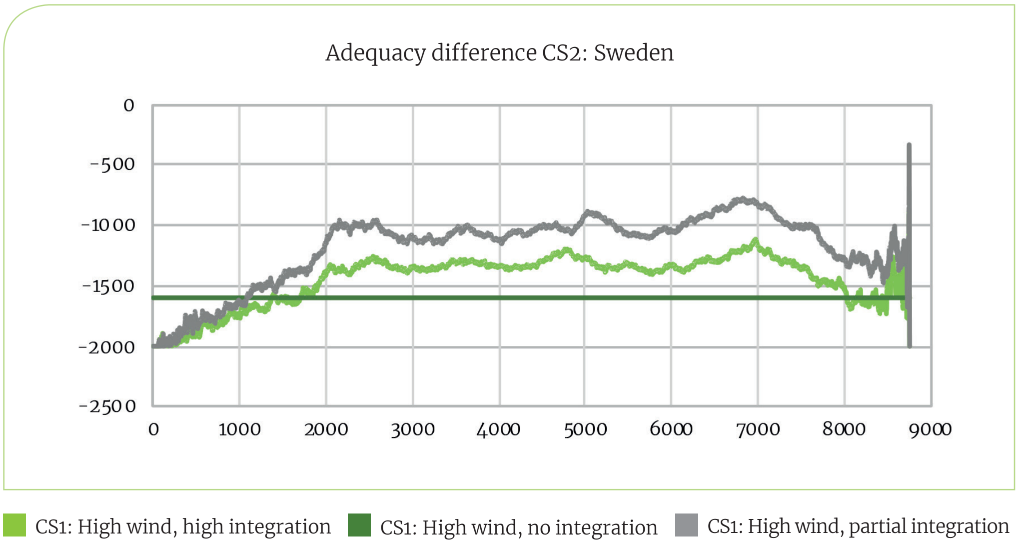



*Figure 20*
*Adequacy difference CS2: Sweden*




Based on the results shown in the figures above, there is sufficient capacity available in all scenarios, but greater integration provides the system with greater flexibility with regard to the adequacy rate.

Cost-Benefit Analysis

### 5.4.2 $CO_2$ Emission

$CO_2$ emissions are included and monetised in the model in different ways: first as an emissions target, and second as additional costs in the marginal costs of conventional generation technologies. While the monetisation of $CO_2$ as a generation cost influences the investment decision, this does not imply compliance with the overall $CO_2$ emissions targets. These are separately implemented as an additional constraint to ensure that the $CO_2$ emission targets are met. Therefore, the resulting $CO_2$ emissions reflect not only monetised aspects, like the generation costs, but also decisions regarding the regionalisation and distribution of $CO_2$ emissions reduction. The $CO_2$ emissions are also separately included to account for regional distribution.

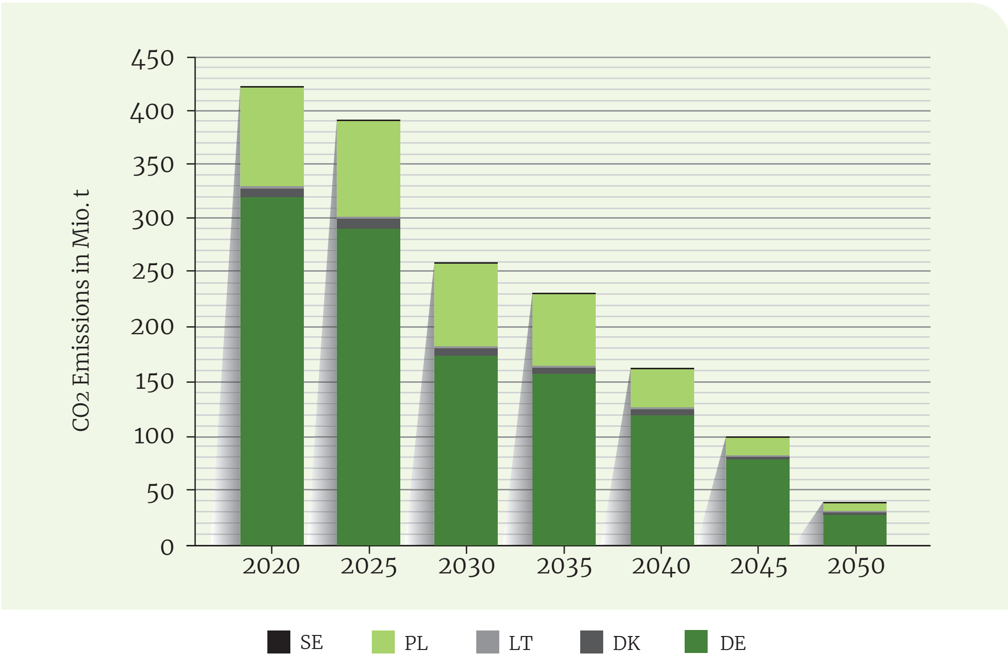



*Figure 21*
*$CO_2$ Emissions in case study 1 with zero integration (in million tonnes)*

The $CO_2$ emissions are a result of the dispatch under the constraint to follow the strict $CO_2$ pathway defined in the model data. The 90% reduction within the electricity sector reduces emissions dramatically in all countries included in the case studies. The resulting emissions distribution varies by only a few percentage points in absolute values and distribution between countries when different scenarios and case studies are compared. This shows the importance of this constraint in decisions on investment and generation. In terms of the distribution of reductions in the market areas of the case studies under analysis here, we can see that all countries reduce emissions by a similar relative margin.

# 6. Cost Analysis

Cost estimations for far-future projects are always subject to high uncertainty, especially if those projects incorporate new technologies (e.g. HVDC components). This uncertainty complicates the development of comprehensible assumptions that can be used to estimate total project costs. For the following analysis, a variety of sources have been reviewed for electricity grid cost assumptions (see chapter 2). The validity of the assumptions should be evaluated through comparison with available cost data from existing projects. For HVDC technology, the scope of this evaluation is limited to the earliest projects, most of which have been implemented in Germany. The cost assumptions applied here are those for which cost predictions were most consistent with available cost references. The cost analysis covers capital expenditures (CAPEX) and operational expenditures (OPEX) for HVAC and HVDC technologies. CAPEX refer to all investments made to commission a transmission asset, while OPEX are all maintenance and servicing costs required to keep the asset in operation. The following sections present the cost model and the derivation of cost assumptions.

## 6.1 Linear Cost Model

A linear cost model (LCM) is used to evaluate costs. The potential integrated grid is described by a defined number of cables and nodes, for which linear cost functions are created to calculate any configuration. This approach has been used in other studies, including in Svendsen (2013)[32] and Härtel et al. (2017).[33] LCM was chosen because it provides a reasonable approximation of the real costs, limits the input data required, reduces complexity,[34] and uses average values to reduce uncertainty. The LCM assumes cost parameters for cables and nodes. Cable costs cover costs of materials and construction. Portions of the cable cost scale with cable length, while other portions scale with the length and the rated capacity of the cable. These effects are represented by individual cost parameters. Fixed costs are also taken into account. Node costs are the total costs for converters or transformers, including construction and the platform cost for offshore nodes. Node costs are represented by power-dependent and fixed-cost parameters. The LCM can thus be applied for any electrical transmission infrastructure layout. The model presented by Härtel et al. is expanded to include OPEX, depreciation, and cost trends.

### 6.1.1 Investment Cost Assumptions

Studies investigate grid costs for different purposes, as profound cost data is crucial for grid investment planning. Those analyses have been used for political decision-making and as a reference point for industry players and academics. However, the cost parameter sets used in the different studies have varied widely and indicate a high level of uncertainty. Therefore it was decided that it would not to be expedient to develop an additional data set. The comparison and evaluation of existing data were based on a recent review of Härtel et al. In this analysis, cost assumptions for voltage source converter-based HVDC (VSC-HVDC) transmission infrastructure were collected and converted to a common format that allows for a comparison of the different parameter sets. The analysis shows significant variation between the 13 parameter sets under analysis. The parameter sets were also evaluated against cost data for realised and contracted HVDC projects.

This comparison revealed large differences between the parameter sets. The authors conclude that costs of interconnectors are overestimated, while costs of offshore wind connections are greatly underestimated. The recent review covers the current status of publicly available cost information for HVDC components in a common format. The HVDC cost assumptions adopted in this analysis are based on that result. The methodology used here is based on the LCM and develops it further for application to concrete cases and other technology components. For HVDC transmission infrastructure, the average parameter set used is based on three studies that could be identified as the most suitable because of the consistency of cost prediction with realised costs for OWF connections: ENTSO-E 2011,[35] ETYS 2013,[36] and North Sea Grid 2015.[37] Although interconnectors do not require DC circuit breakers, they are necessary for meshed HVDC offshore grids to guarantee network reliability. Because this is a completely new technology, cost assumptions for DC circuit breakers are highly uncertain. In the absence of other available cost information, cost assumptions are adopted from the North Sea Grid project. Average parameters for AC technology were retrieved from the primary publications of the same three sources used for the HVDC components. They were then adapted to fit the LCM through linear interpolation. The following Table 5 summarises the average cost parameter assumptions.

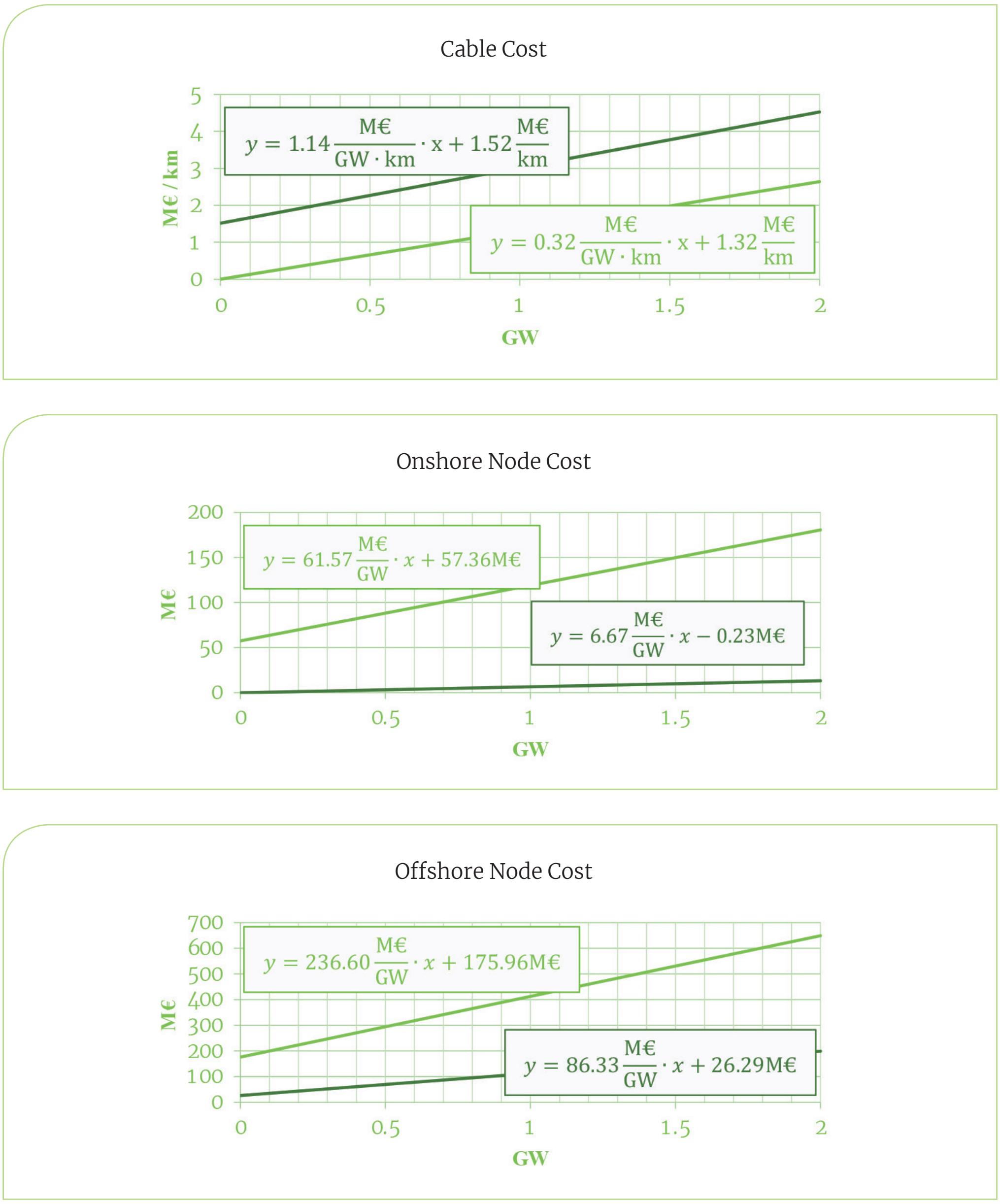
| Description | Unit | HVDC | HVAC |
|---|---|---|---|
| Length- and power-dependent cost of building a cable | M€/GW/km | 0.32 | 1.14 |
| Length-dependent cost of building a cable | M€/km | 1.32 | 1.52 |
| Fixed cost of building a cable | M€ | 0.00 | 0.00 |
| Power-dependent cost of building a node | M€/GW | 61.57* | 6.67 |
| Fixed cost of building a node | M€ | 57.36 | -0.23 |
| Power-dependent additional cost of building an offshore node | M€/GW | 175.03 | 79.66 |
| Fixed additional cost of building an offshore node | M€ | 118.60 | 26.52 |

***Table 5***
*Cost parameter assumptions for CAPEX*

**For DC breakers add 85.71*

Figure 22 shows the cost functions for cables and nodes. The costs of a given cable depend on the technology (HVAC or HVDC), the cable length, and its rated capacity. Node costs also depend on the technology, as well as on the node location (onshore or offshore) and the rated capacity. Cable costs are higher for HVAC infrastructure, while node costs are higher for HVDC infrastructure. For this reason, HVDC transmission systems become more attractive once a certain transmission distance is reached.

*Figure 22*
*Cost functions*




Operational expenditures are based on data from the North Sea Grid project. In the LCM, annual operational expenditures are considered a fixed share of the total capital expenditures. This complies with the ENTSO-E guidelines on operational cost assumptions for long-term projects.

***Table 6***
*Cost parameter assumptions for OPEX*

| Description | Unit | HVDC | HVAC |
|---|---|---|---|
| Annual cost of operating a branch | Share of CAPEX | 2.5 % | 2.5 % |
| Annual cost of operating an onshore node | Share of CAPEX | 1.5 % | 0.7 % |
| Annual cost of operating an offshore node | Share of CAPEX | 2.0 % | 2.0 % |

### 6.1.2 Cost Development Assumptions

Infrastructure investments are usually distributed over decades. For the case studies presented in chapter 0, investments are provided in five-year intervals. Due to learning and scaling effects, transmission infrastructure costs are expected to decline as the technology becomes more mature. Therefore, assumptions must be made for cost development trends.

Because the development status is very different for HVAC and HVDC technologies, these must be considered individually. HVAC technologies have been used in the European electricity grid for decades. Nevertheless, some design optimisation and related cost decreases can be expected for offshore wind application. (Some HVAC innovations still occur; for example, the new HVAC grid access solution from Siemens uses two smaller and significantly lighter transformer modules instead of one large platform.)[38]

HVDC technology has long been used for interconnectors, but not for offshore grid connections. The first HVDC connections for OWFs were used in Germany in 2010, when BorWin 1 began operations. Since then, a total of seven HVDC hub connections have been built in German waters. The investment costs have varied significantly between the different HVDC projects. In early projects, the costs were underestimated, which led to significant cost increases during the planning and construction phases. Later, the contract volumes increased, presumably to more realistic values, and there were slight cost decreases for the most recent projects. However, the costs also depend on the market situation, with high time constraints in the beginning (the German grid operator Tennet is obligated to connect the wind farms and had to base its grid connection projects on the individual wind farm planning status) and limited competition (only three suppliers of HVDC platforms and two cable suppliers). Costs can be expected to fall again significantly as competition and experience increase.

It is difficult to define cost development assumptions through 2050, because longer-term cost projections are associated with greater uncertainty. Therefore, assumptions for different time horizons have been made. Based on the literature, a moderate cost reduction can be assumed for HVAC[39] grid connections of wind farms (see Table 7). A larger cost-reduction potential is observed for HVDC technology because of its low maturity level, as explained above. Cost reductions may result from technical improvements, such as higher voltage levels or regulatory improvements (e.g. with respect to tendering conditions and a streamlined awarding process). Another important cost reduction factor may be an increase in competition due to new market players. This assumption is supported by a market analysis[40] conducted in the scope of the Baltic InteGrid project and by studies in Fichtner (2016)[41]. IEA and IRENA also anticipate significant cost reductions for HVDC technologies. Therefore, this CBA assumes the following annual cost reductions.

| Description | HVDC | HVAC |
|---|---|---|
| Annual cost reduction | 2.50% until 2020<br>2.50% from 2021 to 2030<br>1.00% from 2031 to 2040<br>0.50% from 2041 to 2050 | 1.00% until 2020<br>0.75% from 2021 to 2030<br>0.50% from 2031 to 2040<br>0.50% from 2041 to 2050 |

*Table 7*
*Cost reduction assumptions*

The cost development assumptions are applied in the cost analysis. The assumed values (based on the LCM) are calculated using the year of installation projected in the case studies.

### 6.1.3 Risk Analysis of Cost Assumptions

For a better interpretation of total cost results, a Monte Carlo analysis was conducted to assess the total cost range considering uncertainties. In a Monte Carlo analysis, calculations are performed using hundreds of combinations of cost data assumptions, and defined confidence intervals are created to interpret the expected value. The Monte Carlo analysis was conducted with 100,000 runs. Triangular distributions were assumed for all relevant input parameters. The following Table 8 summarises these parameters in a normalised format.

***Table 8*** *Probability distribution assumptions*

| Parameter Group | P5 | Mode | P95 |
|---|---|---|---|
| HVDC Cables | 0.80 | 1 | 1.20 |
| HVDC Nodes | 0.80 | 1 | 1.35 |
| HVDC Offshore* | 0.90 | 1 | 1.80 |
| HVAC Cables | 0.90 | 1 | 1.10 |
| HVAC Nodes | 0.90 | 1 | 1.10 |
| HVAC Offshore* | 0.90 | 1 | 1.20 |
| Cost Trends | 0.50 | 1 | 1.50 |
| OPEX | 0.80 | 1 | 1.20 |

**Additional cost for offshore nodes*

The input parameters for the Monte Carlo analysis were derived from a comparison of the cost assumptions using available data from recently realised projects. If possible deviations from the average value were high (e.g. parameter HVDC offshore), this was reflected in the assumptions for the Monte Carlo analysis.

## 6.2 Cost Results

The results of the cost calculation for the CBA are presented below. The calculated costs are shown for the different levels of integration in each case study.

### 6.2.1 Total Cost

The LCM can be used to calculate the total costs in each scenario. It is important to note, however, that both cost data assumptions and cost trends are subject to high uncertainty. Therefore, the average results are supplemented by a Monte Carlo analysis. In Figure 23, the expected total costs for the various scenarios are shown, along with selected results of the Monte Carlo analysis. For each scenario, the 50 % confidence interval and the 90 % confidence interval are identified. A direct comparison of case studies and wind farm developments makes two relationships clear: investments are higher for CS1 than for CS2 and higher for high wind development than for low wind development. Both effects result from an increased number of infrastructure components.

Cost-Benefit Analysis

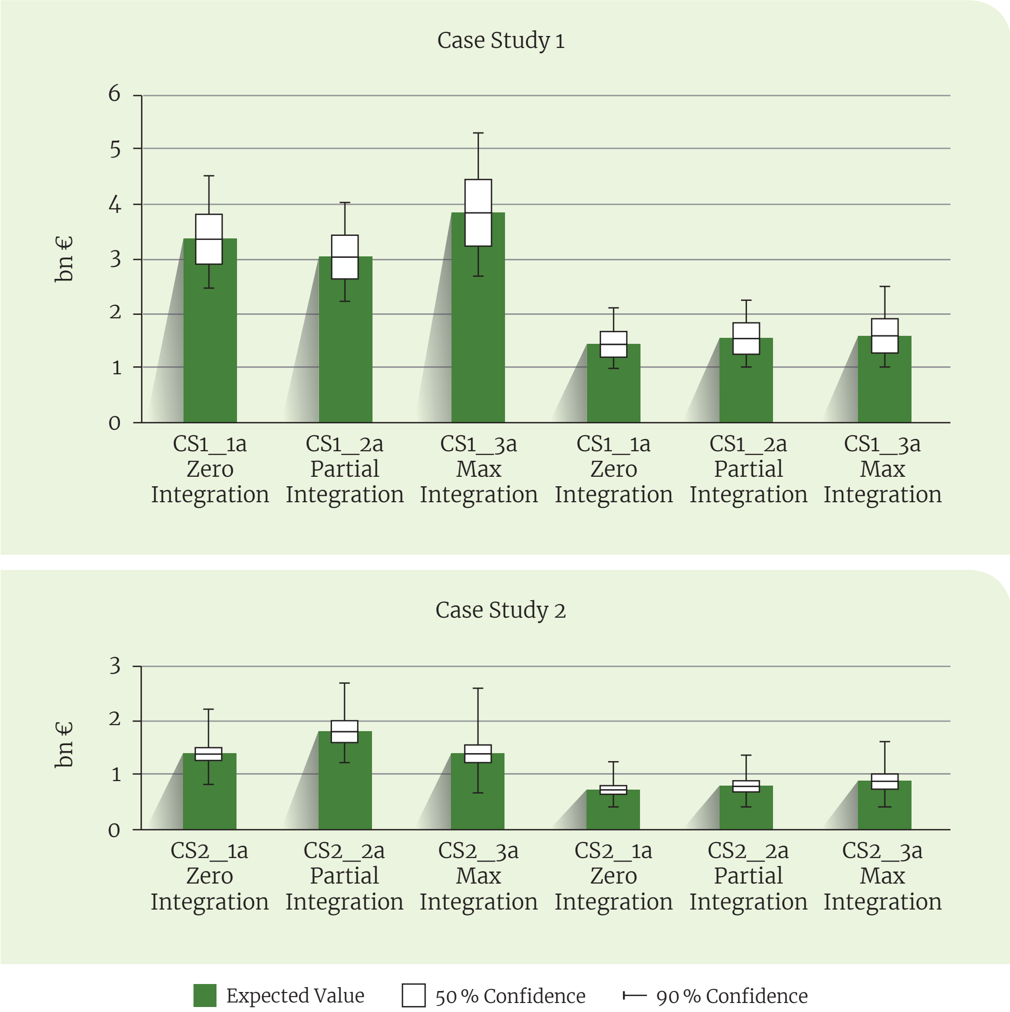



***Figure 23***
*Expected total costs for the various scenarios, including results of Monte Carlo analysis*

The confidence intervals, though fairly wide, are reasonable for such long-term projections. Total cost uncertainty primarily results from uncertainties in the assumptions for cost trends and component costs, as described in section 6.1. Because all scenarios refer to similar infrastructure projects, the types of cost components are the same. It is very unlikely that a change in cost data or trends would affect the overall result for different integration levels, because the ranking of alternative integration levels would stay the same.

### 6.2.2 Cost Structure

An additional output of the cost analysis is the discounted cost structure of each previously defined scenario. The disaggregated costs are presented below for the various HVAC and HVDC components and the four combinations of case studies and wind development assumptions. Cost component groups include CAPEX and OPEX. The cost structures identify the most relevant cost component groups. As explained in chapter 3, three different levels of integration are compared in each of the case studies. The following figures show the cost structures for each scenario.

Cost-Benefit Analysis

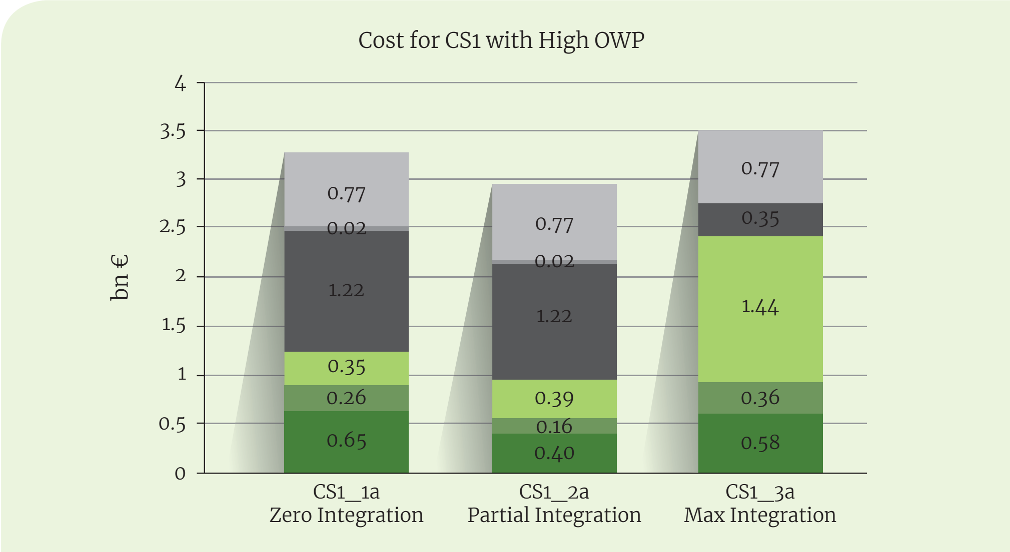



*Figure 24*
*Cost structures for case study 1 with high offshore wind power*

In CS1 with high offshore wind power ('CS1-High'), the lowest total costs occur in the partial-integration scenario (see Figure 24). This is due to a significant reduction in HVDC cable costs and HVDC onshore node costs because of a more efficient grid layout. These cost reductions more than offset the cost increase from the HVDC offshore nodes used for OWF integration. In the maximum-integration scenario, HVAC grid infrastructure is largely replaced with HVDC lines, which decreases costs for HVAC but significantly increases those for HVDC, especially for additional offshore nodes that include DC breakers. These two modifications result in an overall cost increase.

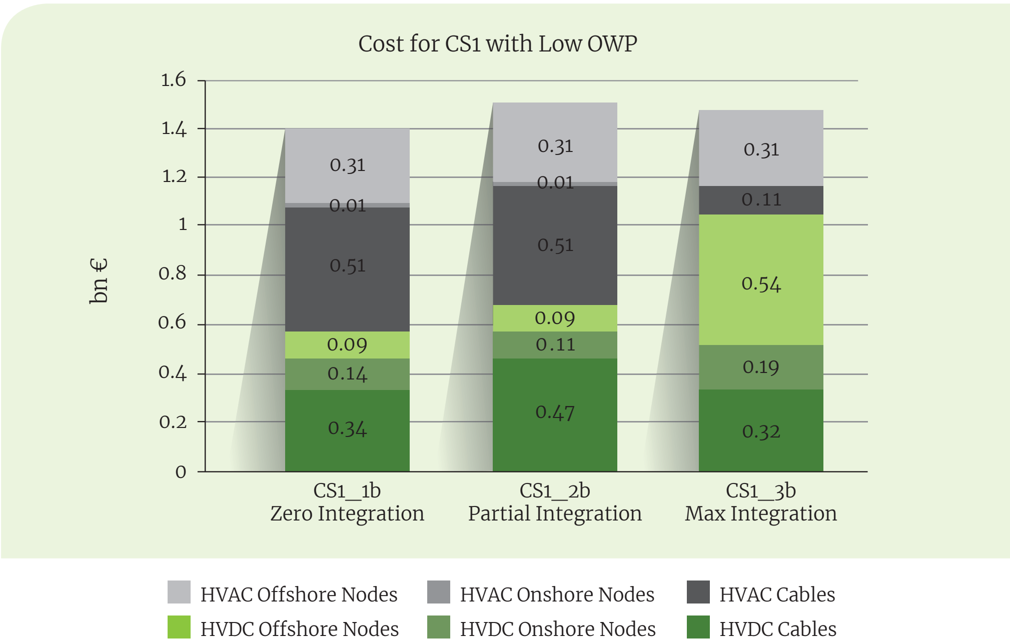



*Figure 25*
*Cost structures for case study 1 and with low offshore wind power*

In CS1-Low (Figure 25), total costs for the different degrees of integration are comparable. The lowest costs are associated with the zero-integration scenario. The cost increase in the maximum-integration scenario is only 7 %, although it is characterised by an entirely different cost structure that is dominated by the costs of HVDC offshore nodes.

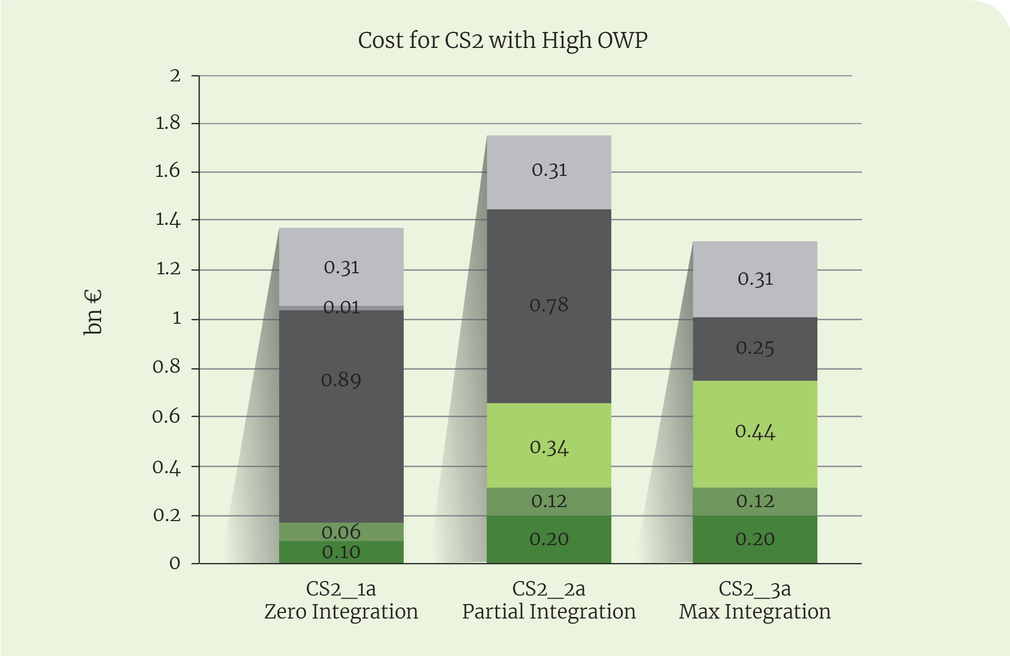



*Figure 26*
*Cost structures for case study 2 with high offshore wind power*

The baseline scenario for CS2-High is characterised by high HVAC costs, largely due to the cost of cables. In the partial integration scenario, the overall cost increases significantly: due to the addition of HVDC offshore nodes, the increase in HVDC costs more than offsets the reduction in HVAC cable costs. In the maximum-integration scenario, HVAC cable costs can be reduced dramatically due to efficient wind farm clustering. This results in a total cost decrease that makes maximum integration the least costly scenario.

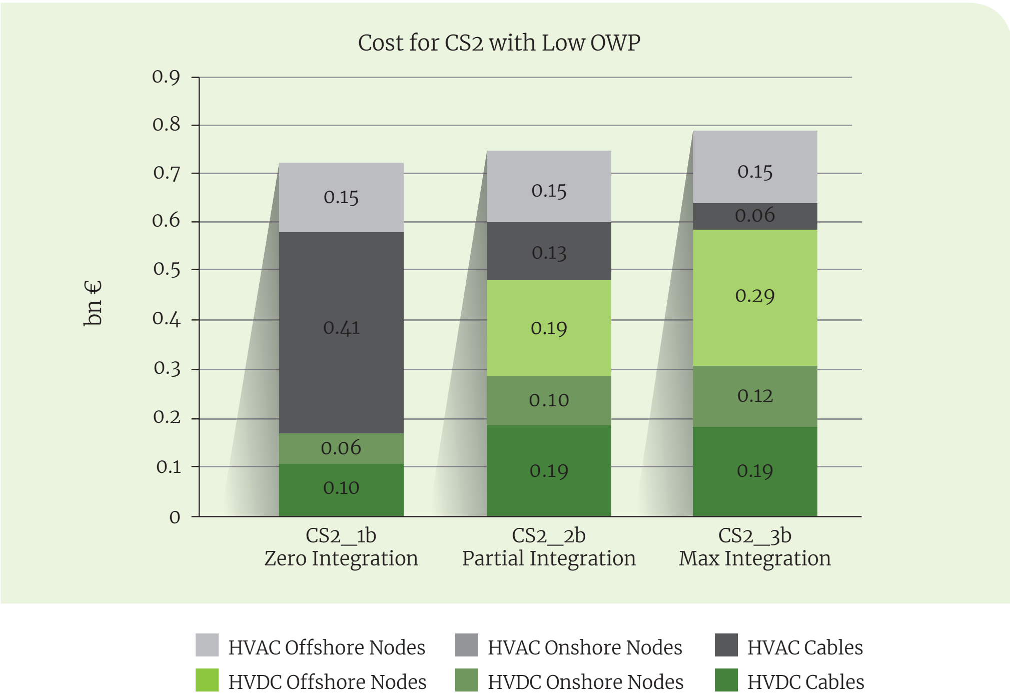



*Figure 27*
*Cost structures in case study 2 with low offshore wind power*

In CS2, total cost differences are minimal for the different levels of integration. Because OWF integration requires high-cost HVDC offshore nodes, the replacement of HVAC infrastructure with HVDC technology results in a moderate cost increase in both the partial-integration case and the maximum-integration case. Here, the zero-integration case is the least expensive.

### 6.2.3 Sensitivity Analysis

As noted above, the cost assumptions made here are subject to uncertainty, particularly with regard to HVDC technology like circuit breakers. Varying the assumptions may change the cost results and thus favour a different level of integration. A sensitivity analysis was performed to evaluate the robustness of the cost analysis and assess the most relevant cost drivers. Each of the disaggregated cost components varied in the range of 50 % to +50 %, with the other factors held constant.* The output was monitored for the most favourable (i.e. cheapest) scenario. In addition, outputs were used to determine which component-cost changes most significantly influence the results.

** For cables and nodes, fixed and variable parameters are grouped and changed collectively*

***Table 9***
*Sensitivity Analysis*

| | CS1 (LT, PO, SE) | | CS2 (DE, SE) | |
|---|---|---|---|---|
| | **High OWP** | **Low OWP** | **High OWP** | **Low OWP** |
| Base Case | Partial | Zero | Maximum | Zero |
| HVDC Cables +50% | Partial | Zero | Maximum | Zero |
| HVDC Cables +30% | Partial | Zero | Maximum | Zero |
| HVDC Cables +10% | Partial | Zero | Maximum | Zero |
| HVDC Cables -10% | Partial | Zero | Maximum | Zero |
| HVDC Cables -30% | Partial | Zero | Maximum | Zero |
| HVDC Cables -50% | Partial | Zero | Maximum | Partial |
| HVDC Nodes +50% | Partial | Zero | Zero | Zero |
| HVDC Nodes +30% | Partial | Zero | Zero | Zero |
| HVDC Nodes +10% | Partial | Zero | Maximum | Zero |
| HVDC Nodes -10% | Partial | Zero | Maximum | Zero |
| HVDC Nodes -30% | Partial | Zero | Maximum | Partial |
| HVDC Nodes -50% | Partial | Maximum | Maximum | Partial |
| HVDC Offshore*+50% | Partial | Zero | Zero | Zero |
| HVDC Offshore* +30% | Partial | Zero | Zero | Zero |
| HVDC Offshore* +10% | Partial | Zero | Maximum | Zero |
| HVDC Offshore* -10% | Partial | Zero | Maximum | Zero |
| HVDC Offshore* -30% | Partial | Maximum | Maximum | Partial |
| HVDC Offshore* -50% | Partial | Maximum | Maximum | Partial |

| | | | | |
|---|---|---|---|---|
| HVAC Cables +50% | Partial | Maximum | Maximum | Partial |
| HVAC Cables +30% | Partial | Maximum | Maximum | Partial |
| HVAC Cables +10% | Partial | Zero | Maximum | Partial |
| HVAC Cables -10% | Partial | Zero | Zero | Zero |
| HVAC Cables -30% | Partial | Zero | Zero | Zero |
| HVAC Cables -50% | Partial | Zero | Zero | Zero |
| HVAC Nodes +50% | Partial | Zero | Maximum | Zero |
| HVAC Nodes +30% | Partial | Zero | Maximum | Zero |
| HVAC Nodes +10% | Partial | Zero | Maximum | Zero |
| HVAC Nodes -10% | Partial | Zero | Maximum | Zero |
| HVAC Nodes -30% | Partial | Zero | Maximum | Zero |
| HVAC Nodes -50% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* +50% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* +30% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* +10% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* -10% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* -30% | Partial | Zero | Maximum | Zero |
| HVAC Offshore* -50% | Partial | Zero | Maximum | Zero |
| OPEX +50% | Partial | Zero | Maximum | Zero |
| OPEX +30% | Partial | Zero | Maximum | Zero |
| OPEX +10% | Partial | Zero | Maximum | Zero |
| OPEX -10% | Partial | Zero | Maximum | Zero |
| OPEX -30% | Partial | Zero | Maximum | Zero |
| OPEX -50% | Partial | Zero | Maximum | Zero |

**Additional cost of offshore nodes*

# 7. Weighing Net Present Value of Costs and Benefits

CBA was performed to evaluate the socio-economic effects of electricity-grid variants. The (differences in) costs and benefits are provided as net present values and can now be balanced against each other to assess the relative benefits of increased integration. The costs are subtracted from the benefits; a positive value indicates that the given level of integration is more favourable than the base case. The following Table 10 summarises the output of the two models.

*Table 10* Results for Case Study 1

| CS1 (PL, SE, LT) | | | |
|---|---|---|---|
| High Offshore Wind Power | | Low Offshore Wind Power | |
| Partial Integration | Max Integration | Partial Integration | Max Integration |
| CS1_2a – CS1_1a | CS1_3a – CS1_1a | CS1_2b – CS1_1b | CS1_3b – CS1_1b |
| Benefit (higher is better) | | | |
| 0.06 bn € | 0.09 bn € | 0.92 bn € | 0.99 bn € |
| Cost (lower is better) | | | |
| -0.30 bn € | 0.24 bn € | 0.11 bn € | 0.08 bn € |
| Benefit - Cost (higher is better) | | | |
| 0.36 bn € | -0.15 bn € | 0.81 bn € | 0.91 bn € |

For CS1-High, the partial-integration case is the most favourable, with lower costs and greater benefits relative to the baseline scenario. A higher level of integration produces greater benefits but higher costs. Therefore, the maximum-integration case is the least favourable here. This conclusion changes in the case of low offshore wind capacity. For increased integration, an increase in benefits offsets the additional costs. In this case, the maximum-integration scenario is the most favourable.

*Table 11* Results for Case Study 2

| CS2 (DE, SE, DK) | | | |
|---|---|---|---|
| High Offshore Wind Power | | Low Offshore Wind Power | |
| Partial Integration | Max Integration | Partial Integration | Max Integration |
| CS2 2a – CS2 1a | CS2 3a – CS2 1a | CS2 2b – CS2 1b | CS2 3b – CS2 1b |
| Benefit (higher is better) | | | |
| 1.83 bn€ | 1.76 bn€ | -0.03 bn€ | -0.01 bn€ |
| Cost (lower is better) | | | |
| 0.38 bn€ | -0.05 bn€ | 0.03 bn€ | 0.07 bn€ |
| Benefit - Cost (higher is better) | | | |
| 1.45 bn€ | 1.81 bn€ | -0.06 bn€ | -0.08 bn€ |

In CS2-High, there is a significant benefit increase in the partial-integration scenario. The increase is slightly lower in the maximum-integration scenario due to the greater use of interconnectors for offshore wind power. Still, the maximum-integration case is the most favourable because it has the lowest total costs. In the low offshore wind case, no extra benefit or cost reduction was observed for wind farm integration. Here, the zero integration scenario is preferable. The following Table 12 identifies the integration level that was found to be the most economical in each scenario.

| | **Case Study 1 (SE / PO / LT)** | **Case Study 2 (DE / SE / DK)** |
|---|---|---|
| **High OWP** | Partial Integration | Maximum Integration |
| **Low OWP** | Maximum Integration | Zero Integration |

***Table 12***
*Most favourable integration levels*

The overall result shows no distinct trend as the level of integration increases. This is because the total exchange capacity between neighbouring countries was held constant in the scenario. A higher degree of wind farm integration appears to make more sense in scenarios with high offshore wind capacity. An additional benefit that is not fully monetarised, such as the security of supply, could also make a higher level of integration more favourable.

# 8. Conclusions

In an effort to reduce the greenhouse gas emissions from electricity generation, most of the European countries in the North Sea and Baltic Sea Regions have set national targets for greater offshore wind power capacity. Increasing the share of renewable energies is expected to cause greater power fluctuations. In response, international electricity grid interconnections have been implemented or are in planning stages. These prospective developments raise questions about the technical feasibility and socio-economic desirability of integrating wind farms into interconnecting grid infrastructure. Various international research projects, many of which are EU-supported, seek to address different aspects of this question.

This report has focused on the BSR. Specifically, two representative study cases have been analysed with respect to their potential costs and benefits. For each case study, three scenarios with different levels of wind farm integration were considered, with the zero integration case serving as baseline scenario. The interconnecting capacity was held constant for the different levels of integration. Two different development paths for wind farm installations were assumed. While all benefits reflected a social welfare optimum, the different topologies and assumptions regarding OWF development allowed for different investment pathways.

**The CBA conducted here produced five central conclusions:**

1. No general trend can be identified as the level of integration increases. This is due to the specific characteristics of the different scenarios. For future infrastructure projects, potential wind farm integration should be evaluated carefully and on a case-by-case basis.
2. A significant socio-economic benefit can be expected for the interconnection of market areas. This interconnection is already part of the zero-integration case. Differences in the benefits are relatively low for the different levels of wind farm integration. The analysis shows that the market benefits of additional integration are, at the very least, small or close to neutral. This includes the benefits that come from the increased rate of adequacy, especially in cases of low overall adequacy. Depending on the scenario, there may be significant benefits to additional integration. In this analysis, only the additional benefits of a higher level of integration are captured; benefits from investments in the base case are not represented, although they may be significant. Individual infrastructure projects should therefore be evaluated in greater detail.
3. Cost differences between the three levels of integration are more significant. In each case, the CBA identifies the least expensive scenario as the most favourable. The cost structure varies significantly between zero-integration and maximum-integration scenarios. The results indicate that replacing HVAC infrastructure with HVDC technology in a meshed configuration could be economically advantageous, but the level of integration must be examined carefully. Although cost assumptions are highly uncertain due to the long-term horizon and especially for HVDC technology, this finding is rather robust to cost variations.
4. A higher degree of integration appears to make more sense for scenarios with high offshore wind capacity, because in such cases the high share of fixed costs can be distributed among many projects.
5. A higher level of integration is associated with further non-monetarised benefits. For example, the security of supply can be increased in many cases because of better market coupling and additional feed-in options for OWFs.

The benefits of enhanced market coupling could be realised in many scenarios, including in the baseline scenario with no OWF integration. Integration could yield additional benefits, especially assuming high offshore wind capacities. The integrated design should aim to reduce infrastructure cost, as such costs strongly affect the overall assessment. Methods to include non-monetary benefits in the CBA should be further developed.

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