European Commission

STUDY ON BALTIC OFFSHORE WIND ENERGY COOPERATION UNDER BEMIP

Final Report

ENER/C1/2018-456
June 2019

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Luxembourg: Publications Office of the European Union, 2019

ISBN: 978-92-76-09690-0
Doi: 10.2833/864823
Catalogue number: MJ-04-19-544-EN-N

EUROPEAN COMMISSION

DIRECTORATE C
Renewables, Research and Innovation, Energy Efficiency

European Commission
B-1049 Brussels

JUNE 2019
EUROPEAN COMMISSION DG ENERGY

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FINAL REPORT

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APPENDICES

1 Abstract

The potential for offshore wind power in the Baltic Sea is substantial. The competitiveness of offshore wind generation varies markedly across the Baltic Sea area, mainly due to wind conditions, connection costs and market values. Especially the southern part of the Baltic Sea shows attractive sites due to higher market values for offshore wind power generation. Thus, there is a scope for better utilization of the most attractive sites for offshore wind power through a cooperative, regional approach.

The market and grid modelling show that offshore wind power in the best sites can be competitive already in 2030, and that offshore wind power can play a significant role in the transition of the Baltic Sea Energy system in accordance with the EU long-term decarbonisation strategy under the UN IPCC Paris Agreement. Cooperation on offshore wind power projects as cross-border renewable energy (RES) projects can realise substantial economic benefits through the achievement of renewable energy targets at lower cost. Additional benefits can be realised by integrating the cooperation on offshore wind power in regional grid planning. Substantial investments in onshore grids are expected to become necessary regardless of the development of the offshore wind power resources. By taking offshore wind power deployment into account early on in grid planning, substantial efficiency gains can be obtained. The development of advanced offshore hubs, connecting wind power to two or more Member States, could also be beneficial, and this option should be explored.

Efficient regional deployment of Baltic Sea wind power resources requires that national administrative and regulatory barriers such as inefficient and non-transparent licencing procedures and the lack of or poor data for maritime spatial planning, are addressed. In addition, regional cooperative solutions on tendering and support mechanisms, on grid connection charges and cost sharing mechanisms, and on integrated regional grid planning, are important pre-requisites for harnessing the offshore wind power potential of the region.

In order to achieve efficiency gains through coordination, a common long-term vision has to be agreed that can be used to identify crucial investments in generation and grid infrastructure, along with appropriate measures and incentives to realise them.

2 Extended Executive Summary

Identification of potential offshore wind The Baltic Energy Market Interconnection Plan (BEMIP) Renewable Energy Working Group is considering the creation of an initiative to support the development of offshore wind power in the Baltic Sea. This report provides the results of a study conducted to inform the creation of this initiative.

The mains aim of the study are to gather information on the potential for offshore wind power in the Baltic Sea Area (BSA), the opportunities for and obstacles to its development, and the possible benefits from and obstacles to regional cooperation and coordination of offshore wind power, as well as to propose a roadmap for the implementation of a coordinated offshore wind strategy for the region.

The study consists of four main parts:

1. Identification of potential offshore wind power sites;
2. Modelling to examine the impacts of different levels of both offshore wind power deployment and regional cooperation on the power and transmission system;
3. Identification of administrative and regulatory barriers to the efficient deployment of offshore wind power in the region;
4. Initial recommendations on how an initiative might seek to address the barriers, provided in the form of a roadmap and action plan.

2.1 power sites

2.1.1 Mapping of offshore wind power potentials …

The study starts with a mapping of the offshore wind power potential in the Baltic sea, accounting for wind conditions, water depth, icing conditions, and spatial and environmental planning constraints.

The potential far exceeds conceivable deployment to 2050. The cumulative capacity of the sites identified exceeds 93 GW and, based on modelling of the relevant wind conditions, these sites could generate 325 TWh/year. To put this in context, final electricity consumption across all BEMIP member states was around 913 TWh/year in 2016, the latest year for which Eurostat data is available.

2.1.2 … and creation of an offshore wind power supply curve for the Baltic Sea

To create a supply curve for offshore wind to be used in the modelling, we assume the placement of 500 MW-offshore wind farms in the identified viable locations in the Baltic Sea. For each site, we estimate the levelised cost of energy (LCOE) based on offshore wind power cost data, wind speeds, and connection costs. A common supply curve for offshore wind power in the Baltic Sea Area as well as supply curves for each jurisdiction are created on this basis.
The construction expenditure (CAPEX) for a generic 500 MW Baltic Sea offshore wind farm is estimated to be €1,345m. The LCOE differs between sites according to wind conditions, distance to shore and icing conditions. The LCOE for offshore wind power at the best sites falls to 50 €/MWh in 2030 and 36 €/MWh in 2050. This LCOE includes connection costs, which account for around 1,6 €/MWh and 1,3 €/MWh respectively.

2.2 Modelling of benefits of coordination

2.2.1 Creation of scenarios

We create six scenarios to explore how coordinated efforts can enhance efficiency of offshore wind power deployment in the region. The modelling is designed to investigate the benefits of coordinated action to utilize the identified offshore wind potential in the BSA.

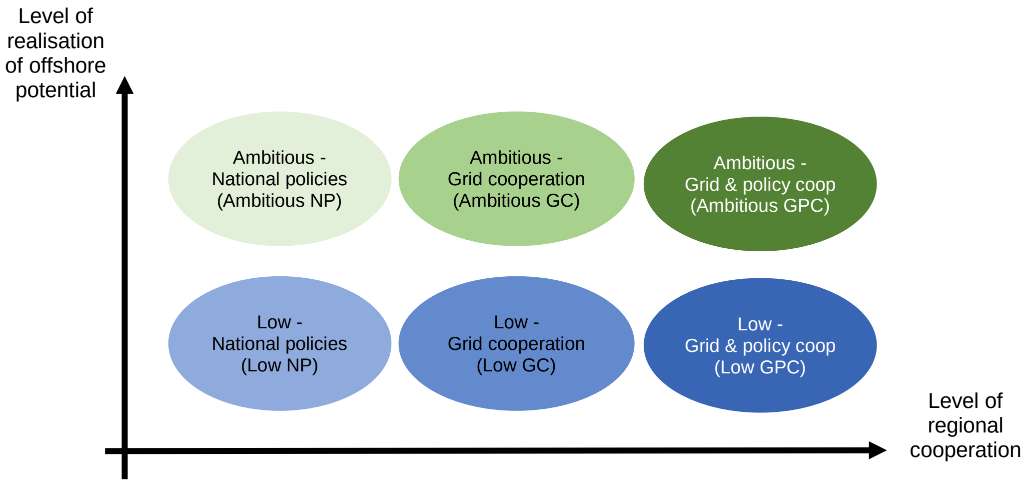
The scenarios describe two different ambition levels and three levels of cooperation:

› Two different ambition levels for offshore wind power
  - *Low scenario* reflecting a continuation of current expectations and trends. From an expected level of 2.5 GW offshore wind power in the BSA in 2020, the capacity increases to 6.5 GW in 2030 and 17 GW in 2050.
  - *Ambitious scenario* reflecting an achievable pathway if a more ambitious and concerted effort is chosen. The capacity more than doubles compared to the low scenario, with 12.7 GW in 2030 and 32.1 GW in 2050.

› Three degrees of regional cooperation
  - *National policies (NP),* in which national targets are met by use of national resources only and developed wind farms are connected to the respective national grids.
  - *Grid cooperation (GC),* in which 45 percent of the national targets are reached by development of four offshore wind power hubs connected to two or three BEMIP countries, thereby also providing increased interconnector capacity in the BSA. The remainder of national targets are reached nationally as in the NP scenarios.
  - *Grid and policy cooperation (GPC),* in which, in addition to the cooperation on offshore wind power hubs, the combined offshore wind power target for the region is optimized.

An overview of the scenarios is presented in the figure below.

Scenario setup for analysis of cooperative deployment of Baltic offshore wind power



In reality, a host of different combinations of renewable energy policies, levels of cooperation on reaching the targets, including offshore wind power ambitions, hub configurations, interconnector development, and coordination of long-term grid planning can be imagined. The use of six distinct scenarios is therefore a simplification to allow analysing the impact of policy choices. Analysing and comparing distinct scenarios help isolate effects of different elements in an otherwise complex picture and identify areas where more analysis of the benefits of coordinated efforts can potentially yield substantial benefits. The model results should therefore be interpreted as indications of the benefits that may be reached through cooperation on the development of offshore wind resources in the BSA.

For the interpretation of the results, it is important to keep in mind that the offshore wind power development levels are fixed in the scenarios in order to make it easier to compare results and analyse the difference between low and ambitious targets. Similarly, the hubs are chosen exogenously, based on preliminary assessments of offshore wind power costs, market values and the value of interconnectors. Moreover, in the cooperation scenarios, we assume that all four hubs are constructed before 2030. Finetuning ambitions and the configurations of hubs through further analysis is likely to reveal further benefits.

2.2.2 Modelling of the scenarios in stages to assess market and grid impacts

The modelling of the scenarios builds on the identified offshore wind power potential. We have combined two modelling approaches to analyse the effects of cooperation on both offshore wind power targets and on grid development.

› A power market model (Balmorel) is used to model market effects of scenarios, i.e. market values, power trade, and investments in power generation. The market modelling takes into account the CAPEX and OPEX costs of generation capacity, including fuel and carbon costs, as well as the costs of connecting offshore wind power to the grid.
› A grid model representing the transmission grid in each country to investigate the cost of congestion management within bidding zones, both in terms of the costs of network

reinforcement and the costs of redispatch in order to manage internal transmission constraints.

The market modelling shows a European power system undergoing a rapid transformation to renewable energy – renewable energy shares reach close to 70% by 2030 and more than 90% in 2050. At the same time, electrification within transport, heating and industry increases the overall demand for electricity.

The grid modelling reveals that grid updates are likely to be needed regardless of the development of offshore wind power in several of the national grids in the BSA in the longer term. The main drivers are the shift from conventional to renewable energy sources and a significant increase in electricity demand.

2.2.3 Offshore wind power can be a cost-competitive option already in 2030

In our simulation of the power market, Baltic offshore wind power in the most attractive areas becomes competitive with other power generation options (both fossil and renewable) by 2030. The costs of offshore wind power deployment are expected to continue to fall. At the same time, increasing fuel and carbon costs help to push fossil fuel generation off the system.

The cost efficiency of offshore wind power varies markedly across the region. The most attractive sites are located in the southern part of the Baltic Sea. These sites benefit from lower costs, owing for example to the absence of sea ice, and higher power prices, owing to their proximity to major centres of demand. In the Northern part of the Baltic Sea, the access to relatively cheap alternative Renewable energy sources (RES), mainly onshore wind, limits the market value of offshore wind power.

These differences mean that cooperative effort sharing mechanisms such as the ones made possible under the recast of Renewable Energy Directive,[1] can unlock significant efficiencies relative to national strategies that only target the best sites within a nation's Exclusive Economic Zone. Policies that encourage the selection of the most attractive sites from a regional perspective are universally positive from an efficiency perspective.

The competitiveness of Baltic offshore wind power is further strengthened over time due to a projected drop in offshore wind power costs over time, diminishing alternative renewable energy options, and increasing CO_2, fuel and electricity prices. Even without regional cooperation, total generation costs are approximately €200 million lower in the Ambitious NP scenario than in the Low NP scenario in 2050.]

From the comparison of aggregated generation costs, one may infer that offshore wind power beyond the Low deployment level may not be a competitive RES option for most BEMIP countries in the short term if deployment is regarded from a narrowly national point of view. The results, outlined in some detail below, show however that increasing the deployment of offshore wind in the BSA becomes increasingly attractive over time and that by optimising efforts across the BSA, the attractiveness can be further enhanced.

[1] See especially Articles 8-13 of Directive 2018/2001/EU.

2.2.4 Additional cost savings can be achieved by regional cooperation on offshore wind power policies

The modelling of the scenarios clearly indicates the benefits of reaching the modelled offshore wind power deployment levels by regional cooperation. Due to different resource endowments and costs of offshore wind in the area, but also because the market value of offshore wind generation varies across the region, the potential can be more efficiently utilized through cooperation. The largest benefits are achieved by coordination of both policies and grid development.

In line with our stepwise approach, we first analyse the difference between the scenarios *without regional cooperation*, i.e., the Low NP scenario and the Ambitious NP scenario. Comparing the aggregated generation costs for the system as a whole, including grid connection costs for offshore wind power, we find that *without regional cooperation* total costs increase to 2030, but in 2050, they could be reduced by around 200 million €/year in the Ambitious NP scenario compared to the Low NP scenario. This means that even without regional cooperation, as offshore wind power becomes more competitive, replacing more other generation (fossil and other renewables) with offshore wind power becomes increasingly competitive over time.

Regional cooperation on advanced offshore wind power hubs in combination with interconnectors (GC scenarios), i.e., connecting offshore wind power and providing additional transmission capacity between countries by construction of hubs, has the potential to increase the value of Baltic offshore wind power compared to the NP scenarios. In the Ambitious GC scenario, aggregated generation costs could be reduced by 700 – 900 million €/year in 2050, compared to the Ambitious and Low NP scenario, respectively. Benefits accrue from more efficient offshore wind deployment, the value of interconnectors that also cater for better integration of renewable generation capacity in general.

Regional cooperation on and support to offshore wind power generation through cross-border support instruments, i.e. opening of support schemes and cooperation mechanisms as set up in the Renewable Energy Directive, leads to a more efficient distribution of offshore wind power capacity outside the hubs across the Baltic Sea as a whole. This stems from the fact that regional cooperation allows putting greater focus on sites with lower deployment costs and more valuable power generation. This would allow for further cost reduction of around 700 million €/year in 2050 in the case with ambitious deployment of Baltic offshore wind power. At the same time, the more efficient distribution of Baltic offshore wind power also facilitates better utilization of other renewable energy sources, such as onshore wind.

Our analysis of offshore hubs shows that additional benefits can to be achieved through advanced hub configurations which increase the interconnector capacity between the market areas. The increases in interconnector capacity provide additional benefits as it facilitates better utilization of onshore wind resources as well. There are however marked differences in the values of the four hubs we have analysed, which indicates that more detailed and careful consideration of hub configurations, and the timing of various hubs, may increase the benefits. Sensitivity analysis on the grid cooperation scenario indicates that the total generation costs are reduced if only the two most profitable hubs are established before 2030. Regional policy cooperation without cooperation on hubs and interconnectors is also found to be profitable. However, the Ambitious GPC scenario, involving cooperation on both advanced hubs and on policies for regional offshore wind development in general, is still found to provide the lowest aggregated generation costs in the long run.

2.2.5 Offshore wind power affects internal grid costs and regional cooperation on grid planning is beneficial

While the market scenarios explore the costs and benefits of different levels of cooperation on the development of offshore wind power in the Baltic Sea, including connections to the onshore grids, the grid modelling explores the impact of offshore wind power on the costs in the internal grids. Regional cooperation on offshore wind power deployment affects internal grid costs differently, and it is important to explore and take such cost into account when developing a concerted effort to utilize offshore wind potentials in the BSA.

To assess the impact on internal grids due to the offshore wind deployment scenarios in 2030 and 2050, the grid model is populated with grid data for all countries in the Baltic Sea Area, namely the Nordic countries, the Baltic countries, Germany and Poland. Grid costs are estimated by comparing flows and congestion patterns, on which basis changes in grid expansion investments and redispatch costs can be estimated. In all scenarios, the projects identified in Entso-E's Ten-Year Network Development Plans and national grid development plans are included.

The grid modelling show that connection of offshore wind power does affect internal power flows and congestion patterns. However, if grid planning takes long-term offshore wind power ambitions into account, significant cost savings can be achieved. Moreover, the impact on internal grid costs depend on the general market developments and are unevenly distributed among the BEMIP countries.

To accommodate both the shift to low-carbon sources of generation and increases in demand, driven by the electrification of heat and transport, significant investments in network capacity are required in the period to 2050. This will be true regardless of the ambitions for offshore wind power in the region. In general, offshore wind power capacity and offshore hubs increase congestion in the network in the vicinity to the connection points but support lower capacity utilisation elsewhere in the grid. This highlights the importance of considering both offshore wind power and network investment planning together.

The results indicate that internal grid costs can be lower in the Cooperation scenarios than in the National Policy scenarios for both levels of offshore wind power deployment, even without upgrades. Additional benefits accrue if viable updates are carried out. Taking viable upgrades into account, total internal grid costs can be reduced by €50 – 75 mill/y in 2030 in the Low scenarios and by €125 – 150 mill/y in the Ambitious scenarios. Corresponding estimates for 2050 range from €160 – 400 mill/y.

The impacts on internal grid costs are however, not evenly distributed between countries. In 2030, grid costs are reduced in all areas except the Nordic countries in the Low cooperation scenarios. In the other market areas, substantial reductions in grid costs can be achieved. In 2050, grid costs in Germany increase even when economical upgrades are taken into account, while grid costs in the other market areas are reduced.

The results are of course derived from a simplified analysis and should be regarded with caution when it comes to the actual numbers. Still, the results indicate that coordination of offshore wind development in the region does not necessarily increase grid costs in the areas affected the most. In addition, substantial cost reductions can be achieved by integrating plans for offshore wind development during grid planning.

2.2.6 Cost-benefit analysis shows that cooperation on offshore wind power and long-term planning can reduced total system costs

The tables below give an overview of the changes of costs and benefits for the system as a whole. The estimates include costs for offshore wind deployment, changes in investment and operation costs in the onshore power systems, and changes in grid investment and redispatch costs. The Low NP scenario is used as the reference case, thus highlighting the impacts of increased grid and policy cooperation, and the impacts of increased ambition levels for offshore wind power in the Baltic Sea. Results are shown for 2030 and 2050 separately.

Changes in costs and benefits in the scenarios in 2030, compared to the Low NP scenario

	Low		Ambitious		
2030	**GC**	**GPC**	**NP**	**GC**	**GPC**
CAPEX offshore	102	84	1115	1341	1343
OPEX offshore	1	1	231	232	233
Hub costs	85	85	0	206	206
Delta CAPEX onshore	24	-41	-604	-562	-704
Delta OPEX onshore	11	25	-261	-250	-272
Delta fuel cost	-36	25	-151	-276	-267
Delta carbon cost	-24	-25	-82	-227	-174
Redispatch costs	-49	-74	61	-65	-92
Grid reinforcement	0	0	0	0	0
SUM	**114**	**80**	**309**	**399**	**273**

Changes in costs and benefits in the scenarios in 2050, compared to the Low NP scenario

	Low		Ambitious		
2050	**GC**	**GPC**	**NP**	**GC**	**GPC**
CAPEX offshore	218	379	2701	3209	3200
OPEX offshore	0	0	373	374	378
Hub costs	210	210	0	454	454
Delta CAPEX onshore	-80	-55	-1664	-1819	-2186
Delta OPEX onshore	-41	115	-510	-499	-586
Delta fuel cost	-234	-1006	-894	-1642	-1917
Delta carbon cost	-51	-264	-221	-505	-465
Redispatch costs	-397	-167	-198	-398	-579
Grid reinforcement	0	0	0	36	36
SUM	**-375**	**-788**	**-413**	**-790**	**-1665**

It is apparent from the tables, that substantial net benefits can be achieved in the long run, and that cooperation on both offshore connection and policies towards offshore wind power makes offshore wind power increasingly competitive. An interpretation of the results is that grid and policy cooperation make it increasingly attractive to increase ambition levels for offshore wind power in the Baltic Sea region.

The results for 2030 indicate higher costs of cooperation and increased ambition levels. As mentioned above, this result is partly driven by the inclusion of all four hubs already in 2030 in the modelling. Sensitivity analyses also show that the configuration and extension of hubs significantly impact the results. Thus, both ambition levels and the cooperation on hubs should be carefully considered going forward. All scenarios show clear benefits from policy cooperation.

The development of offshore wind power capacity would support economic activity in the region both during the capacity's construction and then throughout its operation. The scale and distribution of the employment effect depends on the scale, location and predictability of offshore wind power's deployment. Having reviewed existing research on the size of the employment effect, we estimate that scenarios that deploy a total of 16 – 32 GW of offshore wind power capacity in the Baltic Sea by 2050 would support the employment of 4,000 – 10,000 man-years annually (i.e. full-time jobs) in planning and construction related activity alone in the period to 2050. Work in operations and maintenance related activities would grow steadily over time, alongside operational capacity, to support 15,000 – 29,000 man-years annually by 2050. The total number of annual man-years increases steadily from around 10,000 man-years in 2020 to 20,000 – 40,000 in 2050, depending on deployment levels.

Having reviewed the industries already present in the region, we find that almost all BEMIP countries have the potential to contribute to the offshore wind power supply chain supported by this expenditure through the provision of services and components.

2.3 Market, administrative and regulatory barriers to offshore wind power exist

2.3.1 Cost-effective long-term deployment requires regional coordination and a level playing field

There is significant variation in the market, regulatory, planning and licensing regimes applicable to offshore wind across the different BEMIP member states and consequently the barriers facing offshore wind developers vary. Looking at the region as a whole however, the issues described below are considered to be either inherently regional in nature, or else sufficiently prevalent, to warrant consideration as part of a BEMIP-led initiative.

The lack of coordination of offshore wind power ambitions, and offshore and onshore grid development to cater for efficient development of offshore wind power resources in the region, are the core barriers that need to be addressed. In order to achieve such coordination, a common long-term vision has to be agreed that can be used to identify crucial investments in generation and grid infrastructure, along with appropriate measures and incentives to realise them. Our starting point for assessing barriers and measures to remove them is that an ambitious policy for offshore wind power in the Baltic Sea will help deliver cost-effective long-term solutions for deployment of renewables in the region. To achieve this, we outline our recommendations in the following.

2.3.2 Support mechanisms should be open to offshore wind

There are significant differences in the support regimes applied to offshore wind across the different BEMIP member states. While Denmark, Germany and Lithuania plan to support the development of offshore wind through future tendering rounds, currently there are no predictable prospects of public support for offshore wind elsewhere in the region. The efficient commercial development of offshore wind capacity may be distorted in future by differences in the levels of support offered in different jurisdictions. These differences create an uneven level playing field among projects in neighbouring jurisdictions that may prevent the efficient exploitation of offshore wind sites in the region.

Better alignment of support mechanisms and support levels in the BEMIP region would reduce that source of distortion in market signals. Coordination of support policies and levels would likely prove effective in ensuring a mutually beneficial deployment of the most promising sites. Coordination or even looser alignment can be realised by BEMIP or another cooperative body designated by BEMIP. This body could usefully serve to monitor and facilitate the developments of offshore wind power by, inter alia, enabling its access to support mechanisms. The use of flexibility mechanisms in the RED II directive to support offshore wind in the region should also be investigated and facilitated.

2.3.3 Differences in grid costs faced by offshore wind power create distortions

As it becomes commercially attractive to deploy offshore wind capacity without public subsidy, differences in grid access and connection treatment across national boundaries risk becoming increasingly distortive. Particularly important in this regard are differences among connection charging regimes given the relatively large share of connection costs in the cost of offshore wind projects.

There are marked differences in the extent to which offshore wind developers are responsible for carrying the cost of transmission investments linked to their projects under national connection charging regimes. While in some countries the Transmission System Operator (TSO) has historically covered the cost of offshore network transmission assets (Denmark and Germany for instance), others require developers to either undertake or cover the costs of transmission grid work relatively deeply within the onshore transmission network. In Finland, Sweden and, to a lesser extent, Denmark, generators are also required to pay network tariffs for using the grid, which would also apply to offshore wind power.

The distortionary effects may be counteracted through different levels or depth of cooperation from the closer alignment of these connection charging and access regimes to cooperation in order to facilitate regional grid planning.

2.3.4 Asymmetrical distribution of costs and benefits requires regulatory mechanisms for burden-sharing

The deployment of network infrastructure needed to support the efficient deployment of offshore wind power faces a number of practical barriers largely related to the difficulty of coordinating network activity among a variety of developers and numerous TSOs.

The integrated nature of the transmission network and the potentially important role of cross-border projects implies that many of the necessary investments will give rise to costs and benefits spread across multiple member states. Coordination is made more difficult by the fact that the costs and benefits of the relevant infrastructure will generally be split asymmetrically across many parties. For instance, a good joint Baltic Sea grid solution that benefits the entire region may entail significant costs of domestic grid reinforcements in a small number of countries.

Better mechanisms for the appropriate sharing of these costs and benefits are therefore likely to be needed to facilitate efficient offshore wind deployment. One possible solution could be for BEMIP or another cooperative body to ensure that payments can be made between TSOs to align benefits and costs at a national level and that such payments are treated like any other network costs in the economic regulation. Another option is to establish joint financing mechanisms for cross-border grid infrastructure related to offshore wind power. It should also be investigated whether a set of EU-wide rules could be developed for the regulation of offshore grid assets, as has been done for interconnectors.

2.3.5 Regional grid planning must be strengthened

Despite significant existing efforts to support regional TSO cooperation, barriers to efficient network investment remain. At present, TSO-level cooperation is split among many different groups, including ENTSO-E regional groups and regional security coordinators.

Better use could be made of existing cooperation mechanisms to support the identification of those grid network investments that are needed to enable offshore wind power deployment the region in particular.

2.3.6 Knowledge sharing can improve licensing procedures

It is vital for the deployment of offshore wind power that the necessary licenses are received without undue delay. However, it is also important that the licensing process balances the buildout of offshore wind power with other considerations such as environmental consequences.

We find that the quality of licensing procedures varies markedly across the region, in line with results from other studies. Some regimes are likely to present barriers to offshore wind development owing to: the absence of clear processes, the inability to identify stakeholder objections early, and/or the existence of inappropriately long or repetitive appeals procedures.

Licensing procedures are primarily a matter for national policy and regulation. Knowledge sharing on best practice could however act as a useful guide for those BEMIP member states seeking to develop their own national licensing systems. The current procedures in Denmark and Germany should provide useful inputs to this exercise.

2.3.7 Data quality for maritime spatial planning should be improved

Poor or inaccessible geospatial data hinders both effective maritime spatial planning and the ability of developers to make sound commercial decisions. We observe that there are significant differences in the BEMIP region with respect to the accessibility and quality of geospatial data. At the same time, there are examples of countries that have made good progress in this field, e.g. Germany where a web portal has been established for geographical data relevant to maritime spatial planning. Denmark is also developing a maritime spatial data infrastructure to promote sharing and coordination of data between Danish government agencies. Work to improve the quality, accessibility and compatibility of the data that underpins these decision-making processes will support the efficient deployment of offshore wind in the region.

2.4 Lessons can be drawn from other studies and initiatives

2.4.1 Insights and recommendations from the Baltic InteGrid project

The Baltic InteGrid project, which was finished in 2019, studied the potential for meshed offshore grids in the Baltic Sea. The study concluded that a meshed offshore grid would enable an efficient and cost-efficient deployment of offshore wind in the Baltic Sea. These meshed grids have similar economic and technical characteristics as the hubs identified in our analysis. For that purpose, the Baltic InteGrid study looked into legal, regulatory, technical and planning issues that will affect the possibilities for developing a meshed grid.

A closer look at the findings will help BEMIP to deduce action items for political coordination and for setting the right frameworks to ensure the most cost-effective development of offshore wind planning for the BSR.

A key legal challenge identified by Baltic InteGrid is the establishment of an EU regulatory framework for defining, building and operating a meshed grid. In addition, the project points to the need to resolve spatial conflicts and handle environmental issues, as well as gaining public acceptance. While there are also technological issues that need to be resolved, the project recommendations mainly focus on maritime spatial planning, policy and regulation and network planning. This includes the closer alignment of connection charging regimes and developing a methodology for allocating costs between TSOs related to cross-border investments. Another recommendation is to ensure integration between the Ten-Year Network Development Plans and planning of offshore wind and related grid infrastructures.

2.4.2 Coordination with the North Sea cooperation

In 2009, nine Member States and Norway established what has become the North Seas Energy Cooperation (NSEC) group, a platform for the development of common solutions to grid infrastructure and offshore wind deployment in the North and Irish Seas. Through this work, efforts have been made to coordinate political and regulatory action, share learnings and provide a model for collaboration in other European regions.

The group signed a political declaration in 2016 that set the structure of its current work, based on voluntary collaboration. Dedicated Support Groups have been formed to assist efforts in the following four areas:

- Maritime Spatial Planning
- Development and regulation of offshore grids and infrastructure
- Support frameworks and finance
- Standards, technical rules and regulations

These spheres have been designated in response to challenges facing the NSEC member countries that are quite similar to the ones BEMIP will be confronted with.

One important finding by NSECs concerns cluster-based solutions that on a technical level resemble the hubs investigated in our study. Such projects have been identified to very likely result in cost savings and more efficient deployment of offshore wind parks. Since challenges revolving around legal and regulatory differences in each member state constitute an equally onerous barrier to joint offshore plans in the North and Baltic Seas, approaching the NSEC Support Groups in each of the areas can help to overcome initial questions regarding the optimal manner of regional collaboration on these topics.

Due to the fact that both BEMIP and NSEC, face similar challenges, the results of the already conducted work programmes and studies by NSEC can serve as important guidelines. We also consider that NSEC can provide contact points for the exchange of ideas and insights, and for common learning. The exact form of cooperation between BEMIP and NSEC will need to be analysed and agreed in more detail.

3 Introduction

This is the Final Report for a "Study on Baltic Offshore Wind Energy Cooperation under BEMIP".[2]

The Report comprises the final deliverables for all tasks of the project. These chapters provide an explanation of work undertaken as part of the Task, the results of this work, and a discussion of conclusions or recommendations. The next section in this chapter provides a brief overview of the project as a whole for readers unfamiliar with the project.

3.1 Project overview

The Baltic Energy Market Interconnection Plan (BEMIP) Renewable Energy Working Group is considering the creation of an initiative to support the development of offshore wind in the Baltic Sea. This study is designed to provide this initiative with information necessary to support the effective realisation of the Baltic Sea's offshore wind potential, and to develop a work programme for the initiative in collaboration with key stakeholders.

The study itself is divided into seven Tasks, summarised below. The first five of these Tasks establish an evidence base. Tasks 6 and 7 draw on this information and stakeholder input to develop and refine a work programme for the BEMIP initiative.

[2] Conducted under Framework Service Contract SRD MOVE/ENER/SRD.1/2016-498 Lot 3.

Table 3-1 Summary Task descriptions

Task	Summary
1 Offshore wind sites and costs	Identify potential offshore wind sites in the region and their cost and generation characteristics Provide a high-level estimate of the economic impact of offshore wind development, notably on the supply chain
2 Power system modelling	Undertake detailed power system simulation to help identify the impacts of higher offshore wind deployment and greater regional cooperation Identify potential be Projects of Common Interest (PCIs)
3 Grid modelling	a. Undertake detailed grid modelling to identify the network congestion impacts of greater offshore wind deployment b. Conduct a Cost Benefit Analysis accounting for the network impacts
4 Market and regulatory barriers	Identify market and regulatory barriers to offshore wind deployment in the region and provide recommendations on how these might be addressed
5 Planning and permitting barriers	Identify planning and permitting barriers to offshore wind deployment in the region and provide recommendations on how these might be addressed
6 Roadmap and work programme	Develop a roadmap and associated work programme for an offshore wind initiative under BEMIP
7 Stakeholder workshop	Organise a stakeholder workshop to allow feedback on the proposed roadmap and work programme

4 Task 1 – Offshore wind potential, site characteristics and supply chain analysis

Key Messages from the Results

- The potential number of offshore wind farm blocks with a capacity of 500 MW that can be placed in the Baltic Sea has been estimated based on a screening process that accounts for wind conditions, water depth, and spatial and environmental planning constraints. The total offshore wind farm capacity identified through this process exceeds 93 GW, with national totals of between 4.5 GW in Lithuania and 20 GW in Sweden. Average wind speeds at the identified sites, as measured at 100m above sea level, range between 7.9 m/s and 9.6 m/s and the total net output implied for the gross potential capacity identified is 325 TWh/year. This corresponds to an average capacity factor of 40%.
- The construction expenditure (CAPEX) for a generic 500 MW Baltic Sea offshore wind farm is estimated to be €1,345m. Having reviewed the industries already present in the region, we find that almost all BEMIP countries have the potential to contribute to the offshore wind supply chain supported by this expenditure through the provision of services and components.
- For deployment scenarios that realise cumulative offshore wind capacities of around 16-32 GW in 2050, we estimate implied support for 4,000-10,000 man-years of employment annually in the period 2020-2050 due to planning and construction activity. In addition, there will be a gradually increasing number of jobs linked to operation and maintenance (O&M). By 2050, this O&M activity might support additional annual employment in the range of 15,000-29,000 man-years across the region.
- The exact distribution of these jobs across the region is uncertain. Although O&M-related jobs will be based at the ports used to service the windfarms, and therefore somewhat linked to location of the farms themselves, the planning and construction-related work could be located almost anywhere within the region. Our assessment of the supply chain shows that many BEMIP member states are capable of producing the components required and have the prerequisite skilled labour (albeit not in the numbers needed to produce the number of wind turbines envisioned).
- The location of new jobs will very much depend on where the supply industry chooses to establish its operations. Offshore wind suppliers are already present in some form in many of the BEMIP member states, but the supply chain is notably more developed at present in Denmark and Germany, where it supports offshore wind deployment in the North Sea.

Task 1 comprises the identification of potential offshore wind sites, including their cost and characteristics, and the analysis of the offshore wind supply chain, including an assessment of the potential number of jobs supported in the BEMIP countries. These elements are discussed separately as described below.

In section 4.1,we discuss the approach used to identify sites and to determine their characteristics. We also provide an overview of the results of the work. Detailed results including information on site locations, distance to the shore, electrical losses in the grid connection system and performance data for the wind farm blocks can be found in Appendices A, B and C.

In section 4.2, we provide a detailed discussion of the various elements of the offshore wind supply chain and their contribution to total CAPEX. We also evaluate the potential for BEMIP countries to contribute to the offshore wind supply chain based on the type of industries located in the individual BEMIP countries.

In section 4.3, we provide an overall assessment of the job creation potential in the BEMIP countries based on different deployment scenarios for offshore wind in the Baltic Sea.

4.1 Offshore wind potential and site characteristics

4.1.1 Methodology

Site identification

Potential offshore wind farm areas in each of the BEMIP member countries' territorial waters have been identified. These sites include areas already identified and published by the governments, as well as new areas identified by this study.

Comments from the BEMIP member countries on a preliminary list of potential offshore wind farms were provided and have been taken into account in the site identification process. Areas already marked for offshore wind development and existing wind farms have also been identified based on information from the 4C Global Offshore Wind Farm Database. New areas have been identified through a screening process based on an assessment of the following:

› Wind conditions (minimum 7 m/s)
› Water depth (max 50 m depth)[3]
› Planning issues

Wind conditions were assessed based on the EMD ConWx Europe Mesoscale, while water depth was obtained from the Baltic Sea Bathymetry Database (BSBD). For planning issues / spatial constraints, information was extracted from the 4C Global Offshore Wind Farm and

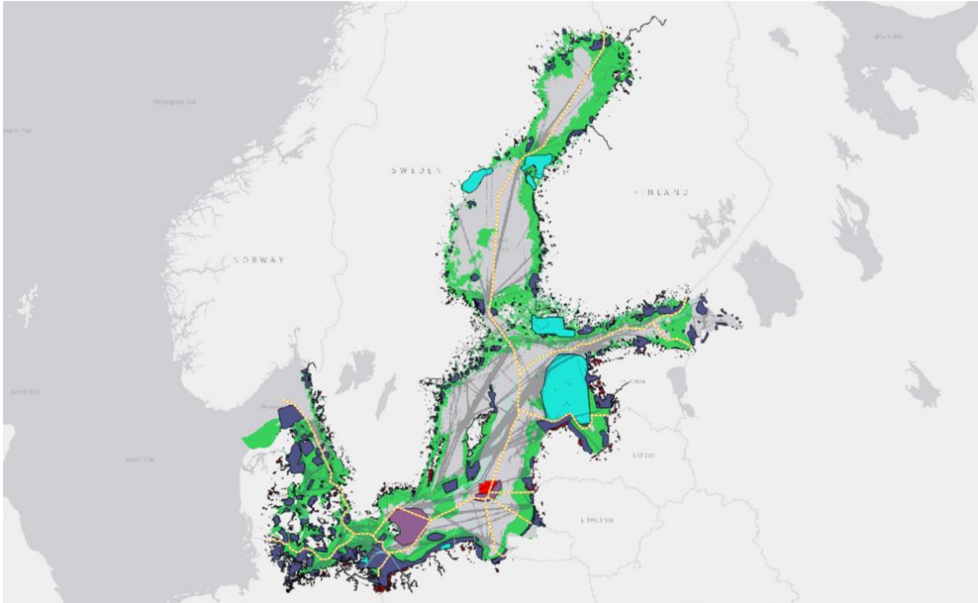
[3] We have not assessed the potential for floating wind turbines in the Baltic Sea. As this assessment shows and due to the generally shallow waters in the Baltic Sea, there is ample technical potential within the 50m depth restriction to meet even the most ambitious deployment scenarios considered in this report.

HELCOM databases. HELCOM is an intergovernmental commission managing and administrating the Helsingfors Convention for the protection of the maritime environment in the Baltic Sea.

The spatial constraints accounted for include the presence of nature protection areas, fishing areas, cable and transmission corridors, shipping traffic corridors, contaminated areas, areas with dumped chemical or conventional munitions and areas with airspace or other military restrictions. Owing to a lack of data, the competing use of the sea by the tourism industry has not been taken into account. Harbour availability has also not been considered. As such, there exist other possible conflicting interests, including local environmental concerns, which may pose barriers to the development of the sites identified through this initial screening process.

All of the data described above was included in a GIS database and site identification performed using a layer-on-layer approach, see Figure 4-1.

Figure 4-1 Area available for offshore wind farms (marked in green)



Note: The light blue areas are UNESCO areas/World Heritage Sites.

Offshore wind farm configuration

In order to identify specific sites and develop meaningful cost estimates, we have considered the placement and construction of a reference 500 MW offshore wind farm. This capacity reflects the industry trend towards larger farms as means of realising scale efficiencies. While smaller farms may be technically feasible, they are less likely to be cost-effective.

The reference farm includes generic 10 MW wind turbines with a hub height of 100m and a rotor diameter of 172m. Each 500 MW wind farm block is modelled as 10 x 5 wind farm grids, with a distance of 8 rotor diameters between wind turbines in the prevailing wind direction and 4 rotor diameters row-wise.

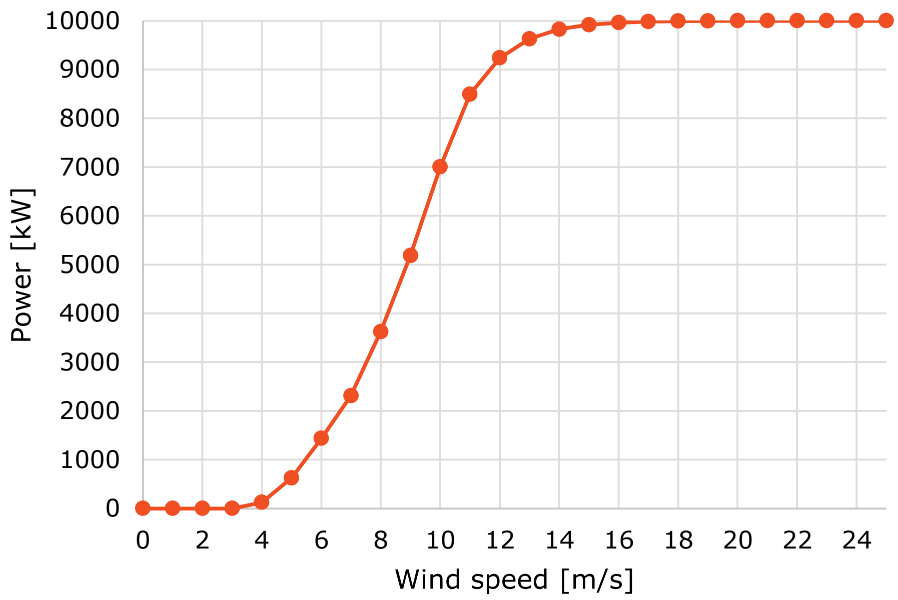
Furthermore, it is assumed that each wind farm block has an offshore substation, with an external cable connected to a pooling substation at the nearest point on the shore. From there, the power is assumed to be transmitted to a point of connection at the closest suitable substation on the national transmission grid level (see further detail below).

Monopile foundations are assumed for each offshore wind farm. This design is expected to be appropriate for the majority of the sites identified, but alternative designs, for example the use of gravity foundations, may be superior in some locations and indeed may be required by spatial planning restrictions[4].

Estimation of annual energy production

The annual energy output of a wind turbine has been calculated using the power curve of the reference wind turbine, see Figure 4-2 and Table 4-1, and the modelled wind distribution at 100 m above sea level (ASL) in the relevant area. The modelled wind distribution is based on 20 years of mesoscale data (January 1998 to December 2018).

Figure 4-2 Power curve for the generic 10 MW reference wind turbine used for the estimation of annual energy production



[4] The final technical characteristics and concrete design of future projects will depend on case-by-case considerations. Their integration into the modelling framework would have gone beyond the possibilities of this scoping study.

Table 4-1 Power curve of generic 10 MW reference wind turbine used for estimation of annual energy production

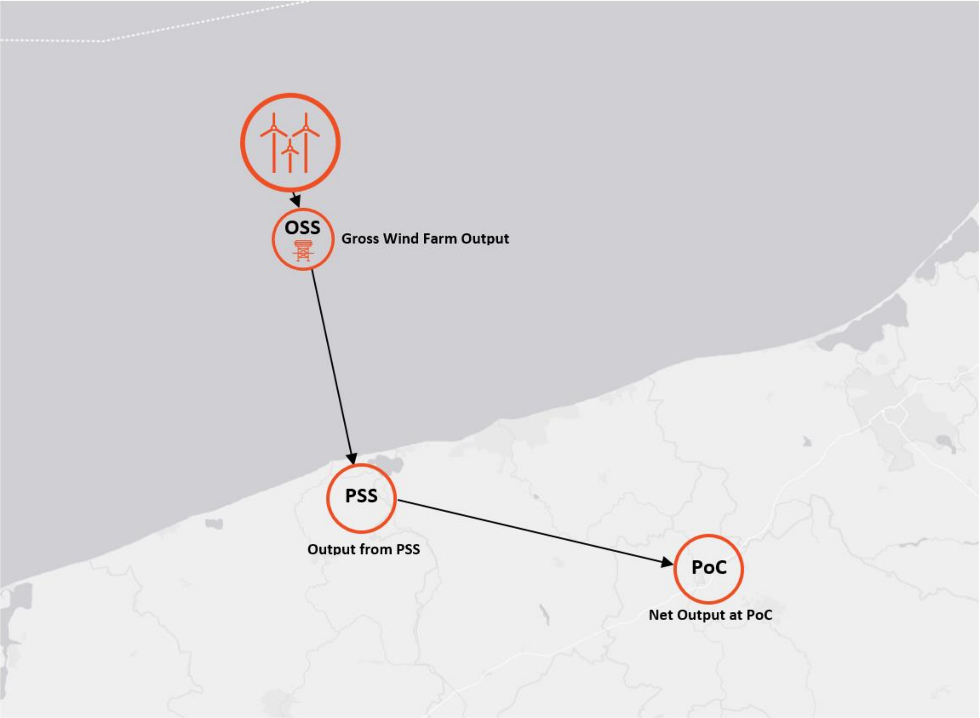
Wind speed [m/s]	Power [kW]
0	0
1	0
2	0
3	0
4	125
5	625
6	1438
7	2313
8	3625
9	5188
10	7000
11	8493
12	9237
13	9630
14	9824
15	9917
16	9961
17	9982
18	9992
19	9996
20	9998
21	9999
22	10000
23	10000
24	10000
25	10000

The *gross output from the wind farm* is calculated as the sum of the output from an individual wind turbine multiplied by the number of wind turbines and is then reduced by wake losses, availability losses, electrical losses in the array cables and losses in the offshore substation (OSS).

The *output from the pooling substation (PSS)* is equal to the gross output reduced by the electrical losses in the export cables and the pooling substation.

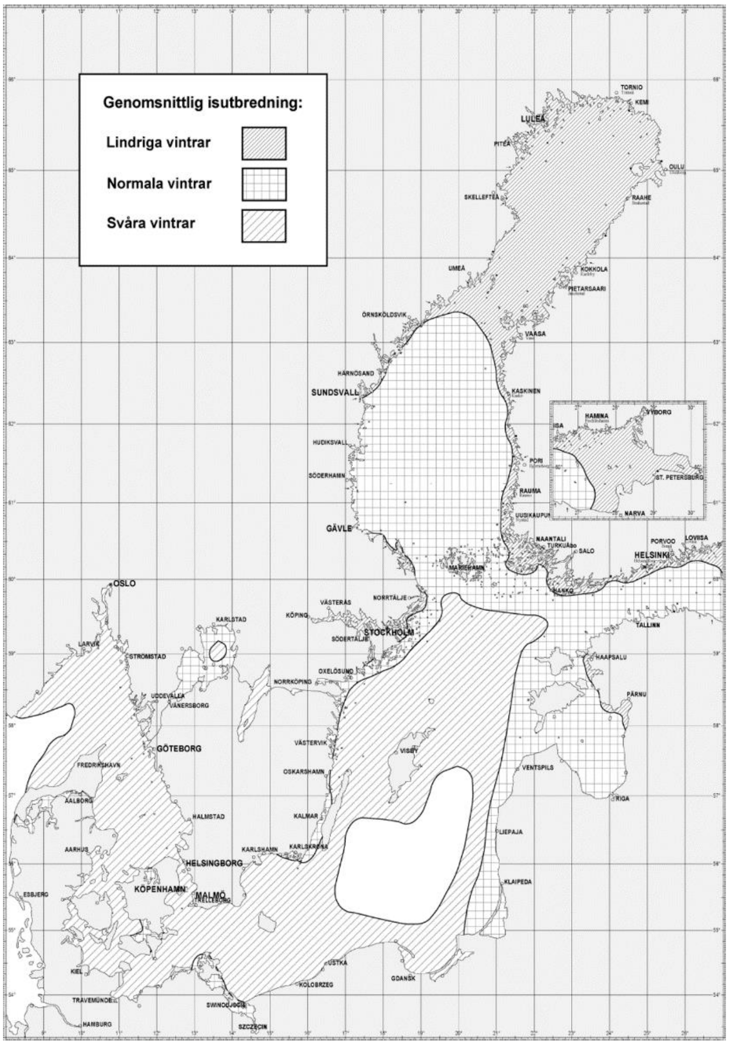
The *net output* at the Point of Connection (PoC), is equal to the output from the pooling substation reduced by the losses in the transmission line between the pooling substation and the PoC. The estimated losses for each 500 MW wind farm block is provided in the list of wind farms (see Appendix A).

Figure 4-3 Illustration of the offshore wind farm, offshore substation (OSS), pooling substation (PSS) and Point of Connection (PoC) configuration.



The effect of sea ice has been taken into account by categorising each wind farm into different sea ice zones corresponding to low risk, medium risk and high risk. For wind farms located in high risk zones, the total availability loss is increased from 5% to10 %, reflecting the more challenging operational conditions and the difficulty of getting access to the site. The categorisation for each wind farm is based on information from Swedish Meteorological and Hydrological Institute, see Figure 4-4.

Figure 4-4 *Average ice spread in the Baltic Sea, prevalence of sea ice during winter. (Lindriga vintrar = Mild winters, Normala vintrar = normal winters, Svåra vintrar = rough winters)*



Source: *SMHI (Swedish Meteorological and Hydrological Institute). https://www.smhi.se/en/theme/ice-conditions-in-the-baltic-1.12257*

Calculation of key economic figures

CAPEX and OPEX have been estimated for a 500 MW offshore wind farm for sea depths ranging from -20 m to -30 m based on COWI's experience and average market prices for project components.

OPEX is divided into fixed and variable costs. Fixed costs include material/equipment costs, rental costs for storage and for operation base / service facilities, scheduled servicing consumables, balance of plant maintenance, staff costs and insurance. Variable costs are related to unscheduled and unplanned servicing, spare parts and the impact of weather conditions.

In cases where a wind farm area includes multiple 500 MW blocks, total OPEX is expected to be higher than that of a single 500 MW wind farm. In such cases, fixed costs are assumed to be almost the same, while variable costs are scaled proportionally with total wind farm capacity.

To take the varying sea depth into account, a linear relationship between foundation costs and sea depth has been assumed, where for each 10 m of increased sea depth, the CAPEX increases by approximately 0.28 M€/MW.

Variations in CAPEX due to the additional challenges posed by arctic conditions have been accounted for by increasing the CAPEX estimate based on the relevant sea ice condition level for the area, as described above. A CAPEX uplift of 0%, 4% and 7% has been imposed based on identified sea ice risk. These uplifts are estimates, as the available evidence on the cost impact is limited and tends to be very site-specific. In "IEA Wind Task 19 - Wind Energy Projects in Cold Climates 2. Edition 2017" several factors that contribute to higher CAPEX are mentioned, including, but not limited to, increased initial project costs due to limited installation schedules, increased equipment costs due, for example, to the need for de-icing systems, and increased financing costs owing to greater uncertainty.

It should be noted that the costs of the required electrical components are subject to large variation depending on actual demand in the market. Large market price variations for wind turbines have been observed in the past and consequently the actual cost will depend on the conditions prevailing in the supply chain. Shifting sea ice conditions, stemming for example from weather changes reducing or extending high-risk zones, may also influence CAPEX and OPEX; these variations from long-term patterns could not be reflected due to their inherent uncertainty.

Key economic figures for the generic 500 MW wind farm

The CAPEX required for a generic 500 MW wind farm is estimated to be €1.34bn. Annual average OPEX is estimated to be €28m. A breakdown of these CAPEX and OPEX costs is presented in Table 3.2 and Table 4-3below. The prices shown are for 2020. The actual costs assumed for each site will vary based on the sea depth and icing conditions as described above.

Table 4-2 Breakdown of estimated average CAPEX, 500 MW offshore wind farm

CAPEX Breakdown	Cost €m
Turbine Supply	655
Foundation Supply	230
Cable Supply	55
Installation Works	70
Substations	85
Others[5]	120
Contingencies[6]	130
Total	1,345
CAPEX/MW	2.7

Table 4-3 Estimated average OPEX per year, 500 MW offshore wind farm

OPEX Breakdown	Cost €m
Fixed costs	22.6
Variable costs	5.2
Total	27.8

Note: See the 'Calculation of key economic figures' section for a description of what is included in these two categories

We estimate the CAPEX cost associated with adding offshore wind capacity to be approximately €2.7m per MW. This is within the range of offshore wind farm CAPEX costs observed by IRENA when estimating the 2010-2017 global average (€2.1-5.0m). The range reflects the impact of local conditions such as water depth and distance to the shore. Relevant examples of CAPEX for offshore wind farms in the North Sea are €3.8m per MW for the 582 MW Gode Wind farm (2016) and €3.2m per MW for 630 MW London Array wind farm (2013). CAPEX costs are expected to fall further to the level estimated in this study.

4.1.2 Results

Identified potential capacity in Baltic Sea

Potential offshore wind power sites with a total capacity of 93.5 GW have been identified in the Baltic Sea. The areas identified consist of existing areas identified by governments/developers

[5] This covers a Feasibility Study, Environmental Impact Assessment, bathymetry and geophysical surveys, geotechnical surveys, supply and installation of on-site wind measurements, port preparation and rental costs, port fees, marine operation management office and facilities, certification and marine warranty survey fees, project management fees, engineering fees, legal fees and insurance.

[6] This covers costs related to extended installation time for foundations, wind turbines and an offshore substation, costs related to extended time for export- and inter-array cabling and a general contingency fund for the development and construction phase.

and new areas identified as part of this study. The total capacity is the sum of 187 wind farm blocks, each with a capacity of 500 MW.

The total estimated potential net output from all of these sites as measured at the identified points of connection to the existing grid in the BEMIP countries is 325.9 TWh/year. This corresponds to an average capacity factor of 39.8 %. Among the sites identified, the capacity factor varies between 32.0% and 42.8%. The long-term mean wind speed in the identified areas at 100 m ASL varies between 7.9 m/s and 9.6 m/s.

Potential per BEMIP member country

See Table 4-4 for a summary of the potential identified in each country using the site identification methodology described in section 4.1.1. It should be noted that, depending on additional factors beyond the screening criteria used in this study, not all of the sites listed in Table 4-4 may prove economically viable due, for example, to economic and project performance requirements or price and technology cost trajectories. On the other hand, additional sites and larger capacity potentials may be identified in individual BEMIP Member States as part of their national strategies, including in the context of the National Energy and Climate Plans under the recast Renewable Energy Directive[7] and the new Governance framework[8]. The finalisation of the National Energy and Climate Plans will occur after this study; therefore, new developments after the completion of the related tasks of this study could not always be reflected. Where additional information was provided by before the finalisation of this study, this information has been included in the relevant country factsheet.[9]

The table 4-4 includes the number of 500 MW offshore wind farm blocks, the total identified potential capacity and the total potential net annual energy production. In addition, we provide the name of the site with the highest capacity factor in each country.

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[7] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources, OJ L 328, 21.12.2018.
[8] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, OJ L 328, 21.12.2018.
[9] This is particularly relevant in the case of Estonia, which in elaborating its National Energy and Climate Plan, has considered a more prominent role for wind energy in its 2030 energy mix than initially envisaged in this analysis.

Table 4-4 Summary of identified potential offshore wind capacity in the BEMIP member countries

Country	Number of 500 MW wind farm blocks	Identified potential capacity [GW]	Potential Total Net Annual Energy Production [TWh]	Highest capacity factor site	Higher capacity factor [%]
Denmark	39	19.5	70.7	DK54-1 Rønne Banke,	42.5
Estonia	14	7.0	24.0	EE New Saarema-1/2	40.3
Finland	16	8.0	26.0	FI New Aalands Hav-1/2	40.9
Germany	16	8.0	29.1	DE Baltic 2, Baltic 2 area	42.6
Latvia	29	14.5	49.2	LV07-2 Baltic Wind Park Phase 1	40.5
Lithuania	9	4.5	15.5	LT New #4-1/2	40.3
Poland	24	12.0	43.2	PL Baltyk Pólnocny phase 1/2	42.4
Sweden	40	20.0	68.2	SE New Oelands Soedra 1/2	42.8
Total	**187**	**93.5**	**325.9**		

Note: The site with the highest capacity factor is not necessarily the most economic. The modelling undertaken in Task 2 accounts both for differences in site-specific costs and in the value of site output when selecting sites to develop.

Note that to take into account the comments from the BEMIP member countries, some existing wind farms with capacities of less than 500 MW have been included in the list. To do so, the existing offshore wind farms have been combined into 500 MW blocks if located in the same area with similar wind conditions. For cases where a potential new area neighbours one or more existing offshore wind farms of less than 500 MW, the new potential area and the existing wind farm(s) have been combined so that both the potential and existing capacity is represented by one or more 500 MW wind farm blocks. This simplification is not expected to have any material impact on the modelling undertaken in Tasks 2 and 3.

List of offshore wind farms and ranked lists

A table listing the identified offshore wind farm sites has been prepared as part of the deliverables from Task 1. For each offshore wind farm, the following information is given:

- Offshore substation coordinates
- Onshore pooling station coordinates
- Coordinates and name of suggested point of connection
- Distance from offshore substation to onshore pooling station
- Distance from onshore pooling station to suggested point of connection
- Sea depth
- Sea ice zone (low risk, medium risk, high risk)
- Wind conditions, including mean wind speed and Weibull parameters for 100m ASL
- Gross and Net Annual Energy Production from the offshore wind farm
- Estimated losses (including availability losses, electrical losses in array cables and offshore substation, electrical losses in export cables and pooling station and electrical losses in transmission cables)
- Capacity factor

› Total capacity in wind farm area (if multiple 500 MW wind farm blocks located in one identified area)

The full offshore wind farm list is provided in Appendix A.

Ranked lists of the wind farms according to capacity factor are included as Appendix B and Appendix C.

Due to the size of the abovementioned tables, they will also be delivered in spreadsheet format.

Maps of existing and potential wind farm areas

Figure 4-5 to Figure 4-13 below are maps showing the identified existing and potential offshore wind farm sites for each BEMIP country. In each map, two colours are used for the areas – one to denote newly identified sites, and the other to denote existing sites. All newly identified sites include "New" in the assigned label.

Figure 4-5 Existing and potential offshore wind farm areas in Denmark

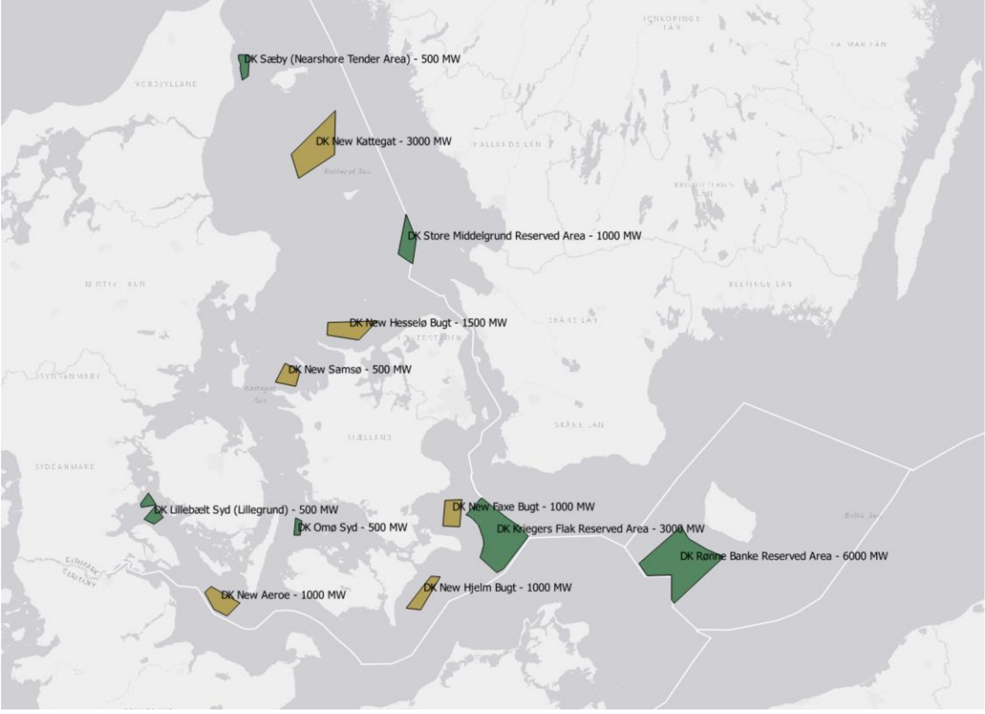


Figure 4-6 Existing and potential offshore wind farm areas in Estonia[10]

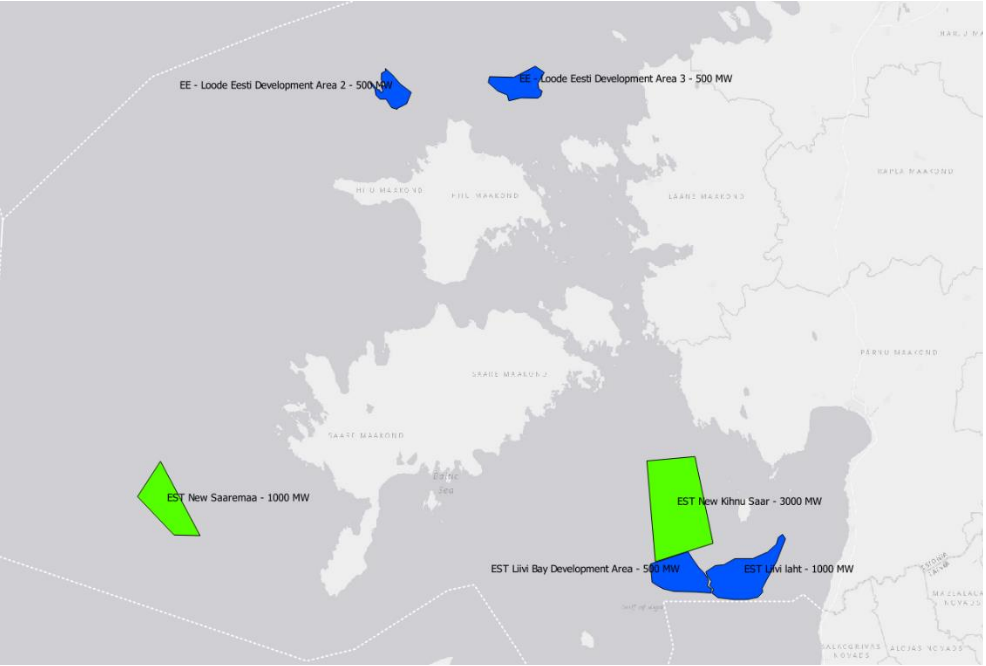
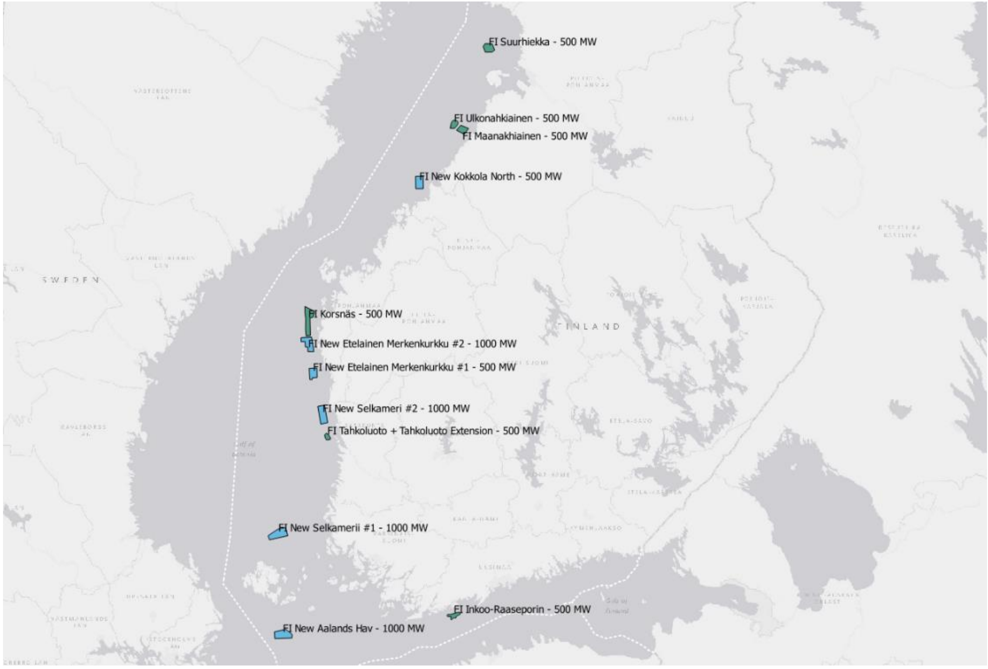


Figure 4-7 Existing and potential offshore wind farm areas in Finland



[10] Additional areas could be added by incorporating areas identified in recent spatial planning. A sketch of the areas likely to be identified for offshore wind development in the Estonian Maritime Spatial Plan can be found in the relevant country factsheet in Appendix E.

Figure 4-8 Existing and potential offshore wind farm areas in Germany

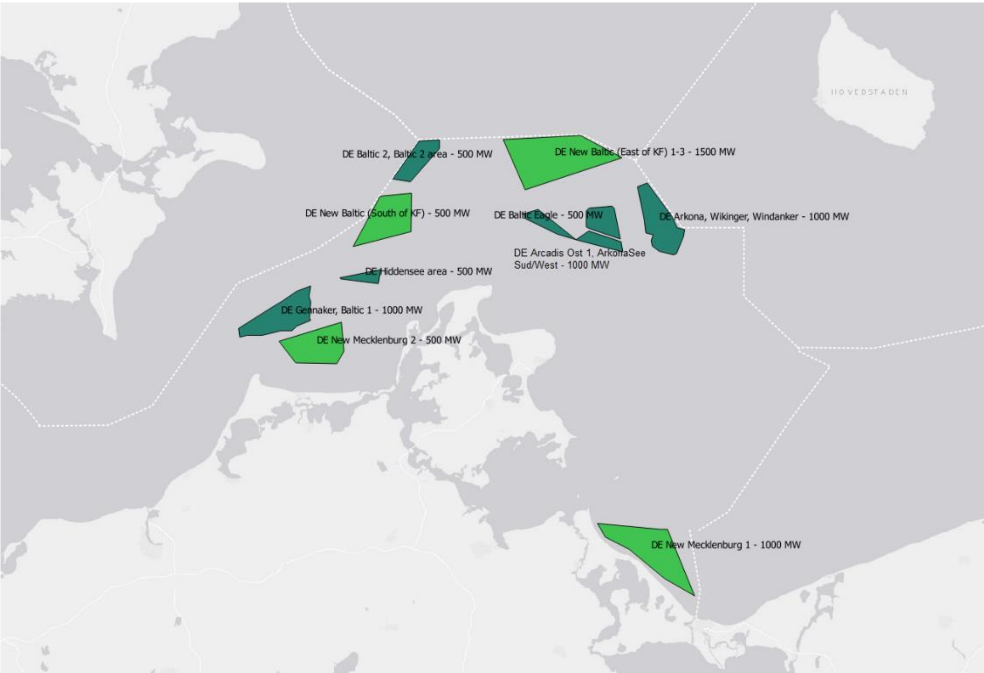


Figure 4-9 Existing and potential offshore wind farm areas in Latvia

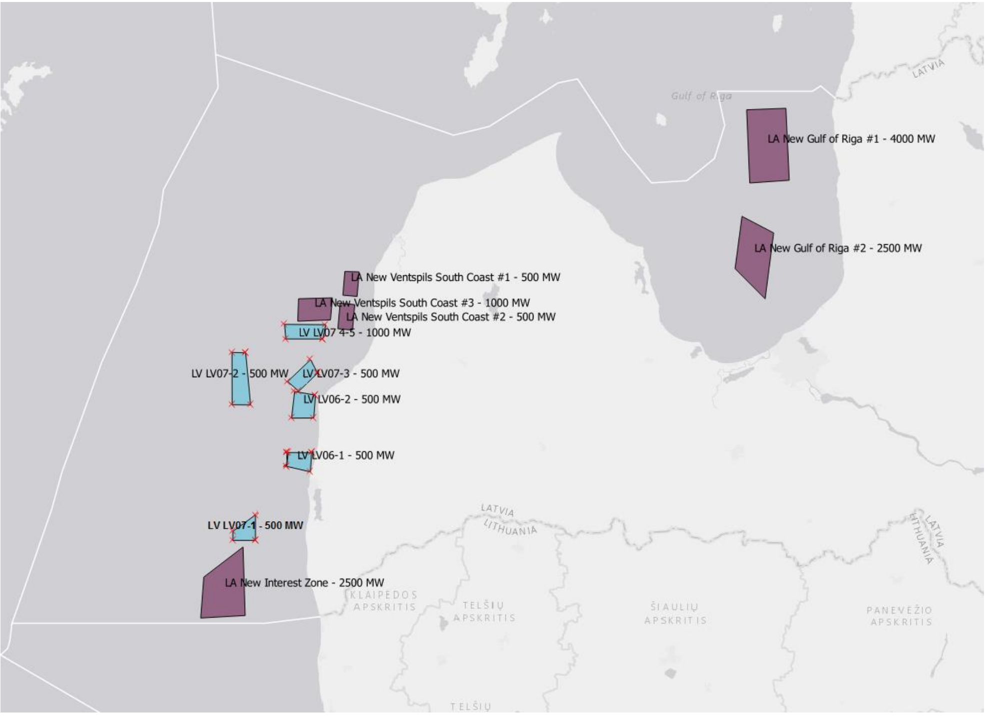


Figure 4-10 Existing and potential offshore wind farm areas in Lithuania

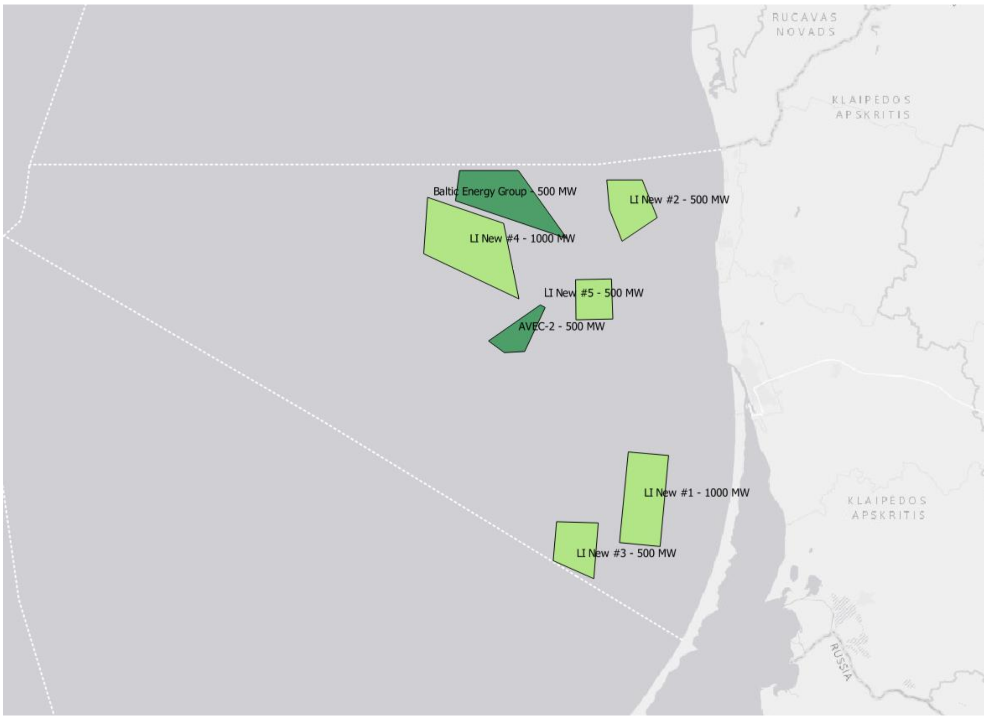


Figure 4-11 Existing and potential offshore wind farm areas in Poland

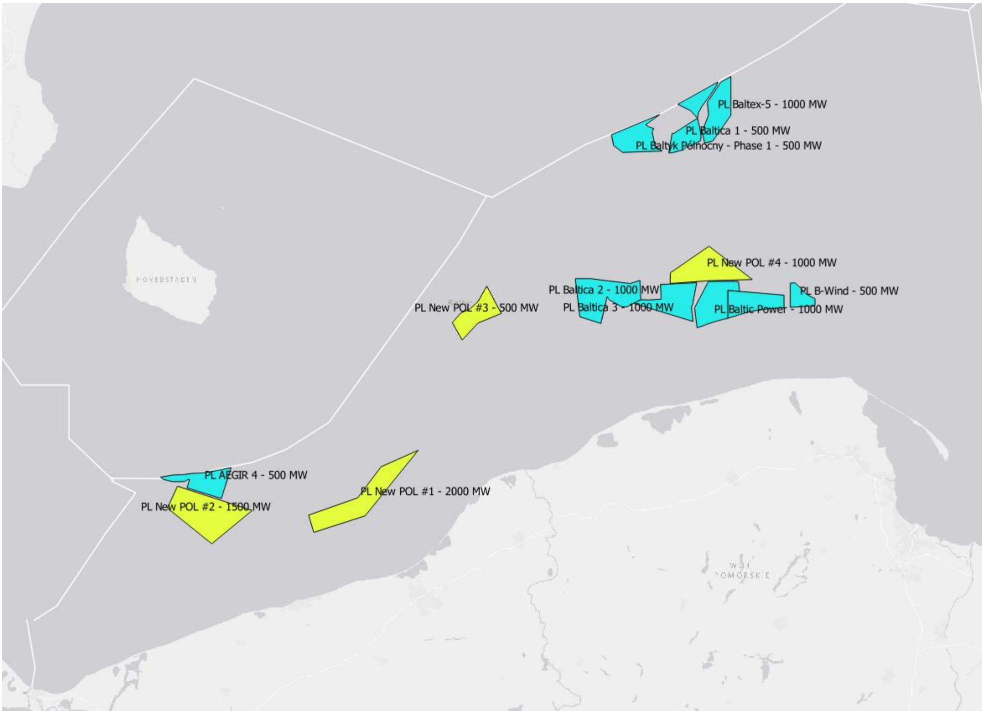


Figure 4-12 Existing and potential offshore wind farm areas in Sweden (southern part)

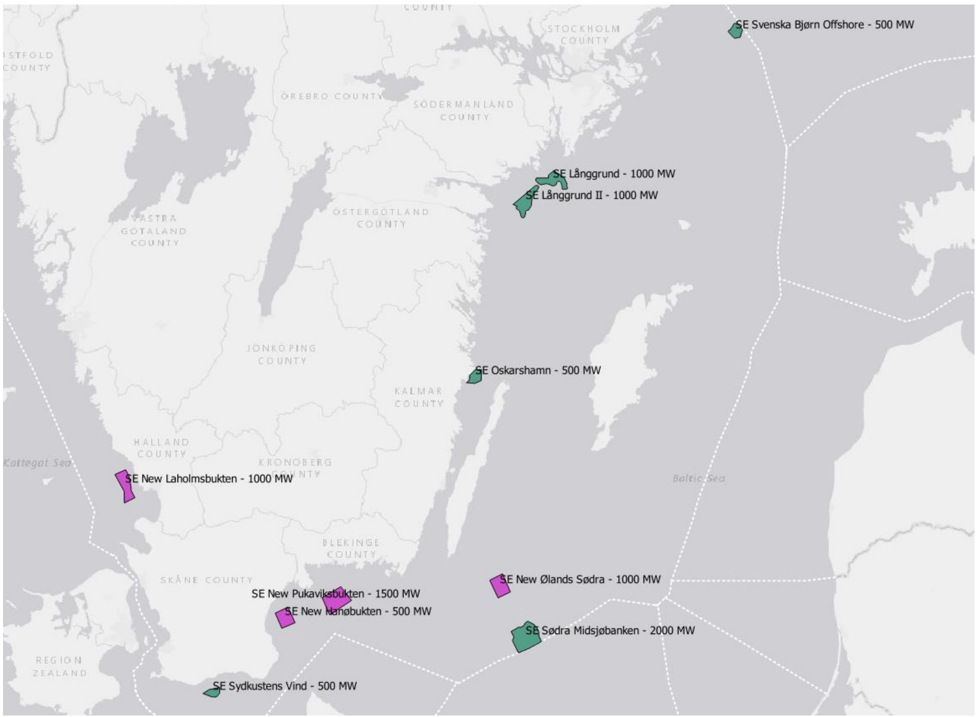
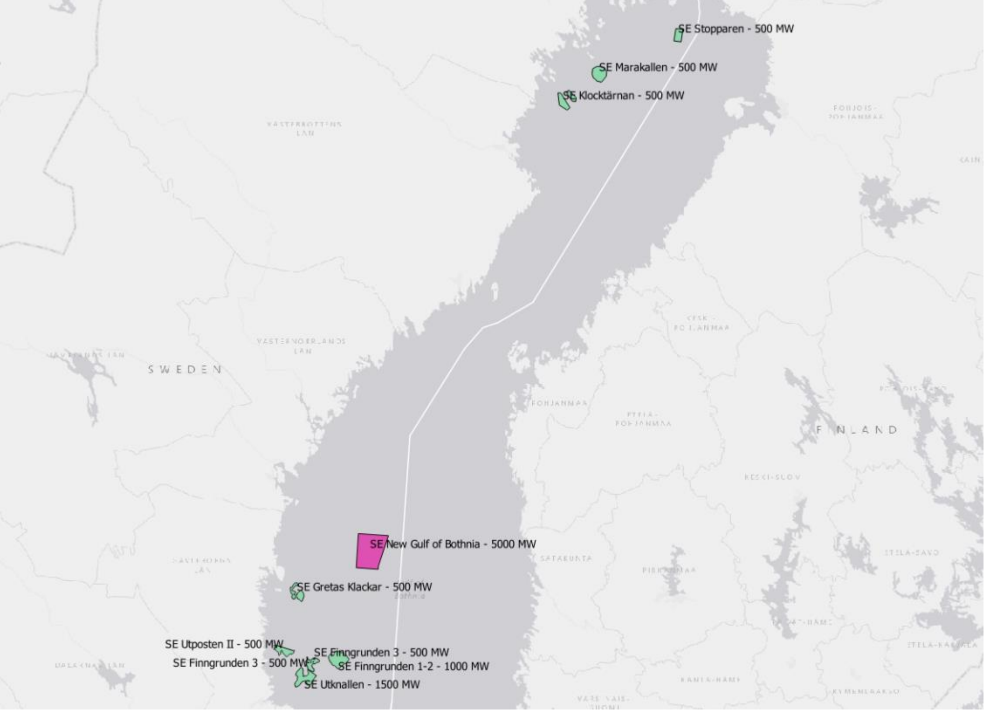


Figure 4-13 Existing and potential offshore wind farm sites in Sweden (northern part)



We are aware of the existence of other offshore wind farms in the pipeline with capacities of less than 500 MW (e.g. Kiri in Finland). In cases where existing wind farms or wind farms in the pipeline are located close enough to each other that these can be grouped into cost-effective 500 MW blocks, these have been added. Otherwise, while these projects may be useful precursors to broader development, these smaller sites are not included in the list of sites for the purposes of modelling regional impacts. This is not expected to have any material impact on the results.

4.2 Supply chain analysis

4.2.1 Methodology

As part of the scenario analysis conducted as part of Task 2 and discussed further in detail in section 5.1.3, we have considered two different deployment cases for offshore wind in the Baltic Sea: a Low and an Ambitious deployment case. These are described in more detail in Table 4-5 below.

Table 4-5 Cumulative offshore wind deployment in the Baltic Sea by year and deployment case

MW	2020	2030	2050
Low offshore development	2,527	6,445	16,945
Ambitious offshore development	2,527	12,695	32,100

Given an assumed turbine capacity of 10 MW, these deployment cases imply the installation of approximately 50 or 100 wind turbines per year in the region in the period 2020 – 2050. We have calculated the quantity of wind farms to be installed in each member state under each deployment case, and these figures underpin our later estimates of job creation in section 4.3.

In terms of the geographic distribution of this activity, most Baltic Sea offshore wind capacity in 2050 is expected in Germany, Poland, Sweden, Finland and Denmark, which collectively represent 91 % of the total installed capacity. This is the case in both the Low and the Ambitious case. Lower absolute levels of development are assumed in Estonia, Latvia and Lithuania, with a total of 1500 MW installed by 2050 in the Low case and 3000 MW in the Ambitious case. This corresponds to about 9% of the total capacity and is well below the potential identified above (see Table 4-4).

We have developed an overview of the possibilities for the individual BEMIP countries to contribute to the offshore wind supply chain by comparing existing industry types and service providers in the BEMIP countries, as set out by Wind Europe, with the services and components required by the offshore supply chain.

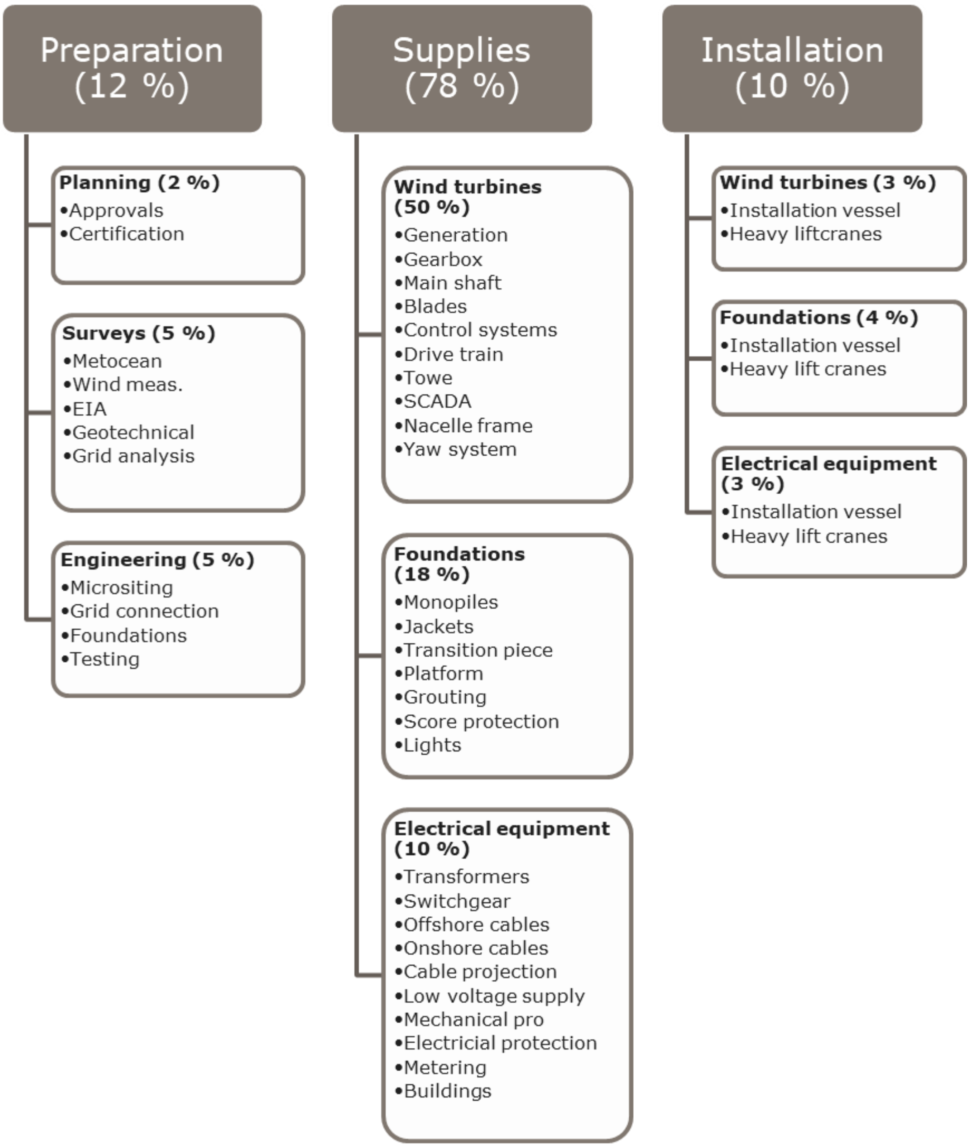
4.2.2 Results

The implementation of an offshore wind farm from the planning phase until construction completion is a highly complex process requiring a wide variety services and components, and consequently an extensive supply chain. The CAPEX supply chain for an offshore wind farm can be divided into three broad groups:

- Planning
- Supplies
- Installation

In Figure 4-14 below, we breakdown each of the CAPEX supply chain groups and show the assumed distribution of the CAPEX costs for the various types of supply.

Figure 4-14 Cost of wind farm by component



The contribution of the BEMIP countries to the CAPEX supply chain will depend on a number of factors including the expected deployment rate for offshore wind capacity in the region. In the Low deployment case, we expect the involvement of local industry and companies to be relatively limited because the economic benefits associated with establishing local manufacturing and service facilities will be limited. Conversely, in the Ambitious deployment case, it may be economically attractive to establish or extend local facilities due to the large volume of components required.

In addition, built windfarms will require operations and maintenance activities expected to support local suppliers in most of the BEMIP countries.

Relevant Industries

A number of wind energy components and services are currently available from suppliers in the BEMIP countries. Based on data from the Wind Energy Forum, we have identified the elements of offshore wind supply chain provided by each BEMIP country. Table 4-6 shows the type of components available from each BEMIP country and the level of employment related to these components.

Table 4-6 Level of identified employment in industries that supply the offshore wind industry by component type and country (L = Large; M = Medium; S = Small; N = None)

Country industry level by components									
Components	**Denmark**	**Germany**	**Poland**	**Estonia[11]**	**Latvia**	**Sweden**	**Finland**	**Norway**	**Lithuania**
Assembly	L	L	S	S	N	N	N	S	N
Blades	L	L	L	N	N	N	N	N	N
Cables	N	S	S	S	S	S	S	M	S
Components	S	L	S	L	N	M	L	S	N
Construction	N	S	N	N	N	N	N	S	N
Foundations	S	S	L	M	N	S	S	N	S
Gearboxes	N	S	N	N	N	N	S	N	N
Generators	N	N	N	L	N	S	S	N	N
Grids	N	S	N	N	N	N	N	N	N
Logistics	N	S	N	M	N	S	N	N	N
Nacelles	S	L	N	N	N	N	N	N	N
O&M	S	L	S	N	N	M	S	S	N
Operations	L	S	N	N	N	N	N	N	N
Other	M	S	S	N	N	S	S	N	M
Port	S	N	N	N	N	N	N	N	N
R&D	L	S	M	N	N	N	N	N	N
Services	N	N	N	N	N	M	M	N	N
Towers	S	M	S	N	N	N	N	N	N

The table shows that Denmark and Germany, as well as Poland and Finland, have existing industries for a significant number of relevant components. Most of the other countries have established industries that could supply at least some elements of the supply chain. This suggests that the foundation for the development of large-scale offshore wind industry is present in the region.

[11] According to the report 'Potential of Offshore Wind Energy Industry For Estonian Companies' (2011, GL Garrad Hassan), Estonia may additionally be able to support activity related to construction, ports, R&D and services.

4.3 Job creation in BEMIP countries

4.3.1 Methodology

Employment impact

The development of the wind industry, and especially the development of offshore wind projects, supports jobs in a variety of sectors. These include engineering and planning services, manufacturing of mechanical and electrical parts for the wind turbine, and assembly and installation activities. A number of jobs will also be created to support the operation of facilities used for the installation and maintenance of turbines and in port operations.

As part of this work, we have estimated the scale of potential job creation in the BEMIP countries for the various deployment cases. Previous studies of the employment effects of offshore wind conclude that approximately 10 man-years of CAPEX-related work are created for each MW installed. This is based on a report from Baltic InteGrid[12] listing revenue and employees for a number of wind power industries. Using this, and the estimated cost of a wind farm, the man-years of work implied per MW is expected to fall in the range of 5-15 man-years/MW. The midpoint, of 10 man-years/MW, correspond with estimates from the Danish Government[13] of 10.25 man-years/MW.

In addition to this CAPEX-related work, approximately, 0.9 man years/MW of ongoing work are related to OPEX. These OPEX-related jobs consist of work linked to the provision of port services, transport, and electrical maintenance work. While CAPEX-linked jobs will be a one-time deal for each wind farm and will only be supported during the planning and construction phase, OPEX jobs will be supported for the entire lifetime of the wind farm.

4.3.2 Results

Combining the estimated deployment of offshore wind capacity under our deployment scenarios, as shown in Table 4-5 above, with the estimated employment effects of CAPEX and OPEX discussed immediately above provides estimates of the total number of jobs supported. Note that because CAPEX jobs are linked to the rate of deployment whereas OPEX jobs are linked to the amount of capacity, a constant rate of offshore wind deployment implies a steady level of CAPEX-related employment[14] but an ever increasing quantity of OPEX-related employment, as shown visually in Figure 4-15 below.

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[12] "Supply chain analysis of the offshore wind energy transmission industry – overview for the Baltic Sea Region", May 2018.

[13] https://efkm.dk/media/11858/faktaark_om_energiudspillet_2018.pdf (Danish)

[14] This steady level is not reached immediately because projects take several years to plan and build and therefore the CAPEX work is spread over several years. The steady state level is only reached when the first wave of projects is reaching completion and the number of projects coming to an end offsets the number of projects starting up.

Figure 4-15 Employment impacts and cumulative capacity over time, Low case

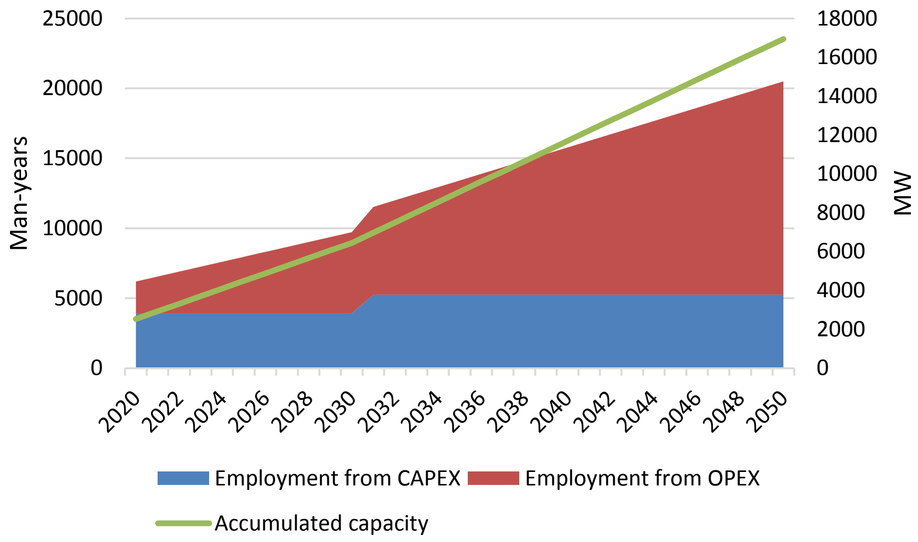


Table 4-7 below shows the estimated total employment effect for both the Low and Ambitious deployment cases, with CAPEX employment disaggregated into the different supply components based on each component's share of CAPEX. By considering where these elements of the supply chain might be located geographically, we can begin to get a sense of the total employment impact in different countries.

Table 4-7 2020 and 2050 employment estimates by deployment case and supply chain segment

Employment	2020 low	2050 low	2020 high	2050 high
CAPEX				
Wind turbine	2,400	3,200	6,100	5,800
Foundation	1,000	1,300	2,500	2,400
Electrical equipment	600	800	1,500	1,400
Operation and maintenance	2,300	15,300	2,300	28,900
Total	6,300	20,600	12,400	38,500

In considering the geographic location of different elements of the supply chain, it should be noted that the bulk of the CAPEX-related employment relates to turbine supply. Germany and Denmark already have an existing turbine supply chain and account for a large share of the anticipated regional offshore wind deployment. Furthermore, any turbine deployed in the region will need to be transported by sea, and sea transport cost considerations are unlikely to be an important reason for sourcing the turbine from one BEMIP member state relative to another. For all these reasons, we anticipate that a disproportionate share of the wind turbine supply jobs associated with Baltic Sea offshore wind deployment would be located in Denmark and Germany. This is especially true under the low deployment case, as the levels of deployment envisaged are unlikely to encourage turbine manufacturers to establish new turbine manufacturing facilities far from their existing production sites. That said, and as we discuss further below, other elements of the supply chain are likely to offer greater employment opportunities for the wider BEMIP region, notably since they can make use of the existing heavy-manufacturing base in some BEMIP countries.

In general, the extent to which an offshore wind supply chain is fostered outside of Germany and Denmark, where it already exists, is likely to depend both on the relative attractiveness of investment in these other markets and on whether the industry has sufficient confidence in the scale of future orders to justify investment in new production lines or facilities. This confidence depends, in turn, on the credibility of commercial or political commitments to support offshore wind deployment.

Job creation under the different deployment scenarios

Low deployment case

The low case corresponds to 400-500 MW of offshore wind deployment per year and annual investment of 1.1-1.4 bn €, as described above. The development in total employment for the whole region is illustrated in Figure 4-15 above.

This case implies support for approximately 4,000- 5,000 man-years of CAPEX-related employment annually. Given the scale and nature of the deployment described in this case, we expect most of this work to fall to the existing supply chain in Denmark and Germany, as we do not expect the level of activity described would motivate manufacturers to invest in new local production capacity elsewhere in the region. Planning and installation activities could, however, be sourced more widely from within the region.

Installation activities, which might be provided by suppliers outside Denmark and Germany, cover approximately 10% of the total CAPEX cost of a project. Assuming the number of jobs supported is roughly proportional to the total cost of the relevant activity, the total number of jobs supported for this type of supply is 400- 500 over the projection period to 2050. Assuming that 20 % of the preparation and installation activity is locally-provided by BEMIP countries other than Denmark and Germany, the added employment in other BEMIP countries corresponds to an annual employment of 80-100 man-years.

The low case also implies support for an increasing number of OPEX-related jobs, with the total amount of work supported reaching 15,300 man-years annually in 2050. Operation and maintenance should be performed from ports located close to the major wind farm areas and the location of the supported jobs is therefore tied more closely to the physical location of the wind farms themselves than is true for CAPEX-related employment.

Ambitious deployment case

In the Ambitious case, offshore wind capacity increases by 1,000 MW per year in the region, corresponding to annual investment of €2.7bn. This implies support for CAPEX-related employment of approximately 10,000 man-years. In this case, wind turbine manufacturers and sub-suppliers might plausibly establish manufacturing and assembly facilities in BEMIP countries other than Denmark and Germany. The Ambitious case may also encourage the development of new port facilities with the capacity to handle a large number of wind turbines.

Looking in greater detail at the number of jobs that might be supported outside of Germany and Denmark, the installation activities that were the focus of employment outside Denmark and Germany in the Low case might be approximately twice as high in the Ambitious case, corresponding to an annual employment of approximately 200 man-years during the period 2020-2050. However, the Ambitious case would also make possible the local sourcing of other types of input, such as those related to preparation. Preparation activities account for approximately 12% of total costs and this implies possible support for another 240 man-years of annual CAPEX-related employment in the BEMIP countries excl. Denmark and Germany.

Supply costs account for approximately 78% of the total CAPEX cost and therefore the majority of the supported employment. This type of activity would be expected to support CAPEX-related employment of 7,800 man-years in the region. BEMIP member states with heavy industry and offshore industries, e.g. Poland, Finland and Sweden, could potentially undertake a large amount of the manufacturing activity associated with major wind farm components like foundations and rotor blades. If we assume that 20% of this activity takes place in BEMIP countries other than Denmark and Germany, this implies CAPEX-related manufacturing employment in the other BEMIP states of a further 1,600 man-years annually.

Finally, the Ambitious case also implies support for an increasing number of OPEX-related jobs. 29,000 man-years of OPEX-related employment are supported across the region in 2050. Again, these activities should be performed from ports located close to the major wind farm areas and will therefore be tied to the location of the farms.

4.4 Conclusions

The screening process undertaken for the Baltic Sea area clearly shows the availability of sites suitable for large scale offshore wind farm deployment – availability that far outstrips credible ambition. Indeed, even our 'Ambitious' deployment case only envisages deployment of around 32 GW, relative to around 93 GW of identified potential. The specific characteristics of these potential sites vary and are detailed in the results of this report. The screening criteria used take into account the quality of wind conditions however and, consequently, the identified sites have an average capacity factor of 40%.

Having reviewed the industries already present in the region, we find that almost all BEMIP countries have the potential to contribute to the offshore wind supply chain through the provision of services and components. The number of jobs supported and their distribution across the region will depend on the level of deployment. The Low and Ambitious deployment cases examined imply support for around 4,000-10,000 man-years of CAPEX-related employment annually, as well as a number of jobs linked to operation and maintenance which increase over time as capacity grows. By 2050, our estimates show support for 15,000-29,000 man-years of OPEX-related employment across the two scenarios.

5 Task 2 – Analysis of demand and supply, investment costs, prices and regional flows

Key Messages from the Results

- An important back-drop for the analysis of the role of Baltic offshore wind power towards 2050, is the profound transition of the power sector. Modelling of associated policy and market frameworks shows European renewable energy shares reach close to 70% by 2030 and more than 90% in 2050. At the same time, electrification within transport, heating and industry increases the overall demand for electricity.
- In this context, Baltic Offshore wind power can be a cost-efficient energy source. Offshore wind power's levelised costs of energy are projected to fall to around 50 €/MWh in 2030 and 36 €/MWh in 2050, including connection costs, which account for around 1,6 €/MWh and 1,3 €/MWh respectively. The analysis shows that based on current market dynamics the most attractive sites are located in the southern part of the Baltic Sea due to lower generation costs and a higher market value of the generated power. The higher market value is explained by the proximity to load centres in central Europe. In the northern part of the Baltic Sea the presence of relatively cheap alternative RES (mainly onshore wind power) and relatively scarcer population limit the market value of offshore wind power.[15]
- By 2030, Baltic offshore wind power in the southern part of the region is competitive with other generation options (both fossil and renewable), even when accounting for the costs of connecting the offshore wind farms to the grid and the lower market value of the intermittent generation.
- By 2050, ambitious deployment levels for Baltic offshore wind power of 32 GW could reduce aggregated generation cost by around 200 million €/year compared to a scenario with lower deployment of 17 GW.
- Regional cooperation on grid development through advanced offshore hubs, which both connect offshore wind power to several markets and provide transmission capacity between countries, has the potential to further increase the value of Baltic offshore wind power, thus lowering aggregated generation costs in the long run. In scenarios with ambitious Baltic offshore wind power deployment, aggregated generation costs could be

[15] We note, however, that resistance to the development of onshore wind capacity in the region could support higher electricity prices in the northern part of the Baltic Sea and that statistical transfer agreements under the recast Renewable Energy Directive could support the development of projects even in areas with relatively low power prices.

reduced by 700-900 million €/year in 2050.

- Regional cooperation on deployment and support to offshore wind power through cross-border support instruments (opening of support schemes and cooperation mechanisms as set up in the recast Renewable Energy Directive) allows for more efficient distribution of offshore wind power capacity across the Baltic Sea as a whole. Coordination to utilise sites with lower deployment costs and more valuable power generation could cater for further cost reduction of around 700 million €/year in 2050 in the case for ambitious deployment of Baltic offshore wind power. At the same time, the more efficient distribution of Baltic offshore wind power also facilitates better utilisation of other renewable energy sources, such as onshore wind.

Task 2 analyses the role of and value of Baltic offshore wind power in the future European power system. The task builds on the identified technical potential in Task 1 and uses a power market model to investigate the implications of deployment of Baltic offshore wind power. We analyse different levels of wind power deployment and different levels of cooperation on offshore wind power in the region. The cooperation scenarios include the establishment of multinational offshore wind power hubs connected to more than one onshore transmission grid and the use of cooperation mechanisms for offshore wind power deployment across the region.

The market modelling takes into account the CAPEX and OPEX costs of generation capacity, including fuel and carbon costs as well as the costs of connecting offshore wind power to the grid. Task 3, presented in the next chapter, considers the cost of congestion management within bidding zones, both in terms of the costs of network reinforcement and the costs of redispatching power plants in order to manage internal transmission constraints.

In section 4.1 we describe the methodology used in the market modelling, including a brief description of the power market model, the main assumptions for the development of the overall European Power system and the scenarios examined. The modelling results are presented in detail in section 4.2, starting with an overview of the transition of the system overall in the horizon up to 2050. The section moves on to compare aggregated generation costs under the different scenarios. Section 4.3 concludes on the findings from the market modelling and analysis in task 2.

5.1 Methodology

This section presents the methodology used in Task 2. First, Balmorel, the fundamental market model used in the analysis is introduced. Then, the overarching policy and economic context in Europe that is assumed in this study is described, before defining the different scenarios for the deployment of Baltic offshore wind power explored in this project.

5.1.1 The Balmorel model

The Balmorel market model is used to analyse the European[16] power market. The model finds a supply and demand equilibrium in the combined electricity and district heating sectors by co-

[16] Figure 5-1 shows the countries included in the power system analysis.

optimising both the dispatch of units and investment in new generation capacity under a given set of assumptions and framework conditions (further described in section 4.1.2).

The development of European power generation capacity, as identified by the model, is the result of a combination of exogenous assumptions, such as existing generation and interconnector capacity, expected capacity expansions and decommissioning, as well as model-optimised investments in power generation, which depend on market conditions and technology costs.

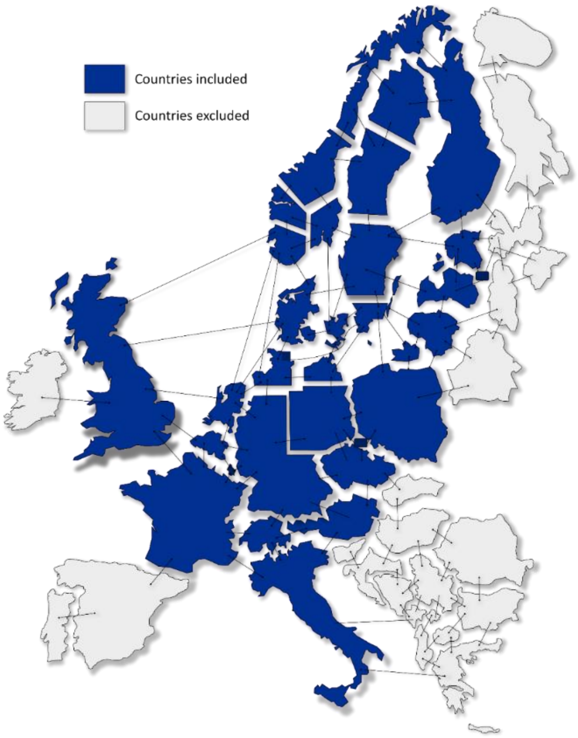
A detailed description of the Balmorel market model can be found in Appendix D.

5.1.2 The European power system

The analysis of Baltic offshore wind power is made in the context of a wider European power system that transitions to high shares of renewable energy generation and sees increasing electrification of the heat and transport sectors. These changes are brought about by a combination of national renewable energy policies, a rising carbon price and continued technological development that combine to make renewable generation technologies the least-cost option for new investments in the power market.

The simulations with the Balmorel model are carried out for a geographic area comprising the Baltic countries, the Nordic countries, Poland, Germany, the Benelux countries, Great Britain, France, Switzerland, Austria, the Czech Republic and Italy. The countries included in the analysis, hereafter the *modelled area*, are highlighted in Figure 5-1. While not covering the whole EU-28, the modelled area covers those areas of the power market significant to the analysis of market developments in the Baltic Sea area.

Figure 5-1 Countries included in the power system analysis, modelled area



Note: Kaliningrad is not included in the modelling area. The cross-zonal connections shown represent options only and do not necessarily reflect those implemented in the modelling.

A discussion of the modelling's consistency with a variety of climate targets is considered further in the box below.

Carbon emissions pathway

The current study focusses on the power and district heating sector. The assumptions on parameters that drive carbon emission reductions are taken from a variety of sources, and the carbon reductions achieved are a result of model optimisation based on these assumptions. Important drivers of the emissions pathway include technology cost developments, carbon and fuel prices and, in the shorter term, national policies on renewable energy. Whether or not the power system described by the scenarios considered is consistent with EU's emissions reduction targets, the Paris Agreement or limiting global warming to 1.5°C depends on developments in other sectors and in countries outside the scope of this analysis. However, there are factors that provide an indication on the likelihood of the scenarios' consistency with these goals.

- In the short term, towards 2030, the model requires that renewable energy deployment levels are *at least* as high as those defined in ENTSO-E's sustainable transition scenario[17], which according to ENTSO-E *is just on track with EU's 2030 targets."*
- The carbon prices applied in the modelling beyond 2030 are based on the International Energy Agency's World Energy Outlook 2017 "Sustainable development" scenario. This scenario *"paints a picture to 2040 that is consistent with the direction needed to achieve*

[17] TYNDP 2018 Scenario Report, ENTSO-E 2018.

the objectives of the Paris Agreement". Whether the global average increase in temperatures would be limited to well below 2 degrees would necessarily depend on the actions taken in the second half of the century beyond 2040.

- Relative to their 2005 level, emissions from power and district heating within the modelled area fall by 67% in 2030 and 96% in 2050 (see section 5.2.2). The share of electricity generation from renewable sources increases to around 70% by 2030 and to more than 90% in 2050.
- To put this in context, the European Commission's 2011 climate roadmap[18] suggested that the power sector's emissions in 2030 should fall by 51–66% relative to their 2005 level in order to achieve an overall emissions reduction of 36–40% over the same period.

Power demand

The assumptions for development of electricity demand in the modelled area are mainly based on ENTSO-E's scenarios in the TYNDP 2018. For 2020 and 2025, data from the Best Estimates (BE) scenarios are applied in this work. For 2030 and 2040 demand assumptions in this work are based on the Sustainable Transition (ST) scenario of TYNDP 2018, which is further extrapolated out to 2050.[19]

The electricity demand assumed for future years accounts for both traditional sources of demand and new demand from:

- Electric vehicles,
- Electricity use for space heating,
- Electricity for industrial electrification (e.g. for the process heat (industry), and
- Electricity for district heating.

Electricity use in district heating and for industrial electrification is determined endogenously in the model simulations and depends on model optimisation. For district heating, the use of electricity is one of the options available to the model to meet district heating demand, in addition to fuel-based technologies (combined heat and power or district heating boilers).

An electrification potential for industrial electrification is defined, which can be supplied using electricity or fuel-based heat generation. The estimated potentials are based on statistics for the share of industrial energy services supplied by oil, gas and coal.[20] We assume that by 2030, up to 50% of this identified potential can be supplied by electricity, reaching 100% in 2050. This equals a potential additional electricity demand of around 350 TWh in 2030 and 700 TWh in 2050 for the modelled area. The model results imply that around 50% of the permissible potential is used in 2030 and around 75% in 2050.

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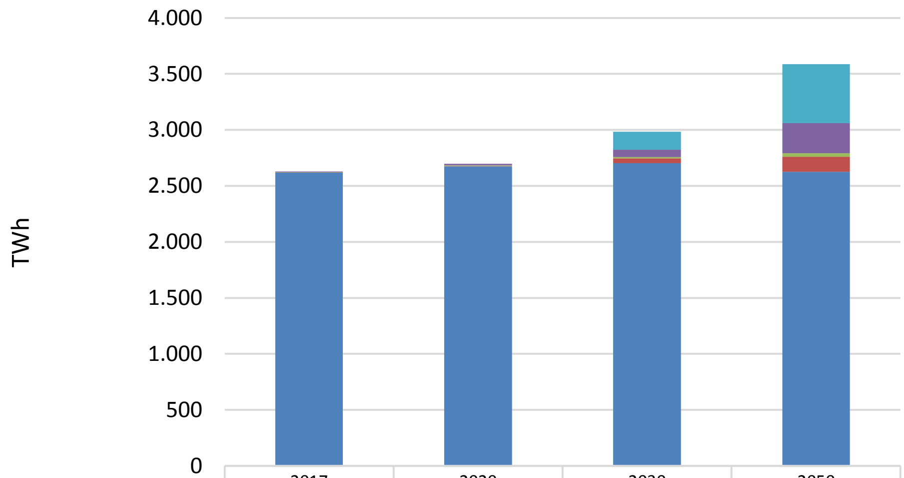
[18] European Commission (2011). A Roadmap for moving to a competitive low carbon economy in 2050. Com(2011) 112 final.

[19] The TYNDP scenarios also include a EUCO (European Commission) scenario for 2030. However, the assumptions on electricity demand for 2030 do not match developments in the Best Estimate scenarios towards 2020 and 2025. Applying the EUCO scenario for 2030 would therefore imply unrealistically rapid changes in electricity demand between 2025 and 2030.

[20] Data based on Mantzos L. et al; *JRC-IDEES: Integrated Database of the European Energy Sector - Methodological note*, EUR 28773 EN, Publications Office of the European Union, Luxembourg, 2017, ISBN 978-92-79-73465-6, doi:10.2760/182725, JRC108244. Energy service defined as "useful energy demand" in the publication.

Figure 5-2 shows the development of total power demand between 2017 and 2050, split by the different types of demand. Parts of the demand projection are subject to model optimisation and are therefore a result of the modelling rather than an exogenous assumption. The specific numbers used in Figure 5-2 shows demand in a scenario with low offshore wind power development in the Baltic Sea Region (Low-NP scenario, see section 5.1.3 for an elaboration of the scenario setup). In the scenarios with more ambitious deployment of offshore wind power, total electricity demand from industry and district heating is approximately 1 TWh higher in 2030 and approximately 4 TWh higher in 2050.

Figure 5-2 Power demand by type in the modelled area



	2017	2020	2030	2050
Industrial electrification	0	0	159	527
Individual heating	5	15	67	267
District heating	2	5	11	31
EV	0	4	43	135
Classic	2.621	2.674	2.704	2.626

Note: Parts of the demand projection are subject to model optimisation and are therefore a result rather than an exogenous assumption. The figure shows demand in the Low-NP scenario.

Renewable energy policies

For each country in the modelled area a minimum level of renewables deployment is anticipated to reflect the effect of climate and energy policies at both national and EU levels. The minimum levels of renewable deployment, which are specified in the model for each country and for each technology out to 2030, are set equal to the deployment levels given in ENTSO-E's "Sustainable Transition" scenario (see Appendix D).

Fuel and carbon prices

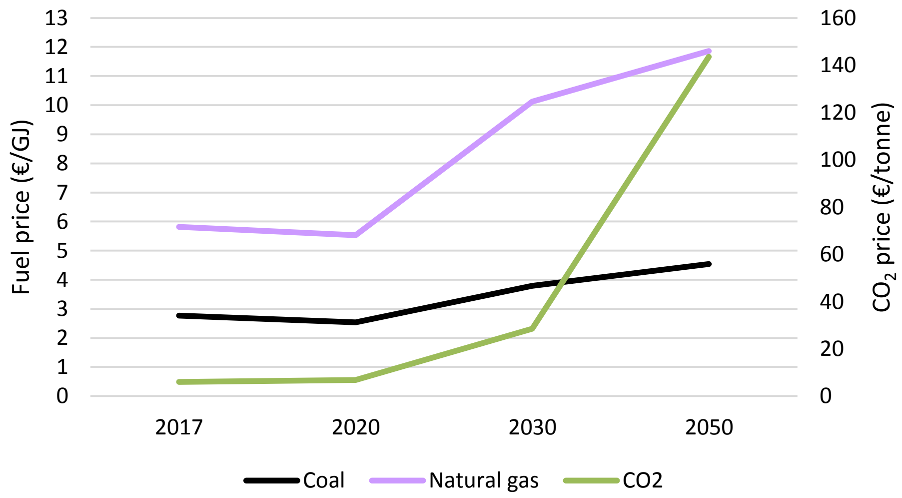
The assumptions used for the development of fuel prices have been defined by the European Commission for the period from 2030 to 2050. Between 2020 and 2030 a transition trajectory between current (primo 2018) fuel prices in the forward markets and the European Commission's assumptions for 2030 has been applied (see Appendix D).

Similarly, the carbon prices are based on the EU Commission's estimates for 2030. Beyond 2030, we assume that carbon prices rapidly align with the price trajectory given in the International Energy Agency's World Energy Outlook 2017 "Sustainable development" scenario.

As Figure 5-3 shows, the natural gas price is projected to double between 2020 and 2050, increasing from just below 6 € per GJ (21 €/MWh) to almost 12 € per GJ (43 €/MWh). Similarly, the price of coal increases by approximately 70% from around 2.6 € per GJ in 2020 to approximately 4.5 € per GJ in 2050.

The price of CO_2 reaches 29 €/tonne in 2030 rising to 144 €/tonne by 2050. It should be noted that the CO_2-price of around 20 €/tonne observed in the autumn of 2018 is substantially higher than the CO_2 price of 7 €/tonne which is used for 2020 simulations.

Figure 5-3 Price projections for coal, natural gas and CO_2



RES shares

In June 2018, the European Commission, the European Parliament and the European Council agreed to increase the renewable energy target to 32% with the possibility of an upward revision in 2023. Both ENTSO-E's scenarios as well as the framework assumption for this study were set prior to the decision on increasing renewable energy targets, and therefore do not explicitly include a minimum target of 32%.

In the modelled area the share of electricity generation from renewable sources increases to around 70% by 2030 and to more than 90% in 2050. This is likely to be well in line with the EU's 32 % renewable target. However, determining renewable energy use as a share of final energy consumption is not possible within the framework of this project since only the power and district heating sectors in the modelled area are covered by the analysis.

The resulting shares of RES-E in the different countries are a result of the model optimisation under the given assumptions and reported in section 5.2 and Appendix D.

Nuclear power

A fixed development of nuclear power generation capacity is assumed in all scenarios reflecting national policies and decided plans.

Development of the transmission grid

Towards 2030, the development of the transmission grid in the modelled area is based on the ENTSO-E's Ten-Year Network Development Plan 2018. After 2030, there are no firm plans for expansion of the European transmission grid, yet further strengthening of the grid is likely to become an important means to integrating high shares of variable renewable energy. To account for this, as a rough assumption, it is assumed that all cross-zonal transmission capacities in the modelled area are increased by 50% between 2030 and 2050.

Overview of main model assumptions and optimisations

The table below provides an overview of the modelling approach applied for the most important topics. The assumptions are presented in more detail in Appendix D.

Table 5-1 Modelling approach to various topics

	Exogenous requirements/assumptions	Model optimisations
Offshore wind power capacity – Baltic Sea	The requirements for installed capacity are set dependent on the scenario.	Optimised site selection based on cost (including connection cost for radial connections), resource quality and market value.
Other offshore wind power capacity – Rest of Europe	Minimum requirements to reflect minimum national ambitions towards 2030. Based on TYNDP scenarios (see page 46) After 2030, no further increases in minimum requirements.	Model can build capacity above minimum requirement if beneficial based on costs and conditions.
Other RE capacities	Minimum requirements reflect minimum national ambitions towards 2030. Based on TYNDP scenarios (see page 46) After 2030, no further increases in minimum requirements.	Model can build capacity above minimum requirement if beneficial based on costs and market conditions.
Nuclear power capacity	Best estimate reflecting national policies/decided plans. Unchanged across scenarios.	No model optimisation.
Fossil fuel capacities	Current capacities and already decided decommissioning in the short run. Policies for phase-out of coal power are taken into account by reducing exogenous capacity for the relevant countries.	The model can decommission existing capacities after 2020 if not economically viable on market terms. The model can invest in new capacities if viable on market terms. For all countries except Poland, no new coal power investments are allowed.

	Exogenous requirements/assumptions	Model optimisations
Transmission capacities	Expected buildout based on current TYNDP towards 2030. Towards 2050 further transmission system expansion is exogenously assumed, resulting in 50% higher cross-zonal transmission capacity compared to 2030.	No model optimisation of general transmission system.
Power demand	Assumed exogenous trajectory for electricity demand from households, service sector, most industrial demand, heating in buildings (excl. district heating) and transport.	Model-optimised use of power for district heating, industrial process heat and hydrogen production. Model has some flexibility on the hourly demand profile for the different demand types.
Fuel prices	Fuel price levels based on input from the European Commission. See Appendix D	
CO_2 prices	CO_2 price levels based on input from the European Commission in 2030 and on IEA's Sustainable development scenario towards 2050. See Appendix D	
Power prices		Modelling result based on investment and dispatch optimisation.

Economic assessment of results

The Balmorel model allows for detailed economic evaluation of both individual power plants, as well as overall scenario economy. In this project, two main economic assessments are carried out:

- Economic assessment of Baltic Offshore wind power
- Economic assessment of the overall economy for a given scenario

The assessment of Baltic Offshore wind power is based on an evaluation of the cost of generation (LCOE) and the market value of the generated electricity. The LCOE consists of the cost of establishing the wind farm (turbines, offshore platforms and transmission) as well as the cost of operating the wind farm.

The assessment of the overall economy is carried out by calculating the total socio-economic cost related to serving both district heating and electricity demand in the modelled countries. This cost is referred to as the aggregated generation cost and includes all technologies in the entire system. The total socio-economic cost is derived from the capital cost of all new installations (C_{CAPEX}), maintenance cost (C_{OPEX}), fuel cost (C_{FUEL}), and the socio-economic cost of GHG emissions (C_{GHG}).

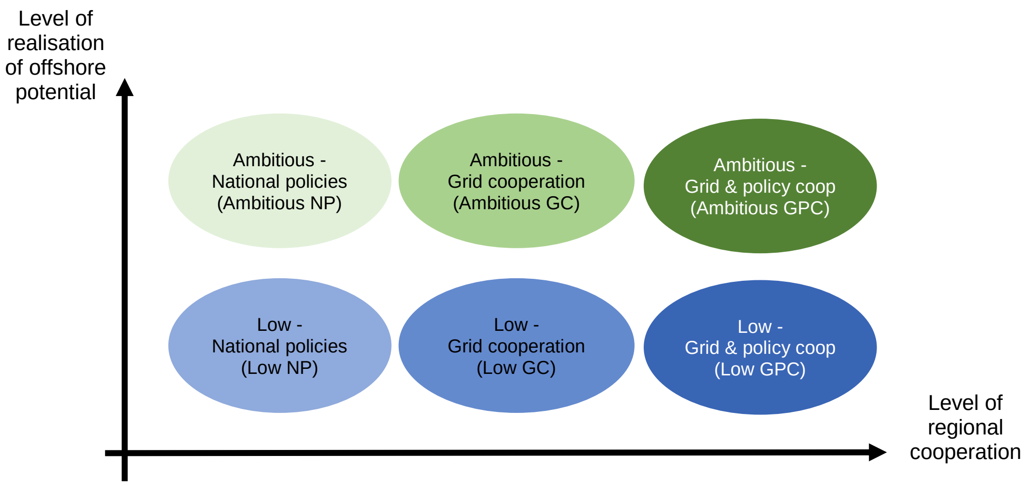
$$C_{tot} = C_{CAPEX} + C_{OPEX} + C_{FUEL} + C_{GHG}$$

Capital cost is calculated using a real discount rate of 5% and a lifetime of 20 years for all technologies, corresponding to the economic requirements for new investments in the model run. For the GHG emissions, only differences in CO_2 emissions are taken into account, while effects on other GHG emissions, particle emissions and other pollutants are disregarded. The cost of emissions is set equal to the applied CO_2- price.

5.1.3 Baltic offshore wind power scenarios

Six scenarios for offshore wind power development in the Baltic Sea are considered, which vary along two dimensions: the level of offshore wind power deployment and the level of regional cooperation (Figure 5-4).

Figure 5-4 Scenario setup for deployment of Baltic offshore wind power



Three levels of regional cooperation are analysed (National policies, Regional grid cooperation, Regional grid and policy cooperation) in conjunction with two levels of total offshore wind power deployment in the Baltic Sea region (Low and Ambitious deployment). These are described in more detail below.

Levels of regional cooperation

In the **National Policies (NP)** scenarios, a fixed capacity of Baltic offshore wind deployment has been defined for each of the individual BEMIP countries. Each country deploys offshore wind generation along this fixed trajectory, but the model is free to select the individual sites used within each country. The offshore wind farms developed in these scenarios are connected to the respective national grids via radial connections. This reflects the main approach used in offshore wind power deployment today.

In the (offshore) **Grid Cooperation (GC)** scenarios, four advanced offshore hub configurations are built. Each of these hubs incorporate specific offshore wind sites that are integral to the hub and provide additional cross-zonal capacity through multiple (advanced) connections. As a result, the offshore hubs serve not only as connection points for wind turbines, but also provide interconnector capacity between the connected electricity markets. Around 45% of total Baltic offshore wind power deployment is connected to the four advanced hubs included in these scenarios.

The hubs have been designed exogenously with the overarching and deliberate objective of creating a scenario with broad grid cooperation across the Baltic Sea. For that reason, hubs are included in both in the Southern and Northern parts of the Baltic Sea region and connections are made to all countries in the region. As we will show later, the hub locations in the southern region are considerably more attractive than the northern locations because they connect bidding areas with low prices (Scandinavia) with bidding areas with high prices (Continental Europe).

The specific locations of the hubs have been selected to reduce cost of connecting the wind farms and to reduce the overall LCOE for offshore wind in the region. The configured hubs 1 and 2 in the southern part of the region are made with inspiration from the Baltic InteGrid project, while the design of hubs 3 and 4, in the northern part of the Baltic Sea Region, have been made specifically for this analysis. It is important to stress that the specific hub design is a complex optimization exercise and further efforts may reveal that other hub configurations would be more attractive.

Also, it should be mentioned that the hub design is not static across scenarios. More wind farms and stronger connections are included for the 2050 scenarios compared to 2030 scenarios and the specific wind farms connected to the hubs also vary slightly between the low and ambitious scenarios to accommodate for the variations in offshore wind deployment targets of the individual countries in the region.

The detailed setup of the hubs is illustrated on Figure 5-5 and Table 5-2. More information can be found in Appendix D. The remaining offshore wind power capacity is connected using radial connections to the onshore transmission network.

Figure 5-5 Configuration of the four advanced offshore hubs

Note: The transmission capacities shown represent those in the ambitious deployment scenarios. The corresponding values for the low scenarios and the connected wind farm capacities are shown in Table 5-2.

In the **Grid and Policy Cooperation (GPC)** scenarios, the four advanced offshore hubs from the grid cooperation scenarios are also established. However, capacity not connected to the hubs is distributed by the model across the entire Baltic Sea in order to achieve regionally cost-effective deployment of the same overall level of offshore wind power capacity. Unlike the grid cooperation scenarios described above, the model does not enforce nation-specific offshore wind power targets. This change allows the model to select the most attractive offshore wind farm sites, namely those that provide the highest earnings relative to the investment made, from across the whole of the Baltic Sea. Cooperation mechanisms under the RES Directive and the opening of cross-borders support could provide the framework for delivering efficient deployment across national borders as envisioned under this scenario. The total level of regional deployment under these scenarios is set equal to the total level of regional deployment under the national policy scenarios to ensure comparability and allow us to isolate the benefits attributable to policy cooperation.

Table 5-2 Interconnector capacity and the wind capacity related to the four hub configurations in the grid cooperation scenarios and the grid and policy cooperation scenarios

Hub	Country	Interconnector Capacity (MW)				Wind capacity (MW)			
		Low scenarios		Ambitious scenarios		Low scenarios		Ambitious scenarios	
		2030	2050	2030	2050	2030	2050	2030	2050
1	Germany	500	1,000	500	2,500	1,000	1,500	600	3,000
	Sweden	500	1,000	500	2,500	-	-	-	-
	Denmark	-	-	-	-	-	500	400	1,500
	Total wind					1,000	2,000	1,000	4,500
2	Sweden	500	1,500	1,500	3,500	-	1,500	1,000	3,000
	Poland	500	1,500	1,500	3,500	1,000	1,500	1,500	2,500
	Lithuania	0	500	500	1,500	-	-	-	-
	Total wind					1,000	3,000	2,500	5,500
3	Estonia[21]	0	500	500	1,000	-	500	500	1,000
	Lithuania	0	500	500	1,000	-	500	500	1,000
	Total wind						1,000	1,000	2,000
4	Finland	500	750	750	750	490	500	500	500
	Sweden	500	750	750	750	467	1,000	1,000	1,000
	Total wind					957	1,500	1,500	1,500
	Total	**3,000**	**8,000**	**7,000**	**17,000**	**2,957**	**7,500**	**6,000**	**13,500**

Levels of Baltic offshore deployment

At the end of 2017, installed offshore wind power capacity in the Baltic Sea equalled approximately 1.4 GW (see D.3.1). Task 1 has, accounting for a range of possible restrictions, identified potential sites for offshore wind farms in the Baltic Sea with a total combined capacity of 93.5 GW. The largest technical potentials found through this exercise exist in Sweden, Denmark, Latvia and Poland. Comparing this technical potential for offshore wind power with external scenarios of potential deployment (see section D.3.1), it is clear that a lack of technically suitable sites is not likely to constrain offshore wind power deployment in the Baltic Sea as a whole. For Germany and Poland however, between 70 – 80 % of the total potential identified is used in the most ambitious scenarios by 2050.

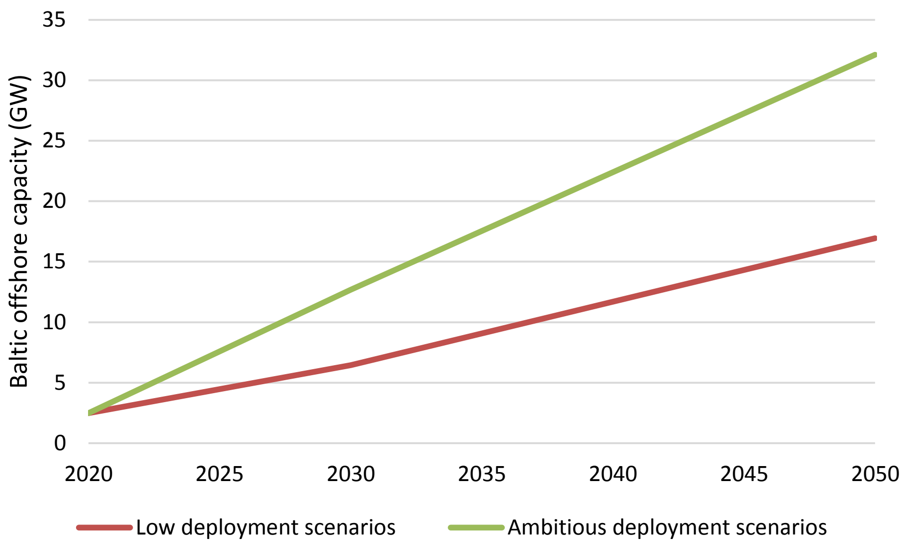
The future deployment of offshore wind power in the region is dependent on how the cost of offshore wind power generation develops relative to other electricity generation technologies, including other renewable energy technologies, as well as the political will to support offshore wind power development through dedicated policies such as an effective CO_2 market and/or renewable energy support schemes.[22]

[21] Estonia indicated a low ambition scenario of 1000 MW of wind capacity by 2030 and a high ambition scenario of 2000 MW of wind capacity by 2030 as suitable to their planned deployment.

[22] The elaboration process of the National Energy and Climate plans was on-going during the finalisation of the study and may result in changes to national deployment plans after the finalisation of the modelling scenarios. Late changes could not be reflected in the modelling.

In this study, two levels of deployment for offshore wind power in the Baltic Sea are explored: Low and Ambitious scenarios. The two levels shown in Figure 5-6 have been set exogenously based on input from the BEMIP renewable energy working group and a variety of external sources (notably ENTSO-E and Wind Europe). Therefore, the total level of Baltic offshore wind power has not been optimised, but the effect of differences in total deployment levels has been analysed. In the scenarios, the rest of the system is however optimized subject to the restriction imposed in the form of Baltic offshore wind deployment. Hence, increased deployment in Baltic offshore wind will to a large extent replace other generation capacity. Depending on market effects, the capacity mix and the location of generation capacity will also vary according to the market optimization in each scenario.

Figure 5-6 Total level of Baltic offshore wind power capacity in the Low and Ambitious scenarios



The Low scenarios are intended to show a continuation of current expectations and trends, whereas the Ambitious scenarios shows an ambitious but achievable pathway for Baltic offshore wind power deployment assuming a concerted effort to facilitate offshore wind power development in the region. Importantly, the scenarios should not be interpreted as representing either the minimum or maximum deployment levels that could conceivably be observed.

› In the **Low scenarios** the pace of deployment over the period from 2020 to 2030 is equal to that expected in ENTSO-E's best estimate scenario. In these scenarios, onshore wind and solar power constitute the main measures used to increase RE shares in the European power system. The implied level of 2030 capacity corresponds roughly to the level seen in Wind Europe's low scenario and is below the levels envisioned by ENTSO-E in its sustainable transition and distributed generation scenarios. By 2050, total capacity is around 20% above the levels shown in ENTSO-E's sustainable transition and distributed generation scenarios for 2040, but almost 20% below the levels seen in ENTSO-E's global

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Revisions to Estonia's ambition not reflected in the modelling have however been included as footnotes in the relevant tables and chapters.

climate action scenario.
Rate of net capacity growth: 400 MW/year (2020-2030), 525 MW/year (beyond 2030)

› In the **Ambitious scenarios** the rate of capacity additions to 2030 is more than doubled compared to the low scenario and thereby well above Wind Europe's central scenario (570 MW/year between 2020 and 2030), but still below Wind Europe's high scenario (1,100 MW/year between 2020 and 2030). The total capacity reached in 2050 is 32 GW, not far from the level of 35 GW seen as an 'upside' scenario by the Baltic InteGrid project when assuming favourable conditions for offshore wind power deployment. Rate of net capacity growth: 1000 MW/year (2020-2050)

The distribution of offshore wind power capacities among countries, as imposed by the national policy scenarios, has been determined using input from other references[23] and input from the BEMIP RES Working Group based on then current plans. In some cases, these plans were updated during the course of the study and these changes are not reflected in the volumes shown below. As such, national ambitions may vary significantly from the levels of assumed deployment shown.[24] In the regional cooperation scenarios, offshore wind power is distributed across the region according to the economically most favourable realisation of regional targets, determined by the modelling. Detailed inputs are shown in Table 5-3.

[23] Sources include: ENTSO-E (2018), *TYNDP Scenario report 2018*; Wind Europe (2018), *Offshore Wind in Europe - Key Trends and Statistics 2017*; Wind Europe (2017), *Wind energy in Europe: Scenarios for 2030;* 50Hertz Transmission, Amprion, Tennet TSO, TransnetBW (2018), *Szenariorahmen für den netzentwicklungsplan Strom 2030 (Version 2019)* – Entwurf der Übertragungsnetzbetreiber; Energinet (2017) – *Rapport 2017 Energinets analyseforudsætninger*; Feedback from the BEMIP working group based on BEMIP Renewable Energy Working Group meeting 24th of May 2018 in Brussels, Belgium.

[24] For example, in Poland, a 10 GW offshore capacity target as soon as 2030 is being discussed, aligned with the phase-out of lignite generation. The capacity pathway we use in this study was decided before this new target was proposed. Modelling results indicate that more ambitious targets compared to the ones assumed in this study may be economically beneficial – however, the study does not investigate or identify the optimal capacity level.

Table 5-3 Offshore wind power capacity requirements in MW in the Baltic Sea for regional low and ambitious deployment scenarios (requirement for Baltic Sea region) and for low and ambitious national policies scenarios (requirements for individual countries in the Baltic Sea region)

	Applicable geography	**2020**	**2030**	**2050**
Regional cooperation scenarios				
Low offshore development	**Baltic Sea region**	2,527	6,445	16,945
Ambitious offshore development	**Baltic Sea region**	2,527	12,695	32,100
National policies scenarios				
Low offshore development	**Denmark***	1,210	1,609	2,109
	Sweden	210	700	3,000
	Finland	33	500	2,000
	Estonia[25]	0	0	500
	Latvia	0	0	500
	Lithuania	0	0	500
	Poland	0	1,500	4,000
	Germany*	1,074	2,136	4,336
Ambitious offshore development	**Denmark***	1,210	1,859	2,800
	Sweden	210	2,000	7,000
	Finland	33	2,000	4,500
	Estonia[26]	0	500	1,000
	Latvia	0	500	1,000
	Lithuania	0	500	1,000
	Poland	0	2,000	8,400
	Germany*	1,074	3,336	6,400

** Only offshore wind power capacity in the Baltic Sea is considered*

5.2 Results

This section describes the results of the power market modelling and the analyses of Baltic offshore wind power deployment scenarios. Section 5.2.1 describes the overall development in power generation in the modelled area. We use the *Low national policies scenario* as a starting point and describes the overall long-term transition of the European power system, focussing on the situations in 2030 and 2050. The subsequent sections focus on the results of the market modelling the Baltic offshore wind power deployment scenarios. Section 5.2.7 concludes on the economic effects of the scenarios based on the market simulations. The market modelling does not account for impacts on internal grid costs within market zones, which are discussed in chapter 6. A comparison of the scenarios that accounts for total system costs (generation and

[25] Estonia indicated 1000 MW for 2030 and 3000 MW for 2050 as suitable for their Low Scenario under their latest plan.

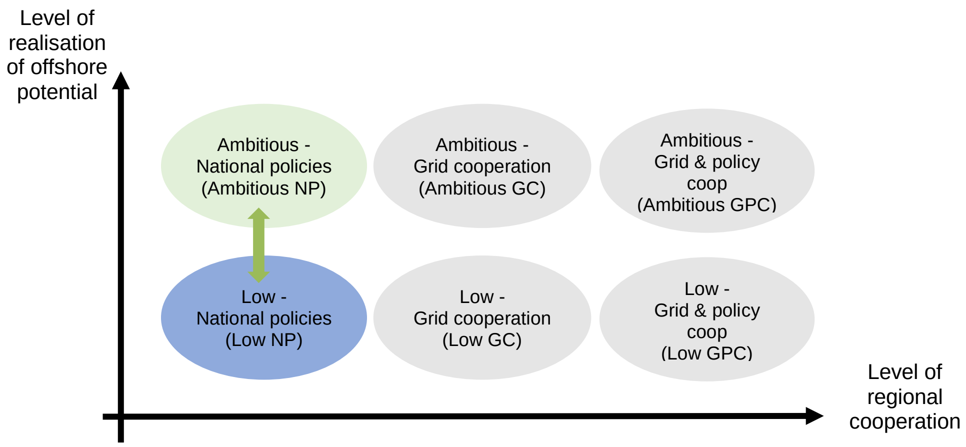
[26] Estonia indicated 2000 MW for 2030 and 4000 MW for 2050 as suitable for an Ambitious Scenario under their latest plan.

grid) can be found in the CBA analysis in Chapter 6. Further details on the market modelling results of all scenarios can be found in Appendix D.

5.2.1 Interpretation of the results

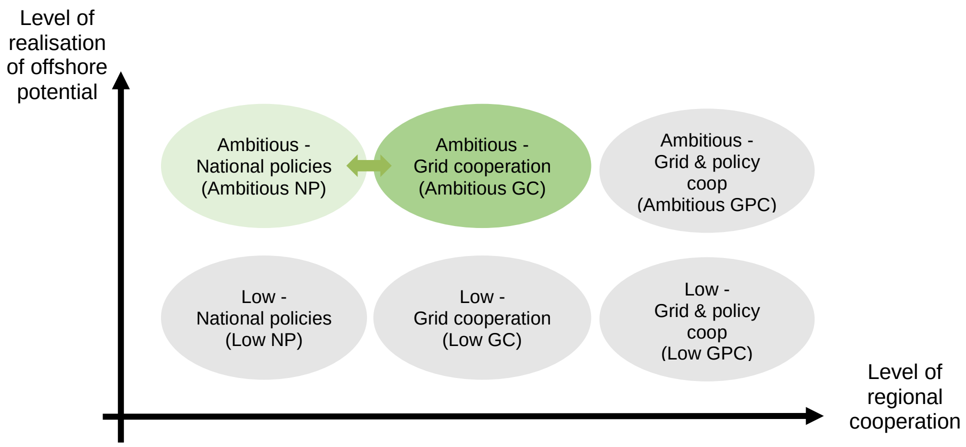
To draw further insights from the analysis, we rely on pairwise comparisons of the different scenarios. For example, to explore the effects of higher offshore wind power deployment we compare aggregate costs between two otherwise equivalent scenarios that differ in terms of the level of offshore wind power deployed. This is demonstrated visually in Figure 5-7.

Figure 5-7 Example of a pairwise comparison of scenarios to explore the effects of different levels of offshore wind power deployment



To analyse the impact of different degrees of cooperation, we compare scenarios with equivalent offshore wind power ambitions, as demonstrated in Figure 5-8.

Figure 5-8 Example of a pairwise comparison of scenarios to explore the effects of regional hubs



Rather than just reporting the difference in aggregate costs, we typically show the changes in each of the different cost elements (e.g. fuel costs and carbon costs). Occasionally, rather than discussing the total change in costs, we normalise this value by dividing it by the total MWh of

Baltic offshore wind power generation, to get a number that shows the change in costs across the scenarios per MWh of offshore wind power generation.

Comparisons of this type form the basis of much of the analysis in the sections that follow.

5.2.2 European power market development

The scenarios and the role of Baltic offshore wind power should be interpreted in the context of the anticipated developments in the European power market. Between 2020 and 2030, the European power system undergoes a very rapid transition to higher RES-E levels and higher shares of variable renewable electricity generation (see Figure 5-9)[27]. By 2030, the RES-E share in power generation for the modelled areas reaches 69% and power sector CO_2 emissions are down 67% relative to their 2005 level (see Figure 5-10).

The combination of rising fuel and CO_2 prices support power price levels that are high enough for onshore wind and solar power to be installed on market terms in many European countries. As a result, the installed RE capacity in many countries surpasses the minimum RE requirements from ENTSO-E's "Sustainable Transition" scenario imposed in the modelling. The question is whether these projects can be realised at the implied pace, rather than whether they are economically competitive. The high RE shares modelled in this work are markedly different from those shown in the European Commission's PRIMES modelling[28], from which we have taken the assumed fuel and CO_2 prices. For comparison, looking only at the areas included in our modelling, the 2016 EU Energy Trends reference scenario shows a RES-E share for gross electricity generation of 42% in 2030, and the EUCO27 scenario shows a RE share of 46%.[29]

The key explanation for the discrepancy in RES-E shares between our modelling and the 2016 EU scenarios is likely to be differences in expectations of the future cost and performance of wind and solar power. The cost assumptions used in this project take into account the rapid reduction in the costs of wind and solar power seen on a global scale since 2016.

European coal power is phased out rapidly in the scenarios, both due to the implementation of announced policies, notably Eurelectric's statement on not investing in new coal fired power plants[30], and commitments by the "powering past coal alliance" to phase out coal by 2030[31]. Beyond 2030, rising CO_2 prices, which reach 140 €/tonne by 2040, further curb fossil fuel generation. CO_2 emissions fall by 95% relative to their 2005 level by the end of the period. Complete decarbonisation does not occur in response to the assumed CO_2 price levels but would be technically feasible in the model if the remaining natural gas demand – which is

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[27] The European results discussed refer to the modelled area in the Low NP scenario. The area-wide results are not significantly different across the different scenarios.

[28] European Commission (2016), *EU Reference Scenario 2016 Energy, transport and GHG emissions - Trends to 2050*

[29] The RE share in our simulations excluding Norway and Switzerland, which are not included in the PRIMES numbers, is 71% in 2030, and strictly speaking it is this number that should be compared with the PRIMES numbers provided.

[30] European Electricity Sector gears up for the Energy Transition - A Statement by Eurelectric, 5 April, 2017

[31] Powering Past Coal Alliance: Declaration, https://unfccc.int/news/more-than-20-countries-launch-global-alliance-to-phase-out-coal

mainly used to cover peak load and provide back-up for wind and PV – was substituted by green fuels, such as biogas or e-fuels. Other options for reaching full decarbonisation would include increased investment in storage technologies.

Figure 5-9 Annual electricity generation by fuel in the modelled area (see Figure 5-1 for included countries), including RES share (secondary axis), Low NP scenario

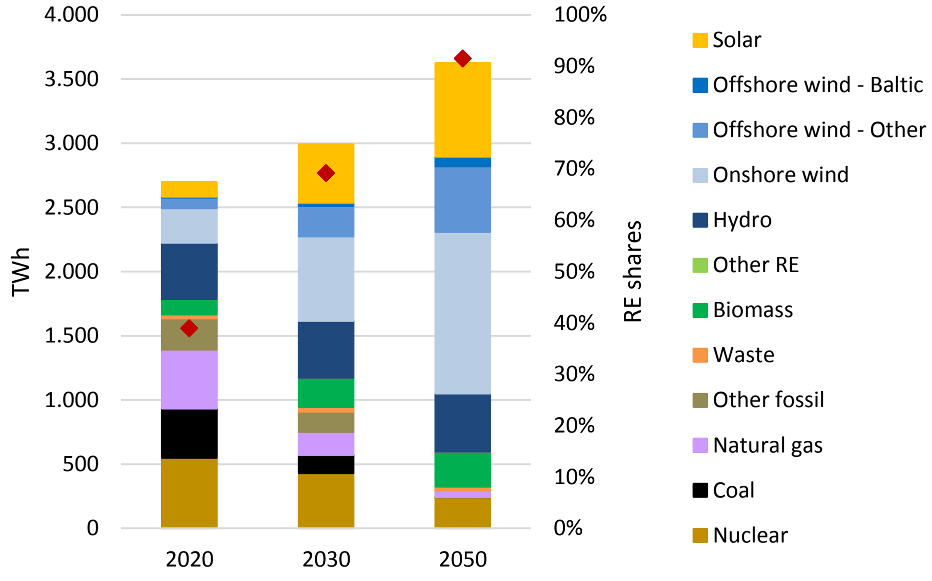
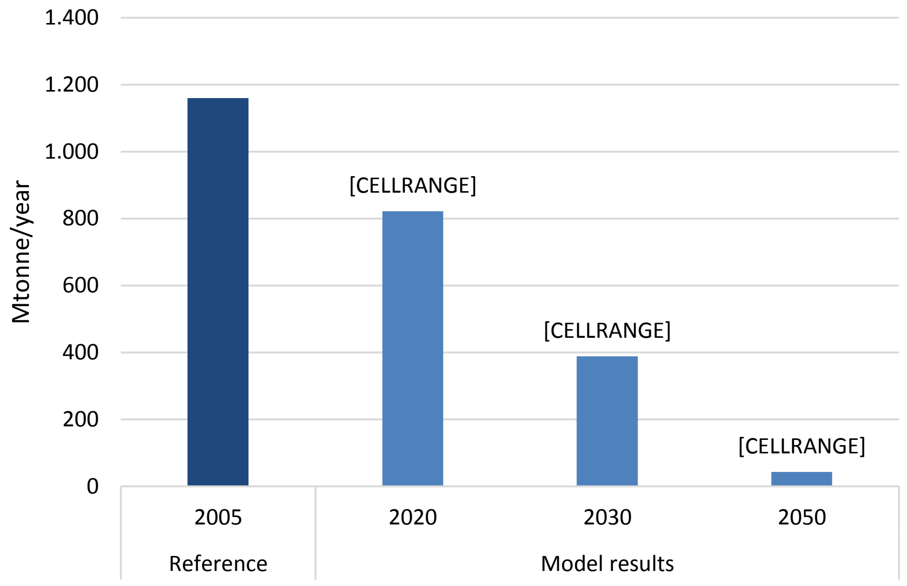


Figure 5-10 Annual CO_2 emission and reductions compared to 2005 for the modelled area (see Figure 5-1 for included countries), Low NP scenario



The assumed increases in fuel and CO_2 prices lead to rising power prices, which reach around 60 €/MWh by 2030 in Germany and Poland (Figure 5-11). Power prices in the Baltic and Nordic countries remain 10-20 €/MWh lower given access to cheaper RE resources in these areas.

Beyond 2030, the continued technological development of wind and solar power and their rising share in the generation mix generally halt further significant increases in average power prices despite rising CO_2 prices. However, this is not the case in Poland, where the limited potential of cheap renewable energy resources causes power prices to increase to approximately 80 €/MWh by 2050.

Price fluctuations increase markedly in all power markets, which is expressed in a substantial number of hours with very low power prices and more situations with price spikes (see Figure 5-12 for an illustration of the price duration curves for Poland).

Figure 5-11 Average annual power prices in the BEMIP region, Low NP scenario

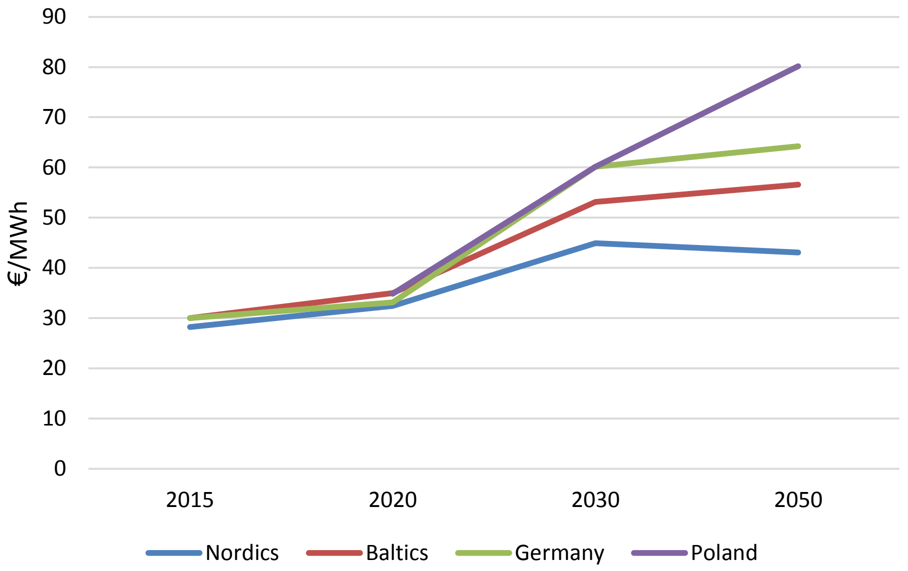
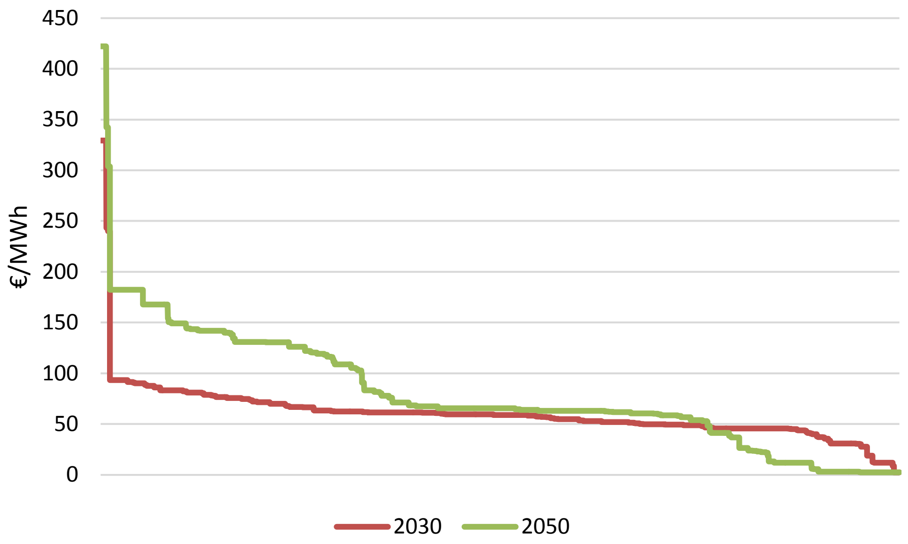


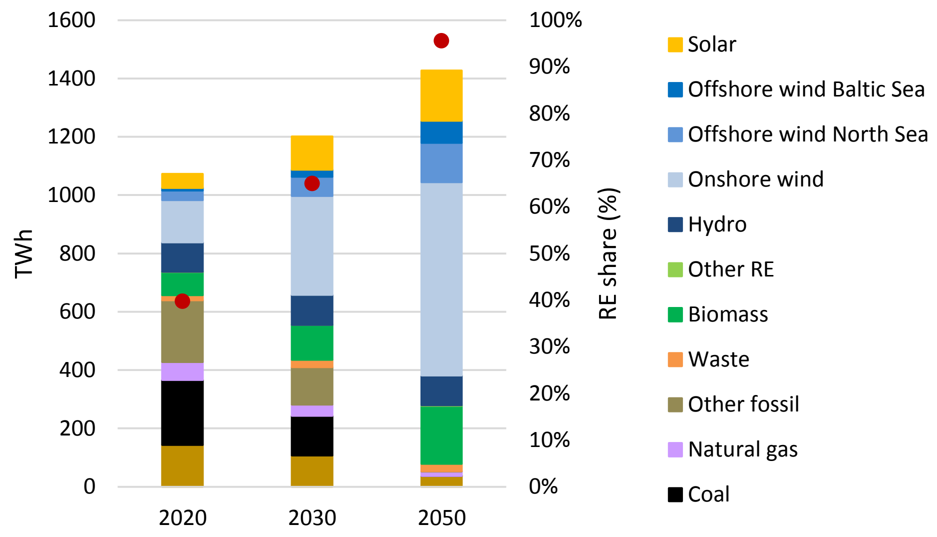
Figure 5-12 Power price duration curves for Poland in the year 2030 and 2050, Low NP scenario



5.2.3 Low offshore wind deployment and National policies

The BEMIP region shows RES-E shares of 65% in 2030 and 96% in 2050 under the Low National Policies scenario. By 2030, offshore wind power represents 8% of total power generation, and this figure reaches 17% by 2050. In 2050, 36% of the offshore generation in the Baltic Sea countries is located in the Baltic Sea, with the remainder in the North Sea.[32]

Figure 5-13 Annual electricity generation by fuel in the Baltic Sea Region (excl. Norway), including RES share (secondary axis), Low NP Scenario



Cost and value of offshore wind power in the Baltic Sea

Figure 5-14 shows the average LCOE and market values (MV) of Baltic offshore wind power per country in 2030. By 2030, the cheapest Baltic offshore wind sites, located in the southwest of the Baltic Sea, have LCOEs at around 50 €/MWh[33], including the cost of connection to the onshore transmission grid, which accounts for around 1.6 €/MWh. The same locations display the highest market value due to high power prices in Germany and Poland, making offshore wind farms at suitable sites economically viable on market conditions in those regions.

Other attractive sites are found in the South East of the region off the coasts of Lithuania and Latvia, where the market value of offshore wind power by 2030 is only 2-6 €/MWh below the levelised cost of electricity generation.

Generally speaking, the highest cost offshore wind farms are located in the western part of the Gulf of Bothnia. At the same time these sites demonstrate the lowest market value due to their location far from load centres in Central Europe.

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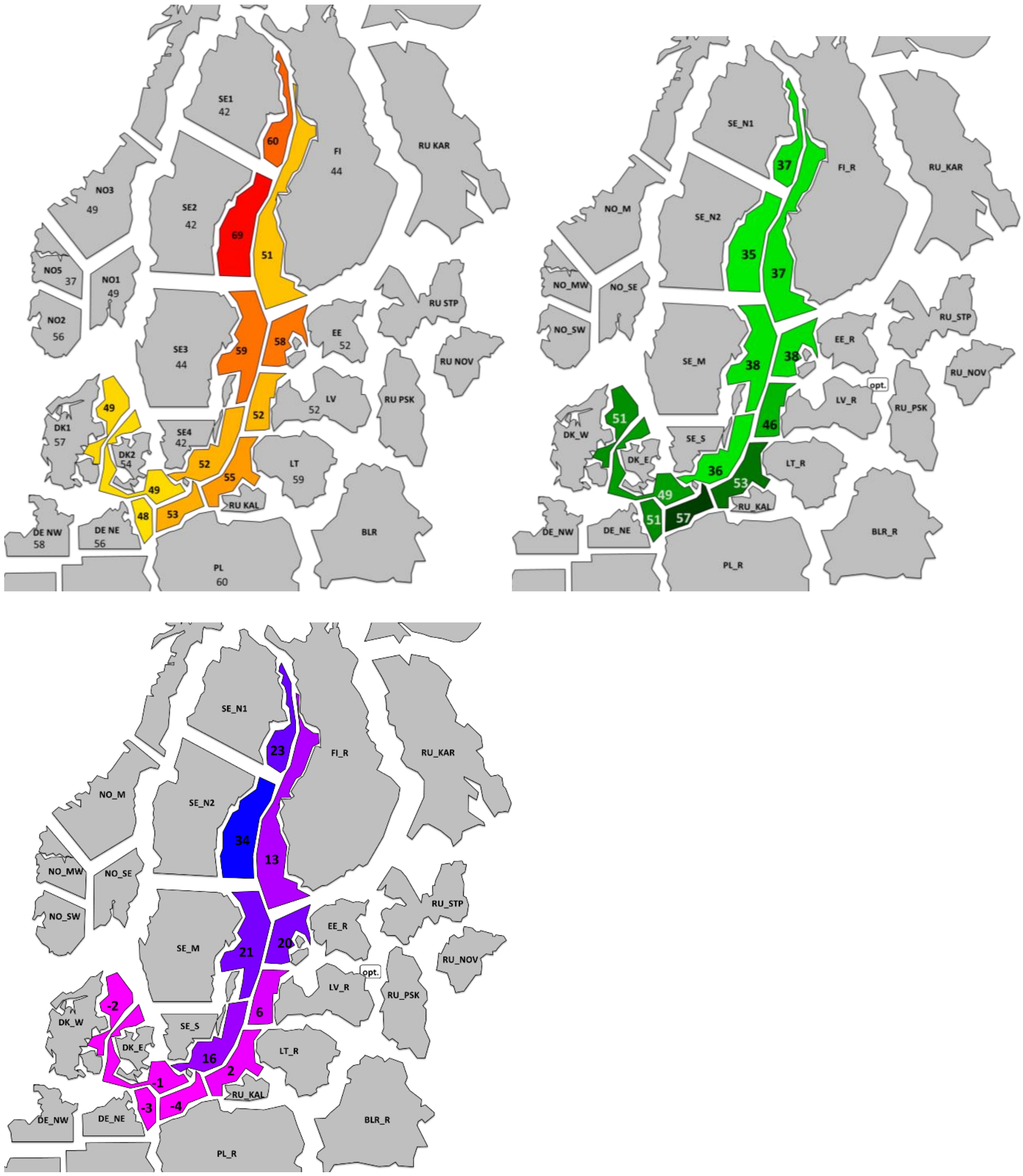
[32] Since offshore wind deployment in the Baltic Sea is fixed by the scenario assumptions, this share is determined in the model by calculating the North Sea capacities deployed by Denmark and Germany.

[33] Based on an economic lifetime of 20 years and a real WACC of 5%.

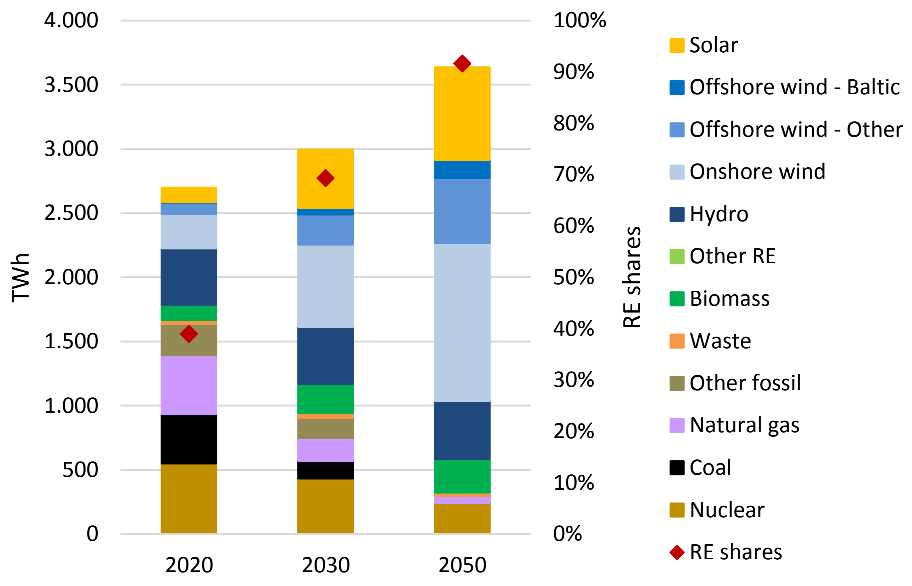
Figure 5-14 Average LCOE of offshore wind power (left), Market Value (MV) of offshore wind power (right), difference between LCOE and MV (below) for offshore wind power (€/MWh) in the Baltic Sea, 2030, Low NP scenario.



5.2.4 Ambitious wind deployment and National policies

The increased deployment of Baltic offshore wind power in the Ambitious NP scenario compared to the Low NP scenario does not change the overall picture of the development of the European power system (Figure 5-15).

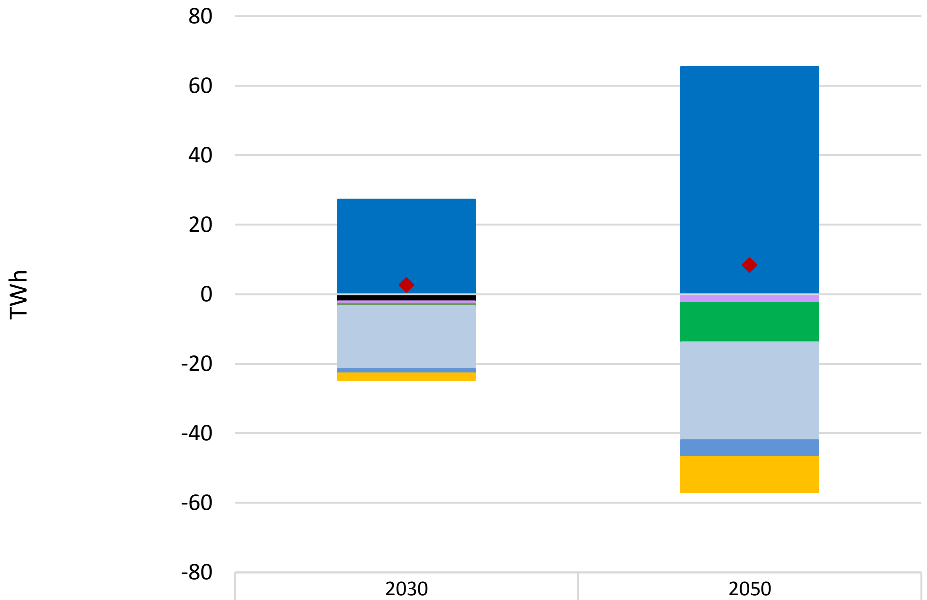
Figure 5-15 Annual electricity generation by fuel in the modelled area (see Figure 5-13) including RES share (secondary axis), Ambitious NP scenario



The buildout of Baltic offshore wind power generation mainly replaces onshore wind in the Baltic Sea region, which would otherwise have been competitive on market terms.

Figure 5-16 shows the changes in generation capacities in the BEMIP countries when comparing the Ambitious and Low national policies scenarios. Increased generation from offshore wind power reduces power prices, particularly on windy days, and thus the income of onshore wind turbines. Consequently, onshore wind deployment is reduced compared to the Low NP scenario. Overall, however, the level of RES generation increases slightly.

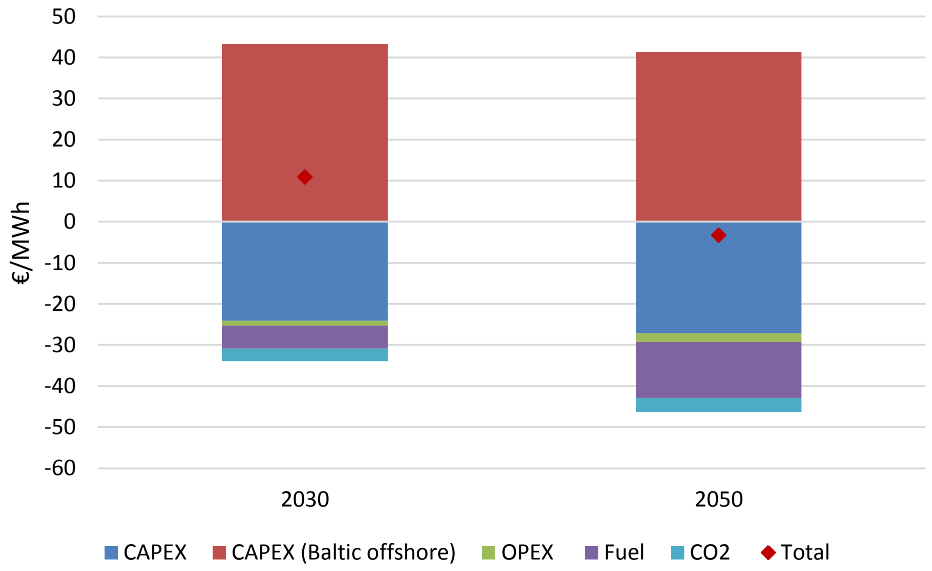
Figure 5-16 *Changes in power generation by source in the BEMIP countries in the Ambitious NP scenario compared to the Low NP scenario.*



	2030	2050
Solar	-2	-10
Offshore wind - Baltic	27	65
Offshore wind - Other	-1	-5
Onshore wind	-18	-28
Hydro	0	-0
Other RE	-	-0
Biomass	-0	-11
Waste	0	0
Other fossil	-1	-0
Natural gas	-1	-2
Coal	-2	-0
Nuclear	0	-0
Sum	3	8

The difference in the overall system generation costs between the Ambitious NP scenario and the Low NP scenario expressed per MWh of additional Baltic offshore wind generation in the ambitious scenario is around 10 €/MWh in 2030, and -3 €/MWh by 2050 (see Figure 5-17). Thus, in the national policy scenarios, the low offshore development scenario is more cost-effective than the ambitious scenario in 2030, but by 2050 this situation has reversed. This is due to improvement in offshore wind power's competitiveness between 2030 and 2050, a result of the projected drop in offshore wind power costs over time, diminishing alternative options for RES-E, and increasing CO_2 and fuel prices. See section 5.2.7 for more details on the generation cost calculations.

Figure 5-17 Changes in aggregated generation costs in the Ambitious NP scenario compared to the Low NP scenario. Shown as €/MWh of additional offshore wind power.*



* *Including connection costs for offshore wind power*

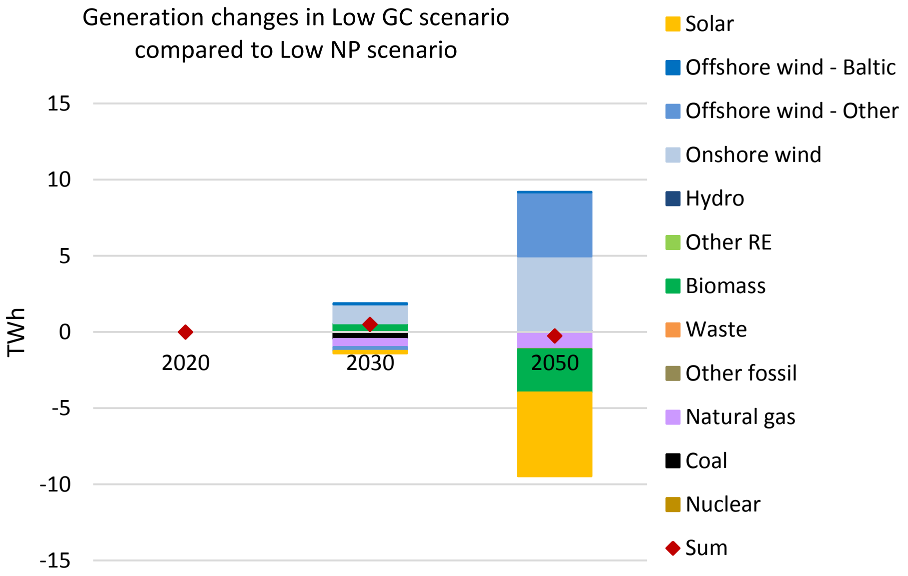
5.2.5 Regional grid cooperation

The grid cooperation (GC) and grid and policy cooperation (GPC) scenarios assume the development of four offshore hubs. These hubs are connected to predefined wind farms and to onshore connection points in at least two different countries. The hubs thereby provide additional transmission capacity between countries in the region, which affects the rest of the power system and should ease the integration of variable renewable energy generation in general.

By 2030, the improved interconnectivity entailed in these scenarios leads to an increase in onshore wind power and biomass generation that mainly displaces coal and gas generation (Figure 5-18). This result applies to the comparison of the GP scenarios to the NP scenario, with Low (Figure 5-18, top) as well as Ambitious (Figure 5-18, bottom) offshore wind power deployment. The main reason is that the increased interconnectivity related to the hubs improves options to transport onshore wind power generation across bidding zones and thereby improves market value for onshore wind power.

In 2050, the higher level of interconnector capacity between countries in the Baltic Sea region results in higher wind power generation both onshore and offshore. The increase in offshore wind power deployment mainly takes place in the North Sea, since offshore wind power capacity in the Baltic Sea Region is fixed by design in the scenarios. At the same time, generation from natural gas, biomass and solar power is decreased. In 2030, these effects apply when comparing the Low GC scenario to the Low NP scenario (Figure 5-18, top), as well as when comparing the Ambitious GC to the Ambitious NP scenario (Figure 5-18, bottom), but are larger in magnitude in the latter case.

Figure 5-18 *Changes in power generation in the modelled area for the Low GC scenario compared to the Low NP scenario (top) and for the Ambitious GC scenario compared to the Ambitious NP scenario (bottom)*



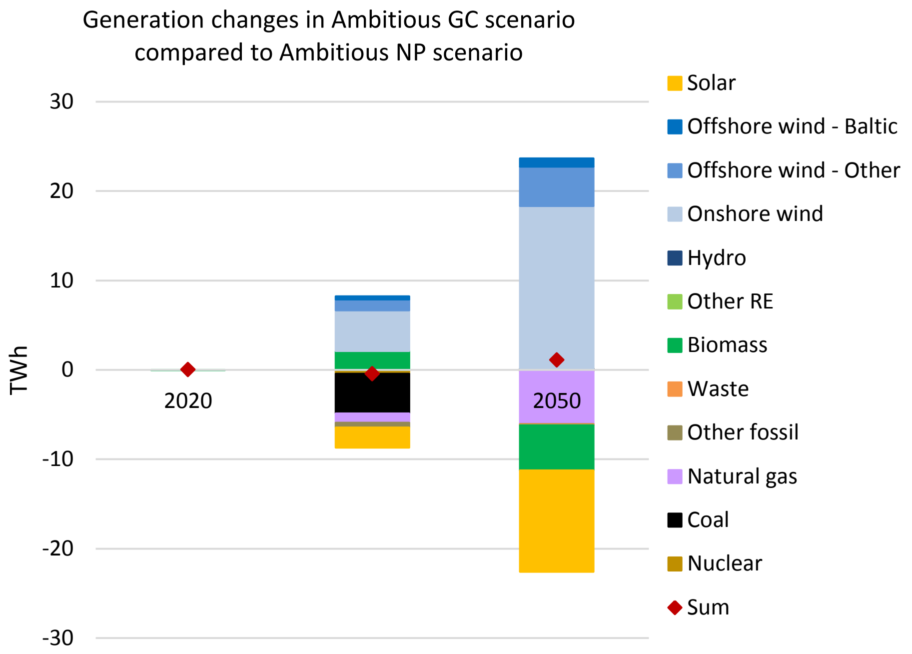
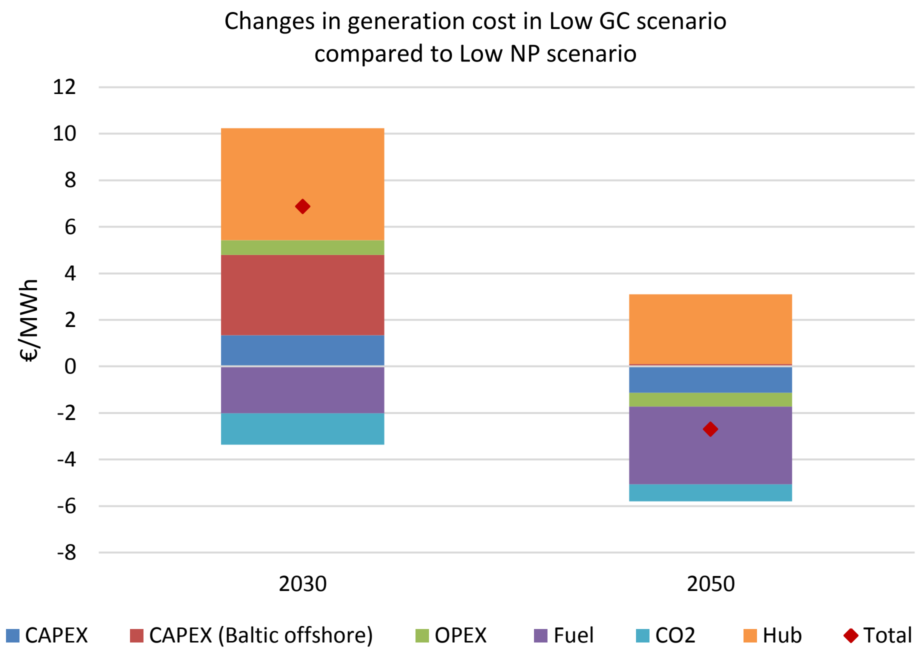
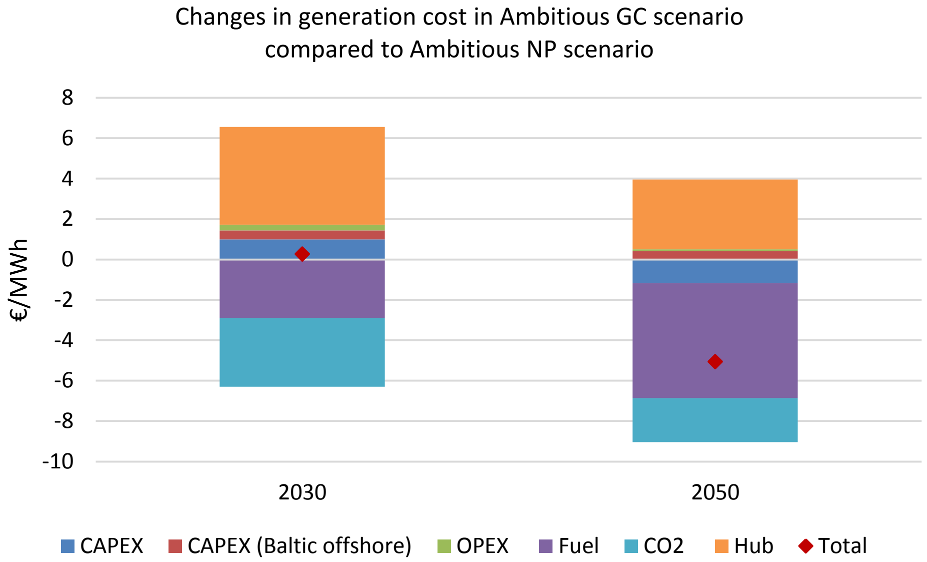


Figure 5-19 shows the differences in average generation cost per MWh between the Low GC and the Low NP scenarios (top panel), and between the Ambitious GC and Ambitious NP scenarios (bottom panel). For the Low GC scenario, aggregated generation costs increase by around 7 €/MWh of Baltic offshore wind power in 2030, while aggregated generation costs decrease by around 3 €/MWh of Baltic offshore wind power by 2050. In the case of ambitious deployment of Baltic offshore wind power, the importance of offshore grid cooperation increases and in 2030, aggregated generation costs are almost the same as in the case without offshore grid cooperation. In 2050, aggregated generation costs decrease by around 5 €/MWh of Baltic offshore wind generation.

The results thus indicate that with the chosen hub configuration, the GC scenario is not cost efficient towards 2030. The cost efficiency of cooperation on the hubs increases however beyond 2030, especially if the ambitious deployment targets for Baltic offshore wind are pursued. However, as we explain in the next section, *Individual hub economy* on page 46, the results vary between the hubs and some of the individual hubs are cost efficient in 2030 in the ambitious scenarios.

Figure 5-19 Changes in generation costs for the Low GC scenario compared to the Low NP scenario (top) and the Ambitious GC scenario compared to the Ambitious NP scenario (bottom). Shown as €/MWh of Baltic offshore wind power.*





** Including connection costs for offshore wind power*

Individual hub economy

Figure 5-19 reports the results of the grid cooperation scenario, assuming all four hubs are developed before 2030. In this section, we disaggregate the results and examine each of the hubs individually.

The marginal market value provided by each of the hubs is a combination of the value of the wind power generated at the hub and the value of the additional interconnector capacity provided. This marginal value can be shown by evaluating the market value of the power generated at the hub and the congestion rent obtained on the transmission line. The congestion rent is in this case shown per MWh of offshore wind power generation at the hub.

Looking at the economic figures for each of the four hubs, as shown in Table 6-4, we observe significant differences both with respect to the cost of generation (LCOE) and the market value of the hubs. Note that the market value reported here includes both the value of generation and the congestion rent.

I should also be noted that the offshore wind power sites included within each of the hubs are not equal in the low and ambitious scenarios. This is the case since a) the total capacity – and therefore number of sites needed to deploy this capacity – varies according to the ambition level, and b) the targeted total deployment of offshore wind capacity in the countries in the different scenarios restrict the options for using specific sites at the hubs. As an example, the LCOE for Hub 1 is lower in both 2030 and 2050 in the ambitious scenario because the more ambitious deployment target for Denmark allows for inclusion of a low LCOE site at Hub 1 in the ambitious scenario which could not be deployed in the low scenario. For other hubs, such as Hub 4, the increased offshore wind power capacity in the ambitious scenario requires the utilization of more expensive sites and therefore the LCOE increases.

The market value of the wind power generation at the hubs is affected by the total amount of offshore wind power generation in the Baltic Sea region, the interconnection of the region, the specific wind power generation profile at the site, and the general power price development over time. Therefore, no general conclusion applicable to all hubs can be drawn on how the market value on the hubs is affected in different years and scenarios. As a tendency, more wind power deployment in itself causes market values to decrease, while higher transmission capacity leads to higher market values in low price areas and lower market values in high price areas.

Hub 1, located in the southeast of the region between Sweden, Germany and Denmark, appears to be the most attractive under the Low deployment scenario – at least in the short term. By 2030 and in the Low Grid Cooperation scenario, Hub 1 demonstrates a relatively low LCOE of approximately 55 €/MWh and a market value of almost the same size. In 2050, the LCOE is reduced to approximately 49 €/MWh, almost 4 €/MWh lower than its market value. In the ambitious scenario, the LCOE is further reduced, since a portion of the wind power capacity is placed at better sites within the same hub, resulting in the LCOE being lower than the market value in both 2030 and 2050, by 0.5 and 3 €/MWh respectively.

Hub 2, located between Sweden, Poland and Lithuania, shows a significantly higher LCOE relative to Hub 1. As a result, Hub 2 ends up adding to net costs in 2030 under the Low deployment scenario. However, under the Ambitious deployment scenario it reduces overall costs. In 2050, the LCOE for Hub 2 is significantly below its market value in both the Low and

Ambitious GC scenarios due to high electricity prices in Poland. The high power prices in Poland are the result of high CO_2 prices combined with a limited access to cheap renewable energy resources, such as onshore wind power in Poland, and should be interpreted with some caution.

Hubs 3 and 4, located further north in the Baltic Sea, suffer from comparatively low market values and do not generate net cost savings under either the Low or Ambitious scenarios by 2050. Therefore, a sensitivity analyses has been carried out, to assess the overall scenario economy without those two hubs. See section 5.2.7.

More information on the cost and market value of the individual hubs is available from Appendix D.

Table 5-4 LCOE and MV per hub in the Low GC and the Ambitious GC scenarios*

		LCOE*	MV	LCOE minus MV
Low Grid Cooperation scenario				
2030	**Hub 1**	55.2	53.8	1.5
	Hub 2	69.5	55.4	14.1
	Hub 3	-	-	-
	Hub 4	60.5	38.4	22.1
2050	**Hub 1**	48.8	52.6	-3.7
	Hub 2	58.1	82.6	-24.5
	Hub 3	52.7	37.3	15.4
	Hub 4	51.1	39.9	11.2
Ambitious Grid Cooperation scenario				
2030	**Hub 1**	51.9	52.5	-0.5
	Hub 2	54.8	62.7	-7.9
	Hub 3	58.4	39.9	18.4
	Hub 4	56.1	38.6	17.5
2050	**Hub 1**	46.7	49.9	-3.2
	Hub 2	52.0	89.5	-36.5
	Hub 3	51.8	33.5	18.3
	Hub 4	54.5	39.5	14.9

*Note: * Including costs for both offshore wind power and the hub connections. LCOEs incl. hub costs, MV incl. congestion rent. There is no capacity at Hub 3 in Low GC scenario in 2030 and therefore no cost and value calculations.*

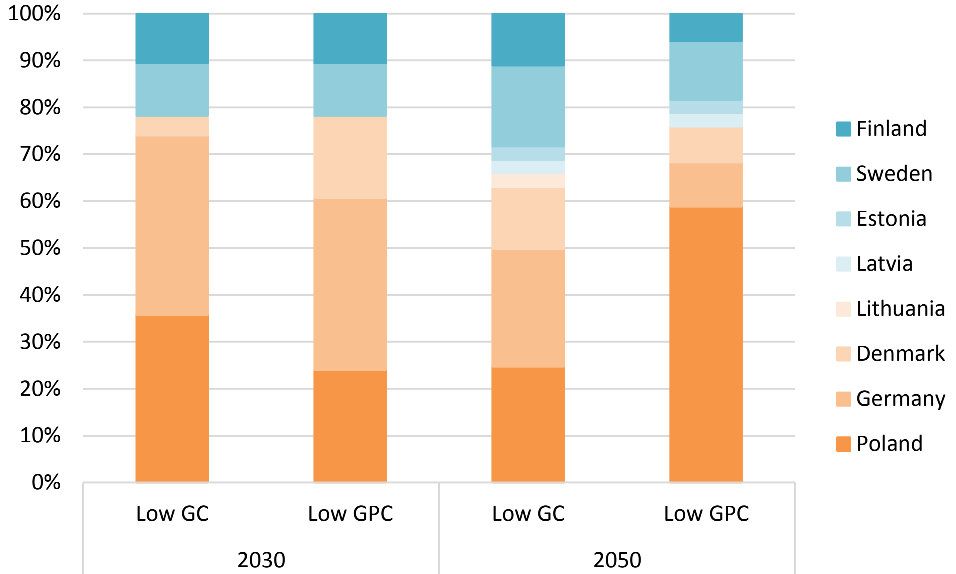
5.2.6 Regional policy cooperation

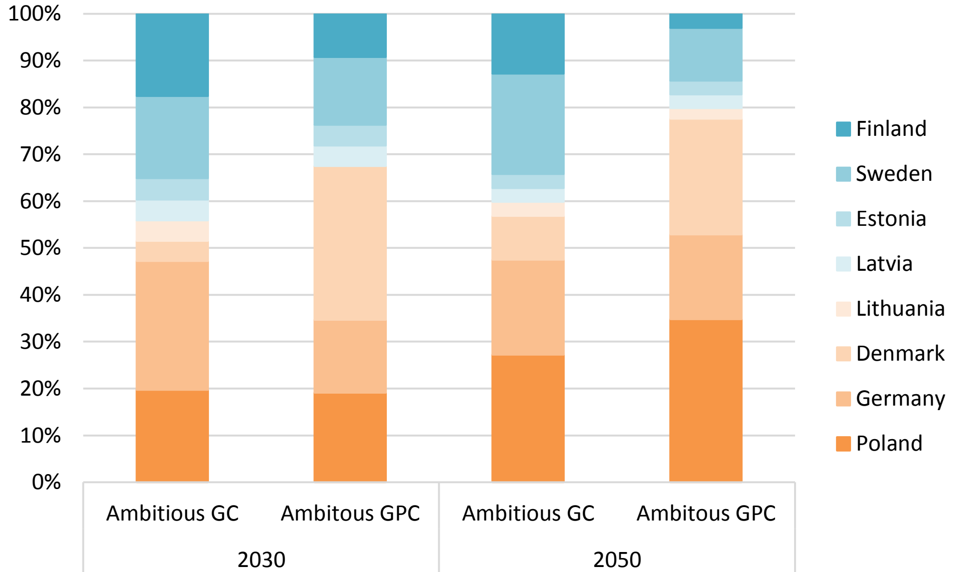
In the regional policy cooperation scenarios, rather than enforcing nationally specific offshore wind power targets, the offshore wind power capacity is optimised across the entire Baltic Sea to achieve the most cost-effective deployment.

The total level of offshore deployment under these scenarios is set equal to the total level of regional deployment under the national policy scenarios to ensure comparability and allow us to isolate the benefits attributable to policy cooperation. The four advanced offshore hubs are also included in these scenarios. Hence, we label them GPC (grid and policy cooperation) scenarios.

As a consequence of regional cooperation on offshore wind power deployment, the offshore wind farms that are developed are located at the sites with the highest market value relative to electricity generation costs. In the policy cooperation scenarios, it is also possible to utilise offshore wind power sites located at the hubs more efficiently than in the GC scenarios. Figure 5-20 below shows how the distribution of offshore wind power capacity throughout the region shifts between the GPC and GC scenarios.

Figure 5-20 Geographical location of offshore wind power in the Baltic Sea Region in the Low offshore wind power cooperation scenarios (top) and the Ambitious offshore wind power cooperation scenarios (bottom).





Looking at the 2030 results for the Low GPC and Low GC scenario, we can see that introducing regional policy cooperation implies developing less offshore wind power capacity in

Poland and more in Denmark, which has the sites with the lowest generation costs and still provides for fairly high market values.

Moving across to the 2050 results, we can see that the share of wind power in Poland increases and ends up higher under the GPC scenario, which in its first phase until 2030 has seen Poland's share in deployment reduced. By 2050, power prices – and thus the market value of offshore wind power – differ significantly across the region and this significantly affects the location of offshore wind power in the regional policy cooperation scenario. In particular, we see high electricity prices in Poland (75-80 €/MWh) attracting a large share of total offshore wind power investment.

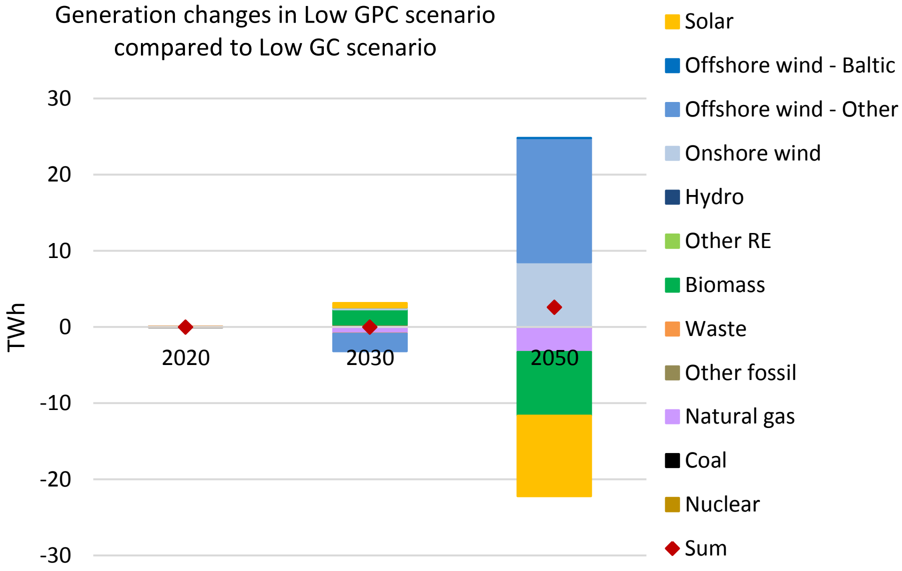
The relocation of offshore wind power capacity to Denmark and Poland is also apparent in the ambitious grid and policy cooperation scenario (Figure 5-20, bottom).

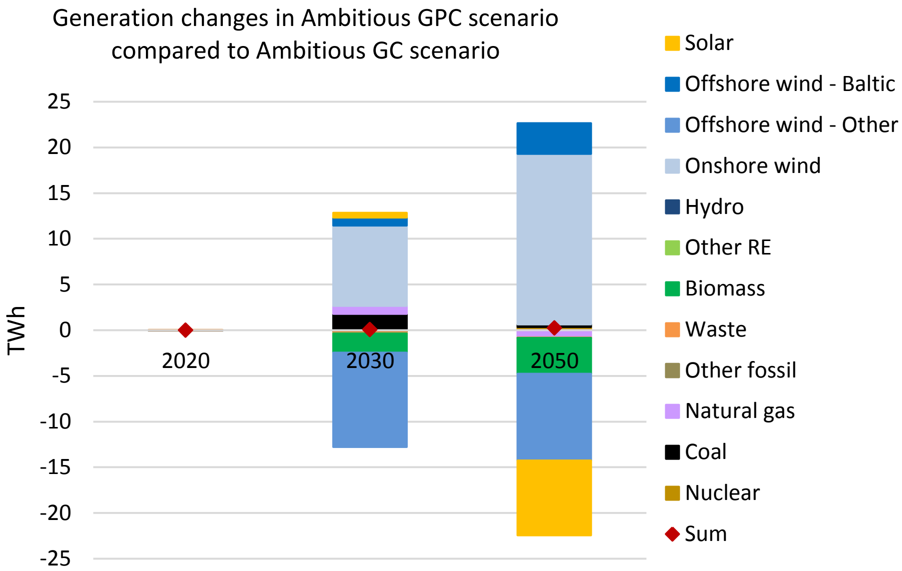
As regards the Baltic countries, which currently have no or little offshore wind power capacity, offshore wind power development only takes place beyond 2030 in the Low offshore wind power scenarios.[34] In the Ambitious scenarios, offshore wind is established already by 2030.

More efficient distribution of offshore wind power capacity in the Baltic Sea also enables more efficient development of other renewable generation, see Figure 5-21. In the Low GPC scenario, the changed distribution in the Baltic Sea results in less biomass and solar power generation in 2050, enabling increased amounts of onshore wind power and offshore wind power in the North Sea compared to the Low GC scenario (Figure 5-21, top). Similar effects are visible in the Ambitious GPC scenario, where redistribution of Baltic offshore wind power facilitates more cost-efficient RES-E deployment with increased amounts of onshore wind power, which in turn replaces biomass, (Non-Baltic-) offshore wind power and solar power (Figure 5-21, bottom). This illustrates that the deployment of offshore wind power in the Baltic Sea, the changed grid configuration (increased interconnector capacities via hubs), and the extent of cooperation on offshore wind power development has market implications that affect the rest of interconnected the system as well. This also demonstrates the merit of taking into account aggregated generation costs in the analysis of the Baltic offshore wind generation scenarios.

[34] This reflects the current situation and the historical trend, which is corroborated up until 2020. It does not however prejudice faster and more extensive deployment, such as that planned by Estonia.

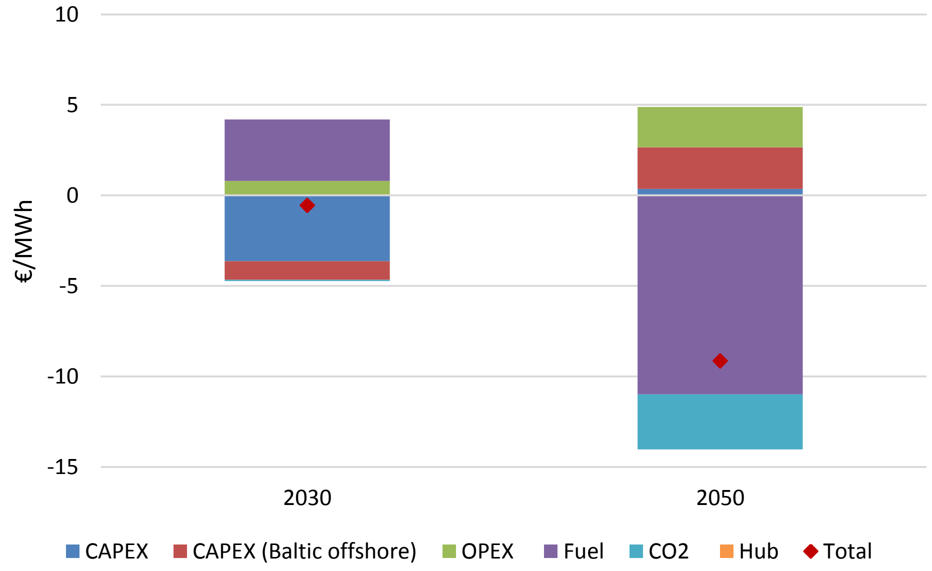
Figure 5-21 Changes in power generation in the modelling area (see Figure 5-1 for included countries) for the Low GPC scenario compared to the Low GC scenario (top) and for the Ambitious GPC scenario compared to the Ambitious GC scenario (bottom)

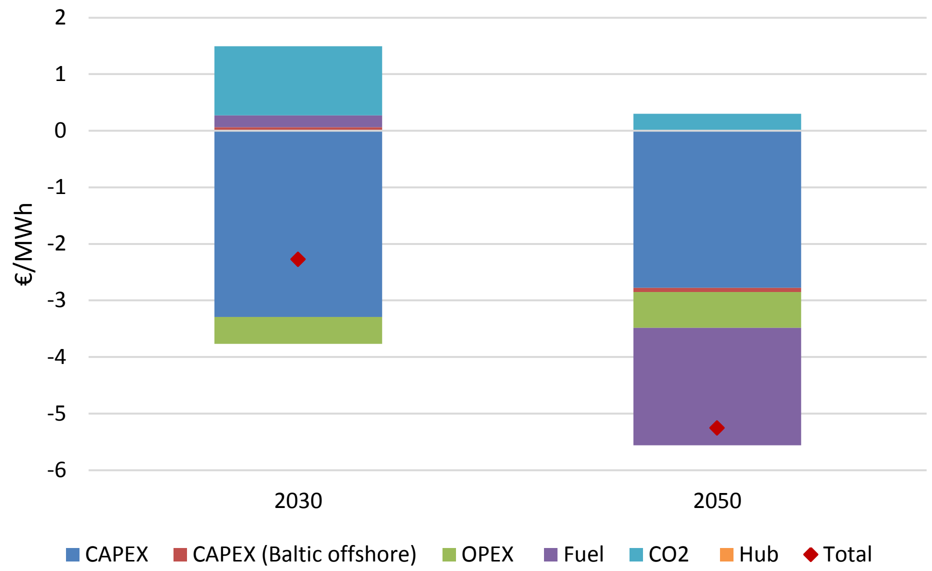




Policy cooperation yields unambiguous economic benefits amounting to a reduction of the aggregated system generation costs with respect to Baltic offshore wind power generation of between 5 and 9 €/MWh in 2050 compared to the grid cooperation scenarios alone (see Figure 5-22). The absolute savings amount to around 650 million € in the low deployment scenario and around 700 million € in the ambitious scenario. In general, allowing the model to select the best sites regionally will always be at least as efficient, and as demonstrated by the results, probably more so, than forcing the model to meet a series of national deployment targets, even where it selects the best national sites available.

Figure 5-22 Changes in aggregated generation costs for the Low GPC scenario compared to the Low GC scenario (top) and the Ambitious GPC scenario compared to the Ambitious NP scenario (bottom). Shown as €/MWh of additional offshore wind power.*





5.2.7 Comparison of scenarios

The scenarios for offshore wind power deployment defined in section 5.1.3 are set up in the Balmorel power market model and the effects analysed for the years 2030 and 2050. As described in the previous sections, higher deployment of Baltic offshore wind power displaces generation from other forms of generation and reduces investment in other types of generation capacity. In the cooperation scenarios, where offshore wind power hubs are developed in tandem with interconnectors and the BEMIP countries cooperate on regional offshore wind deployment, greater renewable investments in the lowest cost areas are facilitated.

The aggregate generation cost in the entire modelling area – which covers Northern, Central and most of Eastern Europe (see Figure 5-1) – is a key parameter for the assessment of the six scenarios. The costs include not only the cost to deploy Baltic offshore wind power, but also all costs associated with the rest of electricity supply, including all CAPEX for new generation capacities, and all OPEX, including fuel and emission costs. Notably, impacts on the costs of onshore grid investments and congestion management within price zones are excluded from the aggregate cost figures provided by the market modelling. Impacts on internal grid costs are analysed separately as part of Task 3 and are accounted for as part of the total Cost Benefit Analysis presented in Chapter 1.

Baltic offshore wind power generation costs

The cost to deploy Baltic offshore wind power consists of the cost of the offshore wind farms themselves (wind turbines, internal connection and offshore substation) and the cost of connecting the offshore substations to an existing substation in the onshore grid. The calculation of the costs of the offshore hub configuration is described in Appendix D.

Table 5-5 shows the aggregate annualised deployment cost[35] for Baltic offshore wind power in the different scenarios. It is apparent that the lowest cost sites are used in the Low scenarios, which show lowest average LCOE. As deployment increases, higher cost sites are used, increasing average LCOE. Adding grid cooperation increases LCOE due to the increased cost for the advanced connections, while regional cooperation mainly lowers average LCOE as better sites are used. However, in the Low GPC scenario, LCOE is increased, since it is worth using more expensive sites in order to achieve higher market value. It is thus important to note that LCOE figures for Baltic offshore wind power alone cannot point out the most cost-efficient scenarios. Market values also has to be taken into account.

Table 5-5 Annualised investment costs for offshore wind power deployment in the Baltic Sea in different scenarios

		Wind farms (€m)	Connections (€m)	Hubs (€m)	Total (€m)	Avg. LCOE (€/MWh)
	Low NP	747	35	0	782	50.32
	Low GC	816	9	85	911	57.47
	Low GPC	798	10	85	893	56.50
	Ambitious NP	1,762	90	0	1,851	51.26
	Ambitious GC	1,900	30	206	2,137	55.72
	Ambitious GPC	1,896	38	206	2,14	54.81
	Low NP	2,566	159	0	2,725	41.00
	Low GC	2,617	64	210	2,891	43.87
	Low GPC	2,771	72	210	3,053	46.04
	Ambitious NP	4,266	223	0	4,49	43.81
	Ambitious GC	4,691	98	454	5,243	47.12
	Ambitious GPC	5,234	135	454	5,822	45.98

Looking at Baltic offshore wind power deployment costs alone, we see that they are higher in the regional grid cooperation scenarios relative to the national scenarios. There are two reasons for this. First, the wind sites located close to the hubs, and supported by their construction, are in deeper waters and, as a result, we see higher costs for the wind farms

35 CAPEX, shown as annualised values using a real WACC of 5%, with assumed lifetimes of 20 years for the wind farms and 40 years for the connections.

themselves. Secondly, the HVDC substations used by the hubs are significantly more expensive than radial AC connections used in the NP scenarios.[36] On the other hand, the hubs provide additional transmission capacity that is not included in the National Policies scenarios, thereby potentially increasing the market value of the offshore wind power generation.

Aggregated generation costs

Looking at the aggregated generation costs, which cover both Baltic offshore wind power and all other forms of generation, provides some insight into which scenarios reflect the most efficient means of meeting projected future electricity demand.

Table 5-6 below shows the headline numbers for all of the scenarios. In 2030, the Low National Policies scenario shows the lowest cost. In 2050, the Ambitious Regional Grid and Policy cooperation scenario shows the lowest cost.

For 2030 under the low deployment case, the grid cooperation scenario and the grid and policy cooperation scenario negatively affect costs because the hubs' costs exceed their benefits. Beyond 2030 however, the changes made under the grid and grid and policy cooperation scenarios prove to be beneficial, even with low deployment.

If we look at policy cooperation alone (without including hubs), we find that it is beneficial even in 2030 and under the low scenario, as shown on Table 5-7.

With an ambitious target for the deployment of Baltic offshore wind power, the need for cross-border transmission capacity increases, and thus the grid and policy cooperation scenario shows the lowest costs, not only in the long term, but also in 2030. In the next section, we explore the impact of the hubs on the results in greater detail.

The results reflect both the increasing need for renewable electricity generation in the system over time and further expected reductions in the cost of offshore wind power.

[36] Radial connection costs are based on 132 kV AC connections, while hub connections are assumed to be 220 kV HVDC. Optimisation of the connection at individual sites as well as different technology choices for the individual hubs could change the relative cost of these components.

Table 5-6 Annual aggregated generation cost (all generation) for the different scenarios

	Baltic offshore wind €m	Hubs €m	Rest of generation mix €m	Total excl. hubs €m	Total incl. hubs €m
Low NP	950	0	261,618	262,568	262,568
Low GC	1,012	85	261,593	262,605	262,690
Low GPC	994	85	261,601	262,595	262,680
Ambitious NP	2,340	0	260,520	262,859	262,859
Ambitious GC	2,363	206	260,304	262,666	262,873
Ambitious GPC	2,367	206	260,201	262,568	262,775
Low NP	3,069	0	320,855	323,924	323,924
Low GC	3,066	210	320,449	323,515	323,725
Low GPC	3,228	210	319,646	322,873	323,083
Ambitious NP	6,144	0	317,566	323,710	323,710
Ambitious GC	6,170	454	316,391	322,561	323,015
Ambitious GPC	6,164	454	315,701	321,866	322,319

Sensitivity discussion

The main scenario design does not allow us to isolate the effect of policy cooperation alone, or the optimal hub selection. To simplify the comparison and have a manageable number of scenarios, the scenarios with policy cooperation includes grid cooperation (GPC), while we have included all four hubs in the cooperative scenarios already in 2030 and regardless of the ambition level for offshore wind power. The results indicate however, that lower costs for offshore wind power might be achieved through policy cooperation even without the construction of advanced hubs, or potentially, through the use of selected advanced hubs. To asses these variations of the main scenario design, four sensitivities have been analysed, to show the effect of:

› Grid cooperation with only the two southern hubs for both the low and the ambitious scenario (2H-scenarios in Table 5-7)
› Policy cooperation without any grid cooperation for both the low and the ambitious scenario (PC-scenarios in Table 5-7)

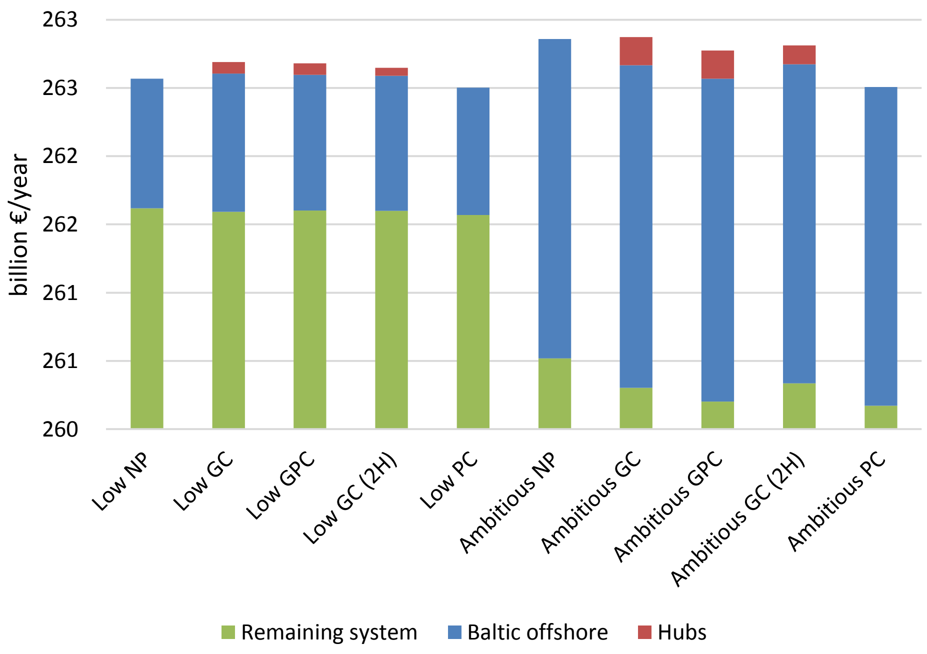
The results of the first sensitivity indicate that grid cooperation on only two hubs is more cost efficient than including all four hubs in both the low and ambitious scenario, both 2030 and 2050. In 2030, grid cooperation on two hubs is still not cost efficient in the low scenario compared to the national policies scenario as it is 80 million €/year more expensive. In 2050, however, this number is reversed to a saving of 250 million €/year. For the ambitious scenario, grid cooperation on only two hubs is now cost efficient in both 2030 and 2050 and shows annual savings of around 50 million €/year in 2030 and 900 million €/year in 2050. The results show that the configuration, timing and location of hubs matter, and that these options should be explored carefully. Also, the impact on internal grids, which may be beneficial, should be taken into account (see next chapter).

Policy cooperation without grid cooperation provides savings of 65 and 350 million €/year in 2030 in the low and ambitious scenario respectively. In 2050, these numbers are increased to around 1,090 million €/year and 970 million €/year respectively. With one exception, policy cooperation without grid cooperation is also more cost efficient than the corresponding main scenario, which also included grid cooperation on all four hubs. However, in 2050, the main Ambitious GPC scenario is more cost efficient, than only applying policy cooperation. The results indicate that hubs should be selected carefully, and that the timing and configuration depends on the ambition level for Baltic offshore wind and the level of cooperation.

Table 5-7 Annual aggregated generation costs, sensitivity analysis on cooperation scenarios

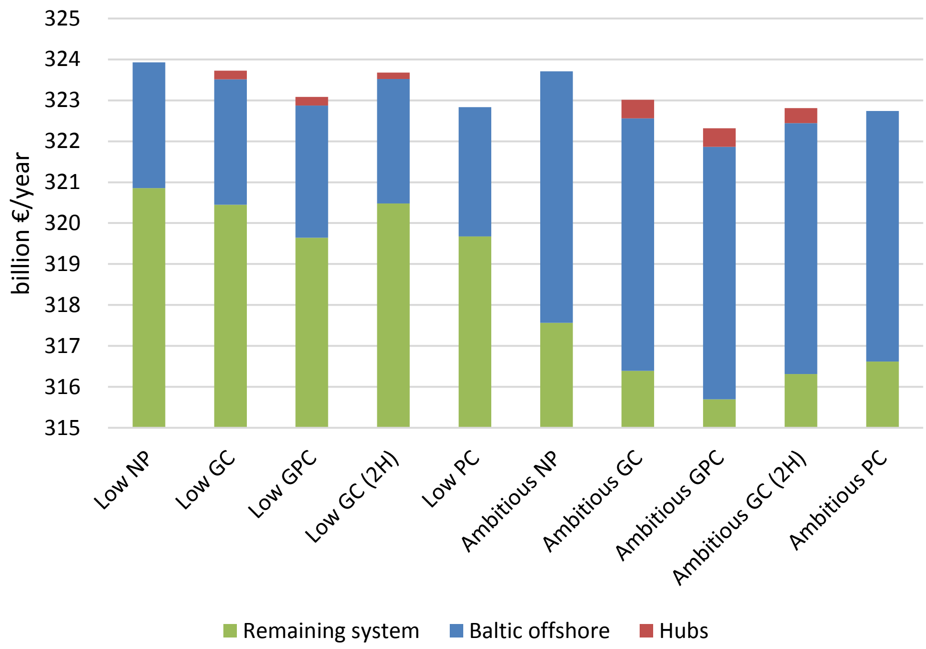
	Baltic offshore €m	Hubs €m	Rest of system €m	Total excl. hubs €m	Total incl. hubs €m
Low NP	950	0	261,618	262,568	262,568
Low GC (2H)	984	58	261,599	262,583	262,641
Low PC	934	0	261,569	262,503	262,503
Ambitious NP	2,340	0	260,520	262,859	262,859
Ambitious GC (2H)	2,323	139	260,336	262,659	262,798
Ambitious PC	2,336	0	260,171	262,507	262,507
Low NP	3,069	0	320,855	323,924	323,924
Low GC (2H)	3,042	150	320,481	323,524	323,673
Low PC	3,161	0	319,675	322,837	322,837
Ambitious NP	6,144	0	317,566	323,710	323,710
Ambitious GC (2H)	6,124	370	316,315	322,439	322,809
Ambitious PC	6,119	0	316,623	322,742	322,742

Figure 5-23 Total annual aggregate generation costs for the different scenarios in 2030



Note: The y-axis does not start at zero.

Figure 5-24 Total annual aggregated generation costs for the different scenarios in 2050



Note: The y-axis does not start at zero.

Pairwise comparison of scenario features

Pairwise comparisons of aggregated costs under the different scenarios helps to illustrate the effect of individual scenario changes. Table 5-8 shows the pairwise comparison of results expressed in relation to the amount of Baltic Offshore wind power and the additional amount of Baltic Offshore wind power. The numbers can be read as *changes in aggregated generation cost for each MWh of Baltic offshore wind generation* or *changes in aggregated generation cost for each additional MWh of Baltic offshore wind generation.*

› Ambitious compared to low scenarios

By comparing aggregate generation costs under the Ambitious and Low deployment scenarios, we see that with national policies the additional deployment of offshore wind power under the Ambitious scenario increases costs in the Baltic Sea Region by 291 Million €/year in 2030, which translates to an additional 12 € per MWh of additional Baltic offshore wind power generation. However, when we look at the 2050 snapshot of the national policy scenarios, the additional buildout of Baltic offshore wind power generation contributes to a reduction in aggregated generation costs of 3 € per MWh of additional Baltic offshore wind generation.

In other words, increased Baltic offshore wind power generation relative to the low deployment case goes from being net costly to net beneficial in the longer term. The reason is that, in 2030, offshore wind power is only competitive relative to other generation technologies in a few areas of the Baltic Sea. Consequently, increasing offshore wind power deployment broadly across the entire Baltic Sea through the use of national targets pushes up total generation costs in 2030. If we had only looked at increased deployment of offshore wind power in the southern part of the Baltic Sea, where deployment costs are lower and the market value higher, there is potentially a net benefit of even higher deployment.

Beyond 2030, as the costs of Baltic offshore wind power fall and there is an increased need for renewable generation in the system, broader deployment of offshore wind power becomes more efficient and contributes to lower aggregate generation costs overall.

Table 5-8 The effect of individual scenario parameters (e.g. the level of offshore wind power deployment) on aggregated generation costs

		€/MWh 2030	€/MWh 2050	Million €/year 2030	Million €/year 2050
Ambitious vs. Low deployment scenarios					
*€/MWh of **additional** Baltic offshore wind power generation*	National policies	12	-3	291	-214
	Grid cooperation	7	-11	183	-710
	Grid and policy cooperation	4	-12	95	-764
Regional grid cooperation vs. no grid cooperation					
*€/MWh of **total** Baltic offshore wind power generation*	Low deployment	7	-3	122	-199
	High deployment	0	-5	14	-695
Regional grid and policy cooperation vs. regional grid cooperation and national policies					
*€/MWh of **total** Baltic offshore wind power generation*	Low deployment	-1	-9	-10	-642
	High deployment	-2	-5	-98	-696

Note: Positive numbers show additional cost. Negative numbers indicate a saving.

› National policy compared to regional grid cooperation

A comparison of the national policies and the regional grid cooperation scenarios shows that deploying all four advanced hubs implies an additional cost of 122 million €/year in 2030, translating to an increase in aggregated generation costs of 7 € per MWh of Baltic offshore wind power generation in 2030 under the low deployment scenario. The reason is that the benefits of better system integration (visible in the form of decreased costs for the remaining generation in the system) are not high enough to offset increases in cost due to both the use of sites in deeper waters and the need for HVDC offshore stations and connections.

Beyond 2030 and at higher deployment levels, we see the hubs bring a net benefit that translates into an average saving of up to 5 € per MWh of offshore wind power generation. Looking at each of the hubs in isolation based on an assessment of the marginal impacts of altering wind power generation and transmission capacity at these locations, we find that the hubs in the southern region (connecting Sweden and Germany, and Sweden, Poland and Lithuania) yield lower aggregate generation costs even in 2030. However, these benefits are not apparent in the headline results because they are offset by the increase in costs brought about by the other two hubs. Again, this suggests that the timing and configuration of hubs should be carefully examined.

› National policy compared to policy cooperation

By comparing the GC and GPC scenarios, we can identify the effect of cooperation on offshore wind power deployment that is not included in the hubs. The results show that such cooperation contributes to lower costs regardless of the deployment level or the year examined. This is to be expected since such cooperation allows us to use the cheapest offshore wind power sites at the locations with the highest market value across the Baltic Sea – irrespective of the distribution of national targets. As illustrated in section 5.2.2 both the LCOE of offshore wind power and the market value of generation vary substantially across the Baltic Sea region. The additional benefit from cooperation amounts to between 1 and 9 €/MWh of Baltic offshore wind power generation.

5.3 Potential projects of common interests

The assessment of offshore wind power in the Baltic Sea provides a basis to point out candidates for projects that could potentially receive the status of Projects of Common Interest (PCI) by the European Commission under Regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure. The list of PCIs is drawn up every two years, starting in 2013, via Commission Delegated Regulation as regards the Union list of projects of common interest. PCIs are characterised by

› having a significant impact on two or more EU countries;
› contributing to the EU's energy and climate goals, by facilitating the integration of variable renewable energy sources;
› enhancing market integration and contributing to the integration of EU countries' networks;
› increasing competition on energy markets by offering alternatives to consumers; and
› increasing security of supply.

Designated PCIs are eligible for funding under the Connecting Europe Facility (CEF). New support arrangements for cross-border renewables projects allow support for both the generation and infrastructure assets involved. Such arrangements are likely to be especially valuable for offshore wind hub projects and are sufficiently flexible to cover storage and conversion facilities, features that would not be eligible for support under the Regulation on guidelines for trans-European energy infrastructure (TEN-E).

The grid cooperation scenarios include a number of hubs, which connect the power systems of two or more countries. Of these hubs, Hub 1 connecting Germany and Sweden, and Hub 2 connecting Poland, Sweden and Lithuania, are potential candidates for PCIs. A list of offshore wind sites which can potentially be connected to these hubs is shown in Table 5-9.

› For both hubs, the connected offshore wind power can contribute to fulfilling the connected countries' renewable energy targets. The potential for offshore wind power in proximity of the hubs is however even higher than the volumes included in the specific scenarios.

› Both hubs would enable utilisation of offshore wind power sites located relatively far offshore, which increases the relevance of exploiting coordinating interconnection.

› The hubs facilitate the integration of variable renewable energy sources, by a) increasing the market value of renewable energy in the overall system and b) replacing generation from *inter alia*, thermal generation from coal, natural gas and biomass (see Figure 5-18)

› Deployment of both the interconnections and the associated wind farms shows a net economic benefit in both 2030 and 2050 in the ambitious scenario, as well as in 2050 in the low scenario (see Table 5-4)

- The interconnectors increase the integration of EU's power network and improve import and export options for the involved countries

- Increase the security of supply by adding import options and specifically for Hub 2, increasing interconnection to the Baltic countries.

Table 5-9: Potential Projects of Common Interest

PCI	Potential connected Offshore Wind Power sites	Total offshore wind power potential	Capacity connected in Low Scenario 2030	Capacity connected in Low Scenario 2050	Capacity connected in Ambitious Scenario 2030	Capacity connected in Ambitious Scenario 2050
Hub 1 connecting Sweden and Germany	DE Windanker, Wikinger, Arkona	1,000 MW	1,000 MW	1,000 MW	600 MW	1,000 MW
	Baltic Eagle	500 MW		500 MW		500 MW
	DE-New Baltic (East of KF)	1,500 MW				1,500 MW
	Rønne Banke Reserved Area	6,000 MW		500 MW	400 MW	1,500 MW
Hub 2 connecting Sweden, Poland and Lithuania	Baltex	1,000 MW				1,000 MW
	Baltica 1	500 MW		500 MW	500 MW	500 MW
	Baltyk Pólnocny	1,000 MW	500 MW	500 MW	500 MW	500 MW
	Södra Midsjöbanken	2,000 MW		1,500 MW	1,000 MW	2,000 MW
	SE-New Oelands Soedra	1,000 MW				1,000 MW

5.4 Conclusions

Based on the power system analyses we draw the following main conclusions:

- The model-based analysis of supply and demand shows a European power system undergoing a rapid transformation to renewable energy – renewable energy shares reach close to 70% by 2030 and more than 90% in 2050. At the same time, electrification within transport, heating and industry increases the overall demand for electricity.
- Technology developments and learning effects imply falling levelised costs for offshore wind. Consequently, Baltic Offshore wind power's levelised cost of energy at the best sites falls to 50 €/MWh in 2030 and 38 €/MWh in 2050, including connection costs.
- The most attractive sites are located in the southern part of the Baltic Sea, mainly due to better wind conditions and a higher market value for the power generated. The higher market value is explained by the proximity to load centres in central Europe. In the Northern part of the Baltic Sea the presence of relatively cheap alternative RES (mainly onshore wind) and grid bottlenecks limit the market value of offshore wind power.

- Even without cooperation, offshore wind power in the most favourable sites in the Baltic Sea could be able to compete with other generation options (both fossil and renewable) already in 2030.
- Cooperation on the construction of advanced offshore hubs, which both connect offshore wind power and increase interconnection capacity between countries, may further increase the value of Baltic Offshore wind power. The regional system analysis suggests that aggregate costs could be reduced by up to €5 per MWh of Baltic offshore wind power generation through the use hubs. The results also show that the configuration and timing of hubs should be carefully considered, and that the efficiency of using hubs is improved by the wider use of cooperation mechanisms for the deployment of offshore wind power in the Baltic Sea area.

In general, regional cooperation mechanisms support a more efficient distribution of offshore wind power capacity across the Baltic Sea as a whole, allowing greater focus on sites with lower deployment costs and more valuable power generation. Scenarios that allow for a more efficient distribution of offshore wind power capacity across the region have aggregate costs that are €5 – 9 lower per MWh of Baltic offshore wind power generation in the longer term.

6 Task 3a – Grid modelling and grid investment options

Key Messages from the Results

- Until 2030, internal grids are likely to be able to cope with the buildout of offshore wind power in all scenarios, assuming that grid investments in line with ENTSO-E's TYNDP 2018 and current national plans are carried out.
- After 2030 and independent of the expansion of offshore wind power, substantial grid investments will be needed in many of the BEMIP countries due to a shift from conventional to renewable energy sources and an expected significant increase in electricity demand from the heating and transportation sectors.
- Offshore wind power deployment and the development of advanced offshore hubs in the Baltic Sea region are expected to both increase and redistribute redispatch costs among BEMIP countries, particularly affecting Estonia, Lithuania, Latvia, Poland and Germany. Targeted and timely investments can significantly mitigate the cost increases.
- Across all BEMIP countries, higher levels of regional cooperation reduce overall grid utilisation and expected socio-economic costs of redispatch compared to purely national approaches: The additional Baltic Sea interconnectors allow for excess offshore wind power to be shared more efficiently between countries and offer alternative trading paths, thereby relieving the grid around existing interconnectors.
- Costs and benefits are not equally shared between the countries. Any cooperation should therefore be accompanied by a fair analysis of the burden of each member state, ensuring that all countries share the benefits of increased cooperation.

The purpose of the grid modelling is to quantify the social welfare effects related to grid congestions and redispatch due to offshore wind deployment, and to investigate how the level of offshore deployment ambition and the level of cooperation between BEMIP countries impact the social welfare effects. To this end, we investigate if offshore wind deployment in the Baltic Sea necessitates onshore grid reinforcements, and if so, aim to identify efficient grid upgrades. We consider an upgrade efficient if the annualised cost for the upgrade is lower than reduction in redispatch costs – that is, the upgrades we include lead to total cost reductions as the system is better adjusted to handle offshore wind.

A grid model simulates physical flows in a nodal representation of the network and therefore allows computation of the location of congestions within zones and estimation of the social welfare cost of redispatch. A grid model also allows us to propose grid reinforcements where the grid congestions occur and evaluate if the reinforcements reduce redispatch cost sufficiently to be economically sensible. The grid modelling does not only compare redispatch costs in a fixed grid in the different scenarios, but also considers how the grid may be reconfigured in order to match the differences in generation and trade between the scenarios. For this study, we used THEMA's The-GRID model.

In Section 6.1 we describe the methodology used for the grid modelling and the calculation of redispatch costs. We proceed to present the results from the grid modelling in terms of utilization of internal grid elements in the relevant countries and regions, in Section 6.2. The impact of offshore wind power on internal grid costs is quantified through a simple calculation of redispatch costs. These calculations create the basis for a discussion of the need for internal grid upgrades due to the offshore wind deployment in the scenarios described in Task 2. Finally, we collect the results from all countries and conclude our findings in Section 6.3.

The impact of redispatch and grid upgrades on total system costs is included in the cost benefit analysis in Chapter 1. For all countries, the results should be interpreted in the context of a system undergoing profound changes towards a system with a high penetration of renewable power generation, electrification of transportation and heating sector, as well as increased cross-border interconnector capacity. Such a system will challenge the internal grids regardless of offshore deployment, as we will see in the model results.

6.1 Methodology

To assess the impact on internal grids due to the offshore wind deployment scenarios in 2030 and 2050, the grid model is populated with grid data for all countries in the Baltic Sea Area, namely the Nordic countries, the Baltic countries, Germany and Poland.

1. *Initial grid configuration:* We define an initial grid configuration for 2030 and 2050. The 2030 configuration is based on the current grid configuration and planned grid updates according to ENTSO-E TYNDP and the national grid plans. The 2050 configuration is based on proposals in the same documents, in addition to a preliminary model-based assessment of congestions in the long run. The initial grid represents the grid configuration that would be planned and developed if offshore wind power deployment is not taken into account. It is the starting point for evaluation of changes in the grid configuration due to the offshore wind power deployment scenarios.

2. *Base case scenario:* As a reference for the impact of offshore deployment on national grids, we analyse the congestion patterns in the initial grid in a base case scenario. The base-case scenario assumes the same generation mix as the Low NP scenario, but no additional offshore wind generation. The construction of this base case scenario allows us to isolate changes in flows and congestion patterns that are attributed to offshore wind power deployment and not to other developments in the system. This is necessary in order to identify 1) a realistic base grid build-out level for our 2050 scenarios, and 2) grid investment and redispatch costs that are associated with offshore wind power.

3. *Identification of congestion patterns in the offshore wind power scenarios:* We run the model with the initial grid configuration when we introduce offshore wind power

according to the market solution in each scenario. The purpose is to identify congestion patterns as a basis for calculation of redispatch costs and identification of candidates for grid investments.

4. *Calculation of initial redispatch costs:* Redispatch costs for each scenario are calculated as the difference in generation costs between the dispatch in the copper plate model and the dispatch in the grid model, including the cost of load shedding, fuel substitution in the heating sector, and countertrade costs and revenues.

5. *Assessment of grid investments:* Where redispatch costs increase, we qualitatively assess a number of possible grid reinforcements. For each proposed upgrade and each scenario, we compute if the cost of that grid investment is lower than the associated redispatch costs. If so, we include the upgrade in our final grid model. As a result, the initial grid configuration is amended to the congestion patterns for each scenario. The costs for grid upgrades and the now-reduced cost for redispatch are then used in the cost-benefit analysis presented in Chapter 1.
Note: We have explored upgrades based on where offshore wind is connected, and what areas seem to be the most affected by the offshore wind development. No formal grid optimization procedure has been applied, thus more cost-efficient options could exist.

6.1.1 Populating the grid model

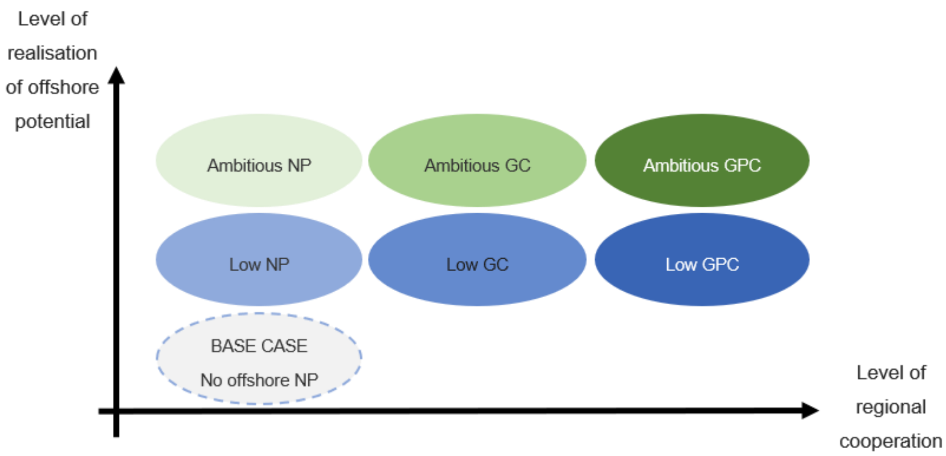
The grid is modelled for the years 2030 and 2050. We have used a variety of publicly available sources to gain information about the grid for the different countries, such as TYNDP data from ENTSO-E, data from transparency platforms, and data from national TSOs. We start by defining an initial grid configuration. For a given year, the initial grid configuration is assumed to be identical in the six scenarios. We then study how congestion patterns in the initial grid are affected when the offshore wind farms and hubs are connected to the transmission grid.

The initial grid configuration in 2030 includes plans for grid development from TYNDP 2018 and national grid development plans (where available), but no additional grid reinforcements that are not already proposed by the TSOs. Some of the initial grid upgrades assumed to take place by 2030 are aimed at strengthening the connection between Poland and the Baltic States, to facilitate the Baltic States' synchronisation with the Continental Grid. We note that some of this strengthening could alternatively be achieved through the development of an offshore grid, which could also then be used to support offshore wind development. However, we have not assumed this in the baseline scenario, which instead undertakes the necessary reinforcement through connections on land.

With regards to grid development towards 2050, we have included some of the projects marked as suggested in TYNDP 2018 and national grid development plans. According to the assumptions used in the market modelling, electricity demand is expected to increase towards 2050, particularly in Poland and Germany, while there is a simultaneous shift from conventional energy sources towards wind and/ or solar power in all market areas. For the grid to be able to accommodate the associated changes in flows, additional reinforcements will be needed, independently of any increase in offshore wind power deployment. As current grid development plans often do not reach very far into the future, we have assumed that additional grid upgrades are carried out in the long run. The choice of such upgrades is based on shadow prices on specific grid elements from earlier iterations of the grid model.[37]

In addition to populating the grid model in accordance with the six scenarios explored in this report, we have created a base case scenario, see Figure 6-1. In the base case scenario, we assume the same generation mix and other parameters as those applied in the Low National Policies scenario for 2030 and 2050 respectively. Offshore wind power development is excluded from the base case scenario. The base case scenario is used as a reference to make it possible to analyse the effect of offshore wind development on internal grid costs independently of the impact of other factors.

Figure 6-1 Scenario setup for deployment of Baltic offshore wind, including base case scenarios.



For each scenario, we have also created a “copper plate” model with no constraints in the internal grids within each price zone as a reference case (grid elements crossing the border between price zones are still subject to capacity constraints). Comparing results from the copper plate model with the full grid model allows the computation of redispatch costs, as elaborated below.

6.1.2 Connection to market modelling and other assumptions

To ensure consistency between the market and grid modelling, and hence allow for a comprehensive cost-benefit analysis across all scenarios and dimensions, the grid model is also populated to match the output from the market modelling in Task 2. Input data obtained from the market modelling include generation mix, demand assumptions, fuel price assumptions, inflow assumptions (hydro power), power prices in adjacent countries and trade capacities between price zones.

The market modelling is based on a bidding zone configuration, whereas the grid model is nodal. We have therefore distributed demand and generation from each energy source among the nodes in the grid. The assumptions about the spatial distribution of demand and generation

[37] Shadow prices reflect the marginal value of increased capacity of grid elements in terms of the frequency and severity of congestions.

are based on historical demand and generation data, and the distribution is similar between scenarios.

6.1.3 Redispatch calculations

Redispatch costs are defined as the cost associated with any deviations from the market solution due to physical constraints in the grid. Redispatch costs are costs related to interventions made by TSOs in order to ensure that the physical flows do not violate grid capacity and stability limits. Redispatch can include changes in generation at different nodes, demand side management, substitution of electric heating with fossil-fuel heating, as well as countertrading. Such interventions represent changes in social welfare compared to the unconstrained solution.

If a line in the The-GRID model is fully utilised, the model will automatically adjust the dispatch or trade to prevent any further loading of the line. Hence, we see higher dispatch costs if some lines in the system are fully utilised (the optimal copper plate solution is not feasible). The model ensures that the dispatch solution is feasible and that no lines are physically overloaded.

We calculate the redispatch cost as the difference in the sum of generation costs, cost of load shedding due to demand response or fuel switching, and countertrading cost/income between the grid and the copper plate model. This calculation yields the welfare economic cost of redispatch, that is, it computes the actual increase in fuel costs, CO_2 emission costs and load shedding costs (value of lost load). The calculation does not identify redistribution effects associated with redispatch – depending on the local regulation regarding reimbursements for up- and down-regulation due to redispatch, generators may profit from being redispatched while consumers may have to pay additional costs beyond the actual increase in fuel costs. However, the redistribution of welfare does not affect the total welfare itself and depends mainly on the market design. It is therefore outside the scope of this study.

The redispatch costs are used 1) as a measure of changes in system costs due to offshore wind development, and 2) to evaluate the value of suggested internal grid upgrades.

1. The redispatch costs for each scenario are compared to the redispatch costs of the base case scenario of 2030 and 2050 respectively. The difference in redispatch costs is then attributed to the offshore wind power development.

2. If the annual social welfare costs decrease by an amount larger than the annualized investment cost of the internal grid upgrade, the investment is considered economically sensible and is included in the modelling.

Note that although high utilisation of lines indicates a need for redispatch, the redispatch costs are not necessarily high. Only the computation of the change of actual redispatch costs following an upgrade of the grid as described in 2) can determine if that grid upgrade would be net beneficial in welfare economic terms.

6.2 Redispatch and reinforcements per area

In this section we go through the findings and results of the grid modelling for each of the countries. Results will then be combined in the following section, to form the basis for concluding remarks.

6.2.1 The Nordic countries

Overview

Model results suggest that the Nordic countries have small challenges with redispatch driven by increased offshore wind power. Unlike the other regions, there is no clear correlation between cooperation and redispatch costs and increased offshore wind power ambitions only slightly increases redispatch costs. Towards 2050, increased offshore wind power deployment may even have beneficial impacts on grid congestions in some scenarios. Due to the small impact of offshore wind power on the grid, we find that grid upgrades are only beneficial in two of the six scenarios, and only in 2050 – see Table 6-1 for numerical results. The table shows the change of social welfare costs compared to the base case and including both annualised grid upgrades and redispatch prior to and after grid reinforcements.

Positive numbers in the *Initial* row imply that the offshore wind deployment creates additional grid congestion and increases the cost of redispatch over a system without offshore wind. The numbers in the *Reinforced* row show the change in total cost (reinforcement and redispatch) compared to the base case if specific investments are undertaken to relieve the most severe congestions. For example, in the GC scenario in 2050, redispatch costs increase by about 90 MEUR compared to the base case. The cost of grid reinforcement is however more than outweighed by the reduction in redispatch costs: with the suggested grid investments, total grid costs can be reduced by 133 MEUR compared to the initial case, meaning that with the reinforcement total system costs are 43 MEUR lower than in the base case.

As we are interested in the effect of offshore wind on redispatch costs, we only consider reinforcements when we observe increased *initial* redispatch costs due to the offshore wind. For example, in the 2050 Low deployment scenarios, *initial* redispatch costs are already reduced compared to the base case. In some cases, we did identify economically viable upgrades even in cases where grid costs were initially reduced in the offshore wind power scenarios, we do not include them in this analysis as we consider them out of scope (not driven by offshore deployment). These results do however indicate that grid costs are highly sensitive to grid configuration and thus, that reduced uncertainty for long-term grid planning can substantially reduce grid costs.

Table 6-1 *Change in social welfare cost due to redispatch and grid reinforcements in the Nordic countries without (initial) and with internal grid reinforcements, in MEUR. Results marked in bold are used in the CBA.*

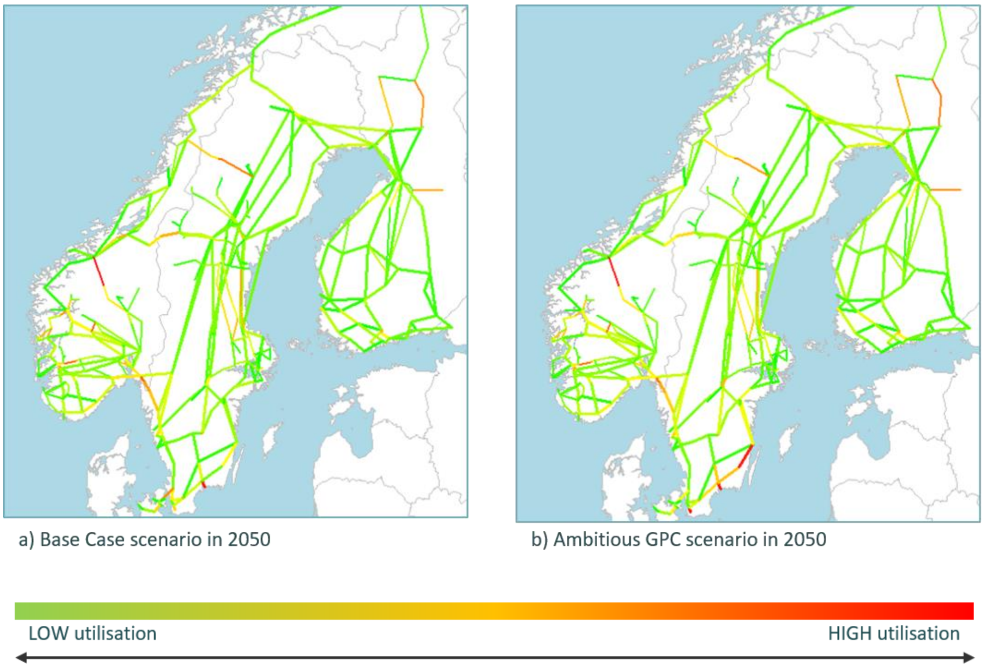
Year	Grid	Low			Ambitious		
		NP	GC	GPC	NP	GC	GPC
2030	*Initial*	**-7.22**	**14.31**	**14.04**	**34.41**	**25.83**	**1.17**
	Reinforced						
2050	*Initial*	**-68.49**	**-94.33**	**-76.51**	**-43.15**	89.73	94.04
	Reinforced					**-42.90**	**-10.60**

Initial grid and redispatch costs without upgrades

The Nordic countries have a robust grid that seems to be able to handle the offshore deployment in the Baltic Sea region foreseen by the scenario analysis without major reinforcements. Furthermore, the energy mix in the Nordic countries, especially in Norway and Sweden, is dominated by hydro power with large reservoir capacity, and the switch from conventional to renewable generation capacity towards 2050 does not affect generation capacity in the rest of the system as much as in the thermal systems on the continent. On the left-hand side of Figure 6-2, we show the utilization of the internal Nordic grid in 2050 in our base case scenario. On the right-hand side, we see the same system in the Ambitious GPC scenario.

The grid model does not allow for overloading of a line. Rather, it uses a different dispatch to avoid any overloads, hence increasing the costs compared to a copperplate dispatch. The difference in cost for the copperplate and grid-constrained dispatch is what we consider the socio-economic cost of redispatch. The colour of lines in the figures shows the utilisation: a green grid element indicates low utilisation, while a red grid element indicates high utilisation in most periods. High utilisation is an indicator that redispatch is needed to ensure secure system operation. However, neither the quantity of redispatched generation nor the cost difference can be directly read from the degree of utilisation.

Figure 6-2 Utilisation of internal grid in the Nordic countries under different scenarios in 2050, Base Case vs. Ambitious – Grid & Policy cooperation, with base case grid configuration.



The grid is not generally subject to high capacity utilisation in either scenario, but we observe some increased utilisation along the coast in the southern parts of Sweden where interconnectors and offshore hub capacity is connected to shore.

The Nordic countries generally have a low absolute level of redispatch costs compared to the other countries. In the initial grid configuration, no clear pattern between redispatch costs and cooperation can be found for the Nordic countries, cf. Table 6-1. In the 2030 low deployment and 2050 ambitious deployment scenarios, redispatch costs increase in the Nordic grid. In the other scenarios, cooperation seems to reduce the need for redispatch. The reason for the increase in the 2030 low deployment GC and GPC scenarios is likely increased trade between the Nordic countries and Poland via the additional offshore hubs. In the ambitious 2050 scenarios, the additional wind power entering the system is likely to be the driver for the increase in grid capacity utilisation in Southern Sweden.

Proposed upgrades and redispatch costs after reinforcements

Figure 6-3 shows the suggested grid upgrades in the Nordic countries. The increased capacity utilisation in Southern Sweden observed in the 2050 ambitious cooperation scenarios can be addressed with internal grid upgrades in that region.

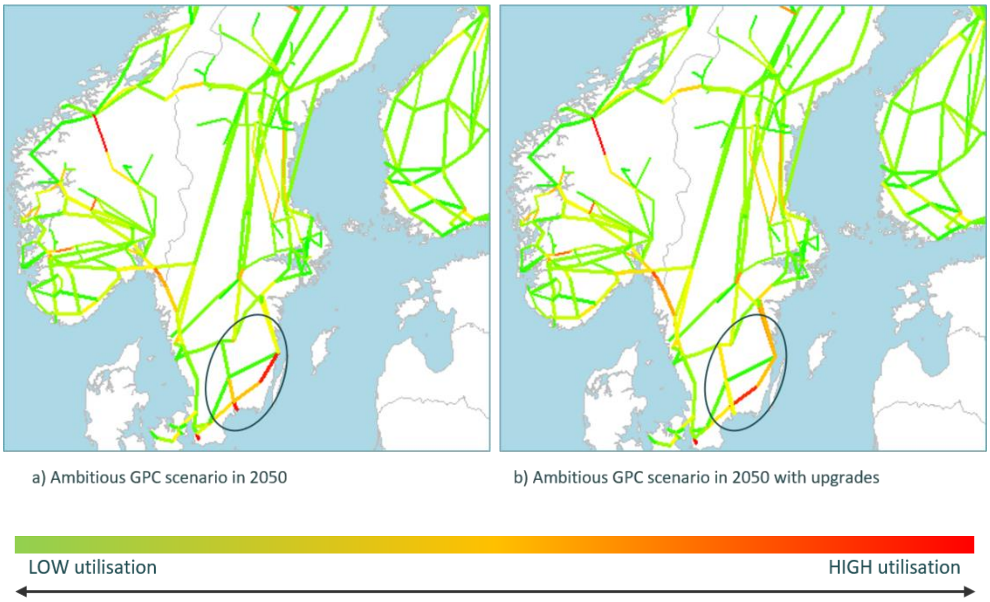
Figure 6-3 Suggested internal grid upgrades in the Nordic countries in 2030 and 2050

Line	2030 [MW]	2050 [MW]	Length [km]
Nybro – Oskarshamn	0	1801	82
Stärnö – Alvesta	0	1801	98

Going back to Table 6-1 showing change in social welfare costs, we see that the increase in redispatch costs due to offshore wind power is modest for the Nordic countries in 2030. Therefore, the reduction in redispatch costs after upgrading grid elements in 2030 does not outweigh the cost of the upgrades, and we do not include any additional reinforcements before 2030.

In 2050, we find that in the low offshore wind scenarios, redispatch costs are reduced in the Nordic system. In the high scenarios, we find that grid upgrades reduce redispatch costs by more than the associated grid investment costs in the GC and GPC scenarios. As the CBA should only analyse the effects of offshore wind power deployment, we have only included upgrades in the 2050 ambitious GC and GPC scenarios, as shown in Table 6-1. The suggested grid upgrades however make sense from a broader system perspective and could be considered even in the low scenario.

Figure 6-4 Utilisation of the Nordic grid in the Ambitious GPC scenario in 2050 without (left) and with (right) internal grid upgrades. The circled area indicates where the grid has been reinforced.



In the circled area in Figure 6-4, we observe that increased capacity near the offshore connection points allows more power to flow into Sweden, increasing the utilization of other lines in the internal grid. The proposed reinforcements affect the grid utilisation pattern. While some lines are still heavily utilised, total redispatch costs are reduced significantly.

6.2.2 Poland

Overview

We expect major changes in the Polish power system towards 2050, driven foremost by continuously increasing electricity demand. The Polish grid will come under significant strain in the long-term and will need adequate reinforcements to cope with the increases in demand.

In Poland, we observe increased grid costs with offshore deployment in all scenarios. However, higher levels of cooperation generally exhibit significantly lower redispatch costs in the Polish grid, as the additional import capacity associated with hubs reduces congestions around existing interconnectors. For 2030, the ambition level has only a minor impact. Towards 2050, a higher ambition level leads to lower redispatch costs. Targeted investments in north-south connections can efficiently address the congestions created by offshore deployment. Table 6-2 summarises the quantitative findings for redispatch costs in Poland.

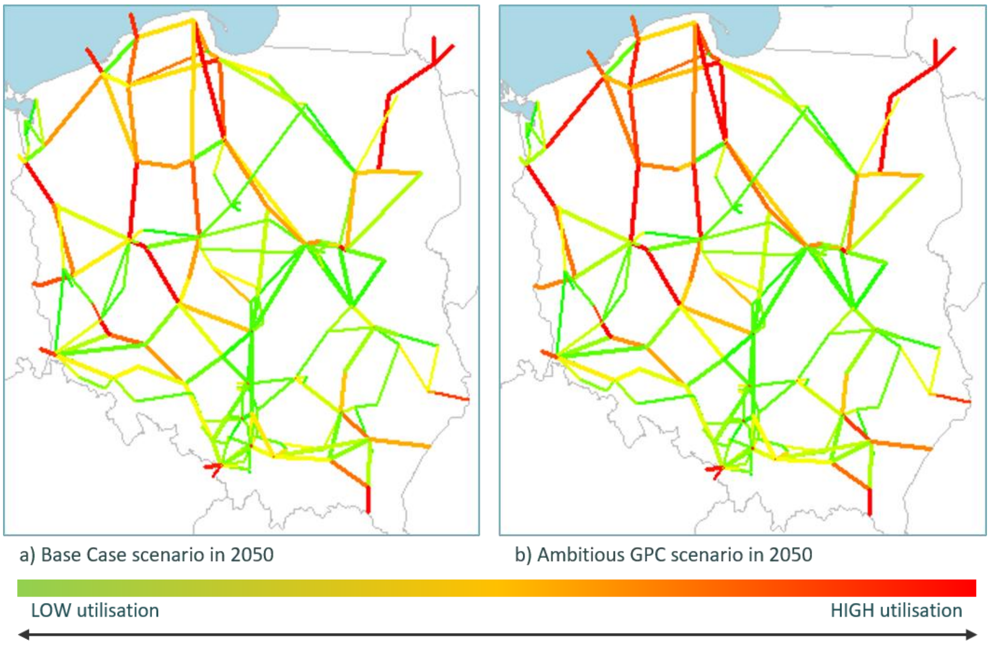
Table 6-2 Change of social welfare cost due to redispatch and grid reinforcements in Poland without (initial) and after internal grid reinforcements, in MEUR. Results marked in bold are used in the CBA.

Year	Grid	Low			Ambitious		
		NP	**GC**	**GPC**	**NP**	**GC**	**GPC**
2030	*Initial*	**152.45**	**130.54**	**104.46**	**164.02**	**106.06**	**114.2**
	Reinforced	-	-	-	-	-	-
2050	*Initial*	555.46	270.65	414.14	414.55	276.78	268.42
	Reinforced	**526.15**	**236.32**	**219.58**	**295.64**	**51.34**	**1.37**

Initial grid and redispatch costs without upgrades

Total electricity demand in Poland almost doubles from 2020 to 2050 in all scenarios. Between 2020 and 2030 the demand increases by a factor of 1.3, and between 2030 and 2050 it increases by a factor of 1.5. Although about 10 percent of this demand is either flexible or can be covered by fuel switching in 2050, the substantial increase in electricity demand will require comprehensive upgrades of the Polish internal power grid. To accommodate some of these needs, we have assumed additional grid investments in Poland before 2050 in our base case scenario. The assumptions are elaborated in the methodology section, Section 6.1.

Figure 6-5 Utilisation of internal grid in Poland under different scenarios in 2050, Base Case (left) vs. Ambitious – Grid & policy cooperation (right), with base case grid configuration.



In 2030, the Polish grid can cope with the offshore wind power development in all scenarios without additional challenges. In 2050, however, the Polish grid is highly utilised prior to any buildout of offshore wind capacity (base case scenario) even with the assumed grid reinforcements, see the left panel (a) in Figure 6-5. In the scenarios with offshore buildout the grid capacity utilization is increased further in the north where the offshore wind capacity is connected to shore.

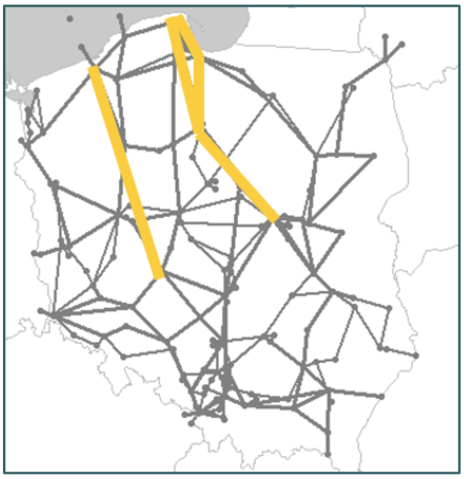
The situation depicted in the right panel (b) in Figure 6-5 is consistent for all the offshore wind power scenarios in 2050. The results suggest that internal grid reinforcements are necessary in all scenarios, even without offshore wind deployment.

However, we also find that increased cooperation and increased offshore wind power ambition reduce redispatch costs compared to the scenario with low ambition and national policies, and prior to any grid upgrades.

Proposed upgrades and redispatch costs after reinforcements

Figure 6-6 shows the suggested grid upgrades in Poland. The upgrades increase the capacity between offshore wind generation and offshore hubs in the north and the demand in the south of Poland.

Figure 6-6 Suggested internal grid upgrades in Poland in 2030 and 2050

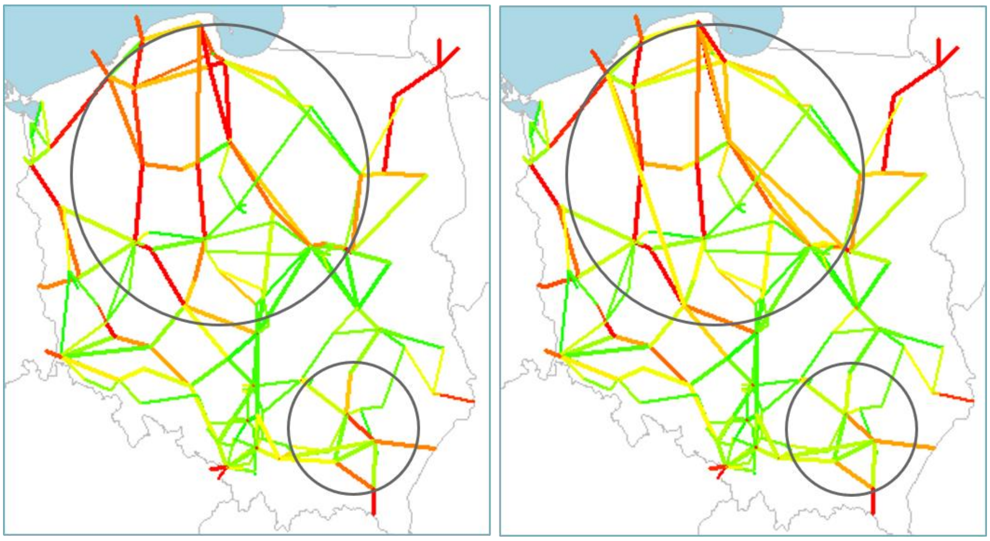


Line	2030 [MW]	2050 [MW]	Length [km]
Gdansk - Grudziadz	0	650	110
Dunowo - Ostrow	0	2000	360
Zarnowiec - Grudziadz	0	1500	150
Grudziadz - Milosna	0	1500	250
Zarnowiec - Gdansk	0	1238	70

See Table 6-2 for a comparison of social welfare costs with and without grid reinforcements. In 2030, the proposed grid reinforcements in Poland are found to be inefficient as the savings in redispatch costs do not offset the investment cost of the reinforcements, and we have therefore not included upgrades in 2030 in the CBA.

In 2050, however, the analysis suggests that upgrades that increase grid capacity from north to south are net beneficial in all offshore wind power scenarios. Figure 6-7 shows how the flows in the grid change as we introduce the internal grid upgrades, and that the utilisation of some of the most congested grid elements are reduced.

Figure 6-7 Utilisation of the Polish grid in the Ambitious GPC scenario in 2050 with (left) and without (right) internal grid upgrades. Circled areas highlight where the utilisation of grid elements is decreased after upgrades.



a) Ambitious GPC scenario in 2050

b) Ambitious GPC scenario in 2050 with upgrades

The grid upgrades are designed to handle the increased utilisation due to offshore wind power development and offshore interconnectors. Independent from the offshore development, the internal grid is highly utilised both before and after the grid upgrades, as shown in the base case scenario in Figure 6-7 (left panel).

6.2.3 Germany and Danish Bidding Zone 1 (DK1)

Overview

The German grid – which has severe issues with congestions today – will be reinforced with new north-south connections around 2025. The German grid is able to handle the Baltic offshore capacity assumed in 2030 with reasonable additional redispatch costs. Regional cooperation seems to alleviate grid congestions in Germany in the short term (the increase in redispatch costs is lower in the cooperation scenarios than in the national policies scenarios). Under the offshore assumptions for 2050, Germany sees increasing redispatch costs, especially in scenarios with high regional cooperation, as these scenarios allocate more offshore capacity and additional trade routes close to the German Baltic Sea coast. Some reinforcements in North-Eastern Germany may be necessary towards 2030 and certainly towards 2050.

Quantitative results for redispatch in Germany are given in Table 6-3. In 2030, redispatch costs in Germany are reduced in the cooperation scenarios. In the long-term, however, the increased offshore wind power capacity in the southern part of the Baltic Sea, especially in the Grid and Policy Cooperation (GPC) scenario, is likely to increase redispatch costs. The results for 2050 have to be viewed in the context of generally high redispatch costs in Germany. These might be addressed by grid reinforcement independent of offshore wind power deployment, which might also reduce the impact of Baltic offshore wind power.

Table 6-3 Change of social welfare cost due to redispatch and grid reinforcements in Germany and DK1 without (initial) and with internal grid reinforcements, in MEUR. Results marked in bold are used in the CBA.

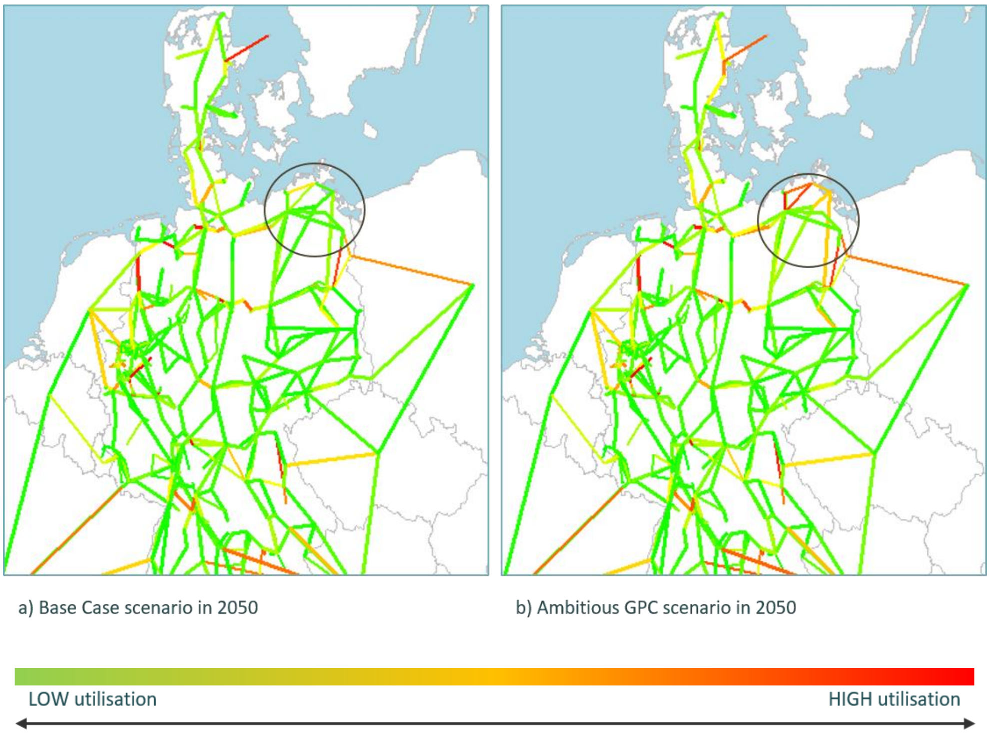
Year	Grid	Low			Ambitious		
		NP	GC	GPC	NP	GC	GPC
2030	*Initial*	73.46	33.28	32.04	111.44	87.52	49.31
	Reinforced	**60.54**	**13.23**	**13.14**	**68.41**	**37.89**	**29.74**
2050	*Initial*	118.79	175.53	351.02	123.08	380.17	248.42
	Reinforced	**9.55**	**23.23**	**299.69**	**7.03**	**291.02**	**143.51**

Initial grid and redispatch costs without upgrades

In the offshore wind power scenarios explored in this study, German nuclear capacity is completely phased out by 2030, coal and lignite capacities are almost halved by 2030 and reduced to zero in 2050, and CHP and gas capacity are halved as we approach 2050. Bio, Solar, offshore and onshore wind power are introduced to cover the demand, which also increases in the same period. The assumed grid development based on ENTSO-E TYNDP 2018 includes several internal grid upgrades in Germany, strengthening the grid from north to south due to the expected high deployment of offshore wind power as well as onshore wind power in the northern parts of Germany, while nuclear and eventually coal plants are expected to be decommissioned in the south.

In our base case scenario in 2050 (left panel in Figure 6-8), we see only few congestions in the system. As we introduce a higher share of offshore wind power connected in the northeast, the grid becomes congested near the connection points. In the Ambitious GPC scenario shown in Figure 6-8 (right panel), the trade capacity through subsea interconnectors also increases the utilisation of the internal grid in Germany.

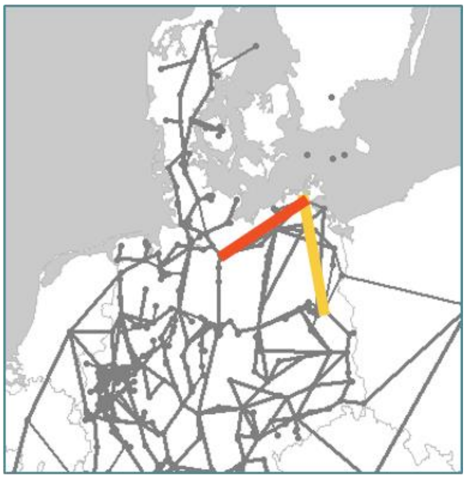
Figure 6-8 *Utilisation of the internal grid in Germany and DK1 under different scenarios in 2050, Base Case (left) vs. Ambitious – Grid & policy cooperation (right), with base case grid configuration. Circled area is where offshore wind is connected and where the grid is experiencing additional utilisation due to the offshore wind power development.*



Proposed upgrades and redispatch costs after reinforcements

Figure 6-9 shows the suggested grid upgrades in Poland. The upgrades increase the capacity between the offshore wind power generation and offshore hubs connected near the island of Rügen, and connection points further inland in Germany. The first upgrade notably connects the Baltic offshore wind generation to the northern end of the new north-south HVDC corridors in Germany.

Figure 6-9 Suggested internal grid upgrades in Germany and DK1 in 2030 and 2050

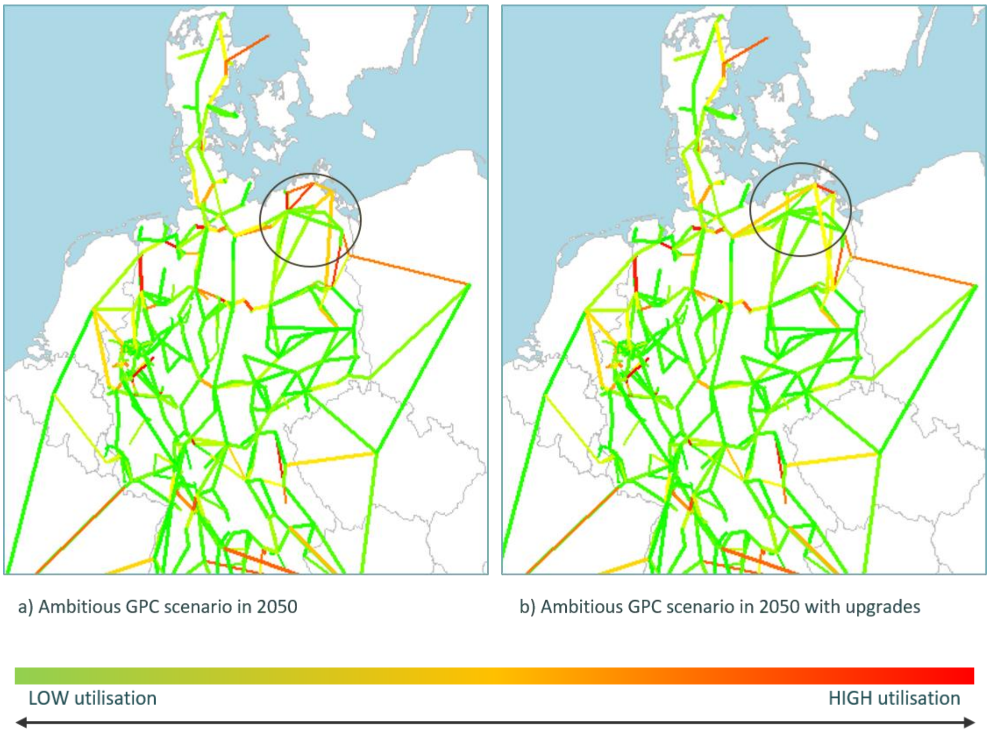


Line	2030 [MW]	2050 [MW]	Length [km]
Lüdershagen -Krümmel	1711	1711	250
Lüdershagen -Neuenhagen	0	1000	240

In Figure 6-8, we observe that the internal grid becomes congested in the northeast due to offshore wind power development. Accordingly, Table 6-3 shows that the redispatch costs are increasing compared to the base case for all scenarios and tends to increase with cooperation and increased offshore ambition.

The total redispatch costs do however not increase in all cases with increasing offshore wind power development and increasing cooperation on interconnector capacity, suggesting that costs in certain parts of the system may be reduced in the offshore wind scenarios, while costs may increase in other parts. Figure 6-10 shows that the suggested grid upgrades relieves the congestion in the northeast related to the offshore wind power development (circled area).

Figure 6-10 Utilisation of the German and DK1 internal grid in the Ambitious GPC scenario in 2050 without (left) and with (right) grid upgrades. Circled area is most affected by Baltic Sea offshore cacapity.



6.2.4 The Baltic Countries

Overview

The Baltic countries are a special case, in the sense that grid congestions here are to a larger extent driven by transit flows from the Nordic countries to Poland. Otherwise, we see similar developments in the power system as in Poland, that is, we expect increasing demand in the Baltic countries and significant changes over time even in the base case.

Offshore deployment and regional cooperation seem to have a positive effect on redispatch costs in the Baltic countries. In 2030, costs are either constant compared to the base case or somewhat reduced. In 2050, costs increases slightly for the National Policy (NP) scenarios, but decrease significantly for the cooperation scenarios, as cooperation on grids allows for imports at different locations, reducing congestions around existing interconnectors. Grid and Policy Cooperation scenarios allocate more offshore wind closer to the Baltic countries, reducing the need for redispatch towards 2050 when the grid is under stress from increased demand. The level of ambition in offshore deployment increases the positive effect of cooperation and the negative effect of a lack of cooperation.

We could identify socio-economically beneficial reinforcements. However, these mainly address the issue of flows from the Nordic countries towards Poland and congestions between the Baltic countries that are independent of any offshore deployment. This also mirrors the findings of the market modelling in Task 2. Since such reinforcements would not be driven by the offshore wind power deployment they are not included in the CBA. Redispatch costs are given in Table 6-4.

Table 6-4 Change of social welfare cost due to redispatch and grid reinforcements in the Baltic countries without (initial) and with internal grid reinforcements, in MEUR. Results marked in bold are used in the CBA.

Year	Grid	Low			Ambitious		
		NP	GC	GPC	NP	GC	GPC
2030	*Initial*	**0.01**	**-1.48**	**0.66**	**0.37**	**-29.2**	**-30.85**
	Reinforced						
2050	*Initial*	**2.44**	**-92.67**	**-140**	**12.41**	**-191.55**	**-207.37**
	Reinforced						

Initial grid and redispatch costs without upgrades

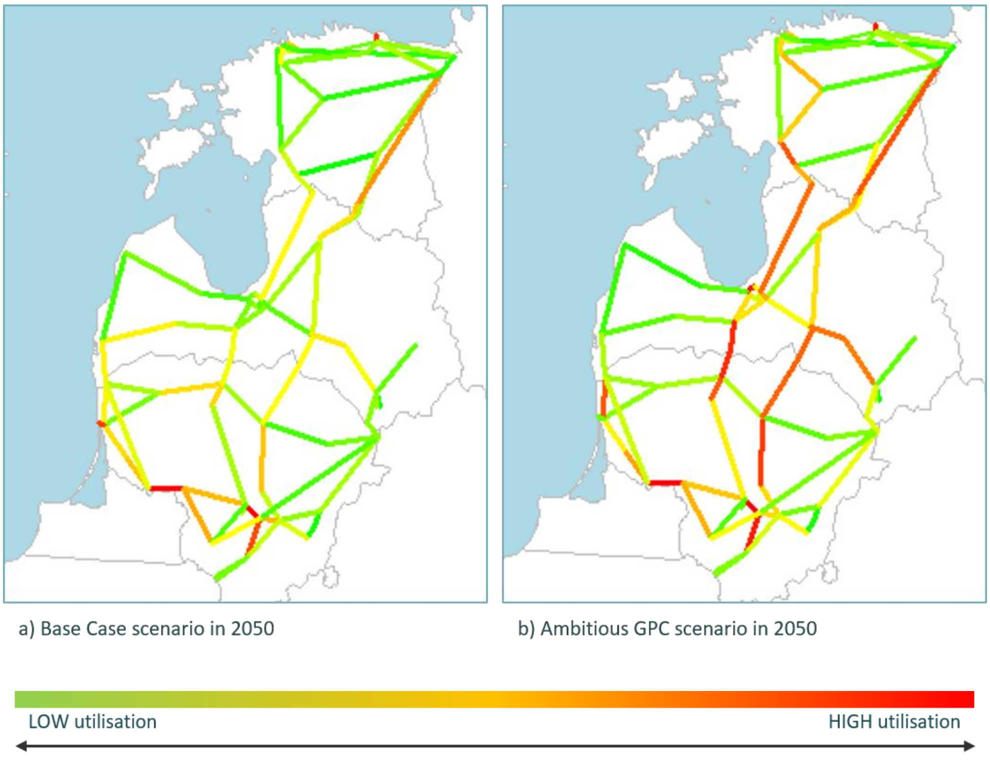
The grids in Estonia, Latvia and Lithuania are expected to be heavily loaded in 2030 due to an increase in demand and a shift towards renewable generation. Between 2030 and 2050, several grid upgrades are assumed to take place in the base case scenario following the synchronisation of the Baltic countries with continental Europe, with the result that the grid is less utilised in 2050 than might be expected considering the significant system changes.

Offshore wind is not a driver for grid congestions. Offshore wind power development does increase the utilisation of some grid elements but reduces the utilisation of others, i.e., offshore wind generation shifts the flows and the congestion patterns in the grid.

In 2030, there is little impact from cooperation in the Low deployment scenarios. With Ambitious deployment and regional cooperation on offshore grids, total system costs are expected to decrease. This is in line with the findings of the market modelling, which identified the value of interconnectors between the Baltic countries.

In 2050, the grid is utilised at or close to its capacity limits in many areas independent of offshore buildout. As in the Polish system, the countries are subject to increased demand, electrification, and a shift from conventional to renewable energy sources. Hence, additional interconnector capacity provided by the offshore hubs in the GC and GPC scenarios has a positive impact on grid loading. In particular, the hubs increase the interconnector capacity between Lithuania and Poland, allowing both offshore wind power connected to the Finnish grid and other power production to flow through the Baltic countries to cover demand in Poland. As a result, the cross-border connections between the Baltic countries are loaded at their full capacity in the Ambitious scenarios, transferring both offshore wind and traded power from north to south. The utilisation of the internal grid in the Baltic States is illustrated in Figure 6-11 for the base case and the ambitious GPC scenario in 2050, assuming the same (initial) internal grid configuration in both cases.

Figure 6-11 Utilisation of internal grid in Estonia, Latvia and Lithuania under different scenarios in 2050, Base Case (left) vs. Ambitious – Grid & policy cooperation (right), with base case grid configuration.



Looking at the flows illustrated in Figure 6-11 it is also worth noticing how the inclusion of hubs, supporting additional trade flows in the GC and GPC scenarios, imply increased congestions in certain parts of the grid while other parts experience reduced loads.

Proposed upgrades and redispatch costs after reinforcements

Figure 6-12 shows the suggested grid upgrades in the Baltic countries. Notably, these are not strictly internal upgrades, but rather upgrades that address cross-border issues.

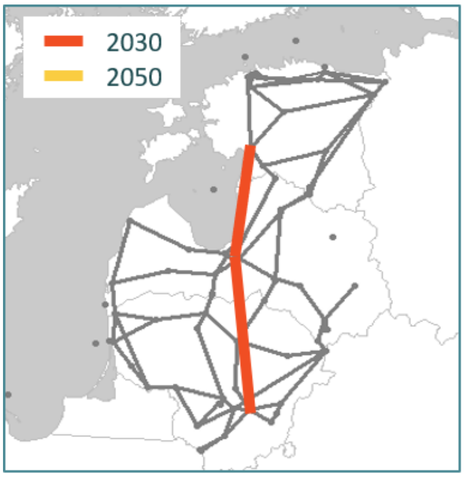
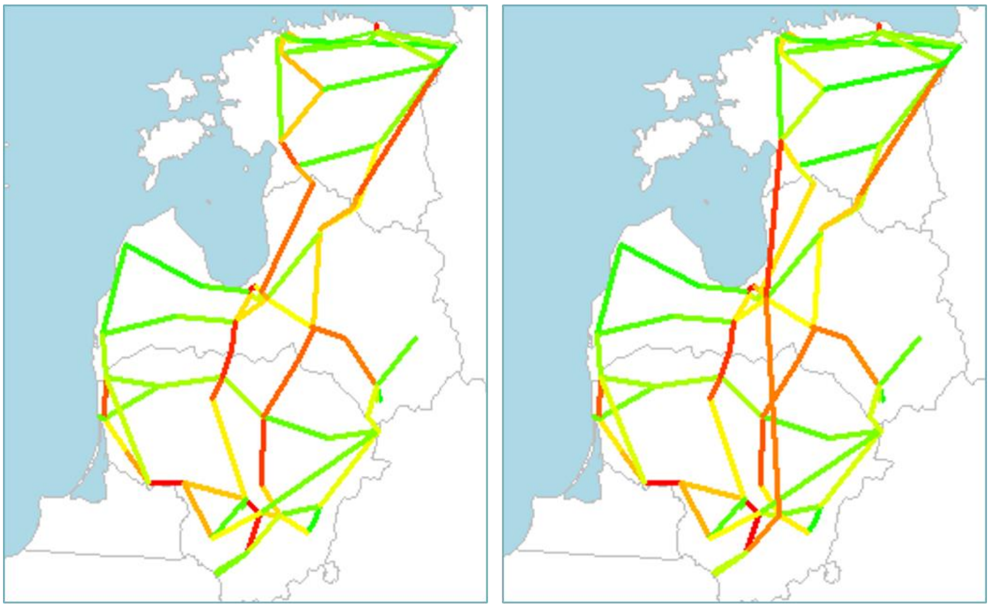


Figure 6-12 Suggested internal grid upgrades in the Baltic countries in 2030 and 2050

Line	2030 [MW]	2050 [MW]	Length [km]
Sindi - Salaspils	500	500	191
Salaspils - Le (Vilnius)	500	500	279

Although offshore wind power development yields reduced redispatch costs in the grid in the Baltic countries compared to the base case scenario for most of the development scenarios (see Table 6-4), we have explored to what extent internal grid upgrades could reduce the cost even further. It should be noted that as the offshore development, combined with increased cross border trade capacity, reduces the redispatch costs in the system, further reduction due to grid upgrades are not included in the cost benefit analysis. However, the grid upgrades suggested in Figure 6-12 make sense in a broader system perspective in both 2030 and 2050 and should be considered regardless of offshore development.

Figure 6-13 Utilisation of the Baltic grid in the Ambitious GPC scenario in 2050 without (left) and with (right) internal grid upgrades.



a) Ambitious GPC scenario in 2050 b) Ambitious GPC scenario in 2050 with upgrades

The utilisation of the internal grid with the suggested grid upgrades in the Baltic countries are illustrated in Figure 6-13 for the Ambitious GPC scenario in 2050. Due to a skewed power balance with high demand and low generation in the most populated areas (Tallinn, Riga and Vilnius) and independent of offshore deployment, the internal grid is struggling to transfer capacity both with and without grid upgrades.

The results of both the market modelling in Task 2 and the grid modelling highlight the benefit of increased interconnector capacity in the Baltic countries. The main direction of the energy flow is from Finland via Estonia and Latvia to Lithuania, and further to Poland. Hence, a regional perspective on grid upgrades and interconnector capacity seems to be appropriate in these countries independent of offshore wind development scenarios.

6.3 Summary

So far, we have discussed effects for individual countries or regions bordering the Baltic Sea. This last section collects the results of the grid modelling across the entire BEMIP region and concludes on the main findings.

6.3.1 Collection of results

The following figures show waterfall plots summarising the results for each scenario across all countries. The first two columns show the increase and decrease of redispatch costs compared with the base case scenario. The third column gives grid upgrade costs, the fourth the savings in redispatch costs due to those upgrades. The final column are the total social welfare costs of congestions that we attribute to each scenario. White numbers give the total welfare cost difference between each scenario and the base case, hence showing the estimated impact of offshore wind on redispatch costs. Red numbers show the relative comparison between the scenarios compared to the Low deployment, NP scenario for 2030 and 2050, respectively.

Figure 6-14 shows total annualised social welfare costs of redispatch and grid upgrades across the BEMIP region in 2030. Although grid costs increase in all the scenarios, even after grid upgrades, we see a clear trend that increased cooperation, both on grid and on policy, lead to decreasing redispatch costs in the given offshore deployment scenarios. This is not only true across the whole region, but also for each individual country. The level of ambition – low or ambitious offshore deployment – has little impact on the total redispatch costs but leads to a slightly different allocation of the costs between the countries. The ambitious deployment, national policies scenario has the highest negative impact on redispatch costs, while the ambitious GPC scenario has the least impact.

Figure 6-14 Total change in social welfare costs due to offshore wind deployment in the BEMIP region in 2030, per scenario, in MEUR.

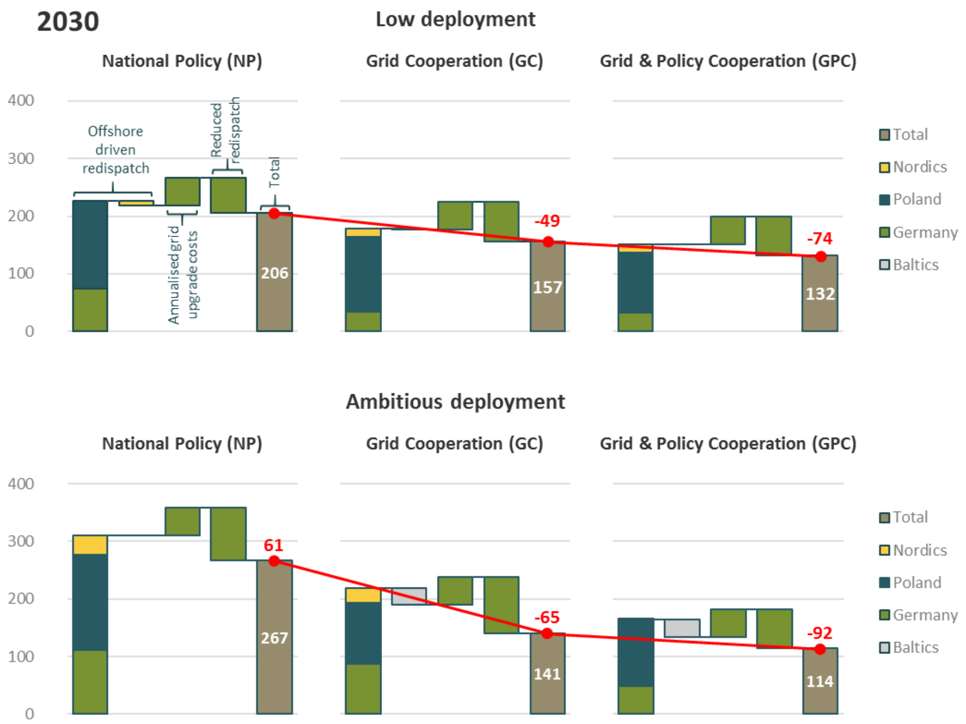


Figure 6-15 shows total annualised social welfare costs of redispatch and grid upgrades across the BEMIP region in 2050. The general trend that increased cooperation and higher ambition leads to lower grid costs across the region is reaffirmed. As in 2030, the scenario with highest cost is the low ambition NP scenario, and the scenario with lowest, in fact negative, impact on redispatch costs is the ambitious GPC scenario.

However, the picture is more complex in 2050: some countries see increasing redispatch costs with increasing cooperation. For example, Germany and the Nordic countries experience increases in the ambitious deployment scenarios. This finding motivates the recommendation that regional cooperation should be accompanied by a fair analysis of the benefits and costs that each member state bears, e.g., due to the connection of an offshore hub.

Also, in the under low ambition scenarios, the GPC scenario exhibits higher redispatch costs than the GC scenario. The increase stems from both Germany and Poland and might be related to insufficient German-Polish cross border capacity. However, it such effects were out of scope for the analysis of internal constraints in this section.

Figure 6-15 Total change in social welfare costs due to offshore wind deployment in the BEMIP region in 2050, per scenario, in MEUR.

As input to the cost-benefit analysis, we use the relative increase or decrease compared to the NP Low deployment scenario, which is used as reference in the analysis of offshore grid power scenarios. The following table summarises the results of the grid modelling for the whole BEMIP region. These numbers are used in the CBA in the next chapter.

Table 6-5 Change of social welfare cost due to redispatch and grid reinforcements in the BEMIP region as a total, after internal grid reinforcements, compared to the Low deployment NP scenario, in MEUR.

Grid	Low		Ambitious		
2050	**GC**	**GPC**	**NP**	**GC**	**GPC**
Redispatch costs	-49	-74	61	-65	-92
Grid reinforcement	0	0	0	0	0
2030	**GC**	**GPC**	**NP**	**GC**	**GPC**
Redispatch costs	-397	-167	-198	-398	-579
Grid reinforcement	0	0	0	36	36

6.3.2 Conclusions

The grid modelling exercise gives some relevant insights into the effect of offshore wind deployment and regional Baltic grids on onshore congestions and need for and benefits of internal grid reinforcements. The main findings are

› Given planned grid upgrades, none of the offshore wind power deployment scenarios drive severe congestions in the internal grid in the Baltic Sea by 2030.

- In 2050, the grid exhibits congestions due to changes in market fundamentals stemming from the energy transition: increased electricity demand, a higher share of generation from intermittent onshore RES generation, and increased exports from the Nordic countries. The higher offshore wind deployment is only a minor driver for grid congestions.

- Targeted grid reinforcements and coordinated grid planning are likely to significantly reduce redispatch costs associated with offshore wind deployment in Germany, Poland and the Nordic countries, and to reduce congestion in general in the national networks. Planning and implementation of such reinforcements should be taken with a long-term vision, considering their benefit and the long lead times of grid projects.

- In general, we find that both in 2030 and 2050 and with both low and ambitious offshore wind power deployment, the impact on grid costs is lower in the cooperation scenarios than in the National Policy scenario. This seems to be driven by two factors: first, additional interconnector capacity provided by hubs allows alternative export routes for the power surplus in the north, thus reducing the overall costs related to congestion. Second, with policy coordination, offshore capacity is installed closer to areas where additional capacity is needed, i.e., notably Poland and the Baltic countries which see a relatively high demand growth. New offshore generation capacity can cover demand growth with less additional stress on the grid than increased imports along existing interconnections.

- The finding that cooperation on Grids and Policies significantly reduces total redispatch costs associated with offshore wind power deployment compared to the National Policy scenarios holds both for Low and Ambitious offshore wind deployment. We also see lower total redispatch costs under Ambitious deployment compared to Low deployment.

- Benefits of increased cooperation are not necessarily shared equally between countries. It might be relevant to discuss costs and benefits of cooperation projects such as offshore hubs incurred by participating countries in detail for each project.

7 Task 3b – Cost benefit analysis

Key Messages from the Results

- The cost-benefit analysis including all results from the market and grid modelling demonstrates the value of regional cooperation. Except for the Low ambition scenario in 2030, all scenarios suggest significant total savings from regional cooperation on offshore wind power deployment in combination with regional grid planning and development. The savings are driven by more efficient dispatch, reduced fuel and CO_2 costs, and to some extend by reduced redispatch costs for TSOs.
- Considering the lead time for cross-border interconnector projects and considering the value of regional cooperation, the CBA clearly suggests that regional cooperation and concrete evaluation of common projects should start as soon as possible. Beneficial cross-border renewables projects may be able to receive support through the Connecting Europe Facility (CEF), provided they are identified and prepared sufficiently early in the selection process.

The cost-benefit analysis compares the social welfare changes between the scenarios. This allows us to understand the effects that different buildout options and levels of cooperation have on social welfare, taking the impacts on generation and grid costs into account.

7.1 Methodology

For the cost benefit analysis, we consider the investment and maintenance costs of generation assets, the total fuel and generation costs, the additional social welfare impacts on redispatch, and the costs of and potential savings due to grid upgrades.

We do not consider a base case without offshore wind. Rather, we compare the scenarios against each other, and comment on whether the low or high offshore build-out ambition is more cost effective, and what level of regional cooperation appears to be the most attractive from an overall regional efficiency point of view.

7.1.1 CAPEX and OPEX of offshore and onshore assets

The costs of installation and maintenance for offshore wind farms were developed in Tasks 1 and 2, together with assumptions for the costs of onshore generation assets. The zonal investment and dispatch modelling in Task 2 was used to determine the cost-optimal investments – both onshore and offshore – that fulfil the given offshore wind deployment targets applied in the low and ambitious scenarios.

For onshore generation assets, we do not use total costs. Instead, the national policy (NP) scenario with low offshore wind ambition is a reference case for such costs against which we measure the relative change in the associated CAPEX and OPEX across the different scenarios.

7.1.2 Hub costs

The hub costs include the CAPEX and OPEX of building the hubs in the scenarios where hubs are used, namely the grid cooperation (GC) and grid and policy cooperation (GPC) scenarios.

7.1.3 CAPEX and OPEX of interconnectors

The zonal modelling also includes decisions on increased interconnector capacity independent of the offshore wind hub connections towards 2050. As we assume the same base interconnector buildout in all scenarios, the cost of these interconnectors is not separately accounted for.

7.1.4 Fuel and carbon cost

The fuel and carbon costs in the different scenarios are taken into account in the cost-benefit analysis by comparing the change in fuel and carbon costs relative to the low NP scenario.

7.1.5 Redispatch costs

As described in 6.1, we analysed grid congestion and redispatch costs in the different scenarios. Note that the redispatch costs computed by THEMA's The-GRID model describe the loss of social welfare resulting from suboptimal dispatch, such as higher fuel consumption, as measured relative to a copperplate scenario (in which there are no transmission constraints). The redistribution effects between producers and consumers are not assessed, as they do not affect the total social welfare.

7.1.6 Grid upgrades

Where estimated redispatch costs were high, we tested different options for onshore grid reinforcements intended to relieve them. If the estimated annualised cost of a grid reinforcement project was lower than the associated redispatch cost savings, we have included the annualised grid upgrade costs and the reduced redispatch cost in our assessment.

We assume a lifetime of 40 years, and a discount rate of 5% annually, for such network upgrade investments, consistent with the assumptions used in Task 2.

7.2 Results

Section 7.2.1 presents the results of the Cost-Benefit Analysis for 2030 and section 7.2.2 the results for 2050. All cost elements are given as the difference in costs between the relevant scenario and the Low NP scenario.

The presented numbers are all annualised and given in millions of real 2018 euros per year. The tables show the level of each type of cost under each scenario.

7.2.1 2030

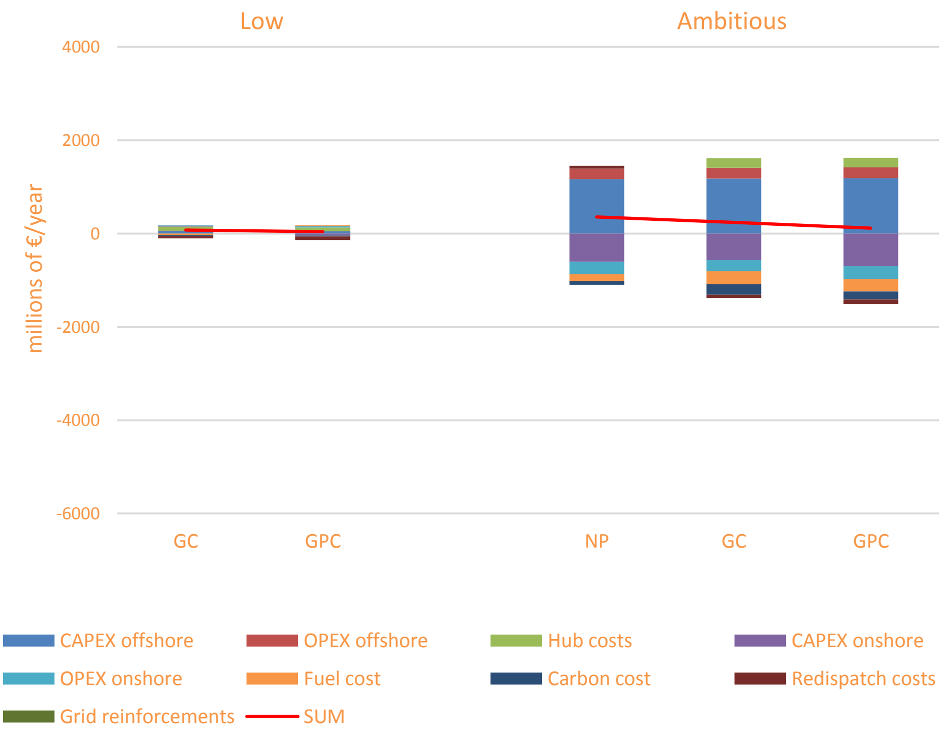
The CBA results for 2030 are presented in Table 7-1 and Figure 7-1. The numbers are provided in terms of changes in costs compared to the Low NP scenario for each element, taken from the modelling results. So, for example, looking at the Ambitious NP column (see, e.g., Table 7-1) we see that the total CAPEX on Baltic offshore wind under this scenario is 1159 million € per year higher than the cost for Baltic offshore in the Low NP scenario in 2030. As the increase in offshore capacity replaces onshore capacity and generation, investments in onshore capacity are reduced by 604 million € per year, in addition, onshore OPEX, fuel and carbon costs are reduced compared to the Low NP scenario.

By comparing the numbers in the SUM row, we can see the net cost or benefit implied by selecting one scenario relative to another. The lower the SUM, the lower overall cost of supplying the electricity demanded compared to other scenarios.

Table 7-1: Costs and benefits in 2030. All numbers in millions of € per year, investments are annualised.

	Low		Ambitious		
2030	**GC**	**GPC**	**NP**	**GC**	**GPC**
CAPEX offshore	61	43	1159	1181	1184
OPEX offshore	1	1	231	232	233
Hub costs	85	85	0	206	206
CAPEX onshore	24	-41	-604	-562	-704
OPEX onshore	11	25	-261	-250	-272
Fuel cost	-36	25	-151	-276	-267
Carbon cost	-24	-25	-82	-227	-174
Redispatch costs	-49	-74	61	-65	-92
Grid reinforcement	0	0	0	0	0
SUM	**73**	**39**	**353**	**239**	**114**

Figure 7-1: Costs and benefits in 2030, relative to Low deployment NP scenario



In 2030, we see somewhat higher SUM costs for an ambitious offshore wind power build-out plan. This indicates that, in the short-term, the level of deployment envisaged in the ambitious scenarios is displacing more cost-effective alternative forms of generation. However, when we compare the scenarios with ambitious buildout, the use of regional hubs in the Baltic Sea and regional cooperation clearly provides benefits. A better integration of markets and investments leads to lower overall CAPEX and OPEX, especially on the side of fuel costs and CO_2 emissions. In addition, redispatch costs are lower in the scenarios involving hubs and cooperation on targets.

As the detailed grid analysis shows, by supporting alternative paths for trade flows, the development of the hubs can create local congestion on parts of the grid, while simultaneously reducing grid loading in the areas neighbouring existing interconnectors. The implementation of the hubs also allows for excess wind generation to be more easily shared with neighbours, thus reducing redispatch costs. Targeted investments in onshore grid upgrades can significantly reduce the total grid costs of integrating offshore wind, that is the sum of the cost for redispatch and for grid reinforcements. In the cooperation scenarios, total grid costs are lower than in the National Policy scenarios.

It is also worth noting that the GC and GPC scenarios assume that all four hubs are built by 2030 (cf. section 5.2.5 and 5.2.7 for a discussion). It is reasonable to expect that some of these hubs will produce net benefits earlier, i.e. before 2030, while others will produce benefits only later. As such, despite the slightly higher costs for a solution with all four hubs in 2030, the results cannot be interpreted to suggest that there hub solutions are generally not beneficial in 2030 even under a low offshore buildout scenario. In addition, considering the long lead-times for international interconnector projects and the positive cost-benefit ratio for all policy and ambition scenarios in 2050, the cooperation on offshore hubs should start well before 2030.

In 2030, regional cooperation scenarios reduce the cost of ambitious deployment. The benefits increase with an increasing level of cooperation, i.e., the reduction in costs under a grid and policy cooperation (GPC) scenario is considerably higher than under the GC scenario. In low deployment scenarios, regional cooperation does not produce benefits in the 2030 timeframe; however, it makes the overall cost only marginally higher, which may be worth investing as it prepares for significant gain in cost reduction in the longer 2050 timeframe even under low deployment as shown below.

7.2.2 2050

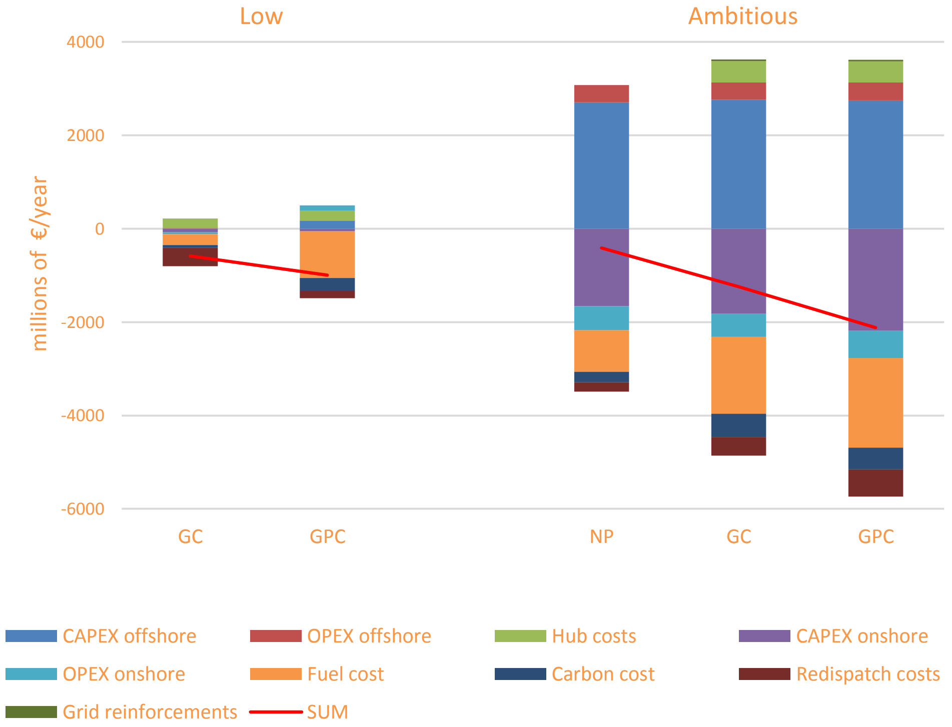
The CBA results for 2050 are presented in Table 7-2 and Figure 6-2. The numbers are provided in terms of changes in costs compared to the Low NP scenario for each element, taken from the modelling results.

Scenarios with a negative SUM have lower total system costs than the National Policy, Low ambition scenario. The table thus show that cooperation on offshore wind power deployment provides lower total costs than the NP scenario with a low offshore wind deployment level. Moreover, in 2050, ambitious national offshore deployment objectives result in lower costs than those with lower deployment rates.

Table 7-2: Costs and benefits in 2050. All numbers in millions of € per year, investments are annualised.

	Low		Ambitious		
2050	**GC**	**GPC**	**NP**	**GC**	**GPC**
CAPEX offshore	-3	159	2701	2727	2717
OPEX offshore	0	0	373	374	378
Hub costs	210	210	0	454	454
CAPEX onshore	-80	-55	-1664	-1819	-2186
OPEX onshore	-41	115	-510	-499	-586
Fuel cost	-234	-1006	-894	-1642	-1917
Carbon cost	-51	-264	-221	-505	-465
Redispatch costs	-397	-167	-198	-398	-579
Grid reinforcement	0	0	0	36	36
SUM	**-596**	**-1008**	**-413**	**-1272**	**-2148**

Figure 7-2: Costs and benefits in 2050, relative to Low deployment NP scenario



Regional cooperation on both grids (GC scenario) and grid and policy cooperation (GPC) scenario shows clear and strong benefits in 2050 in both the Low and Ambitious deployment scenarios. The GPC scenario shows a particularly large potential for cost reduction compared to the national policies (NP) scenario.

The savings from cooperation are driven by three effects: first, by the increased trade capacity, which can be seen by the decrease in total costs from the NP to the grid cooperation (GC) scenario. The additional savings stem to a large part from reduced fuel and carbon costs, indicating that the additional trade flexibility between the Baltic power systems via the offshore hubs creates significant socio-economic benefits. Second, by a more efficient allocation of offshore farms across the Baltic Sea to regions where we expect strongest demand growth, as can be seen by the additional decrease of costs between the GC and GPC scenarios. Third, by a decrease in redispatch costs with increased cooperation – again stemming from a more efficient utilisation of onshore grids due to more efficient allocation of offshore capacity and additional interconnector capacity.

Onshore grids will need to be adjusted to the changing generation and demand patterns, and todays grids will not be able to efficiently handle either the demand increase or new generation capacity. Hence, the grid-related cost and savings reported in Table 7-2 assume an appropriate development of the onshore grids and include the costs for grid reinforcements driven by offshore wind. Considering the long lead times observed for grid reinforcements and grid extensions, it will be necessary to start planning and development of onshore grid upgrades sufficiently early, taking into account expected offshore developments and regional cooperation.

Comparing Low and Ambitious offshore wind scenarios shows the benefit of ambitious offshore wind power deployment in all policy scenarios. Again, the savings that can be achieved on the side of fuel costs and CO_2 emissions are the main driver for the savings with ambitious deployment, while the increased CAPEX and OPEX of offshore wind power are to a large extend offset by reduced CAPEX and OPEX of onshore generation capacity. Total redispatch costs are lower in the Ambitious scenario than in the Low deployment scenario.

7.3 Conclusions

The cost-benefit analysis based on the modelling exercises leads us to the following conclusions

› In most of the cases examined, regional policy as well as grid cooperation, including the deployment of advanced offshore hubs, reduces total system costs, fuel consumption and CO_2 emissions, and supports a more efficient utilisation of assets. The most significant savings can be achieved with grid and policy cooperation (GPC) coupled with Ambitious deployment, and towards 2050 such cooperation produces even bigger cost reductions compared to the Low deployment case in the National Policy scenario.

› Cooperation on advanced offshore hubs reduce costs for both offshore wind deployment levels and all scenarios in 2050. In 2030, however, cooperation on advanced offshore hubs look less cost effective in scenarios with low offshore deployment. Considering the lead time needed for the planning, permitting and building of interconnectors, the fact that some hub solutions may be net beneficial even in the near term, and the universal benefits associated with cooperation on deployment objectives across all timeframes, the results suggest that efforts to cooperate on offshore wind buildout in the region can help to deliver greater social welfare.

› The cost savings attributable to scenarios with higher offshore wind deployment and with increased regional cooperation stem mainly from reduced fuel costs and lower CO_2 emissions, and to a relevant part also from more efficient grid usage and hence lower redispatch costs. The investment costs of offshore wind installations are also partly offset by reduced investments in onshore generation capacity.

The modelling indicates a general need for future grid reinforcements, especially in the Baltic States and in Poland due to increasing demand in these countries. The deployment of offshore wind and increased trade via interconnected Baltic grids lead to only limited additional redispatch costs and may in certain cases reduce the utilisation of other parts of the national grids. The additional redispatch costs can be partially offset by targeted investments in grid reinforcements.

8 Task 4 – Analysis of and recommendations to address market and regulatory barriers

Key Messages from the Results

- There are significant differences in the market and regulatory regimes applied to offshore wind across the different BEMIP member states. While Denmark, Germany and Lithuania plan to support the development of offshore wind through future tendering rounds, offshore wind is unlikely to attract any public support elsewhere in the region.
- There are marked differences in the extent to which offshore wind developers are liable for the cost of transmission investments linked to their projects under national connection charging regimes. While in some countries the TSO covers the cost of offshore network transmission assets, others require developers to either undertake or cover the costs of transmission grid work relatively deep within the onshore transmission network.
- The efficient commercial development of offshore wind capacity may be distorted in future by differences in the levels of support offered in different jurisdictions, as well as by significant differences in the extent to which developers are exposed to connection costs and network tariffs. These differences create an uneven playing field among projects in neighbouring jurisdictions that may prevent the efficient exploitation of offshore wind sites in the region and reduce the benefits of a regional approach.
- The deployment of network infrastructure needed to support the efficient deployment of offshore wind faces a number of practical barriers largely related to the difficulty of coordinating network activity among a variety of developers and numerous TSOs. This coordination is made even more difficult by the fact that the costs and benefits of the relevant infrastructure will generally be split asymmetrically across many parties. Improved mechanisms for the appropriate sharing of these costs and benefits are therefore likely to be needed to facilitate efficient offshore wind deployment.
- The lack of coordination of offshore wind ambitions, and offshore and onshore grid development to cater for efficient development of offshore wind resources in the region, are the core barriers that need to be addressed. In order to achieve such coordination, a common long-term vision has to be agreed that can be used to identify crucial investments in generation and grid infrastructure, along with appropriate measures and incentives to realise them.

The purpose of this task is to:

- Describe the current market regulation for offshore wind power generation and the relevant investment framework in the BEMIP member states,
- Assess whether current market and regulatory conditions constitute barriers to investment in offshore wind power generation or the necessary infrastructure, and
- Make recommendations on how the barriers can be removed or reduced through national measures and coordination between member states.

To complete the work, we have used a combination of public documents and interviews with key stakeholders (notably national wind associations and TSOs). We have also reviewed some of the available legislation where needed. Finally, we have used insights from previous projects such as Baltic InteGrid extensively both with respect to the factual background and for formulating hypotheses on barriers, particularly on barriers to network investments.[38] These sources have been complemented by own independent assessment when seeking to identify the most important factors and develop appropriate recommendations.

A description of the current market regulations and an overview of some of the relevant EU regulation can be found in the factsheets included in Appendix E. Section 8.1 below summarises current practice on those areas most important for the efficient deployment of offshore wind in the region in future.

In section 8.2, we go on to discuss elements likely to constitute barriers to the efficient deployment of either offshore wind capacity or the necessary network infrastructure. In this section, we focus on areas that are likely to be within the scope of a future BEMIP offshore wind power initiative, and do not consider legitimate and proportionate 'barriers' to development, like environmental protection.

This assessment considers two questions:
Are efficient investments in offshore wind capacity commercially viable from the perspective of offshore wind investors?
Are TSOs encouraged and enabled to develop the necessary supporting infrastructure, both across borders and internally?

Finally, we make our recommendations on measures to remove or reduce the most important barriers in section 8.3.

8.1 National and European market and regulatory frameworks

Having reviewed the current market and regulatory frameworks applicable to BEMIP member states, the most important features of these arrangements for the future deployment of offshore wind are those factors that significantly influence either the expected profitability offshore wind investments, and therefore its commercial viability, or else the likelihood of investments in the supporting network infrastructure.

[38] See e.g. Baltic InteGrid (2019): Baltic InteGrid review: towards a meshed offshore grid in the Baltic Sea. Final Report. February 2019. The Baltic InteGrid study is also an important part of the background for Task 5 documented in the next chapter.

It is worth noting that the overarching market arrangements in the region are broadly favourable to commercial development of generation projects. Notably the energy markets in the region are liberalised and will shortly be coupled at both the day-ahead and intraday stages, as detailed in the factsheets. We also find that risk mitigates such as power purchase agreements are available throughout the region to support investments in renewables in general. These should also be available to offshore wind, particularly with expected cost reductions and further market integration and development. Since the market arrangements are broadly favourable, most of the barriers relate to the regulatory framework.

A wide range of electricity market design issues are potentially relevant. There are three areas that deserve particular attention: the network charging regime, the support mechanism for offshore wind and the TSO's regulatory framework. The first two have a significant effect on the commercial viability of investment in offshore wind capacity. The third sets the context for decisions on network investment.

Other design features, of secondary importance, include balancing responsibility requirements, ancillary services requirements, priority feed-in and curtailment risks, congestion management methods, gate closure times and imbalance pricing. In our estimation however, these factors will have less direct impact on the expected profitability of offshore wind power projects, or the likelihood of grid projects, in the period 2020-2050. In particular, work is already underway to address many of the issues related to these design features. For instance, many general market design issues have been analysed in the context of offshore wind power development in the North Sea region. The recommendations on how to resolve these barriers that can also serve as a template for the Baltic Sea region and for EU regulation in general (see 3E et al., 2015,[39] for a comprehensive overview and analysis of such barriers in the context of a North Sea offshore grid, including the role of EU regulations in reducing or removing barriers to offshore wind). Ultimately, we expect these features to either be resolved through other measures, e.g. Network Codes and other EU regulations, or to have comparatively small impacts on the future level and efficiency of investment in the Baltic Sea region. The rest of this section therefore focuses on the three key issues noted above.

8.1.1 Connection and network charges

The BEMIP countries apply different connection charging regimes to power producers, as illustrated in Figure 8-1 and explained in further detail below. These differences imply significant differences in the commercial viability of otherwise identical offshore wind projects between member states. Other things being equal, these differences are likely to distort the pattern of investment and may result in inefficient offshore wind investment within the region.

The EU Electricity Directive (2009/92/EC) grants flexibility to EU member states to develop their own grid tariff methodologies, reflecting the peculiarities of the national electricity system.

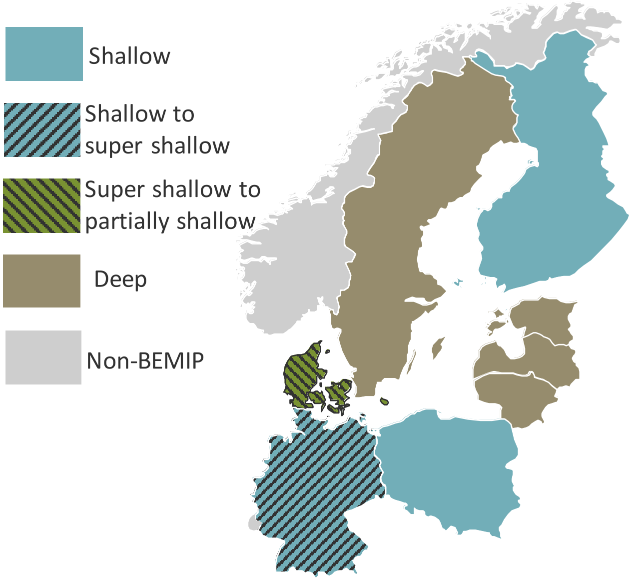
ENTSO-E categorises these connection charging regimes using the following definitions:

- Super-shallow: All connection costs are socialised via grid tariffs; no costs are charged to the connecting entity.

[39] 3E, DWG, DNV GL, ECN and CEPS (2015): North Sea Grid. Offshore Electricity Grid Implementation in the North Sea. Final Report. 24/03/2015.

- Shallow: Connecting users pay for the infrastructure used exclusively to connect their installation to the transmission grid (line/cable and other necessary equipment).
- Deep: Connecting users pay shallow charges and the cost of any reinforcements/extensions required in the existing transmission network.

Figure 8-1: Type of connection charges in BEMIP countries



Source: THEMA Consulting Group based on ENTSO-E (2018). Note: Striped colouring indicates that various connection charges may be applied to different generators within a Member State.

Relatively super-shallow regimes

Germany and Denmark generally apply super-shallow connection charges to offshore wind farms. Although the connection cost regime does not provide any direct incentive to developers to help minimise the costs of connection, the authorities are still able to ensure the efficient placement of offshore wind farms through a centralised model of site identification. German offshore projects do not bear the costs of grid connection, except as relates to the grid from the offshore wind park to the offshore transformer station. In Denmark, investors bidding into the auctions do not pay for grid connection or transmission costs, as these costs are paid by the TSO. However, for the upcoming tender for the Thor offshore wind farm, the offshore substation and connection cable to the onshore grid will be part of the tender and will be financed through subsidies for the wind farm.[40]

The exact definition and corresponding practice of connection charging regimes varies between countries, which means that the lines between the regimes may be blurred in practice. Nevertheless, the ENTSO-E overview clearly shows that there are fundamental differences in the connection charging regimes in the Baltic Sea region.

Relatively shallow regimes

Finland and Poland formally have shallow connection charges without centralised site selection. In Poland, the TSO covers the costs of reinforcement and development within the

40 https://ens.dk/sites/ens.dk/files/Vindenergi/brief_tender_for_thor_offshore_wind_farm_30march2019.pdf

existing network, while electricity producers pay for the direct line and any extension or rebuilding costs for the substation. Finland has a standard fee based on the average costs of connection infrastructure, but developers are directly responsible for the financing of infrastructure to bring the power to a connection point nominated by Fingrid. As a result, the developer can face significant effective connection costs beyond the formal connection charge.

Relatively deep regimes

Connection charges in **Sweden, Estonia, Latvia and Lithuania** are comparatively deep. In **Sweden,** generators connecting to the grid pay the direct costs related to this (lines, substations etc.) and may be asked by the TSO to cover deeper reinforcement works. In practice, deeper network costs are often not passed on through the charge. There is, however, an ongoing debate in Sweden about whether connection charges for offshore wind farms should be subsidised. The 2016 Swedish political agreement for energy states that connection fees for offshore wind should be removed and, in 2018, the Swedish Energy Agency published proposals to remove the grid connection costs for offshore wind power at the request of the government. However, it has since concluded that such measures may be incompatible with state aid regulation.

In **Estonia**, network connection charges, including necessary reinforcements in the grid, are paid by the project developer. However, exemptions for offshore connection charges are being considered. In **Latvia**, all producers pay a connection fee, which covers all connection equipment and reinforcement. The connection fee is based entirely on the actual costs of connecting the relevant assets.

Although connection charging in **Lithuania** is generally deep, renewable energy producers have so far faced reduced grid connection charges. In particular, renewable energy plants with a capacity of more than 350 kW only bear 40% of the associated connection costs, which include any necessary grid developments costs.[41] However, the Ministry of Energy submitted a draft law on Energy from Renewable Sources on August 10th, 2018 that would require renewable energy producers to cover all of the associated connection-related costs. [42]

Other network tariffs

Another factor that influences the competitive position of offshore wind is the obligation to pay generator network tariffs (G tariffs). Throughout the Baltic Sea region, generators are only obliged to pay a G tariff in Denmark, Finland and Sweden (ENTSO-E, 2018). These tariffs apply to all generators and, as such, do not affect domestic competition (except for the possible distortion between technologies with different load factors where capacity is used as the charging base). However, these tariffs clearly affect the relative profitability of offshore wind projects across the region. This effect of these tariffs is most marked in Sweden, where generators are currently paying around 38 per cent of overall TSO revenues recovered through capacity charges on consumption and generation.

[41] http://www.res-legal.eu/search-by-country/lithuania/single/s/res-e/t/gridaccess/aid/grid-development-15/lastp/159/

[42] https://enmin.lrv.lt/en/news/government-to-consider-a-new-model-for-development-of-renewable-energy

Current EU regulation (838/2010) limits the maximum average G tariff in the Nordic region to 1.2 €/MWH. For other countries in the Baltic Sea region the maximum allowed G tariff according to the EU regulation is 0.5 €/MWh.

8.1.2 Support mechanisms for offshore wind

Direct support schemes for offshore wind generation make a significant difference to the commercial viability of offshore wind projects. Current and planned support varies markedly across the region, as described below.

No specific support mechanism for offshore wind is planned in Finland, Sweden, Latvia or Estonia

Finland granted €20 million to a demonstration project in 2015 and is planning two technology-neutral auctions to secure 1 TWh of renewable energy each (excluding hydropower) between 2018 and 2020. However, offshore wind is unlikely to submit any successful bids due to its cost disadvantage relative to other renewable technologies.

Similarly, offshore wind is unlikely to be competitive under **Sweden**'s technology-neutral electricity certificate system for new renewable electricity production. Since wind power plants became eligible for electricity certificates in 2003, only one offshore wind park, Kårehamn (2013), has been developed in Sweden without additional support. The two other projects developed in Sweden in the last decade, Lillgrund (2007) and Vanern (2009), received pilot support from the Swedish Energy Agency ("Energimyndigheten").[43] Even if offshore wind were cost competitive under this regime, it is unlikely that an offshore wind farm could be developed in time to receive meaningful support from the electricity certificate system. The debate in Sweden has therefore instead focused primarily on whether offshore wind parks should be exempted from connection charges, as described in the previous section.

In 2017, the Government of **Estonia** approved The Estonian Energy Development Plan until 2030 (ENMAK). The plan targets an increase in the share of renewable energy in final domestic electricity consumption from nearly 30% in 2017 to 50% in 2030. The development of offshore wind power would likely be required for the target to be achieved, not least given the practical limits placed on onshore wind development by local opposition and radar interference. However, the 2030 objectives also include a commitment to subsidy-free renewables.[44] Amendments to the Electricity Market Act in 2018 established a system of technology-neutral tenders for renewable generation that will provide winning bids with a sliding premium to the market electricity price for twelve years. Tendering rounds for 2021 (450 GWh) and 2023 (650 GWh) are planned, with scope for additional rounds thereafter.

Latvia currently has no support mechanism for offshore wind and is likely to reach its 2020 renewable energy target through the development of other renewable energy sources.

[43] https://www.energimyndigheten.se/globalassets/nyheter/2015/rapport-havsbaserad-vindkraft.pdf

[44] https://www.mkm.ee/en/news/approved-energy-sector-development-plan-ensures-estonias-energy-supply

Under EU regulation, national authorities are free to allow renewable energy producers from other Member States to participate in their support schemes. It is therefore possible for subsidised offshore wind development to occur in countries that do not themselves provide support. The use of cross-border support schemes can enable a more efficient allocation of offshore wind farms, as seen in Task 2, and potentially facilitate investments that cross countries' Exclusive Economic Zones.

Denmark, Germany and Lithuania will hold specific tenders for offshore wind, while Poland may include support through so-called 'technology baskets'

Denmark, Germany and Lithuania are planning new tenders for offshore wind in the 2020s. The Polish government announced in July 2018 that offshore wind would be eligible for support through auctions.

In June 2018, **Denmark** signed an agreement to develop three new offshore wind farms with a total capacity of at least 2.4 GW by 2030. The first of the offshore wind farms will be tendered in 2021 and commissioned between 2024 and 2027. The second farm will be tendered in 2023 and, though the tender date for the third is yet to be decided, it is due to be commissioned by 2030. The decision to build three offshore wind farms rests on the assumption that it will be possible to build offshore wind farms without public subsidies within a few years.[45] In contrast to previous Danish offshore tenders, the intention is to include parts of the associated cost of the transmission infrastructure, i.e. the task of cabling from the offshore wind farm to the mainland, in the tender.

The German draft NECP includes a total of 15 GW of offshore wind power by 2030. The Offshore Wind Act (WindSeeG) in **Germany**, which entered into force on January 1, 2017, contains the details of future tenders for offshore wind projects. A transitional regime applies to offshore wind installations commissioned between 2021 and 2025. WindSeeG's new 'central' auctioning scheme will apply to plants commissioned from 2026 onwards.[46] In the central model, government authorities will select appropriate sites and perform a preliminary investigation of them. Development rights to these sites will then be auctioned. Only successful bidders will receive funding. The duration of the market premium payments received has been set at 20 years from commissioning, although the associated permit for operation will be valid for 25 years.

In 2017, the Government of **Lithuania** decided to centralise development of offshore wind park sites. An environmental impact assessment for the offshore areas will be prepared centrally until 2021, after which the fully permitted sites will be tendered to potential investors. In **Poland**, the Renewable Energy Act entered into force in July 2016 and replaced the earlier green certificate system with an auction scheme.[47] Following an amendment in June 2018, offshore wind power was placed in Basket II of the scheme, which now covers projects based on offshore wind, hydropower, biofuels and geothermal energy. Under the scheme, these technologies will compete against one another for funding from the same budget. New installations supported under auction basket II can sell up to 5,400,000 MWh of energy for a maximum amount of over PLN 2.5 billion (approx. €607 million), i.e. PLN 450 (€105) per MWh.

[45] https://www.efkm.dk/media/12222/energiaftale2018.pdf
[46] WFW. http://www.wfw.com/wp-content/uploads/2017/01/Germanys-offshore-wind-tender-system-Features@p54-56.pdf
[47] https://www.iea.org/policiesandmeasures/pams/poland/name-145058-en.php

The 2018 amendment also removed the requirement for offshore wind farms to have valid building permits before entering the auction.

8.1.3 TSO regulatory models

As noted previously, the efficient regional development of offshore wind requires supporting investments in transmission infrastructure. The regulatory model facing each TSO determines their willingness and ability to undertake the necessary infrastructure investment.

The TSOs in the region are mainly state-owned, with the exception of 50Hertz in Northern Germany, which has a private majority ownership. The Finnish TSO Fingrid has a significant private minority ownership.

The regulatory models vary from cost of service/rate of return regulation to revenue cap regimes (CEER, 2017). Germany, Finland and Sweden have introduced revenue cap models, while the Lithuanian TSO is subject to a hybrid price-/revenue cap model. Estonia, Latvia and Poland have what is essentially rate of return regulation, although the Polish model also has an incentive element through the application of OPEX efficiency requirements. The Danish model is in transition from a non-profit cost of service model to a revenue cap regime that is not finalised at the time of the writing of this report. In all countries, new investments can be added to the regulatory asset base, either through applying the actual historical investment cost, a calculated replacement value or standard engineering costs. The investments are generally rewarded with a regulatory WACC that includes a risk premium, i.e. the tariff base is increased with an element equal to the addition to the regulatory asset base multiplied by a rate of return. While the detailed parameter values vary, the approaches are broadly similar and in line with typical estimates of TSO cost of capital. The historical exception is Denmark, but here the TSO has had a clear political mandate for investments and access to loan capital at the same cost as Danish government bonds. Regulatory depreciation times tend to be in the 30-40 year region, which is fairly typical of European TSO regulatory regimes.

8.2 Assessment of implications

In this section, we identify the market and regulatory barriers to the efficient deployment of offshore wind in the Baltic Sea. We look at the barriers facing both the development of offshore wind capacity itself and the barriers to developing the supporting network infrastructure, since efficient deployment will inevitably require the coordinated investment in both. Although we cover a broader set of issues, our focus is on the barriers that are potentially likely to be of interest for a future BEMIP initiative to support offshore wind deployment, given the overall objective of the study. Therefore, particular attention is paid to the issue of international coordination and alignment of framework conditions. The rest of this section is divided among a discussion of barriers to investment in generation capacity and in network infrastructure respectively. The next section, section 8.3, discusses recommendations based on the identified barriers. Section 9 considers planning and licensing barriers, as addressed in Task 5 of the study.

8.2.1 Barriers to investment in generation capacity

Some offshore wind sites are more valuable, from a social cost benefit perspective, than others. Similarly, some other generation options will be more or less valuable than the deployment of offshore wind. Efficiency requires that the market and regulatory processes in place result in the investment in the most valuable generation projects and the most valuable sites.

Since this investment will be undertaken commercially, this requires that the market and regulatory process in place make the most valuable options the most commercially attractive. At some level, commercial and social incentives for offshore wind deployment are aligned. Developers and society as a whole aim to target projects with low costs and high outputs of valuable electricity. However, there are elements of the current framework that result in a disconnect between commercial realities and economic efficiency. Most notably, differences in regional practice, notably with regard to support schemes and network cost charges, mean that the commercial attractiveness of otherwise identical projects can vary markedly across national borders. As a result, socially beneficial sites can be unprofitable and go undeveloped, while inferior sites are prioritised.

National support schemes, as well as regionally applied schemes like the EU Emission Trading Scheme (ETS), are major determinants of the overall and relative profitability of different generation projects and of offshore wind specifically. Differences among the national schemes result in very significant differences in the profitability of projects within the region and risk distorting commercial interests within the region. Within the BEMIP members states, only Germany and Denmark have targeted support mechanisms for offshore wind. Other countries have technology-neutral schemes, but in general the current support levels in these schemes favours technologies with lower near-term costs. In general, offshore wind projects are unlikely to be selected or even apply for these technology-neutral schemes. The differences in national support levels imply that most valuable sites, from a regional perspective, may not be developed.

While there is at least one example of joint support scheme in the region, the Norwegian-Swedish market for electricity certificates, there is little practical experience from using this flexibility enhancing cooperation mechanism of the renewable energy directive. Currently, to our knowledge, no general framework or guidelines exist as regards how such mechanisms should be designed to ensure efficient regional investments. A previous study by THEMA for the Nordic Council of Ministers in 2013 highlighted some of the challenges and pointed to the need for establishing guidelines and regulatory frameworks to reduce the transaction costs and facilitate the use of support mechanisms across border.[48]

Differences in network charging regimes are similarly susceptible of distorting the commercial level playing field across the region and may fail to give developers appropriate incentives to help minimise network costs. Two types of economic efficiency issues arise here. First, it must be noted that connection charges for offshore wind farms and network tariffs for generators vary significantly among the BEMIP countries. Like differences in the support regime, this creates a perverse distortion in the commercial attractiveness of identical projects across national boundaries. The same problem also occurs with network tariffs more generally, and similarly affects all forms of generation. Notably, some countries also apply feed-in tariffs for

[48] THEMA Report 2013-12, Offshore wind farms as joint projects.

generators, while others do not. However, because connection costs are relatively large for offshore wind projects, these differences become more important to the overall commercial case.

Second, the connection charging regime can, if done well, create incentives for developers to minimise the network cost implications of their development, by passing the true cost implications on to the developer. Shallow connection charges encourage developers to select sites with lower direct costs associated with linking the asset to the transmission network. Deep connection charges mean that developers also need to account for potential reinforcement costs (ACER, 2015). Deep connection charges therefore provide more complete locational signals, which take account of congestion for example.

However, the efficiency impacts of deep connection charging are not simple. Notably, deep charges , if done badly, can make marginal developers liable for the costs of major network infrastructure upgrades, which grant wider social benefits, and ensure that even socially efficient investments fail to occur.[49] In addition, the incentive effects of connection charging may not be relevant in a system, like that in Denmark and Germany, where site and network decisions are made centrally and any additional costs would be paid for through subsidy anyway.

In general, therefore, efficient commercial deployment of offshore wind capacity in the region requires that commercial incentives are not distorted by differences in support levels and network cost liabilities across borders. It also requires that sites are chosen with regard to their network cost implications, either through the use of an appropriate connection charging regime or else through effective spatial planning. At present, support and liabilities do vary markedly across the region and the distribution of future commercial development is likely to be inefficient as a result.

8.2.2 Barriers to investment in network infrastructure

Unlike investments in offshore wind generation capacity, the market and regulatory barriers restricting appropriate investment in network infrastructure are not related to commercial profitability.

In general, the TSO regulatory models support investment by allowing new network assets to be added to the regulatory asset base and remunerated by a regulatory WACC. To the extent that an investment is considered risky, third-party financing via connection charges may reduce or eliminate the financial risk of the TSO (for those countries that use such charges). The feedback from interviews indicate that the TSO regulatory models are not considered a barrier to investment. The observed investment behaviour of the TSOs in the region supports this observation.

However, challenges remain. The regulatory models used are mainly designed to accommodate investments within national borders. For instance, it is not obvious that a payment from a TSO for an investment in another country would be approved by the paying

[49] This is ultimately a coordination failure, in which is difficult to apportion the cost of network upgrades to the multiple future beneficiaries of the capacity.

TSO's national regulatory authority. Even if the regulatory context [on cross-border infrastructure investment] were clear, there are several practical challenges to the realisation of large and complex cross-border [grid] investments. Another issue is the possibility that cross-border offshore grid assets are considered as interconnectors subject to EU regulation.[50] An interconnector will generate congestion revenues based on the price difference between interconnected market areas and the interconnector capacity, and can only be used for specific purposes, unless exemptions are made. It is not immediately clear how the EU regulation of interconnectors will apply to cross-border offshore grids (this issue is also raised by the Baltic InteGrid project[51]).

We discuss these barriers further below. We begin by noting a couple of general barriers to efficient deployment [of new grid investment] before exploring the challenges related to cross-border projects and investment programmes in detail.

General barriers

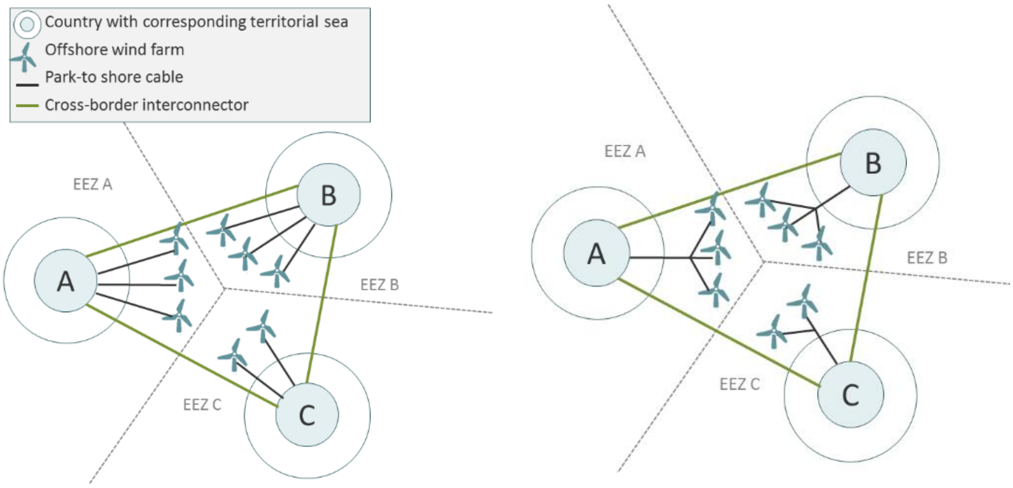
The first point worth noting is that although national revenue regulation of TSOs differ across the region (see section 8.1.3 above), all TSOs in the region are incentivised to and financially capable of undertaking network development programmes designed to meet the future needs of the network, including the possible development of offshore wind. [52] Hence the economic regulation of the TSOs is not considered a barrier for the development of the necessary offshore grids, as the TSOs should be able to raise capital for investments and earn a sufficient return on the network assets within the current investment framework whether the assets are located onshore or offshore. The challenges that prevent efficient network developments from occurring are of a more practical nature. Of these two are worthy of note: the challenge of coordinating offshore investments across multiple developments and the capacity of TSOs to drive forward very large investment programmes.

The first of these challenges stems from the fact that the efficient deployment of offshore wind power generation would require that different wind farm projects in the same area are locally coordinated and clustered. Such projects clustering of sites with appropriate wind and geological conditions has been carried out in practice and produce economies of scale also for offshore electricity network development. However, it has also been common to design transmission infrastructure to connect a single offshore wind farm to the transmission grid of one country (*park-to-shore cables*). This connection model does not take advantage of economies of scale in the design of transmission infrastructure. The figure below contrasts the two cases with radial connections vs. coordinated solutions.

[50] See Regulation (EC) No 714/2009 — conditions for access to the network for cross-border exchanges in electricity.
[51] Baltic InteGrid (2018): Establishing an offshore meshed grid. Policy and regulatory aspects and barriers in the Baltic Sea Region.
[52] In Denmark, the TSO regulation and organisation is currently being changed. However, given Danish policies and plans to encourage offshore wind power development, it would seem unlikely that changes to the TSO regulation and organisation will create barriers to offshore wind deployment.

Figure 8-2 Radial connections and local coordination of offshore wind power parks

a) Radial connections of offshore wind power parks *b) Local coordination of offshore wind power plants*



Source: Baltic InteGrid

While local coordination of grid infrastructure in connection with offshore wind farms is clearly desirable in theory, it can be difficult to realise in practice without strong central coordination. With the exception of those countries adopting fully centralised models of development, systems are generally not set up to facilitate local coordination among developers and the TSO across multiple development. Coordination can also founder because of the challenge to apportion network investment costs across multiple developers, if, for example, network assets need to be over-dimensioned initially and there is a risk that subsequent developments do not occur.

The second general barrier to realising the necessary network investment concerns is the ability of the TSOs to develop and carry out the planning and investment programme given the practical limits they face to finding skilled staff and senior leadership time. Several TSOs in the Baltic Sea region are already developing and implementing large investment programs to replace aging infrastructure, respond to the need of adjusting network charging schemes brought about by the development of onshore renewables and electrification, and to secure the synchronisation of the Baltic States with the European Continental grid. It is difficult to assess whether the call on TSO resources by these current challenges constitute a long-term barrier to offshore wind, but it is likely to be a real constraint today.

Cross-border infrastructure

In addition to these general barriers to efficient network investment, there are a large number of additional challenges associated with the types of cross-border planning and assets that are likely to be required for efficient offshore wind development. These challenges, and the number of parties that need to be involved, mean that cross-border projects are far more complex than their national equivalence. This increased complexity, and the greater transaction costs and risks that accompany it, pose a significant barrier for projects with a regional cross-border scope.

At a very general level, coordination itself becomes difficult as the number of actors increases, and differences in the private incentives of multiple TSOs and developers multiply. However, there are a number of more specific issues that may also hamper projects to develop cross-border infrastructure. In the paragraphs that follow we discuss the difficulties involved in:

- attributing the benefits of network investments and the asymmetric allocation of these benefits;
- allocating public support to offshore projects connected to a foreign national grid;
- and applying legal and regulatory schemes to the unusual situation of cross-border offshore assets.

A basic requirement for successful cross-border cooperation on infrastructure development is an agreement on how to divide the costs and benefits associated with the joint investment project. However, this can difficult to achieve in the context of network development for offshore wind. First, it can be challenging to agree on a common valuation and attribute the benefits arising from such joint network development projects c. Cross-border network investments may, for example, create diffuse and varied benefits in the form of lower congestion throughout multiple national grids, support the achievement of various national policy goals, and give rise to employment and distributional effects by enabling generation investments and changing regional power prices. Estimating and attributing the value of these impacts is inherently difficult.

In addition to this, and even if the benefits of a project were easily attributable, the asymmetric distribution of costs and benefits across project partners may prevent cross-border projects, that is net costly for one of the parties involved.

In theory, the asymmetric distribution of benefits and costs can be mitigated through payments between TSOs, i.e. the TSO with a net benefit makes a payment to the TSO that carries a net cost. Examples include the creation of the Nea-Järpströmmen line between Norway and Sweden, built in 2008.This project entailed a voltage upgrade to 420 kV of an existing line, and required pushing forward a reinvestment on the Swedish side which was not deemed profitable by the Swedish TSO. However, the Norwegian TSO Statnett received national regulatory approval for paying a connection charge (that could be recovered through Statnett's tariffs) to compensate the Swedish TSO Svenska kraftnät for the extra costs (an increase in the Net Present Value of reinvestment costs) on the Swedish side. However, it is important to note that this agreement was facilitated by the long-standing cooperation between the Norwegian and Swedish TSOs and the need for imminent measures to reduce the risk of a local power shortages in the Norwegian grid.[53] Experience shows that such payments between TSOs are usually difficult to implement in practice and are likely to be further complicated if multiple TSOs and commercial developers are involved.

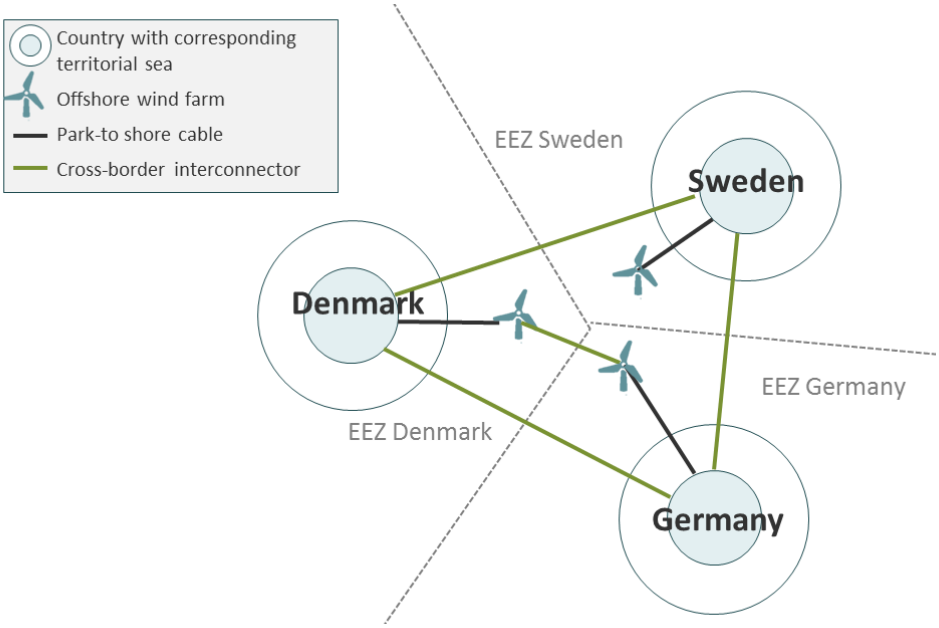
Alternatively, for those projects where it is appropriate, co-development and cost sharing arrangements, often used in the case of cross-border interconnectors, can be applied, although transaction costs may be substantial. A case in point is the experience of the German and Danish TSOs participating in the Kriegers Flak Combined Grid Solution currently under construction (see Box below).

[53] NordREG (2010): Grid investments in a Nordic perspective. Report 3/2010 reviews the challenges and possible solutions at the Nordic level.

Box: Experience from the Kriegers Flak Combined Grid Solution

The world's first project to combine cross-border interconnection with grid connection for offshore wind farms is currently under development in the Baltic Sea. The Kriegers Flak Combined Grid Solution is a joint venture between the Danish TSO Energinet and the German TSO 50Hertz. The TSOs are responsible for the development of the wind power connection from the maritime substation to shore. The set-up is illustrated in the figure below.

Figure 8-3: Kriegers Flak - Combined Grid Solution



Source: Baltic InteGrid, stakeholder interviews

There are several interesting aspects of the Kriegers Flak project with relevance for our analysis of barriers.

Firstly, the Danish national regulatory authority determined that Kriegers Flak could be granted *priority access* when electricity is transmitted to Denmark, thereby granting the offshore wind farm similar treatment to other wind farms in the area despite the unusual set up. Although priority access does not explicitly cover the cross-border transmission of electricity, it limits the transmission capacity available for cross-border flows in practice (Baltic InteGrid, 2018). It thus illustrates a possible inefficiency related to priority access and suboptimal use of the offshore grid capacity.

The *distribution of costs* is also interesting to consider. To help realise the project, the Danish and German TSOs agreed to a rather straightforward approach to sharing the resultant costs and benefits. The TSOs first established a reference cost assuming that traditional radial connections to the two countries were built. Any costs in addition to the reference costs were then split 50/50 between the two TSOs. A prerequisite for this approach is therefore agreement between the TSOs on the size and nature of the additional costs associated with the combined grid solution. However, this would likely have been more complex if more parties had been involved (Sweden was also part of the original group).

Operation solutions also needed to be agreed to tackle differences in the respective national regulations. Important differences in the economic *TSO regulation* and in the *market regulation*, such as those covering congestion management and balancing responsibilities, had to be accounted for. Physical meetings between the national regulators were organised to establish a common understanding of the regulatory challenges. The project also benefited from efforts to harmonise market regulation on a European level, in particular the development of Network Codes on e.g. Capacity Allocation and Congestion Management and Electricity Balancing.

Finally, the project also received EU financing as a PCI (Project of Common Interest), which illustrates the possible role of *common financing mechanisms*.

Another barrier, which is particularly relevant to the development of offshore hubs, concerns how national support schemes might deal with the connection of an offshore wind farm to the grid of another member state. An offshore wind farm connected to a hub may deliver electricity to several national grids but may not be eligible for support under existing national schemes, which may render it unviable commercially. Alternatively, it might receive support under multiple schemes and be overcompensated. The Baltic InteGrid Project (2018) has suggested that the most practical solution would be that the offshore wind farm is remunerated according to the EEZ (Exclusive Economic Zone) where it is located, independent of the country in which they feed their electricity in the grid. If necessary, the national administrative bodies could then correct the remuneration payments and calculate the contributions to the EU renewable energy target accordingly. Another option is that countries could work cooperatively to create common support mechanisms, such as the electricity certificate scheme in Norway and Sweden. The Connecting Europe Facility (CEF) is yet another possibility. Under CEF, it is foreseen that support will be made available for a limited number of cross-border renewable energy projects, where offshore wind power in the Baltic Sea could qualify.

Finally, it may be challenging to apply existing laws and regulations sensibly in the context of offshore wind hubs, as explored in detail by the Baltic InteGrid (2018) project.[54] For example, cross-border hubs may be classified as interconnectors under EU law and therefore be bound by rules on congestion revenue regulation, ownership and system operations. This can create additional uncertainty, *inter alia* about how costs can be recovered through tariffs and/or congestion revenues. Alternatively, the interconnector assets that make up the hub might be classified (partly) as a RES connection and thereby be regulated under the RES framework (cf. the Danish regulation of the Kriegers Flak connection).

[54] See in particular Baltic InteGrid (2018): Establishing an offshore meshed grid. Policy and regulatory aspects and barriers in the Baltic Sea Region. They conclude (p. 61) that “The current legislative framework has not yet been adapted to address grid architectures that differ from the classic radial connection of OWP and classical interconnectors – especially regarding requirements to operate dual-purpose cables that serve both as interconnectors and park-to-shore cables”.

8.3 Recommendations

The model analyses in Tasks 2 and 3 suggest that substantial long-term cost savings and higher ambition levels can potentially be realized by developing wind resources where the net market value is highest and by coordinating offshore wind development with the development of offshore grid structures. In formulating our high-level recommendations in this chapter, we take as our starting point the scenarios with a high degree of regional cooperation. (The suggested roadmap presented in in Chapter 1 provides more detail.)

A first step to realise the offshore wind power potential would be to establish a common vision for the Baltic Sea area. The modelling suggests that substantial benefits may be reaped by such coordination and regional long-term planning. In order to realise the vision, long-term grid development according to a common plan is a crucial factor. Hence, in order to reap the full benefit of coordinated offshore wind power development in the Baltic Sea region, the development of onshore and offshore grid (interconnectors) has to be planned accordingly. Working from the common vision for a low-carbon, high-renewable energy sector in 2040 and 2050, one should work backwards to identify the crucial offshore wind power and related grid investments needed to realise the plan.

In this perspective, barriers to efficient regional development of offshore wind power in the Baltic Sea area mainly originate from two categories of framework conditions:

1. Unnecessary variations in policy across countries or technologies: An uneven playing field across national power markets related to differences in the support levels provided by national renewable energy support schemes, or in connection charges or network tariffs. National frameworks may also differ in terms of the preference for offshore wind power in vis-à-vis other renewable energy sources.

2. Lack of coordination mechanisms: Efficient utilisation of the offshore wind potential in the Baltic Sea area requires coordination of offshore wind support schemes, of offshore grid development including interconnectors, and of onshore grids.

Coordination issues include both planning of offshore wind power and related grid infrastructures and economic mechanisms for aligning incentives at the national level to ensure that jointly beneficial projects are realised.

Implementation of the third energy package, including network codes, the recast of the RES directive and the implementation of the market design proposals in the Clean Energy package, should cater for increased alignment of market and regulatory framework conditions for offshore wind. As a result, market conditions, RES support schemes, and to some extent grid charges, are likely to be harmonised to a larger extent. However, there are several barriers that are likely to remain for some time yet.

Although full harmonisation of price signals and support mechanisms is probably not necessary or feasible, some countries apply regulations that may in effect constitute a barrier to the development of offshore wind power in the national market. Firstly, existing support mechanisms are not necessarily suitable for offshore wind power. While e.g. Denmark and Germany use targeted tenders for offshore wind power, other countries use technology-neutral mechanisms that effectively exclude offshore wind power from competing in the short run. This may also hamper offshore wind power in the long run when it is expected to be competitive within a cooperative scenario due to reduced learning effects, too slow development of the supply chain and lacking exploitation of economies of scale. Ensuring that national support mechanisms are open to offshore wind power should therefore be a priority.

As offshore wind power will often have high network connection costs, even shallow connection charging regimes is one possible source of distortion. Examples include varying practices when it comes to connection charges and G-tariffs. In the current models, only a few countries (Sweden, Finland and to a smaller extent Denmark) apply G tariffs. We also note that there are substantial differences with respect to connection charging, where Denmark (historically) and Germany stand out with practically full socialisation of offshore wind network costs. Greater alignment of connection charging regimes should therefore be addressed.

Experience suggests that the common principles for the establishment of offshore wind power infrastructure, including offshore hubs, are not fully developed. Coordination of multiple stakeholders, including TSOs and offshore wind developers, from several countries, has proved to be lengthy and costly processes for the cases that exist, e.g. the Kriegers Flak project and experiences from the North Sea region. Common principles and framework guidelines could greatly reduce transaction costs and uncertainty for developers as well as for involved TSOs. The key economic coordination issues are multinational support mechanisms for offshore wind power and mechanisms for financing of joint network investments.

Existing support mechanisms tend to exclude multinational projects. Utilising flexible mechanisms in the RES directive is an obvious option to facilitate coordination (joint projects and joint support mechanisms are particularly relevant), However, the flexible mechanisms have not been widely used so far, hence, there is a lack of experience when it comes to the design and practical implementation of these mechanisms.

The coordination challenge is most pronounced when it comes to the development of offshore infrastructure projects, in particular offshore hubs, although in principle the challenges apply to any grid investment related to offshore wind power displaying cross-border benefits and costs.

We have seen that coordinated development is likely to have asymmetric consequences for onshore grid development and associated costs among the BEMIP countries. Today, however, no specific regulatory regime exists for advanced offshore hubs or other grid investments regionally, and even if such a framework would exist, its integration with national regulatory regimes is not straightforward.

In order to incentivise TSOs to make investments according to the “common good”, i.e. the vision for the efficient regional utilisation of offshore wind power in the Baltic Sea region, they also need to be compensated for the additional costs that arise from jointly beneficial investments that are not beneficial for an individual TSO. The same thinking would apply to general development of interconnectors in the region.

Developing guidelines and standard contractual arrangements for fair regional cost allocation would offset or balance out the asymmetric distribution of costs and benefits and could build on regional assessments of grid impacts. While this would be a task that would require considerable commitment of administrative capacity and coordination at the beginning of cooperation on regional development, it is not without precedent and such efforts could to some extent build on principles developed for common cost and benefit analysis and capacity adequacy assessments by ENTSO-E.

Another measure for promoting efficient allocation of offshore wind farms could be the introduction of a common financing mechanism. Cooperation mechanisms in the RES directive are relevant in this context. Also, a regional fund with monetary contributions from participating Member States could be established to boost the development in the region. Coordination with the EU PCI framework could be an option, as well as the Connecting Europe Facility allocation for cross-border renewable energy projects.

9 Task 5 – Identification of and recommendations to address market, planning and permitting barriers

Key Messages from the Results

- There are three main barriers related to planning and permitting in the region: poor and/or fragmented geospatial data; complex, extended or ineffective licensing regimes; and insufficient regional grid planning that considers the future needs of offshore wind capacity. The first two of these problems are not uniformly present in every BEMIP member state, as some of the BEMIP countries have made considerable efforts to establish an efficient licensing framework for offshore wind projects. However, these barriers are sufficiently prevalent to hamper offshore wind in the region as a whole.
- Good geospatial data is essential for effective maritime spatial planning and for enabling informed decision-making by commercial developers of offshore wind farms. Unfortunately, data issues are present in many BEMIP states. As a first step to support better data gathering and sharing in the region, we recommend that the Working Group initiate cooperation among the appropriate regional maritime data/planning agencies to develop a data management model. This would establish a common standard for data structures, formats and access arrangements that would both help countries to identify possible gaps in their domestic arrangements and form the foundation for more effective cross-border planning.
- The quality of licensing procedures varies markedly across the region. Some regimes are likely to present barriers to offshore wind development owing to: the absence of clear processes, the inability to identify stakeholder objections early, and/or the existence of inappropriately long or repetitive appeals procedures. Knowledge sharing on best practices could act as a useful guide for those BEMIP member states seeking to improve their own national licensing systems.
- While there is significant regional cooperation on environmental and spatial planning issues, TSO-level cooperation is split among different groups that handle network planning within ENTSO-E and the three Regional Security Coordinators active in the region. Existing cooperation is in any case not focused on the future needs of offshore wind. More use could be made of existing cooperation mechanisms to support the identification of those grid network investments that are needed to enable renewable investments in general, and offshore wind deployment in particular.
- In the longer term, joint financing mechanisms for cross-border grid infrastructure and

operational cooperation via the relevant Regional Security Coordinators could also be considered, to enable TSO collaboration on investments in addition to planning. Furthermore, the processes on identifying candidates for joint financing of cross-border offshore wind power projects under the Connecting Europe Facility and network planning could be coordinated.

The purpose of this task is to:

- Describe the current authorisation and permitting regimes for offshore wind and transmission investments in the BEMIP member states,
- Identify barriers related to planning, authorisation and permitting for offshore wind and transmission investments, including maritime spatial planning, and
- Evaluate and make recommendations on options for reducing the barriers identified, both through national measures and cross-border coordination.

The work under Task 5 has consisted mainly of a review of the existing literature and public documentation. We have also carried out our own analysis to establish a set of criteria for a suitable planning and authorisation regime, which we have compared with our findings on the national and regional systems in place.

The main deliverable with respect to the description of current authorisation and permitting regimes is attached in the form of country factsheets (see Appendix E). There is also a factsheet on relevant EU regulation. We refer to these factsheets for further details.

9.1 Barriers and gaps

9.1.1 Assessment criteria

When assessing the planning and authorisation regimes, we consider barriers as well as gaps. Our assessment is based primarily on economic theory, i.e., our general criterion for assessing planning and regulatory elements is whether they hinder economically efficient investments in offshore wind power and grid infrastructure. We assume that cooperative solutions for offshore wind power deployment in the Baltic Sea region such as those analysed in previous chapters, are economically efficient. By barriers we therefore understand regulatory elements that hinder investments in offshore wind and related infrastructure or make such investments exceedingly complex or costly compared to the underlying real economic costs. By gaps we mean legislation, rules or other elements that are missing and that are required for offshore wind and related grid infrastructure to be developed efficiently.

As a starting point for our assessment, we have defined a set of criteria that characterise an efficient planning and authorisation regime. The criteria are set out in the table below. We have organised the criteria according to three main areas:

1. Maritime spatial planning including data management
2. Licensing procedures
3. Regional cooperation

Table 9-1 Criteria for an efficient planning and authorisation regime

Criterion	Key issues
Maritime spatial planning incl. data management	Existence of binding maritime spatial plans Data coverage, availability and quality
Licensing procedures	Clearly defined procedures Conflict management Stakeholder involvement
Regional cooperation	Coverage of relevant areas Sufficient mandate and powers

On maritime spatial planning, we consider it important that the countries have the necessary framework in place to meet the requirements of the Maritime Spatial Planning Directive, or that they have a clear path towards implementing the directive. Under this criterion we also considered the Member States' data management practices regarding offshore wind and related maritime data. With respect to data management, we considered whether the necessary data exists, whether it is easily available to stakeholders and the quality of the data. Necessary data comprises, among other things, geospatial information on wind conditions, offshore grid plans, maritime spatial plans, shipping, bathymetry, oceanography, pollution and environmental parameters, geology, biology and the marine environment.

On licensing, we consider it important that the processes involved are clearly defined. The type and number of permits required should be clear to investors, and there should be efficient coordination to ensure that these processes are not delayed unnecessarily. Furthermore, the procedures for appeals should be transparent and have clear deadlines. These requirements are in line with the RED II directive.[55] It is also highly recommended that any outright restrictions on the availability of areas for offshore wind deployment (such as military considerations) be established as early as possible in the process to avoid unnecessary work on projects that cannot be realised. Under this heading, we therefore also consider conflict management mechanisms and stakeholder involvement.

On regional cooperation, we consider it important that there are regional bodies or organisations that support cooperation in areas vital for efficient planning and authorisation [of offshore wind power and related grid infrastructures]. While the powers of these bodies may be limited by national or EU law, appropriate fora should at least exist where planning issues can be discussed and possibly also resolved. Areas where cooperation is beneficial include network planning and operations (incl. options for a Baltic Sea offshore grid), data management, maritime spatial planning, and environmental issues.

9.1.2 Findings

In this section we set out our assessment of country performance along the different dimensions, based on our review of the national frameworks as documented in the factsheets.

[55] Directive (EU) 2018/2001.

Maritime spatial planning and data management

We find that there are significant differences between the BEMIP countries regarding their progress on implementing maritime spatial plans consistent with the Maritime Spatial Planning Directive.[56] Some countries have comprehensive plans in place or those are at an advanced stage (for instance draft consultation plans), while others have plans that cover only a portion of the relevant geographic area. However, it is assumed that all BEMIP countries will comply with the Spatial Planning Directive, which requires that plans are in place no later than 31 March 2021, and that plans will therefore be put in place in the coming years. The table below gives an overview of the status in the BEMIP member countries.

Table 9-2 Summary of Maritime Spatial Planning (MSP) status in the BEMIP countries

Country	MSP status
Denmark	› No MSP yet, but sectoral plans in existence will give input to MSP › Act on maritime spatial planning has been adopted
Estonia[57]	› No MSP yet, but two pilot projects have been carried out and will be included in national MSP › MSP based on Planning Act and Government orders
Finland	› Draft MSP process underway, three regional MSPs will be developed by regional councils › One regional land use plan includes regional territorial sea area › MSP is covered by the Land Use and Building Act, but MSPs are non-binding
Germany	› Federal MSPs for Germany's EEZs (Exclusive Economic Zones) in the North and Baltic Seas and regional (federal state level) plans for the territorial sea areas as part of the respective coastal federal states' comprehensive spatial plans › MSP is covered by the Federal Spatial Planning Act
Latvia	› No MSP in place, draft process underway › MSPs are covered by Spatial Development Planning Law
Lithuania	› No separate MSP, but maritime territories are part of a comprehensive plan at the national level › MSP is covered by the Law on Territorial Planning
Poland	› Only pilot MSP in existence, drafting process underway › MSP regulated by the Act on sea areas of the Republic of Poland and the maritime administration
Sweden	› MSPs at advanced stage of drafting, consultation ongoing with final proposals expected end of 2019 › MSPs are regulated by the Swedish Environmental Code and the Planning and Building Act

Source: www.msp-platform.eu, country factsheets

We have not assessed the quality of the plans in detail, but the Swedish draft plans submitted in 2018 would seem to be an example of plans that would enable efficient deployment of offshore wind within a comprehensive planning framework that includes all relevant stakeholders. The draft plans explicitly identify areas to be used for offshore wind power generation. We also find the German system to be comprehensive and well-suited to the needs of offshore development as it explicitly identifies priority areas for offshore wind within a multi-layered planning framework due to Germany's federal structure and the resultant division of responsibility between the federal and state governments.

[56] Directive (EU) 2014/89.

[57] With regard to the Hiiumaa wind park, the developer will continue with the environmental assessment. The results will be published in the end of August 2019.

On data management, several shortcomings can be observed at the national level. Lack of data, data being fragmented and spread across many providers and poor data quality are expected to act as a barrier, or at least increase costs, for potential investors and to reduce transparency in general.

The German approach to data management is particularly interesting and might serve as a possible best practice for other countries or for the development of a regional Baltic Sea data management model. The planning authority, the Federal Maritime and Hydrographic Agency (BSH), maintains GeoSeaPortal, which provides a central online access point for the relevant geographic data. BSH also maintains a database on the current and planned use of the marine environment. We also note that Denmark is working to develop a Danish Marine Spatial Data Infrastructure to promote the sharing and coordination of data between the Danish authorities.

Licensing procedures

On licensing procedures, the use of one-stop shops is considered best practice and is required by the new Renewable Energy Directive. One-stop shop can be a highly efficient way of organising the licensing process. However, it must be noted that the creation of a one-stop shop is not sufficient in itself, since the legislation and procedures underlying the planning process can still be inefficient and excessively complex. From a general perspective, some of the issues that can persist, despite the use of one-stop shops include:

› Complex and not clearly defined processes,
› Ineffective stakeholder engagement that does not identify major objections sufficiently early in the process, and
› Long or repetitive appeal processes that increase investor uncertainty beyond what is justified by the need to ensure effective stakeholder consultation.

National governance structures may make the implementation of one-stop shop ineffective, if complexity and partly overlapping and parallel processes are not addressed.

The table below gives an overview of the main characteristics of the licensing systems in the BEMIP countries.

Table 9-3 Overview of the offshore wind licensing systems in the BEMIP countries

Country	Licensing procedure
Denmark	› One-stop shop coordinated by the Danish Energy Agency which also issues the necessary licences
Estonia	› Several permits necessary, handled in distinct, but parallel processes
Finland	› Several permits necessary, including municipal-level building permit
Germany	› Different regimes depending on whether the installation is inside territorial waters (state procedure) or outside but within the EEZ (federal procedure) › Federal procedure involves the BSH as the main planning authority
Latvia	› Licensing framework in place, but not tested in practice and no clear mechanism for coordinating processes across ministries
Lithuania	› Planning procedures in place, but very difficult to develop offshore wind in practice as there is no legislation in place to authorise developers to survey the seabed › Planned tendering process would be a way to address this
Poland	› Authorisation regime in place, process is not clear

Country	Licensing procedure
Sweden	› Process depends on whether or not proposed windfarm is within territorial waters › Separate licences covering the different aspects necessary

Source: Country factsheets, Baltic InteGrid Project

As an example of the potential challenges involved, the Baltic InteGrid project studied the case of the Hiiuma windpark in Estonia.[58] As of March 2018, 144 months (12 years) had passed since the submission of the first licence application for the special use of water. This permit must be obtained before other procedures can be completed, limiting the scope to run processes in parallel. Furthermore, appeals are possible at each step of the process, and can lengthen the procedure by several years in total. While this example is probably an extreme case, it highlights the potential costs and risks arising from inefficient licensing procedures.

Regional cooperation

There are three main cooperative bodies, in addition to BEMIP itself, in which all BEMIP member states participate:

- HELCOM – the Baltic Marine Environment Protection Commission, which governs the Convention on the Protection of the Marine Environment of the Baltic Sea Area (Helsinki Convention). HELCOM acts, amongst other things, as a policy maker, by developing environmental objectives and actions, as an information provider on the Baltic marine environment and as a supervisory body.

- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea. VASAB is an intergovernmental organisation that prepares policy options for the territorial development of the Baltic Sea Region and provides a forum for the exchange of know-how on spatial planning and development between the Baltic Sea countries. It provides recommendations on policy measures and promotes methodology development and cooperation projects.

- BASREC – Baltic Sea Region Energy Cooperation. The format of the BASREC group was revised in 2015. Previously, BASREC covered issues of energy and energy-related climate policy in the Baltic Sea Region through a ministerial process, including regular ministerial meetings and a presidency/secretariat that supported BASREC on an ongoing basis. The initiative to propose a meeting on an energy issue of common interest can still be taken by any member, but there are no longer any regular meetings.

In addition, the transmission system operators (TSOs) in the Baltic Sea region cooperate through a number of fora, including the ENTSO-E regional groups for network planning and three different Regional Security Coordinators (RSCs) to support security of supply. There is a separate ENTSO-E region comprising the Baltic Sea region that includes all BEMIP member states. The three RSCs are: the Baltic RSC covering Estonia, Latvia and Lithuania; the Nordic RSC covering Denmark, Finland, Norway and Sweden, and TSCNET (Transmission System Operator (TSO) Security Coordination Network) Services covering, among others, all the German TSOs, Poland and Denmark.

[58] Baltic InteGrid (2018): Establishing an offshore meshed grid. Policy and regulatory aspects and barriers in the Baltic Sea Region. Chapter 4.4 includes a review of the Hiiuma case.

While there is significant regional cooperation on environmental and spatial planning issues, TSO-level cooperation on offshore grid planning in the Baltic Sea is not organised in any standing group that could be tasked with considering the network requirements of offshore wind development and potential solutions at a regional level. Ad-hoc projects like Baltic InteGrid exist to explore this space, but direct TSO collaboration would eventually be required to realise any proposed solution. ENTSO-E's role in facilitating cooperation on network planning could conceivably fill some of the gaps, but the development of offshore wind and related grid infrastructure is only one of the many objectives of the existing ENTSO-E structures. Operational network cooperation is also spread across three different RSCs. As such, Baltic offshore grid cooperation may not be adequately covered by these existing processes. A greater focus on Baltic Sea regional grid planning could therefore be warranted.

9.2 Recommendations

Based on an overview of current planning and authorisation regimes, the elements below could potentially be useful contributions for a BEMIP offshore wind power initiative:

1. Establishing a common Baltic Sea data management model
2. Supporting knowledge sharing on the design of offshore wind licensing procedures
3. Supporting greater regional TSO cooperation with an emphasis on offshore grid planning

Each is described in further detail below.

9.2.1 Data management model

A data management model is meant as a set of guidelines that set out the types of data that should be made available and specify common data structures, formats and access arrangements. The goal of these guidelines would not be to enforce identical data requirements for planning purposes, but to create a set of standards that facilitate regional cooperation and ensure the availability and compatibility of data from multiple sources. In the longer term, a joint Baltic Sea regional data portal could be developed.

As the BEMIP Renewable Energy Working Group does not possess the specialist knowledge required to agree on appropriate standards, any work to develop a data management model would likely need to be initiated by the Working Group, but conducted among the BEMIP Member States' maritime data/planning agencies.

The German model for data management through the GeoSeaPortal[59] could act as a possible point of departure for a common Baltic Sea data setup.

9.2.2 Knowledge sharing on licensing procedures

Knowledge sharing on best practice would possibly act as a useful guide for BEMIP member countries seeking to develop their own national licensing systems and make best use of the knowledge gained by those countries in the region that already have extensive experience with

[59] https://www.geoseaportal.de

offshore wind licensing and the redesign of licensing procedures. The content of the exercise would need to be analysed in more detail, but should probably cover at least the following elements:

- Mechanisms to coordinate licensing processes requiring several permits (and, if applicable, the approval of government support) and a model for one-stop shop processes, for those countries interested in implementing such a model;
- Effective appeals procedures,
- The use of deadlines in the planning process, and
- Effective stakeholder involvement.

The most developed German and Danish licensing procedures could provide examples and useful elements of best practice.

9.2.3 Regional TSO cooperation

As noted above, more could usefully be done to support cooperation among the regional TSOs in relation to grid development for the purposes of enabling offshore wind deployment, building on the work, for example, of the Baltic InteGrid project. Initially, regional TSO cooperation can be limited to cooperative offshore grid planning. This could usefully be coordinated through ENTSO-E's TYNDP processes, but requires a more explicit focus on the potential grid network investments needed in order to enable renewable investment, particularly offshore wind deployment. It should be noted that the 2018 TYNDP includes a separate Regional Insight Report on a Northern Seas Offshore Grid that could serve as inspiration for the Baltic Sea region as well. It is in any case vital that the Baltic Sea offshore grid perspective is included in the scenario building and infrastructure needs assessment that are carried out at an early stage of the TYNDP process. Offshore wind power developers and grid infrastructure investors should also be encouraged to submit grid infrastructure projects for consideration during these stages.

The TYNDP process and regional offshore grid planning will also benefit from coordination with the European Commission's work identifying cross-border offshore wind power projects for consideration under the Connecting Europe Facility. Ensuring that information about relevant offshore wind power projects is made available for ENTSO-E and the regional TSOs at an early stage will help integrate generation and grid planning. Ideally, this should happen during the initial processes on scenario building and infrastructure needs assessment.

In the longer term, joint financing mechanisms for cross-border grid infrastructure and operational cooperation via the relevant RSCs could also be considered, to enable TSO collaboration on investments in addition to planning.

The North Seas Energy Cooperation (NSEC) group, which was originally formed to support integrated offshore network planning in the North Sea, could serve as a source of inspiration for a similar initiative in the Baltic Sea.

10 Task 6 – Roadmap and action plan

10.1 Introduction

The analysis undertaken as part of this project has identified the significant potential for offshore wind development in the Baltic Sea. It has also shown the benefits of cooperation among the BEMIP member states on the development of offshore wind deployment and has identified several practical barriers that prevent deployment or otherwise impair efficiency.

In this chapter, we draw on the understanding of opportunities and barriers established through this and related work to develop both a roadmap for offshore wind power development in the Baltic Sea Area and an action plan for the BEMIP group specifically.

The roadmap outlines an achievable pathway towards efficient offshore wind deployment in the Baltic Sea Area. It establishes an overarching vision of the activity needed over the next 10-20 years in order to realise the potential benefits of developing the BEMIP states' offshore wind power as efficiently as possible and as an integral part of the strategy to achieve the general long-term renewable energy and climate change targets.

The roadmap also provides the context for BEMIP's role in supporting offshore wind deployment as outlined in the proposed action plan. The action plan looks at the actions that can be carried out by the BEMIP group specifically to support the realization of the roadmap.

In both cases, these plans are rooted in the opportunities and barriers identified in our analysis. The next section therefore recaps these opportunities and challenges, in order to establish a foundation for the subsequent plans. Sections 10.1 and 10.4 then set out the details of the roadmap and action plan respectively.

10.2 Opportunities and barriers

The proposed roadmap and action plan have been developed based on an assessment of the opportunities and barriers to the efficient deployment of offshore wind identified through this study and takes into account similar analysis conducted in relation to the North Seas' offshore wind development cooperation. The opportunities and barriers are summarised below for ease of reference later.

- **Cooperation on offshore wind deployment can help to realise the development of the most efficient sites**
  The detailed analysis on the economics of offshore wind sites across the Baltic Sea shows that that there are significant variations in the quality of projects. Differences in wind speed, construction costs and, just as importantly, the likely price of electricity across the region imply that some projects will be more cost-efficient than others. Cooperative mechanisms can ensure that the best sites are developed and that the resultant efficiencies are shared.

- **Existing national policy mechanisms often effectively exclude offshore wind or multinational projects**
  Our analysis suggests that offshore wind will make up part of the least-cost energy mix in the region and that multinational projects that combine offshore wind deployment with the provision of cross-border transmission capacity have the potential to be net beneficial. However, many existing national support schemes are effectively inaccessible to offshore wind projects and even those schemes that are in place would struggle to cover multinational projects. As a result, such projects are effectively excluded even though they are likely to make up part of the cost-efficient solution to meeting national energy and climate change targets.

- **Policy uncertainty prevents beneficial supply chain investments**
  Investments in developing the regional offshore wind supply chain are likely to have long payback periods and will require an expectation that the volume of offshore wind deployed in the region will be sufficient to justify the associated upfront cost. The inability of governments to credibly signal their commitment to offshore wind deployment, even where it is a formal part of their national planning, ultimately prevents investments that would bring regional benefits both in terms of reduced deployment costs, but also through support to the regional economy.

- **The coordination of offshore support (notably tendering) can result in better planning and greater competition**
  The preparation of bids for offshore wind projects creates significant work for developers. A clustering of multiple tendering rounds can leave developers unable to appropriately resource all bid development opportunities and result in bid development being under-resourced or else in non-participation in the bidding round. Coordination among member states on tendering can avoid this and thereby support better bid quality and superior competition. It can also enable subsequent tendering rounds to benefit from the information revealed as part of earlier tendering processes in other countries.

- **Poor quality or poorly accessible maritime data in the region can hamper spatial planning and increase development costs**
  Although experience differs across the region, some BEMIP states have relatively poor maritime data. The data that does exist can also be challenging to access and divided among multiple different government bodies. A lack of data generally hampers the quality of spatial planning, while the lack of data and poor accessibility also imposes real costs on potential developers.

- **Lack of a regional spatial plan for offshore wind deployment hampers the identification and deployment of projects**

The importance of Maritime Spatial Planning for ensuring the rational and efficient use of the sea was recognised in the Maritime Spatial Planning Directive. The BEMIP states are in the process of developing national plans consistent with the requirements of the Directive, an activity that includes a degree of consultation with neighbouring countries. However, this work falls short of developing a plan for the Baltic Sea as a whole and the lack of regional-level planning is a barrier to the identification of efficient projects, particularly those requiring multinational cooperation.

› **Complicated licensing procedures for cross-border projects dissuade and delay the consideration of such projects**
Licensing procedures often entail considerable cost and risk for potential project developers. Cross-border projects generally require developers to navigate two or more independent licensing regimes, increasing the risks of project failure and therefore dissuading the consideration of projects that cross-national borders even where this might be advantageous for all involved member states and the region as a whole, both from the perspective of cost-efficiency and with respect to maximising the market value of new generation. PCI status for network investment can and does enable streamlined consensus, however their limited scope for interconnectors does not sufficiently address the challenges of regional projects. The Commission proposal to include a budget window under the Connecting Europe Facility for renewable energy projects, covering also generation can be a further facilitating component. This avenue will have to be investigated as appropriate depending on the outcome of the relevant negotiations.

› **Poor national licensing regimes in some countries can harm the realisation of both multinational and national projects in the region by dissuading efficient investment and adding directly to the costs of deployment**
Some national licensing regimes are unlikely to support efficient offshore wind investment in the region. Problems include the use of complex and/or ill-defined procedures, ineffective stakeholder engagement that does not identify major objections sufficiently early in the process, and long or repetitive appeals processes that increase investor uncertainty beyond what can be justified by the need to ensure effective stakeholder consultation. These issues add to deployment costs and ultimately can result in efficient projects going unbuilt.

› **Lack of cost-sharing / common-financing mechanisms for necessary network investment prevent the network from accommodating efficient offshore wind deployments**
Large-scale deployment of offshore wind in the Baltic Sea will change the current pattern of flows in the regional transmission network. Network investment is required to accommodate these changes, but the benefits of these investments are often diffuse and accrue to multiple parties in many nations. Some of the required investments may also be internal to a member state and therefore they may not benefit easily from the use of EU funds, even though the benefits accrue to multiple countries. Realising these investments inside a BEMIP country is likely to require mechanisms through which the many beneficiaries can contribute to their cost. The lack of such mechanisms may result in offshore wind energy being frozen out of the existing grid configuration.

› **Inadequate consideration of the requirements imposed by offshore wind development as part of regional grid planning prevents the necessary enabling**

investment in the network
Regional grid planning is currently facilitated through ENTSO-E's Ten-Year Network Development Plan process. However, this process should ideally incorporate a more-thorough consideration of the network requirements imposed by the deployment of Baltic offshore wind. For example, the 'Baltic offshore wind farms' sensitivity analysis conducted as part of the Regional Investment Plan 2017 involved adding just 1000 MW of offshore wind capacity to Estonia and Lithuania. An appropriate consideration may be hindered in practice by the ten-year horizon of the current planning process, since the development and implementation of a cross-border offshore wind project could easily take ten years and therefore fall outside the planning horizon. One possible source of information that might be used to improve the visibility of long-term wind power developments is the new list of cross-border RES projects to be drawn up by the European Commission (see the discussion of 'work to identify projects of common interest and cross-border RES projects' under 10.4.1). Incorporating this list into the TYNDP scenario design and considering the need for interim network investments in order to realise these projects should help to improve the quality of regional grid planning.

› **Variations in network charging distort site selection**
Differences in charging regimes are susceptible to become increasingly more distortive for the efficient deployment of offshore wind projects, in case national schemes are progressively opened up to projects in other member states, following the new provisions in the revised Renewable Energy Directive, and as offshore wind becomes commercially viable without support. Connection charges can constitute a large share of an offshore wind project's costs and differences in the national approach to charging could easily become the determining factor in which projects are selected for development. The resultant distortion in project selection would likely harm overall cost-efficiency, with lesser quality projects submitting winning bids solely because of their advantageous tariff treatment.

› **Lack of regulatory and contractual arrangements suited to multinational projects adds to the risks and costs of project development**
The regulations governing power system assets are not designed to accommodate combined offshore wind hub and related interconnector projects, or else offshore grids, as demonstrated also by the findings of the Baltic InteGrid project.[60] Similarly, experience with the Kriegers Flak Combined Grid Solution project in the North Seas showed the need to develop novel contractual solutions. The absence of appropriate regulatory and contractual arrangements increases the risk and cost associated with such projects and makes them more difficult to develop even where they would contribute to the overall operational and cost efficiency of the system design.

› **Inconsistencies in national regulation may increase the costs of development and operations**
Experience in the North Seas has shown that inconsistencies among countries in areas

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[60] http://www.baltic-integrid.eu/index.php/download.html?file=files/baltic_integrid/Arbeitspaket%202/WP%203%20Development%20of%20the%20Baltic%20Grid%20Concept/3.1%20Regulation%20and%20Policy/Outputs/BIG%203.1_MAIN%20REPORT_Establishing%20a%20meshed%20offshore%20grid%20policy%20and%20regulatory%20aspects%20and%20barriers_final.pdf

such as health and safety requirements, crew and vessel requirements, and component certification can inflate costs. For example, these differences can limit the ability to service multiple farms using the same support equipment, or re-use designs from similar projects elsewhere. Work to identify and remove unnecessary barriers, for example through the mutual recognition of standards, can therefore help to reduce costs.

10.3 Roadmap

10.3.1 Purpose and approach

The roadmap described in this section aims to set out a realistic vision for the activity required to realise efficient offshore wind deployment in the Baltic Sea. The elements of the roadmap have been identified based on an assessment of what can realistically be done to remove the barriers and seize the opportunities listed above. The links to these factors are drawn out explicitly below.

The roadmap is intentionally flexible as regards the overall level and pace of offshore wind deployment. The efficient level of deployment is uncertain and will inevitably depend on the future development of, among other things, renewable energy and carbon abatement technologies. This is not to say that the adoption of clear capacity objectives cannot be a useful part of a future planning process, but rather to note that defining capacity objectives has not been considered as part of this study. The conclusions of the study needs to remain robust to the selection of various options, including ambition levels, and thus help enlighten BEMIP decision making processes.

Although the study is not designed to adopt a specific numerical objective, it is however important to recognise that offshore wind deployment in the Baltic Sea is almost certainly part of the least-cost pathway to meeting regional, European and the world's climate change objectives. To underline this point, the EU's long-term analysis implies that achieving a 1.5°C target would imply deploying around 440 GW of offshore wind capacity in Europe.[61] As such, the question is not if, but how much and how quickly, offshore wind should be deployed in the Baltic Sea.

In the period to 2030, we assume that deployment ambitions are consistent with those laid out in member states' National Energy and Climate Plans (NECPs), albeit with a recognition that faster deployment may prove to be desirable or necessary.

The roadmap also builds on the results of the modelling work conducted as part of this study showing the efficiency benefits associated with cooperative deployment of offshore wind and the use of multinational offshore wind hubs, at least in some locations. Since effective cooperation supports efficient deployment, the roadmap includes realistic steps to realise greater regional cooperation in relation to the deployment of offshore wind.

[61] In-Depth Analysis in Support of the Commission Communication COM(2018) 773, p.77. See: https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

10.3.2 Proposal

The proposed roadmap itself is shown in Figure 10-1 below and consists of a number of steps that are organised by subject area and approximate timing. We discuss each of these in detail in the remainder of this section, noting the organisation or group that we believe is the logical owner of the associated task. We also set out a list of relevant stakeholders that ought to be involved and explain the nature of the anticipated work and the barrier that the work is intended to address, as well as indicating a timeframe for the different elements and the linkages between roadmap elements.

We use the following system for referring to the different roadmap elements:

› The numbers 1-5 are used for referring to the main policy areas:
  - *1 Support mechanisms and targets*
  - *2. Maritime Spatial Planning*
  - *3. Licensing*
  - *4. Electricity network*
  - *5. Standards and regulation*
› The letters a-f denote the individual roadmap elements under each type of policy area.
› Finally, the timeframe is indicated by ST (short term, 2020-2025), MT (medium term, 2025-2030) and LT (long term, 2030-2040).

Particularly important in terms of stakeholder interaction will be the need to sensibly involve and collaborate with similar work that is ongoing in the North Sea. The box below provides some background on this work. Specific interactions are noted in the description of the relevant elements.

Regional Cooperation in the North Sea and best practices for BEMIP

In 2009, nine Member States and Norway established what has become the North Seas Energy Cooperation (NSEC) group, a platform for the development of common solutions to grid infrastructure and offshore wind deployment in the North and Irish Seas. Through the group, efforts were made to coordinate political and regulatory action, share learnings and provide a model for collaboration in other European regions. It was hoped that deployment costs could be driven down through collaboration in, for example, developing joint maritime spatial plans, harmonising rules and coordinating tenders.

The group signed a political declaration in 2016 that set the structure of its current work, based on voluntary collaboration. Importantly, dedicated Support Groups were formed to assist efforts in the following four areas:

› Maritime Spatial Planning
› Development and regulation of offshore grids and infrastructure
› Support frameworks and finance
› Standards, technical rules and regulations

These spheres have been designated in response to challenges facing the NSEC member countries that are quite similar to the ones BEMIP is confronted with. Cooperation in said areas entails cost efficiencies and can lead to a timelier implementation reducing the costs of the energy transition.

One important finding by NSEC concerns cluster-based solutions at the borders of the involved states exclusive economic zones (EEZs). Such projects have been identified to very likely result in cost savings and more efficient deployment of offshore wind parks and could hence serve as a model approach to BEMIP member states.

Since challenges revolving around legal and regulatory differences in each member state constitute an equally onerous barrier to joint offshore plans in the North and Baltic Seas, approaching the NSEC Support Groups in each of the areas can help to overcome initial questions regarding the optimal manner of collaborating on these topics.

One important step that could build on the work of NSEC Support Group 2 would be the establishment of regular meetings to agree on common objectives taking into account individual countries' offshore development plans.

Due to the fact that both, BEMIP and NSEC, face similar challenges, results of the already conducted work programmes and studies, as well as coordination efforts of the North Sea initiative can serve as important guidelines, contact points for the exchange of ideas and insights, and for common learning.

Other projects or bodies established in the North Seas that are relevant for cooperation on offshore wind power related issues may also serve as useful models or potential collaborators for the tasks outlined below. These include:

- *CPMR North Sea Commission* (1989), a general body aimed at strengthening of partnerships between regional authorities in the North Sea
  - Such a body already exists for the Baltic Sea. Cooperation platforms set up as part of the institution could facilitate exchange of ideas, practices and cooperation in order to achieve a common approach in the development of a regionally-coordinated offshore wind sector.
- *SEANERGY 2020* (2012), a programme to remove maritime spatial planning (MSP) obstacles, identify inconsistencies between national MSP processes and implement new shared MSP instruments
  - The MSP challenges and solutions identified in this initiative financed by the Intellligent Energy for Europe Programme could serve as an important guideline for BEMIP's actions in this area.
- *MAP MEP* (2015), an interactive energy map for the North Sea
  - EMODnet should serve as a logical successor to the above project and comprise energy projects in the Baltic countries as a centralised MSP tool for all involved member states.
- *PROMOTioN* (2015), a project to support the development of meshed HVDC offshore grids
  - Baltic InteGrid and PROMOTioN arrived at similar conclusions: cost savings and efficiency can be increased by pursuing a meshed offshore grid in the North as well as in the Baltic Sea. A comparison of both final reports could give valuable insights into areas where more cooperation would be beneficial for the regions.
- *Inn2Power* (2016), a project to facilitate improved access to the offshore wind market for

small and mid-sized enterprises in the region

- › Since the development of an offshore wind market will lead to job growth in the sector, establishing a platform for an overview of and the exchange among SME players will greatly improve the local strengths of the sector.

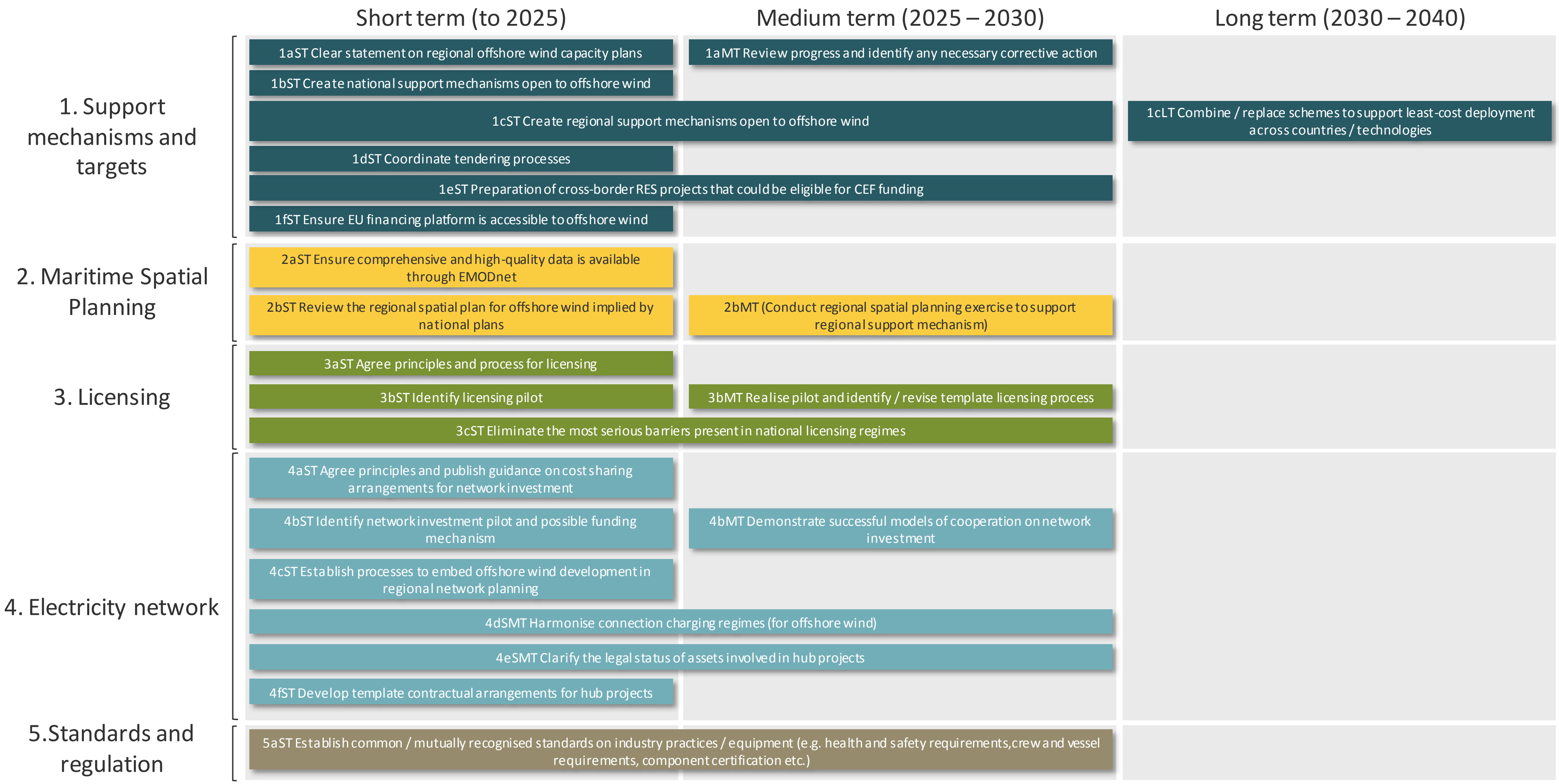
› *NorthSEE* (2016), a project to encourage greater coherence in MSP in the areas of shipping, energy and environmental protection

- › Reaching out to the NorthSEE responsibles will help to identify lack of coherence and give input to BEMIP to overcome challenges that are going to be very similar to the ones in the North Sea space.

› *SEANSE* (2018), a project to encourage coherent strategic and environmental assessments for renewable energy sources (RES) in the development and implementation of MSP

- › Similar to NorthSEE, a closer look at the findings from SEANSE will give guidelines to common procedures in the strategic and environmental evaluation of RES in the Baltic Seas.

Figure 10-1 Roadmap



1aST Develop clear statement on regional offshore wind capacity plans

Owner: BEMIP
Stakeholders: National governments
Barrier: Policy uncertainty prevents beneficial supply chain investments
Link to other roadmap elements: Feeds into 1aMT
Timeframe: 2020-2025
Description:

Governments are in the process of identifying how they will meet their obligations under the revised Renewable Energy Directive and initial plans are being set out as part of the National Energy and Climate Plans (NECPs). Some of these plans have begun to look at what is required in terms of new renewable generation capacity. BEMIP Member States should consider their offshore wind development plans also in view of the BEMIP regional cooperation and integrate possible synergies in the relevant sections of their NECPs (noting the requirements of Article 12 of the relevant governance regulation, Regulation (EU) 2018/1999). These member states need to be conscious of the fact that their plans will be taken as signals as regards the direction of future policy for the affected stakeholders. The BEMIP cooperation is well-positioned to support the regional dimension of national offshore wind development plans and could consider making a clear statement of expected offshore wind deployment levels.

The requirements of the NECPs also need to be fed into the considerations as regards the design of national support schemes discussed below, so that these schemes are capable of delivering the required investment. The expected deployment levels are likely to be important to inform regional grid and maritime spatial planning.

1aMT Review progress and identify any necessary corrective action

Owner: BEMIP
Stakeholders: National governments, EU Commission
Barrier: Policy uncertainty prevents beneficial supply chain investments
Timeframe: 2025-2030
Link to other roadmap elements: Builds on 1aST, feeds into 1fST
Description:

Progress against the expected path for offshore wind deployment communicated as part of the NECPs should be followed up by the BEMIP regional group to ensure that the group can respond and make facilitating actions, as necessary. This follow-up would prove useful in informing the development of regional support mechanisms or other possible actions under regional offshore wind cooperation in the short, medium and long term.

This process may also help to inform the Commission's wider assessment of progress against the 2030 renewable targets as part of discussions on the financing platform, noted below (1fST). This is also part of the governance process since the Commission is responsible for evaluating the NECPs, including the regional cooperation aspects.

1bST Create national support mechanisms open to offshore wind

Owner: National governments
Stakeholders:
Barrier: Existing national policy mechanisms often effectively exclude offshore wind or multinational projects
Timeframe: 2020-2025
Link to other roadmap elements: Feeds into 1cST and 1cLT, interacts with 1aST and 1dST
Description:

Support schemes will need to be adapted to meet the formal requirements of the revised Renewable Energy Directive and of the Governance Regulation, both in terms of the overall ambition for renewable deployment and to enable access to projects from another Member State. As part of this work, the current exclusion of offshore wind from national schemes should be addressed. This is not to say that every member state must have specific support for offshore wind deployment, but rather that the support that is available should be open to offshore wind if a developer is able to identify a competitive project. Specific consideration should also be given as to how the support scheme would operate if asked to contribute to a cross-border project, such as offshore wind hubs with farms located in or requiring facilitation from multiple countries. A statement of principles as to how the scheme would be extended to cover such joint offshore wind projects would considerably facilitate the greater consideration of such projects.
This work interacts with the development of firm offshore wind capacity planning, which should establish a clearer view of the expected timing of deployment, and of efforts to coordinate tendering process across member states (1aST and 1dST).

1cST Create regional support mechanisms open to offshore wind

Owner: National governments, BEMIP, European Commission
Stakeholders:
Barrier: Existing national policy mechanisms often effectively exclude offshore wind or multinational projects
Timeframe: 2020-2030
Link to other roadmap elements: Builds on 1bST and feeds into 1cLT
Description:
As shown in the scenario analysis results, regional cooperation that enables support to be allocated to sites regardless of national jurisdiction reduces the costs of deployment. Specifically, relatively costly sites can be substituted for lower cost sites elsewhere in the region. The REDII (2018/2001/EU) provides for the voluntary opening of national support schemes at least 5% from 2023 to 2026 and at least 10% from 2027 to 2030 to producers located in other member states, with a review clause by 2023 as regards the need for making that level of partial opening mandatory. A possible further and useful step in this direction is to work on the cross-border aspects of support mechanisms that equitably apportion support costs among involved member states in view of a regional offshore wind cooperation. Well-functioning cross-border support mechanisms as possible end goal (real or theoretical) would likely guide the design of the national schemes considered above and allow for a smoother transition in support of the regional level.
It should be noted that although a technology-neutral approach may ultimately be efficiency enhancing, the creation of a multinational technology-neutral scheme by the late-2020s is deemed to be unrealistic. The development of an offshore wind scheme would instead represent an achievable stepping stone to a more comprehensive support scheme later, if needed, that could cover multiple technologies.
Note that this action interacts with the planned review of the REDII (2018/2001/EU) requirements of the opening of support schemes by 2023, as well as the suggested effort to align connection charging in 4dSMT below. The review should be used as an opportunity to help put in place an appropriate level of support in view of the needs of the BEMIP regional cooperation.

1cLT Combine / replace schemes to support least-cost deployment across countries / technologies

Owner: National governments, European Commission
Stakeholders:
Barrier: Existing national policy mechanisms often effectively exclude offshore wind or multinational projects
Timeframe: 2030-2040
Link to other roadmap elements: Builds on 1bST and 1cST
Description:
As noted above, a regional support scheme for offshore wind, while a useful basis for establishing regional cooperation in that particular area, may itself result in inefficiencies as regards overall renewable development due to an inability to support other technologies. In the long run, consideration should be given to elaborate more comprehensive tools that enable efficient trade-offs not just between countries, but also among technologies. By the 2030s (or earlier, if possible), offshore wind may also be alternatively supported through more horizontal support schemes, such as carbon pricing, and so a consideration will be needed as regards how such schemes should be adapted to continue enabling an efficient rollout of offshore wind power.
Some countries (e.g. Sweden and the UK), already employ technology-neutral schemes that support offshore wind deployment alongside competing technologies. Experience from the North Sea countries can also be helpful in this regard.

1dST Coordinate tendering processes across national support schemes

Owner: National governments
Stakeholders: BEMIP
Barrier: The coordination of offshore support (notably tendering) can result in better planning and greater competition
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
The value of coordinating different national tendering processes has already been recognised in the North Seas' offshore wind cooperation process. This coordination activity should ideally be extended to cover the Baltic Sea, and possibly beyond, to avoid the crowding out of competition and missed opportunities to learn about developers' true costs.

1eST Preparation of cross-border RES projects that could be eligible for CEF funding

Owner: European Commission, BEMIP RES WG
Stakeholders: Project developers, ENTSO-E
Barrier: Cooperation on offshore wind deployment can help to realise the development of the most efficient sites; Inadequate consideration of the requirements imposed by offshore wind development as part of regional grid planning prevents the necessary enabling investment in the network
Timeframe: 2020-2030
Link to other roadmap elements: Builds on 2aST; feeds into 4cST
Description:
The Commission's proposal for a new Connecting Europe Facility includes a dedicated financing window for cross-border renewable projects. Depending on the final agreement by the European Parliament and the Council, it will be possible for BEMIP Member States to propose

cross-border offshore wind projects for support from the new CEF. The BEMIP RES WG could have an important and key role to select and prepare a potential cross-border renewable offshore wind project to be included in the list of such projects, based on a future Commission Delegated Act to be adopted after the new Connecting Europe Facility is adopted together with the EU new Multiannual Financial Framework.
The creation of a publicly available database of potential cross-border offshore wind projects through this process would act as a useful source of information both for identifying the best use of regional and European funding, and in developing fit-for-purpose regional network development plans. The presence of such a list would make clearer the potential pipeline of such projects to the many relevant stakeholders involved, not least network planners and potential funding authorities, supporting better long-term decision making generally.

1fST Ensure EU renewable financing mechanism is accessible to offshore wind

Owner: European Commission, BEMIP RES WG
Stakeholders: EU Council & Parliament
Barrier: Existing national policy mechanisms often effectively exclude offshore wind or multinational projects
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
The Governance Regulation for the EU 2030 renewables target allows for the creation of a Union-level renewable financing mechanism. The Commission should ensure that the mechanism has the opportunity to support offshore wind generation, for example, by appropriately accounting for the long project development time required.

2aST Ensure comprehensive and high-quality data is available through EMODnet

Owner: National government agencies
Stakeholders: BEMIP, EMODnet secretariat, VASAB, HELCOM
Barrier: Poor quality or poorly accessible maritime data in the region can hamper spatial planning and increase development costs
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
Work to improve the quality and accessibility of maritime spatial data is already being undertaken by the European Marine Observation and Data Network (EMODnet), which has its own secretariat. The respective national agencies should work with BEMIP, EMODnet and industry to identify weaknesses and improve data quality and accessibility as needed. Doing so will strengthen the foundation of spatial planning exercises and reduce offshore wind development costs.
A review of the North Sea's various MSP coordination projects, e.g. NorthSEE and SEANSE, may be helpful in identifying potential improvements and ways of working.

2bST Review the regional spatial plans for offshore wind implied by national plans

Owner: VASAB
Stakeholders: HELCOM, EMODnet, BalticScope, Baltic InteGrid
Barrier: Lack of a regional spatial plan for offshore wind deployment hampers identification and deployment of projects

Timeframe: 2020-2025
Link to other roadmap elements: Feeds into 2bMT
Description:
National maritime spatial plans are currently being developed to meet the requirements of the Maritime Spatial Planning Directive (20114/89/EU) and must be completed by 31 March 2021. As a starting point for the development of a regional vision for offshore wind development, these plans should be reviewed collectively to identify opportunities for efficient multinational offshore wind projects. Also, any possible conflicts between offshore wind development plans and other considerations set out in the maritime spatial plans should be identified and if necessary lead to revisions of offshore wind development and network plans.
It is recommended that the BEMIP group finds ways to cooperate on this work with the competent national planning institutions in charge of the national maritime spatial plans in the Baltic Sea region mentioned above, instead of creating new parallel bodies and work processes for this task.

2bMT Conduct regional spatial planning exercise to support regional support mechanism

Owner: VASAB
Stakeholders: HELCOM, BalticScope, BalticInteGrid, BalticLines, NorthSEE to learn from best practices
Barrier: Lack of a regional spatial plan for offshore wind deployment hampers identification and deployment of projects
Timeframe: 2020-2025
Link to other roadmap elements: Builds on 2bST
Description:
Depending on the results of the above mentioned review of the national maritime spatial plans, it may be appropriate to conduct a dedicated regional planning process for offshore wind development designed to establish, in particular, whether the opportunities identified as part of that review are in line with the offshore wind development objectives at regional level and, possibly, to explore design issues for spatial planning from a regional perspective , for example the appropriate routing of offshore electricity grids.
Key regional spatial constraints have already been identified as part of the Baltic InteGrid and BalticLines initiatives. The results of this work should therefore form the foundation of any future review of the national maritime spatial plans in the BEMIP region.

3aST Agree principles and process for licensing of multinational projects

Owner: BEMIP
Stakeholders: National government agencies, cf. Baltic InteGrid and Baltic Energy Areas (BEA-APP), NSEC best practices
Barrier: Complicated licensing procedures for multinational projects dissuade and delay the consideration of such projects
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
The ‘right’ licensing process depends on the specifics of the project. However, by agreeing, in general terms, how multinational offshore wind projects could be best licensed and the broad principles that are to be adhered to as part of the licensing process, BEMIP, possibly in cooperation with the North Seas Energy Cooperation group that face similar issues, can help lay down the groundwork for future multinational projects. In particular, the principles developed

through this process should help to accelerate the identification of an appropriate licensing approach and reduce uncertainty on the part of both potential developers and national licensing authorities as regards what are the key elements and requirements to address. Since multinational offshore wind projects can be eligible for designation as Projects of Common Interest (PCIs) under the EU Connecting Europe Facility, the licensing arrangements relevant to PCIs could form the natural starting point for considering the relevant licensing approach.

The results of the Baltic InteGrid's thematic working group on policy and regulation, as well as BEA-APP's experience with onshore regional cooperation, can be utilised as an initial assessment of the legal, regulatory and institutional differences and may also offer some insight into possible approaches for the development of common principles.

3bST Identify pilot project/s for developing licensing solutions

Owner: BEMIP
Stakeholders: European Commission
Barrier: Complicated licensing procedures for multinational projects dissuade and delay the consideration of such projects
Timeframe: 2020-2025
Link to other roadmap elements: Feeds into 3bMT, interacts with 2bST, 4bST and 4eSMT
Description:
In addition to possible actions to agree on a high-level approach to multinational licensing, work should be undertaken to identify pilot projects for offshore wind, so that these could inform the work on licensing by the actual challenges of real-world development. Hubs can be pilots, but pilots can also be cross-border wind power not connected to hubs
This action is to be undertaken in conjunction with the review of national maritime spatial plans (2bST), and the work on clarifying the legal status of the assets used in possible hub projects if hubs are selected as pilots (4eSMT).
The pilot/s used to explore licensing cooperation for offshore wind generation may or may not be the same as the one/s used to explore mechanisms for cooperation on network investment financing, described below (roadmap element 4bST).

3bMT Realise pilot and identify / revise template licensing process

Owner: Developer(s)
Stakeholders: BEMIP
Barrier: Complicated licensing procedures for multinational projects dissuade and delay the consideration of such projects
Timeframe: 2025-2030
Link to other roadmap elements: Builds on 3bST
Description:
The pilot identified above will ultimately need to be deployed in the medium-term and the experience from the development used to refine, in particular, the principles and processes governing the licensing of multinational offshore wind projects and, potentially, the legal treatment of hub assets.

3cSMT Eliminate the most serious barriers present in national licensing regimes (e.g. failure to identify pivotal objections early, repetitive processes)

Owner: National government agencies
Stakeholders: Baltic InteGrid for regulatory cohesion recommendations
Barrier: Poor national licensing regimes in some countries can harm efficiency by dissuading

efficient investment and adding directly to the costs of deployment
Timeframe: 2020-2030
Link to other roadmap elements:
Description:
National licensing agencies should work with their counterparts in mature offshore licensing regimes and with industry to identify the barriers to offshore wind development present in their national regimes and to proactively remove them. The nature of these regimes implies that it is appropriate for this review and adaptation process to be under the responsibility of the relevant national authorities. However, BEMIP can play a useful role in sharing experiences of best practices and facilitating the work of national authorities in change national licensing regimes where appropriate in order to remove barriers to efficient offshore wind deployment.

4aST Agree principles and publish guidance on cost sharing arrangements for network investment

Owner: ENTSO-E
Stakeholders: TSOs, cf. PROMOTioN North Sea initiative
Barrier: Lack of cost-sharing / common-financing mechanisms for necessary network investment prevent the network from accommodating efficient offshore wind deployments
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
Our analysis shows the need for network investments that will benefit multiple countries in the BEMIP region. The analysis also shows the absence of cost sharing mechanisms capable of helping realise transmission grid projects that benefit multiple countries. Although the extent to which countries will benefit from any specific investment will vary on a case-by-case basis, cross-country or regional agreements to provide funding for mutually beneficial network investments would be facilitated by the development of accepted principles capable of forming the starting point for detailed negotiations. This is relevant for projects within the onshore networks and for efforts to develop regional offshore grids.

4bST Identify network investment pilot/s and possible funding mechanism

Owner: ENTSO-E, European Commission, BEMIP RES WG
Stakeholders: NSEC
Barrier: Lack of cost-sharing / common-financing mechanisms for necessary network investment prevent the network from accommodating efficient offshore wind deployments
Timeframe: 2020-2025
Link to other roadmap elements: Can be seen in connection with 3bST and 1eSt
Description:
Efforts to develop principles for cross-border cost sharing for network investment should be tested and refined through real pilots to ensure that they are fit-for-purpose and to create confidence in their use. Suitable pilot projects should therefore be identified, as appropriate, together with the funding sources. Such pilots might include the grid investment needed to realise a potential cross-border renewable offshore wind project identified by the BEMIP RES WG as part of the list of cross-border renewable projects under the new Connecting Europe Facility (see 1eSt). Separately, the Commission and ENSTO-E also need to ensure that this list of cross-border renewable projects is also taken into account when developing the list of electricity PCI under the TYNDPs (see 4cST).
As noted previously, piloting is also encouraged to test and develop cooperation mechanisms on licensing for offshore wind generation (3bST). It should be investigated whether it makes

sense to coordinate the pilots for offshore wind generation and network investments and choose grid/generation projects that are linked together.
It is also anticipated that BEMIP will seek to identify possible sources and mechanisms of project funding, which can be seen in conjunction with the identification of pilots. This may include, among others, the Connecting Europe Facility. Again, collaborating with the North Seas partnership is likely to prove helpful with the identification of funding options and the creation of a project identification process.

4bMT Demonstrate successful models of cooperation on network investment

Owner: TSOs
Stakeholders: ENTSO-E
Barrier: Lack of cost-sharing / common-financing mechanisms for necessary network investment prevent the network from accommodating efficient offshore wind deployments
Timeframe: 2025-2030
Link to other roadmap elements: Builds on 4bST and can be seen in connection with 3bMT
Description:
The pilot projects identified above in the first half of the 2020s should then be implemented and the lessons learned are to be used to refine the funding mechanisms suggested under roadmap element 4bST above.

4cST Establish processes to embed offshore wind development in regional network planning

Owner: ENTSO-E, BEMIP
Stakeholders: Baltic InteGrid, Baltic Offshore Grid Forum (BOGF)
Barrier: Inadequate consideration of the requirements imposed by offshore wind development as part of regional grid planning prevents the necessary enabling investment in the network
Timeframe: 2020-2025
Link to other roadmap elements: Can be seen in connection with 2bST, 2bMT and 4bST
Description:
Our analysis suggests that current grid planning processes and cooperation groups within e.g. ENTSO-E do not focus on the regional aspects of the grid infrastructure needed for offshore wind deployment.
We propose that ENTSO-E and BEMIP work together to establish a practical method for developing network planning arrangements [, given both the extensive planning work already undertaken by ENTSO-E that could be built on and the need for input from the member states and their respective TSOs. The planning process should include identification and cost-benefit analysis of grid projects related to offshore wind, and recommendations on projects to be prioritised.
This work should also inform the spatial planning actions described above and inform any development of a regional spatial plan (2bST and 2bMT). It should also support the work to identify possible pilots for cooperation on licensing and cost-sharing with respect to domestic and regional (offshore) grid projects, including hubs, needed for the deployment of offshore wind (4bST).

4dSMT Align connection charging regimes (for offshore wind)

Owner: ENTSO-E, TSOs
Stakeholders: ACER
Barrier: Variations in network charging distort site selection
Timeframe: 2020-2030

Link to other roadmap elements: Can be seen in connection with 1bST, 1cST and 1cLT
Description:
Our analysis showed that there are significant differences in developers' exposure to connection costs across the BEMIP member states. These differences are liable to distort investment decisions. The distortive effect of these differences and the associated efficiency cost will grow in proportion to the extent that support schemes become more open across borders and as offshore wind development becomes commercially viable without support. Addressing these distortions is likely to require some alignment of connection charging, at least as it applies to offshore wind projects in the Baltic Sea.
The issue of inconsistent connection charging is not unique to the region or to offshore wind. However, the associated efficiency costs are likely to be larger in this instance, both because connection costs are relatively large for offshore wind projects and therefore a more important driver of investment behaviour and because offshore wind developers are more likely to face a genuine choice between locations with different connection charging regimes when they consider where to make investment.
Member states, regulatory authorities and TSOs should therefore begin to consider options to remove the sources of this potential distortion in a timely manner and, if necessary, give ENTSO-E the task of initiating the necessary work, to avoid undermining efficient deployment. This effort will need to consider the total impact of tariffs for generators and connection charges on the cost of offshore wind in different locations since both contribute to total generator costs. Looking at connection charges alone may not be sufficient to effectively align different systems therefore. At the same time, it is desirable to have a mechanism available for stimulating offshore wind investments in the most efficient locations from a total system perspective (including grid costs), either through tariffs and connection charges or through the licensing regime (or a combination). This process is likely to require an extended period of consideration and consultation, which reinforces the need to start work now.
This work will be an enabler for efficient support mechanism design, since absent charging alignment, schemes will need to be designed to offset distortions from network tariffs. E.g., if an offshore wind project is obliged to pay a connection charge in country A, but not in country B, despite the connection costs being the same in both countries, the project should receive higher support in country A to eliminate the distortion from varying network costs. Support mechanism design in roadmap elements 1bST, 1cST and 1cLT should therefore be informed by progress against this task.

4eSMT Clarify the legal status of assets involved in hub projects

Owner: European Commission, ENTSO-E
Stakeholders: Developers, TSOs
Barrier: Lack of regulatory and contractual arrangements suited to multinational projects adds to the risks and costs of project development
Timeframe: 2020-2030
Link to other roadmap elements: Can get input from 4bST
Description:
As analysed by inter alia the Baltic InteGrid project, the legal status of offshore wind-related grid assets are not completely clear. E.g. an offshore grid may be deemed an interconnector under EU law under some circumstances, which entails a set of regulations related to inter alia congestion revenues and operation of the assets. Whether existing regulations apply to offshore wind-related grid investments, can create uncertainty for TSOs and offshore wind developers. The European Commission should, in partnership with the relevant regional groups, therefore look to review the necessary legal texts and, if deemed necessary, clarify the

legal treatment of these assets and ensure their efficient functioning under current market rules. Network investment pilots (4bST) and knowledge sharing with the Baltic InteGrid project and the North Seas Energy Cooperation can provide important input. Given that these legal issues are present at Community level, this is a natural area where BEMIP should look to collaborate with North Seas Energy Cooperation.

4fST Develop template of contractual arrangements for hub projects

Owner: BEMIP, North Seas Energy Cooperation
Stakeholders: TSOs, Developers, BOGF
Barrier: Lack of regulatory and contractual arrangements suited to multinational projects adds to the risks and costs of project development
Timeframe: 2020-2025
Link to other roadmap elements:
Description:
Hub projects will likely require novel contracting arrangements that clearly allocate the various parties' rights and responsibilities. Such projects will likely be made easier, in both the Baltic and North Seas, if a common template for the contractual arrangements can be prepared to serve as a starting point for project-specific negotiations.
This work could be undertaken in partnership with the North Seas Energy Cooperation group, since this region would also likely benefit from the results, and should draw on experience with existing projects, such as Kriegers Flak.

5aST Establish common / mutually recognised standards on industry practices / equipment

Owner: BEMIP, North Seas Energy Cooperation
Stakeholders: National regulators, Developers, Operators, Equipment manufacturers
Barrier: Inconsistencies in national regulation may increase the costs of development and operations
Timeframe: 2020-2025
Link to other roadmap elements: Builds on 2aST
Description:
BEMIP should seek to learn from the experience of the North Sea, where differences in national standards have been identified as hindering low cost deployment and operation. It should engage early with the North Seas Energy Cooperation's support group on standards, technical rules and regulations in the offshore wind sector (Support Group 4) to help identify likely problem areas and explore the scope for common work in this field across the North and Baltic Seas. Part of this action would be to identify the standards and mutual recognition practices that are common to both offshore wind development areas and extend the work on those that are being developed by North Seas Energy Cooperation to cover the Baltic Sea offshore wind projects. This would lead to an increase in the potential efficiencies stemming from standardisation and savings, for example in component, equipment and maintenance costs.
We have assumed that work on standardisation and the mutual recognition of standards is ongoing throughout the 2030s, as initial work to deal with easy-to-treat problems gives ways to more challenging and time-consuming issues later in the period.

10.4 Action plan

In this section, we set out specific actions that the BEMIP group could undertake in support of the roadmap described in the previous section. The actions are grouped by different work streams according to how we envisage that the work can be organized.

1. Work to identify national and regional offshore wind power ambitions and identify candidates for PCI and cross-border RES projects

2. Work on creating favourable market and support frameworks for offshore grid

3. Work on licensing of offshore wind power projects

4. Work on grid development needs and conditions

5. Cooperation to establish common standards

Under each work stream we propose different activities that the BEMIP group could undertake. These activities should be seen as options and examples, and the list is not exhaustive.

The proposed actions could be carried out in parallel but to some extent reflect a natural sequence: In order to develop the cooperation on offshore wind power in the BSA and identify candidates for cross-border RES projects, an overview and common understanding of the ambitions should be established. Based on this, candidates for projects of common interest and/or joint offshore wind power projects can be identified. In parallel, work on market and support frameworks can start with a mapping of barriers to offshore wind power and a plan to remove them, followed by work to facilitate licensing procedures and develop common standards. The identified candidates may then be used as pilots by which support frameworks, licensing, and grid cooperation can be explored. Work to establish cooperation on the improvement of data can be done in parallel and independent of other actions.

Many of the activities can draw on work already carried out by the North Sea Group (NSG) and for some cooperation with the NSG would provide mutually beneficial. Several of the issues are common to multilateral cooperation on the development of offshore wind power, be it in the Baltic Sea or the North Sea. Moreover, the projects affect and are affected by the same market, and features such as licensing, data, standards, and grid issues should be aligned over a larger area than the Baltic Sea Region. We mention such activities under each work stream and also provide a summary section at the end of this chapter.

10.4.1 Work to identify national and regional offshore wind power ambitions and identify candidates for PCI and cross-border RES projects

Establish a common statement on national and regional ambition levels for offshore wind power

Working with the NECP authors and the offshore wind industry, the BEMIP RES working group should develop a clear, explicit and common articulation of what is expected in terms of the level of offshore wind power deployment per Member State and for the Baltic Sea Area. In particular, the BEMIP RES working group should work to ensure that a common articulation of coordinated national and regional offshore wind development objectives is included in a joint chapter of the NECPs of the BEMIP Member States.

The aim of this process would be to produce a "statement of common understanding" that sets out the range of offshore wind deployment expected in the region within the framework of the NECPs. The aim would not be to push for ambition beyond that in the NECPs but to explore and clarify the expected role for offshore wind power, which would provide a basis for the regional cooperation on offshore wind power planning and inform network and investment planning.

As a next step, the BEMIP working group could work to secure political commitment to the statement so that national governments would certify that the description is an accurate expression of expected development.

BEMIP should regularly review progress against the common statement and update the statement as necessary to reflect new information that is developed as part of other work streams. A time plan for such reviews, e.g. every 3rd year, including a plan for stakeholder involvement and information exchange with relevant parties, such as TSOs, should be set up by the BEMIP working group.

Initiate work to identify projects of common interest and cross-border RES projects

Drawing on the expected deployment of offshore wind power in the NECPs' "statement of common understanding" and on the identification of favourable sites and areas for offshore wind power provided in this and other studies, the BEMIP working group could create an initial list of candidates for support either as PCIs or cross-border RES projects or ideally both. Candidate projects should be selected for further assessment, for example regarding the mapping of wind speeds, spatial planning challenges, etc. The aim would be to develop a short-list of possible pilot projects that could be developed further as PCIs and/or cross-border RES projects. The BEMIP RES working group could thereby play an important role in preparing such projects for inclusion in the list of cross-border RES projects under the new CEF RES window and help ensure that these projects are coordinated with the TYNDP electricity grid PCIs, which ideally should go hand-in-hand with any planned cross-border offshore wind project investment.

We expect that cross-border RES projects would be promising wind power sites with simple connections to shore that can be developed in cooperation between two or more BEMIP Member States, while PCI projects would be hub projects, including interconnection to two or more Member States. Hub projects could also be developed as cross-border RES projects, where even Member States that are not connected to the hub participate to gain the wider benefits, such as less internal congestion in their national grids and new trading opportunities.

The aim of this work item should be to provide a basis for the selection of pilot projects that can be used to elaborate and demonstrate the licensing, grid, financing and other issues identified as barriers. An initial assessment of the pros and cons of each project would also be valuable as part of this work.

10.4.2 Work to improve the support framework for offshore wind power in the Baltic Sea Area

Work to improve the support framework for offshore wind power in the Baltic Sea Area can be carried out along the following avenues:

- Remove barriers in national support frameworks
- Coordinate tendering processes across national support schemes
- Identify the potentially relevant funding mechanisms for projects of interest
- Develop regional support mechanisms open to offshore wind

Explore how national support mechanisms can be made more favourable to offshore wind power

Building on the identified barriers in current support systems for renewable electricity identified in this study, an early action for the BEMIP working group could be to review national renewable energy support schemes and flag barriers to offshore wind power.

A natural next step would be to map and explore options to address the identified barriers, and to develop a common approach to their removal. The focus should be not only to remove barriers for support to offshore wind power, but also to identify differences among national support schemes that may distort the efficient utilization of offshore wind power from a regional point of view.

Such a review and assessment will provide valuable input to the process of selecting candidates for regional PCI and cross-border offshore wind power projects in the BSA.

A document outlining emerging best practices in the North Sea cooperation might serve as a good starting point for the discussion of support incentives. Building on the work done by NSEC in this regard could enable BEMIP to propose tried-and-tested pathways to more efficient subsidy schemes to support offshore wind.

Coordinate tendering processes across national support schemes

BEMIP could act as a forum for the exchange of information on tendering processes and, where appropriate, help establish separate multilateral channels for the sharing of information among relevant national agencies and regulators.

By exchanging information on tendering processes, the BEMIP countries may cooperate on the timing of tenders and on the specification of tenders. Creating such a forum for exchange of information and eventually for coordination of tendering processes, would provide valuable input to the creation of regional support mechanisms or tenders open to cross-border RES projects.

Again, the North Seas Energy Cooperation's work can provide some input on how to structure concerted tenders in the Baltic Sea. A review of the first results that have been published by NSEC and establishing contact with the working group on the design of the support framework would constitute a first step that could be followed up by collaboration. Since Germany, Denmark and Sweden are part of both, BEMIP and NSEC, coordinated tendering across the regions could be discussed as later step in the cooperative work.

Identify the potentially relevant funding mechanisms for projects of interest

Having identified possible candidates for cooperation on offshore wind power projects, the BEMIP group could help explore the available funding sources that could be used to develop these. The group could take on work to outline a possible high-level funding plan for each of the projects, noting the potential, where applicable, to use third-party or EU financing to cover some or all the expected cost.

Develop proposals for a regional support mechanism open to offshore wind

The BEMIP working group should follow efforts to open national support mechanisms to foreign projects and develop one or more proposals for how a regional support mechanism for offshore wind could be designed, including principles for equitable sharing of costs and benefits associated with offshore winds development.

A report outlining one or more possible regional support mechanisms for offshore wind should be published. The report should include an explanation of how national policy frameworks can be realistically adapted to create and work alongside the proposed mechanisms. It should also consider the role of financial support for cross-border RES projects under the Connecting Europe Facility.

10.4.3 Work on licensing of offshore wind power projects

In order to make the licensing of offshore wind more efficient and transparent, the BEMIP group could initiate the following activities:

› Establish national forums to identify and eliminate the most serious barriers in national licencing regimes
› Create a network of national fora for the sharing of best practice on offshore wind licencing in the BSA
› Develop principles and processes for licencing of multinational projects
› Review template licencing process in view of pilot experience

Eliminate the most serious barriers present in national licensing regimes (e.g. failure to identify pivotal objections early, repetitious processes)

› Instigate the creation of national forums between industry and the relevant national agencies to identify specific issues and develop reform proposals
› Share best practice on offshore wind licensing

The BEMIP group could instigate the creation of a network of national forums to consider the barriers to offshore wind development present in national licensing regimes through its contacts in the relevant national agencies and industry bodies. Relevant stakeholders in the offshore wind industry should be invited to participate in or provide input to such a network. The BEMIP group could arrange stakeholder consultations to map the barriers as seen from the developers' side.

BEMIP should also work with industry, the North Seas Energy Cooperation group and the licensing agencies in the BEMIP region with experience from offshore licensing to identify the components of best practice and the approaches used to achieve these in practice. This information should then be compiled into an information pack and presented to the national forums established in the step up.

The learning resources developed through this process should be published as part of a standalone information pack that can be used as reference material on the effective licensing of offshore wind.

Develop principles and a process for licensing of multinational projects and review template licencing process

In addition to the work on barriers in national licensing regimes, the BEMIP group could, building on the best practices identified in the barrier study (above), start work to develop licensing procedures for common projects and offshore wind power hubs located in multiple jurisdictions. This work could start with a preliminary assessment of barriers related to the identified pilot projects and continue with development of common principles.

BEMIP should initially engage with the North Seas Energy Cooperation group to explore whether and, if so, how they may wish to cooperate on this work. In the event that co-working is not considered appropriate, BEMIP should seek to develop an initial proposal for the principles and processes to be used based on a review of any earlier work conducted by the North Seas Energy Cooperation group and the Baltic InteGrid project. The establishment of a working committee including representation from the national planning authorities may be needed for this purpose.

This proposal should then be workshopped with the national authorities and industry to ensure its feasibility and acceptability and to identify what further action might be useful in terms of formalising its use.

BEMIP should conduct a review of the licensing procedures used as part of any multinational offshore wind pilot project to identify lessons for future projects. This review should ideally be included in the initial specification of the pilot(s) to ensure that relevant information is captured throughout the pilot. The group could commission and publish a report covering the experience of the project(s) and the lessons learned.

The aim of this work would be to develop a proposal setting out the expected licensing process to be applied to generic multinational offshore wind projects, such as a hub connected to an interconnector. The proposal may be accompanied by a statement of principles to help determine the appropriate licensing approach for problem cases. The proposal should clarify for any potential developers of multinational projects the licensing process that they will be subject to.

10.4.4 Work on grid development needs and conditions

In order to efficiently develop offshore wind power resources in the Baltic Sea Area, it is necessary to integrate ambitions in the grid planning, and to establish cooperation on grid development and the sharing of costs and benefits of associated grid development, applying to offshore as well as onshore grids.

The BEMIP working group work related to grid issues could include

› Work proactively to support ENTSO-E's inclusion of Baltic offshore wind power development in its regional grid planning processes and follow up on Baltic InteGrid's recommendations regarding the TYNDP

- Coordination of connection charging regimes for offshore wind power
- Develop template contractual arrangements for hub projects
- Agree principles and publish guidance on cost sharing arrangements for network investment

Support ENTSO-E's inclusion of Baltic offshore wind development in its regional grid planning processes

BEMIP should proactively engage with ENTSO-E to supply it with the inputs it requires to undertake a thorough consideration of the needs of offshore wind development as part of the regional grid planning process. This will include discussing with ENTSO-E how and when the BEMIP group can usefully engage. The development of a clear statement on regional offshore wind capacity expectations, discussed above, is likely to form one element of this work. The results of the work to identify projects of common interest and cross-border RES projects (described above) are also likely to be useful inputs to the scenario building and infrastructure needs assessment tasks that occur early on in the TYNDP process.

One outcome of this work could be the creation of a list of contributions that BEMIP can realistically and usefully make to the network planning process.

BEMIP could make steps so that Baltic InteGrid's recommendations with regard to the TYNDP plan[62] are reflected in subsequent regional network planning exercises. For example, in cooperation with the Baltic Offshore Grid Forum, BEMIP could review and assess ENTSO-E's next TYNDP process and, if appropriate, engage with ENTSO-E to ensure that the recommendations are in line with the outcomes of previously conducted studies by the initiatives.

Coordinate connection charging regimes for offshore wind

BEMIP could instigate the creation of a forum on the alignment of offshore wind connection charging. Work on connection charging is expected to be led by regional TSOs and NRAs. However, BEMIP could play an important role in setting up a forum among the relevant actors and elevating the issue internally within these organisations.

BEMIP could initially reach out to the North Seas Energy Cooperation group and explore the scope for a broader regional cooperation on the alignment of connection charges. In cooperation with the North Seas Energy Cooperation group and the European Commission, regional TSOs and NRAs could be engaged and supported in forming a working group capable of considering possible solutions for connection charging.

[62] http://www.baltic-integrid.eu/index.php/download.html?file=files/baltic_integrid/Work%20packages/WP%205%20Recommendations/5.1%20-%20Recommendations%20to%20the%20Ten%20Year%20Network%20Development%20Plan/BIG_5.1_%20Recommendations%20to%20the%20TEN%20YEAR%20NETWORK%20DEVELOPMENT%20PLAN%20%28TYNDP%29_final.pdf

Develop template contractual arrangements for hub projects

BEMIP should, in close cooperation with the North Seas Energy Cooperation group, work to develop contractual arrangements to support the creation and operation of a multinational offshore wind hub.

BEMIP could contribute to the development of common principles and a template contractual arrangement for hub projects, by conducting an in-depth review of the lessons learned from the Kriegers Flak combined grid solution project. This work should also draw on earlier thinking undertaken as part of the North Seas Countries Offshore Grid Initiative. The review of experience from Kriegers Flak would focus on the contractual and regulatory arrangements used for the Kriegers Flak project, the challenges experienced in the process, and how these were solved.

The specific goal should be to identify and propose useful templates for future multinational cooperation, including regulatory solutions, that may have wider applicability in the region.

The high-level contractual framework developed through this work should explain the key features of the proposed arrangement and the rationale underlying the selected framework. The ultimate objective of the work should be to provide a solid jumping off point for practical discussion in relation to possible pilot projects. In particular, the report should make clear the key stakeholders involved and how they would be expected to contract with one another.

Agree principles and publish guidance on cost sharing arrangements for network investment

The uneven distribution of costs and benefits could prove to be an important obstacle to the efficient realization of advanced hubs and cross-border offshore wind power projects in the Baltic Sea Area. This obstacle is not particular to the Baltic Sea, and development of cost sharing arrangements for network investments is expected to be led by ENTSO-E.

BEMIP could nevertheless take an active role to contribute to the reduction of this barrier. For example, BEMIP could instigate the creation of a forum appropriate for developing solutions for the cooperative financing of network projects. This forum will need to include not just the TSOs and BEMIP, but also the North Seas Energy Cooperation group and NRAs.

Here, BEMIP should work with ENTSO-E to identify the relevant stakeholders and, as needed, push the participants to deliberate and propose a set of cost-sharing principles for those network investments necessary to enable offshore wind deployment.

10.4.5 Cooperation to improve data quality and availability, and establish common standards on industry practices

Finally, BEMIP could play a role in activities related to making available data necessary for developers of offshore wind power in the BSA, and to common industry standards for offshore wind power in the area, specifically:

- Ensure comprehensive and high-quality data is available through EMODnet
- Establish common or mutually recognized standards on industry practices and equipment

Ensure comprehensive and high-quality data is available through EMODnet

BEMIP should work with the EMODnet Secretariat, industry and the relevant national bodies to identify detailed actions to improve data quality and accessibility for use in the planning and development of offshore wind sites.

A detailed list of problems and gaps, as well as detailed actions designed to address these should be developed and agreed.

BEMIP should also help develop and secure a political commitment to the provision of high-quality maritime data from the relevant national agencies to EMODnet, including an agreement to carry out the actions identified through the step above. A political commitment to this affect can be used to motivate the actions identified in the step above.

Establish common or mutually recognised standards on industry practices and equipment

BEMIP could establish a dedicated support group to identify and realise possible efficiency gains from the adoption of common standards or the mutual recognition of standards. In doing so, BEMIP should ensure that its membership and remit is suitable for realizing the goals of the group.

As noted above, the North Seas Energy Cooperation's support group on standards, technical rules and regulations is already focussed on this task in the context of the North Sea. A sister group could be established for the Baltic Sea that can join up efforts across both regions and establish the necessary links between industry and national regulators in the Baltic Sea region. The group should be tasked initially with identifying quick wins, e.g. as regards mutual recognition of standards, and then working with the key bodies to realise them.

10.4.6 Cooperation with the North Seas Energy Cooperation Group

As noted under several of the actions outlined above, parallel work is already carried out by the North Seas Energy Cooperation (NSEC) Group. Moreover, several of the barriers related to licensing, cost sharing, grid planning, data access, funding etc. are not particular to offshore wind power in the Baltic Sea. The activities of the North Seas group should therefore be used as inspiration for work in the BEMIP group. On many of the issues, it would be natural to cooperate with the North Seas Energy Cooperation Group, and initiatives to establish such cooperation should be taken.

For example, the NSEC Group's political declaration signed in 2016 could serve as an example to follow to organize similar work for the BEMIP countries. Importantly, dedicated support groups were formed to support work in the following four areas:

› Maritime Spatial Planning
› Development and regulation of offshore grids and infrastructure
› Support frameworks and finance
› Standards, technical rules and regulations

By forming sister groups, BEMIP could not only learn from the work already carried out by the NSEC support groups, but also collaborate with these groups to develop the work further.

Important to note is also that three of the BEMIP countries are already a part of the NSEC, namely Denmark, Germany, and Sweden.

10.4.7 List of BEMIP actions

The list below gives an overview of the BEMIP actions proposed above by work stream. Emphasis is given on actions that the BEMIP group could undertake in the short term to facilitate the development of the Baltic Seas offshore ambitions according to the outlined roadmap in chapter 3.3.

Following the emphasis on coordination with the NSEC group, establishing contact with the relevant initiatives, sharing best practices and starting collaboration where outlined constitutes an important first action point for achieving BEMIP's objectives. Apart from the first workstream, the workstreams fit nicely with the NSEC's subgroup organization.

Work to identify national and regional offshore wind power ambitions and identify candidates for PCI and cross-border RES projects

1. Establish a common statement on national and regional ambition levels for offshore wind power
2. Initiate work to identify projects of common interest and cross-border RES projects under CEF

Work to improve the support framework for offshore wind power in the Baltic Sea Area

1. Explore how national support mechanisms can be made more favourable to offshore wind power
2. Coordinate tendering processes across national support schemes
3. Identify possible funding mechanisms
4. Develop proposals for a regional support mechanism open to offshore wind

Work on licensing of offshore wind power projects

1. Establish national forums to identify and eliminate the most serious barriers in national licencing regimes
2. Create a network of national forums for the sharing of best practice on offshore wind licencing in the BSA
3. Develop principles and processes for licencing of cross-border projects
4. Review template licencing process in view of pilot experience

Work on grid development needs and conditions

1. Work proactively to support ENTSO-E's inclusion of Baltic offshore wind power development in its regional grid planning processes and follow up on Baltic InteGrid's recommendations regarding the TYNDP
2. Coordinate connection charging regimes for offshore wind power
3. Develop template contractual arrangements for hub (cross-border) projects
4. Agree principles and publish guidance on cost sharing arrangements for network investment

Cooperation to establish common standards

1. Ensure comprehensive and high-quality data is available through EMODnet
2. Establish common or mutually recognized standards on industry practices and equipment

11 Task 7 – Stakeholder workshop proceedings

A stakeholder workshop was held in Brussels on March 15, 2019.

Thirty stakeholder representatives registered for the workshop, representing national and European wind power associations, wind power developers, academia and authorities.

Representatives from the EU Commission and the consortium responsible for the study were also present.

11.1 Agenda

The agenda below shows the programme of the workshop. As can be seen, the consortium presented the study and received feedback from those present over the course of the day:

- Welcome & Introduction
- Presentation: Potentials
- Presentation: Market and grid modelling
- Q&A session

- Presentation: Barriers
- Q&A session
- Presentation: Summary of insights

- Presentation: Recommendations for a roadmap and work plan
- Feedback from stakeholders
- Workshop conclusions

11.2 Summary of input to the study

The sections that follow summarise the key messages and points of discussion under each of the agenda items shown above. Unless otherwise stated, the discussion points reflect the opinions provided by some of the stakeholders at the meeting.

11.2.1 Introduction

The consortium explained that the presentation given reflected the modelling and analyses performed by the consortium as part of this study. The report is a scoping report and is intended to form the basis of further analysis and work by the BEMIP Working Group on Renewable Energy. The Road Map and Workplan shared was a proposal put forward by the consortium, rather than a considered position on behalf of the Working Group. The final report from the study (i.e. this report) would only be finalised and published after it had been discussed further by the BEMIP Working Group.

11.2.2 Potentials and modelling

Cost of icing: The impact of icing on the cost of wind power in the north of the Baltic Sea was questioned. Stakeholders noted that the problems resulting from icing were possibly overstated, and that icing could also be a challenge further south. The consortium noted that icing had been explicitly included in the modelling framework based on comments from the BEMIP working group. The consortium's assessment is that icing increases both foundation costs and OPEX, due to access challenges. Despite this, icing is not a major determinant of geographic differences in the overall attractiveness of wind within the region. The consortium agreed to reflect further on the issue.

Impact of global warming/impact on wildlife: The assessment of offshore wind potential accounts for existing conservation zones. Several stakeholders argued that climate change would change assumptions on icing and on the areas relevant for nature conservation, e.g. by changing the migrations of birds and hatching areas. As such changes are highly uncertain, the consortium argued that it would be very difficult to meaningfully account for such changes in the modelling.

Market area and price assumptions: Stakeholders queried the model's consideration of more distant power systems / markets and the impact of underlying price assumptions on the results. The modelling accounts for a larger market area than just the BEMIP states and wind power potentials in the North Sea are included. Other fundamental pricing assumptions are based on the EU's Long-term Strategy. Long-term carbon prices are taken from IEA's most ambitious scenario. (These issues are discussed in-depth as part of this report in Appendix D.)

Assumptions about offshore wind power costs: The assumptions on wind power costs are important. Wind resource data is drawn from meso scale data. Some cost data is based on Cowi experience. Direct connections are assumed to the closest node in the onshore grid and made through AC connections. Hubs, however, are assumed to be connected via DC links. Capacity factors are assumed to increase over time in response to continued technological development.

11.2.3 Barriers

General: Several stakeholders expressed the opinion that the presentation of barriers provided an accurate reflection of reality and matched the results from other studies.

Quality and availability of MSP data: Some stakeholders felt that a lack of MSP data was a relatively minor challenge relative to the lack of national policies. A prioritisation should therefore be made between the barriers. It was noted that the results from the MSP work underway in Sweden should be taken into account when considering further the hubs identified.

Military restrictions: Stakeholders noted that military restrictions ought to be taken into account in the assessment. The timing of military interventions is a particular challenge in the Swedish planning system. The barrier posed by radar interference is significant and, according to some stakeholders, should be addressed by investment in new radar systems.

The cost and ownership of sea cables: The cost of sea cables is included in the modelling. The consortium did not believe that the use of specific ownership models, e.g. merchant cables, would solve the fundamental coordination challenge, but agreed to mention the issue in the report.

Differences in connection charges and grid costs: Stakeholders asked that a discussion of the impact on these incentives on private investors should be included in the final report.

Public acceptance issues: Stakeholders also asked that barriers related to public acceptance be included.

Nature conservation rules are applied differently: Stakeholders noted that some countries do not allow wind turbines in Natura2000 areas, while others do.

11.2.4 Summary of insights

Stakeholders asked to see the following points reflected when the main insights from the study were communicated:

- It is important that the modelling conclusions on hubs are properly caveated in the executive summary.
- The need for a long-term vision should be highlighted.
- It is important to stress the urgency – we still have time, but processes must be set in motion now if it is to be used.
- It is important to prioritise the recommendations.
- It is important to highlight that other scenarios and evaluations beyond those considered in the report are possible, e.g. when it comes to hub configurations.

11.2.5 Proposed Roadmap and Work Plan

General: Stakeholders expressed a belief that the proposed Roadmap represented a good starting point with many good measures. It was quite complex but seemed to be clear on the necessary first steps. It was useful to differentiate between short-term actions and long-term planning.

Regional offshore wind power ambitions: The stakeholders felt that the BEMIP WG should work to obtain a clear expression of national views on offshore wind power as part of the NECP process. Specifically, the BEMIP WG should compile the Baltic offshore targets stated in the draft NECPs and compare these targets to the scenarios in the study. This should be on the agenda for the next Working Group meeting. The EC commented that offshore wind power plans should be included in the NECPs since the common format calls for technology-specific estimates.

Statement of political desire: Some stakeholders felt that the Roadmap was missing a common statement on what is politically desired. Political will is key to implement favourable conditions for offshore wind. Such a statement should be related to the RES Directive, the NECPs, the Paris agreement, and the 2050 roadmap. It was felt that if Member States do not start thinking about offshore wind in this context, cooperation was not going to happen. Political will was felt to be the key to the creation of favourable market and support frameworks.

Short-term actions: It was felt that incentives for cross-border projects could be improved in parallel with actions aimed at addressing licencing and MSP procedures. It was also noted that work had to be undertaken to mobilise the industry before focusing too much on cross-border projects. Some countries are determined enough to start their own projects first (Sweden, Poland, Finland). That said, it was also recognised that cross-border projects have a very long lead time and so work would need to begin early in order to realise them within a reasonable timeframe.

Cooperation with work on the North Seas: Stakeholders felt that the BEMIP countries should be inspired by successful cooperation in the North Seas and require a similar forum for cooperation. It was suggested that the North Seas Energy Cooperation initiative be asked for its views on the suggested actions.

Appendix A List of existing and potential offshore wind farms

Existing areas

Wind Farm ID	Name	Country	WF OSS Coordinates, Geo [deg]-WGS84		Pooling Substation Coordinates, Geo [deg]-WGS84		Point of Connection Coordinates, Geo [deg]-WGS84		Name of Point of Connection	Average Sea Depth in Area	Sea Ice Zone	Mean WS 100 m ASL	Weibull Parameters in Area		Gross Production ekskl. wake	Gross Production inkl. 13 % wake	Distance from OSS to Pooling Substation	Distance from Pooling Substation to Point of Connection	Availability Losses	Electrical Losses (array cables, offshore substation)	Gross Wind Farm Output	Electrical Losses (export cables, pooling substation)	Output from pooling substation	Electrical Losses (transmission cables)	Net Output	Capacity Factor	Capacity	Total capacity in wind farm cluster
			Longitude	Latitude	Longitude	Latitude	Longitude	Latitude		[m]	[1/2/3]	[m/s]	A [m/s]	k [-]	[MWh]	[MWh]	[km]	[km]	[%]	[%]	[GWh]	[%]	[GWh]	[%]	[GWh/y]	[%]	[MW]	[MW]
DE83	Baltic Eagle	DE	14.264093	54.855358	13.671220	54.563593	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.77	2.3998	2376465	2067524.55	50.0	47.2	5%	3%	1906.5	2.5%	1859.09	1%	1840.5	42.0%	500	500
DE84	DE Windanker, Wikinger, Arkona - 1	DE	14.048992	54.844999	13.631755	54.578885	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.80	2.3983	2407601.2	2094613.044	40.2	49.0	5%	3%	1931.4	2.5%	1883.45	1%	1864.6	42.6%	500	1000
DE85	DE Windanker, Wikinger, Arkona - 2	DE	14.1193	54.755559	13.666501	54.559074	13.683875	54.139149	Lubmin 400 kV Substation	-30 to -40	1	9.4	10.75	2.3949	2394390	2083119.3	36.6	46.9	5%	3%	1920.8	2.5%	1873.12	1%	1854.4	42.3%	500	
DE86	DE ArcadisOst, ArkonaSee Sud, ArkonaSee West - 1	DE	13.669981	54.808107	13.420405	54.678513	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.77	2.3989	2402149	2089869.63	21.8	62.3	5%	3%	1927.1	2.5%	1879.18	1%	1860.4	42.5%	500	1000
DE87	DE ArcadisOst, ArkonaSee Sud, ArkonaSee West - 2	DE	13.853909	54.781113	13.631755	54.578885	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.4	10.73	2.3956	2391895.7	2080949.259	26.7	48.9	5%	3%	1918.8	2.5%	1871.16	1%	1852.5	42.3%	500	
DE88	DE Hiddensee Area	DE	12.947649	54.688615	13.105634	54.587713	13.683875	54.139149	Lubmin 400 kV Substation	-10 to -20	1	9.4	10.66	2.4206	2373698.6	2065117.782	15.2	62.5	5%	3%	1904.2	2.5%	1856.93	1%	1838.4	42.0%	500	500
DE89	DE Gennaker, Baltic 1 - 1	DE	12.682515	54.608893	12.521518	54.479269	12.214814	54.100135	Bentwisch 400 kV Substation	-10 to -20	1	9.3	10.59	2.4268	2350701.8	2045110.566	17.8	46.8	5%	3%	1885.8	2.5%	1838.94	1%	1820.5	41.6%	500	1000
DE90	DE Gennaker, Baltic 1 - 2	DE	12.532252	54.573081	12.521518	54.479269	12.214814	54.100135	Bentwisch 400 kV Substation	-10 to -20	1	9.3	10.59	2.4268	2348051.6	2042804.892	10.5	46.8	5%	3%	1883.7	2.5%	1836.86	1%	1818.5	41.5%	500	
DE91	DE Baltic 2, Baltic 2 area	DE	13.153844	54.948295	13.286272	54.670306	13.683875	54.139149	Lubmin 400 kV Substation	-30 to -40	1	9.5	10.79	2.4426	2409175.2	2095982.424	32.2	64.4	5%	3%	1932.7	2.5%	1884.68	1%	1865.8	42.6%	500	500
DK-52-1	Store Middelgrund Reserved Area 1	DK	12.136079	56.463532	12.271910	56.125021	12.199505	55.894735	Gørløsegård 400 kV Substation	-20 to -30	1	9.2	10.58	2.4120	2320118.4	2018503.008	38.6	26.0	5%	3%	1861.3	2.5%	1815.01	1%	1796.9	41.0%	500	1000
DK-52-2	Store Middelgrund Reserved Area 2	DK	12.136079	56.463532	12.271910	56.125021	12.199505	55.894735	Gørløsegård 400 kV Substation	-20 to -30	1	9.2	10.58	2.4120	2320118.4	2018503.008	38.6	26.0	5%	3%	1861.3	2.5%	1815.01	1%	1796.9	41.0%	500	
DK53-1	Kriegers Flak Reserved Area	DK	12.779166	55.123618	12.511980	55.008062	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.3	10.54	2.4492	2347324.8	2042172.576	21.3	58.9	5%	3%	1883.1	2.5%	1836.30	1%	1817.9	41.5%	500	3000
DK53-2	Kriegers Flak Reserved Area	DK	12.796022	55.139110	12.511980	55.008062	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.3	10.54	2.4492	2347324.8	2042172.576	23.2	58.9	5%	3%	1883.1	2.5%	1836.30	1%	1817.9	41.5%	500	
DK53-3	Kriegers Flak Reserved Area	DK	12.780949	55.117673	12.511980	55.008062	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.2	10.54	2.4492	2346422.7	2041387.749	21.0	58.9	5%	3%	1882.4	2.5%	1835.59	1%	1817.2	41.5%	500	
DK53-4	Kriegers Flak Reserved Area	DK	12.902183	54.913621	12.535828	54.952991	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.54	2.4492	2390191.6	2079466.692	23.8	64.9	5%	3%	1917.5	2.5%	1869.83	1%	1851.1	42.3%	500	
DK53-5	Kriegers Flak Reserved Area	DK	12.837919	54.965771	12.549388	54.962173	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.54	2.4492	2391230	2080370.1	18.4	64.4	5%	3%	1918.3	2.5%	1870.64	1%	1851.9	42.3%	500	
DK53-6	Kriegers Flak Reserved Area	DK	13.003076	54.973517	12.549388	54.962173	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.54	2.4492	2398844.9	2086995.063	29.0	64.4	5%	3%	1924.4	2.5%	1876.60	1%	1857.8	42.4%	500	
DK54-1	Rønne Banke Reserved Area	DK	14.162095	54.871944	12.549412	54.958643	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2401568.4	2089364.508	103.5	64.8	5%	3%	1926.6	2.5%	1878.73	1%	1859.9	42.5%	500	
DK54-2	Rønne Banke Reserved Area	DK	14.269821	54.876989	12.549445	54.959606	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2401568.4	2089364.508	110.3	64.7	5%	3%	1926.6	2.5%	1878.73	1%	1859.9	42.5%	500	
DK54-3	Rønne Banke Reserved Area	DK	14.378033	54.883294	12.549430	54.960583	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2401568.4	2089364.508	117.2	64.6	5%	3%	1926.6	2.5%	1878.73	1%	1859.9	42.5%	500	6000
DK54-4	Rønne Banke Reserved Area	DK	14.485596	54.887078	12.549445	54.959606	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2369313.1	2061302.397	124.0	64.7	5%	3%	1900.7	2.5%	1853.50	1%	1835.0	41.9%	500	
DK54-5	Rønne Banke Reserved Area	DK	14.592512	54.892573	12.549390	54.963595	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2369313.1	2061302.397	130.8	64.3	5%	3%	1900.7	2.5%	1853.50	1%	1835.0	41.9%	500	

Wind Farm ID	Name	Country	WF OSS Coordinates, Geo [deg]-WGS84		Pooling Substation Coordinates, Geo [deg]-WGS84		Point of Connection Coordinates, Geo [deg]-WGS84		Name of Point of Connection	Average Sea Depth in Area	Sea Ice Zone	Mean WS 100 m ASL	Weibull Parameters in Area		Gross Production ekskl. wake	Gross Production inkl. 13 % wake	from OSS to Pooling Substation	Pooling Substation to Point of	Availability Losses	Losses (array cables, offshore	Gross Wind Farm Output	Losses (export cables, pooling substation)	Output from pooling substation	Losses (transmission)	Net Output	Capacity Factor	Capacity	Total capacity in wind farm
DK54-6	Rønne Banke Reserved Area	DK	14.688893	54.929142	12.549445	54.959606	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2369313.1	2061302.397	136.7	64.7	5%	3%	1900.7	2.5%	1853.50	1%	1835.0	41.9%	500	
DK54-7	Rønne Banke Reserved Area	DK	14.250906	54.938511	12.549388	54.962173	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2401568.4	2089364.508	108.7	64.4	5%	3%	1926.6	2.5%	1878.73	1%	1859.9	42.5%	500	
DK54-8	Rønne Banke Reserved Area	DK	14.358958	54.944816	12.549343	54.965369	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2381338.8	2071764.727	115.6	64.1	5%	3%	1910.4	2.5%	1862.91	1%	1844.3	42.1%	500	
DK54-9	Rønne Banke Reserved Area	DK	14.466200	54.948690	12.549366	54.963319	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2381338.8	2071764.727	122.4	64.3	5%	3%	1910.4	2.5%	1862.91	1%	1844.3	42.1%	500	
DK54-10	Rønne Banke Reserved Area	DK	14.573766	54.953825	12.549366	54.962829	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2369313.1	2061302.397	129.2	64.4	5%	3%	1900.7	2.5%	1853.50	1%	1835.0	41.9%	500	
DK54-11	Rønne Banke Reserved Area	DK	14.426385	55.010570	12.549366	54.962829	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.4	10.78	2.3921	2373134.8	2064627.276	119.9	64.4	5%	3%	1903.8	2.5%	1856.49	1%	1837.9	42.0%	500	
DK54-12	Rønne Banke Reserved Area	DK	14.482737	54.824802	12.549412	54.958643	12.006513	55.451960	Bjæverskov 400 kV Substation	-20 to -30	1	9.5	10.78	2.3921	2385440.8	2075333.453	124.5	64.8	5%	3%	1913.7	2.5%	1866.11	1%	1847.5	42.2%	500	
DK58	Sæby (Nearshore Tender Area)	DK	10.590421	57.378606	10.513163	57.376586	10.089206	57.062732	Vester Hassing 400 kV Substation	-10 to -20	1	8.7	9.87	2.4306	2135561.9	1857938.853	4.6	43.2	5%	3%	1713.2	2.5%	1670.64	1%	1653.9	37.8%	500	500
DK73	Omø Syd	DK	11.231453	55.119068	11.296250	55.194433	11.254367	55.208475	Stigsnæs Power Plant	-10 to -20	1	9.1	10.40	2.5069	2300885.2	2001770.124	9.3	3.1	5%	3%	1845.8	2.5%	1799.97	1%	1782.0	40.7%	500	500
DK83	Lillebælt Syd (Lillegrund)	DK	9.801640	55.085564	9.788322	55.073150	9.270722	55.036959	Kassø 400 kV Substation	-20 to -30	1	8.6	9.82	2.5357	2133693.6	1856313.432	1.6	33.2	5%	3%	1711.7	2.5%	1669.17	1%	1652.5	37.7%	500	500
EE05-1	Liivi laht	EE	23.942285	57.938734	24.346440	57.863920	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.8	10.13	2.4239	2195866.6	1910403.942	25.3	65.7	5%	3%	1761.6	2.5%	1717.81	1%	1700.6	38.8%	500	1000
EE05-2	Liivi laht	EE	24.077153	57.977194	24.393039	57.951573	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.8	10.13	2.4239	2195866.6	1910403.942	18.8	55.5	5%	3%	1761.6	2.5%	1717.81	1%	1700.6	38.8%	500	
EE LB-1	Liivi Bay-1-1	EE	23.814320	57.925564	24.373048	57.895996	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.422	2210052.1	1922745.327	33.2	61.9	5%	3%	1773.0	2.5%	1728.91	1%	1711.6	39.1%	500	1000
EE LB-2	Liivi Bay-1-2	EE	23.663564	58.003143	24.085218	58.251542	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.21	2.4165	2223219.5	1934200.965	37.0	39.4	5%	3%	1783.5	2.5%	1739.21	1%	1721.8	39.3%	500	
EE LE-1	Loode Eesti 1	EE	22.341587	59.121625	23.444521	59.053873	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.14	2.3087	2201522.5	1915324.575	63.6	99.4	5%	3%	1766.1	2.5%	1722.24	1%	1705.0	38.9%	500	500
EE LE-2	Loode Eesti 2	EE	22.887421	59.139489	23.444521	59.053873	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.8	10.00	2.3476	2166799.0	1885115.13	33.2	99.4	5%	3%	1738.3	2.5%	1695.07	1%	1678.1	38.3%	500	500
FI05	Suurhiekka	FI	24.675307	65.258676	25.267803	65.269978	25.693007	65.266044	Li 400 kV Substation	0 to -10	3	8.3	9.56	2.3018	2000282.2	1740245.514	27.6	19.8	10%	3%	1519.6	2.5%	1481.83	1%	1467.0	33.5%	500	500
FI06	Korsnäs	FI	20.938553	62.841278	21.123648	62.797796	21.850939	63.052552	Tuovila 400 kV Substation	0 to -10	3	8.9	10.15	2.3368	2182034.6	1898370.102	10.6	46.4	10%	3%	1657.7	2.5%	1616.47	1%	1600.3	36.5%	500	500
FI12	Inkoo-Raaseporin	FI	23.814557	59.866700	23.722849	59.939414	23.909138	60.022140	Inkoo 400 kV Substation	-20 to -30	2	8.7	9.95	2.4351	2132740.0	1855483.8	9.6	13.9	5%	3%	1710.9	2.5%	1668.43	1%	1651.7	37.7%	500	500
FI21	Ulkonahkiainen	FI	23.952686	64.639899	24.251654	64.532917	25.736753	64.916904	Pikkarala 400 kV Substation	-10 to -20	3	8.5	9.69	2.2912	2037546.3	1772665.281	18.6	82.4	10%	3%	1547.9	2.5%	1509.43	1%	1494.3	34.1%	500	500
FI22	Maanahkiainen	FI	24.168913	64.566021	24.251654	64.532917	25.736753	64.916904	Pikkarala 400 kV Substation	-10 to -20	3	8.2	9.34	2.2876	1924490.8	1674306.996	5.4	82.4	10%	3%	1462.0	2.5%	1425.68	1%	1411.4	32.2%	500	500
FI23	Tahkoluoto + Tahkoluoto Extension	FI	21.319988	61.654888	21.471094	61.598450	21.535463	61.581833	Tahkoluoto 400 kV Substation	-20 to -30	2	8.6	9.81	2.3552	2083897.3	1812990.651	10.2	3.9	5%	3%	1671.8	2.5%	1630.22	1%	1613.9	36.8%	500	500
LT06	Baltic Energy Group	LT	20.519396	55.969230	21.052276	55.919159	21.257782	55.681893	Klaipeda 300-330 kV Substation	-20 to -30	1	9.1	10.36	2.3438	2260943.4	1967020.758	33.6	29.3	5%	3%	1813.8	2.5%	1768.72	1%	1751.0	40.0%	500	500
LT10	AVEC - 2	LT	20.532823	55.805719	21.062088	55.838128	21.257782	55.681893	Klaipeda 300-330 kV Substation	-40 to -50	2	9.1	10.34	2.3418	2255182.4	1962008.688	33.3	21.3	5%	3%	1809.2	2.5%	1764.21	1%	1746.6	39.9%	500	500
LV06-1	JK ENERGY Offshore Wind Park	LV	20.997867	56.588332	21.014398	56.587399	21.201358	56.542021	Grobina 300-330 kV Substation	0 to -10	2	8.6	9.76	2.3783	2069491.0	1800457.17	1.0	12.5	5%	3%	1660.2	2.5%	1618.95	1%	1602.8	36.6%	500	1000
LV06-2	JK ENERGY Offshore Wind Park	LV	21.006457	56.777028	21.061858	56.777986	21.201358	56.542021	Grobina 300-330 kV Substation	0 to -10	2	8.9	9.76	2.3783	2167991.0	1886152.17	3.4	27.6	5%	3%	1739.2	2.5%	1696.00	1%	1679.0	38.3%	500	
LV07-1	Baltic Wind Park - Phase 1	LV	20.647221	56.345615	20.978063	56.344914	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.0	10.30	2.3629	2245752.1	1953804.327	20.4	25.9	5%	3%	1801.6	2.5%	1756.84	1%	1739.3	39.7%	500	500
LV07-2	Baltic Wind Park - Phase 1	LV	20.605072	56.819451	21.057155	56.822422	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.2	10.30	2.3629	2289540.4	1991900.148	27.5	32.4	5%	3%	1836.7	2.5%	1791.09	1%	1773.2	40.5%	500	500
LV07-3	Baltic Wind Park - Phase 1	LV	20.985792	56.898396	21.071391	56.842600	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	2	9.0	10.30	2.3629	2217241.0	1928999.67	8.1	34.4	5%	3%	1778.7	2.5%	1734.53	1%	1717.2	39.2%	500	500

Wind Farm ID	Name	Country	WF OSS Coordinates, Geo [deg]-WGS84		Pooling Substation Coordinates, Geo [deg]-WGS84		Point of Connection Coordinates, Geo [deg]-WGS84		Name of Point of Connection	Average Sea Depth in Area	Sea Ice Zone	Mean WS 100 m ASL	Weibull Parameters in Area		Gross Production ekskl. wake	Gross Production inkl. 13 % wake	from OSS to Pooling Substation	Pooling Substation to Point of	Availability Losses	(array cables, offshore	Gross Wind Farm Output	(export cables, pooling	Output from pooling substation	(transmission Losses	Net Output	Capacity Factor	Capacity	capacity in wind farm
LV07-4	Baltic Wind Park - Phase 1	LV	20.953485	57.051785	21.168829	56.887736	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	2	9.1	10.30	2.3629	2266491.0	1971847.17	22.4	38.5	5%	3%	1818.2	2.5%	1773.06	1%	1755.3	40.1%	500	1000
LV07-5	Baltic Wind Park - Phase 1	LV	21.076177	57.064304	21.286993	56.949697	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	2	9.1	10.30	2.3629	2266491.0	1971847.17	18.0	45.6	5%	3%	1818.2	2.5%	1773.06	1%	1755.3	40.1%	500	
PL16-1	Baltyk Pólnocny - Phase 1	PL	17.344190	55.488274	17.760856	54.798965	18.111377	54.719302	Zarnowiec 400 kV Substation	-20 to -30	1	9.5	10.81	2.3419	2399050.2	2087173.674	81.1	24.2	5%	3%	1924.6	2.5%	1876.76	1%	1858.0	42.4%	500	1000
PL16-2	Baltyk Pólnocny - Phase 1	PL	17.236084	55.481879	17.430364	54.749757	18.111377	54.719302	Zarnowiec 400 kV Substation	-20 to -30	1	9.5	10.81	2.3419	2399050.2	2087173.674	82.3	43.9	5%	3%	1924.6	2.5%	1876.76	1%	1858.0	42.4%	500	
PL19	Baltica 1	PL	17.489087	55.494849	17.766870	54.799577	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.5	10.77	2.3241	2387405.1	2077042.437	79.3	23.8	5%	3%	1915.2	2.5%	1867.65	1%	1849.0	42.2%	500	500
PL20-1	Baltica 2	PL	17.065764	55.003469	17.250020	54.727691	16.891359	54.501814	Slupsk 400 kV Substation	-40 to -50	1	9.3	10.60	2.3359	2333816.4	2030420.268	32.9	34.1	5%	3%	1872.3	2.5%	1825.73	1%	1807.5	41.3%	500	1000
PL20-2	Baltica 2	PL	17.204584	55.043369	17.352626	54.741956	16.891359	54.501814	Slupsk 400 kV Substation	-40 to -50	1	9.3	10.60	2.3359	2333816.4	2030420.268	34.8	39.9	5%	3%	1872.3	2.5%	1825.73	1%	1807.5	41.3%	500	
PL21-1	Baltica 3	PL	17.459585	55.041688	17.558141	54.765630	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.3	10.54	2.3181	2316556.6	2015404.242	31.3	35.9	5%	3%	1858.4	2.5%	1812.23	1%	1794.1	41.0%	500	1000
PL21-2	Baltica 3	PL	17.441271	55.017279	17.541279	54.764580	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.3	10.54	2.3181	2316556.6	2015404.242	28.8	36.9	5%	3%	1858.4	2.5%	1812.23	1%	1794.1	41.0%	500	
PL23-1	Baltic Power	PL	17.675959	55.050155	17.772205	54.800216	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.3	10.51	2.3073	2305556.8	2005834.416	28.5	23.5	5%	3%	1849.6	2.5%	1803.62	1%	1785.6	40.8%	500	1000
PL23-2	Baltic Power	PL	17.571095	54.985935	17.659266	54.779247	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.3	10.51	2.3073	2305556.8	2005834.416	23.7	29.8	5%	3%	1849.6	2.5%	1803.62	1%	1785.6	40.8%	500	
PL27	B-Wind	PL	18.047441	55.036929	18.068843	54.829328	18.111377	54.719302	Zarnowiec 400 kV Substation	-40 to -50	1	9.2	10.47	2.2944	2295380.9	1996981.383	23.1	12.5	5%	3%	1841.4	2.5%	1795.66	1%	1777.7	40.6%	500	500
PL61-1	Baltex-5	PL	17.613806	55.526328	17.897620	54.818738	18.111377	54.719302	Zarnowiec 400 kV Substation	-40 to -50	1	9.5	10.78	2.3212	2391056.6	2080219.242	80.7	17.6	5%	3%	1918.2	2.5%	1870.51	1%	1851.8	42.3%	500	1000
PL61-2	Baltex-5	PL	17.651732	55.601446	17.914546	54.821796	18.111377	54.719302	Zarnowiec 400 kV Substation	-40 to -50	1	9.5	10.78	2.3212	2391056.6	2080219.242	88.3	17.0	5%	3%	1918.2	2.5%	1870.51	1%	1851.8	42.3%	500	
PL62	AEGIR 4	PL	15.176454	54.498735	15.291469	54.144947	16.095274	54.126565	Dunowo 400 kV Substation	-40 to -50	1	9.3	10.58	2.3808	2334074.4	2030644.728	40.0	52.4	5%	3%	1872.5	2.5%	1825.93	1%	1807.7	41.3%	500	500
PL63	A-Wind	PL	17.738521	55.016889	17.856717	54.813574	18.111377	54.719302	Zarnowiec 400 kV Substation	-30 to -40	1	9.3	10.49	2.3009	2300468.9	2001407.9	23.8	19.4	5%	3%	1845.5	2.5%	1799.64	1%	1781.6	40.7%	500	500
SE42	Sydkustens Vind	SE	13.527856	55.316235	13.528457	55.387884	13.167925	55.394865	Trelleborg 400 kV Substation	-20 to -30	1	9.3	10.55	2.4473	2342715.8	2038162.746	8.0	22.8	5%	3%	1879.4	2.5%	1832.69	1%	1814.4	41.4%	500	500
SE51-1	Långgrund	SE	17.688034	58.683668	17.491917	58.779836	16.138451	58.597219	Glan 400 kV Substation	-30 to -40	1	8.8	10.05	2.4672	2187556.4	1903174.068	15.6	80.8	5%	3%	1754.9	2.5%	1711.31	1%	1694.2	38.7%	500	1000
SE51-2	Långgrund	SE	17.652732	58.676193	17.413745	58.791828	16.138451	58.597219	Glan 400 kV Substation	-30 to -40	1	8.8	10.05	2.4672	2187556.4	1903174.068	18.9	76.8	5%	3%	1754.9	2.5%	1711.31	1%	1694.2	38.7%	500	
SE52-1	Långgrund II	SE	17.345180	58.565302	17.135578	58.663669	16.138451	58.597219	Glan 400 kV Substation	-30 to -40	1	8.7	9.90	2.4881	2142107.8	1863633.786	16.3	58.2	5%	3%	1718.5	2.5%	1675.76	1%	1659.0	37.9%	500	1000
SE52-2	Långgrund II	SE	17.213397	58.494733	16.992189	58.494129	16.138451	58.597219	Glan 400 kV Substation	-30 to -40	1	8.7	9.90	2.4881	2142107.8	1863633.786	12.9	50.8	5%	3%	1718.5	2.5%	1675.76	1%	1659.0	37.9%	500	
SE53	Gretas Klackar	SE	17.681525	61.499844	17.482827	61.622551	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	8.5	9.71	2.4434	2078497.5	1808292.825	17.2	106.1	5%	3%	1667.4	2.5%	1625.99	1%	1609.7	36.8%	500	500
SE54	Utposten II	SE	17.488571	61.081367	17.202406	61.084321	16.990209	60.604093	Rörberg 400 kV Substation	-30 to -40	2	8.3	9.44	2.4881	1994654.7	1735349.589	15.4	54.6	5%	3%	1600.2	2.5%	1560.40	1%	1544.8	35.3%	500	500
SE55-1	Utknallen	SE	17.853349	60.872881	17.322012	60.871655	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	8.6	9.62	2.4963	2116969.9	1841763.813	28.8	34.8	5%	3%	1698.3	2.5%	1656.09	1%	1639.5	37.4%	500	
SE55-2	Utknallen	SE	17.706999	60.890804	17.328653	60.883098	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	8.6	9.62	2.4963	2116969.9	1841763.813	20.5	36.1	5%	3%	1698.3	2.5%	1656.09	1%	1639.5	37.4%	500	1500
SE55-3	Utknallen	SE	17.732362	60.862342	17.317502	60.869791	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	8.4	9.62	2.4963	2059398.0	1791676.26	22.5	34.5	5%	3%	1652.1	2.5%	1611.05	1%	1594.9	36.4%	500	
SE07-1	Finngrunden	SE	18.275632	60.968729	17.243855	61.003820	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	9.0	10.24	2.4138	2245182.2	1953308.514	55.8	46.5	5%	3%	1801.1	2.5%	1756.39	1%	1738.8	39.7%	500	1000
SE07-2	Finngrunden	SE	18.349235	61.020474	17.241664	61.007529	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	9.0	10.24	2.4138	2245182.2	1953308.514	59.7	46.9	5%	3%	1801.1	2.5%	1756.39	1%	1738.8	39.7%	500	
SE07-3	Finngrunden	SE	17.868086	60.992853	17.243855	61.003820	16.990209	60.604093	Rörberg 400 kV Substation	-20 to -30	2	8.7	10.24	2.4138	2174541.8	1891851.366	33.7	46.5	5%	3%	1744.5	2.5%	1701.13	1%	1684.1	38.5%	500	500

Wind Farm ID	Name	Country	WF OSS Coordinates, Geo [deg]-WGS84		Pooling Substation Coordinates, Geo [deg]-WGS84		Point of Connection Coordinates, Geo [deg]-WGS84		Name of Point of Connection	Average Sea Depth in Area	Sea Ice Zone	Mean WS 100 m ASL	Weibull Parameters in Area		Gross Production ekskl. wake	Gross Production inkl. 13 % wake	from OSS to Pooling Substation	Pooling Substation to Point of	Availability Losses	(array cables, offshore	Gross Wind Farm Output	(export cables, pooling	Output from pooling substation	Losses (transmission	Net Output	Capacity Factor	Capacity	Total capacity in wind farm
SE11-1	Södra Midsjöbanken	SE	17.223051	55.633543	15.847199	56.074314	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-20 to -30	1	9.5	10.84	2.3434	2309399.4	2009177.478	98.9	62.8	5%	3%	1852.7	2.5%	1806.63	1%	1788.6	40.8%	500	2000
SE11-2	Södra Midsjöbanken	SE	17.327244	55.661104	15.993953	56.200905	15.861571	56.767812	Nybro 400 kV Substation	-20 to -30	1	9.5	10.84	2.3434	2309399.4	2009177.478	102.5	63.6	5%	3%	1852.7	2.5%	1806.63	1%	1788.6	40.8%	500	
SE11-3	Södra Midsjöbanken	SE	17.212340	55.694655	15.993953	56.200905	15.861571	56.767812	Nybro 400 kV Substation	-20 to -30	1	9.5	10.84	2.3434	2358385.7	2051795.516	94.5	63.6	5%	3%	1892.0	2.5%	1844.95	1%	1826.5	41.7%	500	
SE11-4	Södra Midsjöbanken	SE	17.317647	55.722982	15.999790	56.210459	15.861571	56.767812	Nybro 400 kV Substation	-20 to -30	1	9.5	10.84	2.3434	2407371.9	2094413.553	98.3	62.6	5%	3%	1931.3	2.5%	1883.27	1%	1864.4	42.6%	500	
SE15	Klocktärnan	SE	21.926831	65.050855	21.546296	65.066519	21.842496	65.804032	Svartbyn 400 kV Substation	-10 to -20	3	8.2	9.46	2.3457	1975823.6	1718966.532	17.9	83.1	10%	3%	1501.0	2.5%	1463.71	1%	1449.1	33.1%	500	500
SE31	Oskarshamn	SE	16.693319	57.388260	16.674799	57.410548	16.657450	57.415904	Simpevarp 400 kV Substation	-10 to -20	1	7.9	8.93	2.4810	1807566.4	1572582.768	2.7	1.2	5%	3%	1450.1	2.5%	1414.05	1%	1399.9	32.0%	500	500
SE33	Svenska Björn Offshore	SE	19.810764	59.575703	19.063948	59.723219	17.852230	59.688288	Odensala 400 kV Substation	-30 to -40	1	9.2	10.52	2.3964	2320488.3	2018824.821	45.1	68.1	5%	3%	1861.6	2.5%	1815.30	1%	1797.1	41.0%	500	500
SE37	Stopparen	SE	23.840819	65.524621	23.716572	65.706562	21.842496	65.804032	Svartbyn 400 kV Substation	-20 to -30	3	8.3	9.56	2.2654	1999750.4	1739782.848	21.0	86.3	10%	3%	1519.2	2.5%	1481.43	1%	1466.6	33.5%	500	500
SE38	Marakallen	SE	22.477619	65.245540	21.987689	65.413133	21.842496	65.804032	Svartbyn 400 kV Substation	-10 to -20	3	8.4	9.66	2.2969	2035676.4	1771038.468	29.4	44.0	10%	3%	1546.5	2.5%	1508.05	1%	1493.0	34.1%	500	500

Newly identified areas

Wind Farm ID	Name	Country	WF OSS Coordinates, Geo [deg]-WGS84		Pooling Substation Coordinates, Geo [deg]-WGS84		Point of Connection Coordinates, Geo [deg]-WGS84		Name of Point of Connection	Sea Depth	Sea Ice Zone	Mean WS 100 m ASL	Weibull Parameters		Gross Prod.	Park Prod. - 13 % wake	Distance from OSS to Pooling Substation	Distance from Pooling Substation to Point of Connection	Availability Losses	Electrical Losses (array cables, offshore substation)	Gross Wind Farm Output	Electrical Losses (export cables, pooling substation)	Output from pooling substation	Electrical Losses (transmission cables)	Net Output	Capacity Factor	Capacity	Total capacity in wind farm cluster
			Longitude	Latitude	Longitude	Latitude	Longitude	Latitude		[m]	[1/2/3]	[m/s]	A [m/s]	k [-]	[MWh]	[MWh]	[km]	[km]	[%]	[%]	[GWh]	[%]	[GWh]	[%]	[GWh/y]	[%]	[MW]	[MW]
DK-New Kattegat-1		DK	11.077859	56.856581	10.780224	56.532652	10.139633	56.274604	Trige 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2368048.6	2060202.282	40.3	48.8	5%	3%	1899.7	2.5%	1852.51	1%	1834.0	41.9%	500	3000
DK-New Kattegat-2		DK	11.179158	56.891167	10.784854	56.533853	10.139633	56.274604	Trige 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2362829.2	2055661.404	46.5	49.1	5%	3%	1895.5	2.5%	1848.43	1%	1829.9	41.8%	500	
DK-New Kattegat-3		DK	11.296988	56.935346	10.834847	56.528297	10.139633	56.274604	Trige 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2357609.8	2051120.526	53.3	51.2	5%	3%	1891.3	2.5%	1844.34	1%	1825.9	41.7%	500	
DK-New Kattegat-4		DK	11.076238	56.909091	10.795744	56.534009	10.139633	56.274604	Trige 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2368048.6	2060202.282	45.1	49.6	5%	3%	1899.7	2.5%	1852.51	1%	1834.0	41.9%	500	
DK-New Kattegat-5		DK	11.169433	56.955612	10.533780	57.222456	10.089206	57.062732	Vester Hassing 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2362829.2	2055661.404	48.5	32.2	5%	3%	1895.5	2.5%	1848.43	1%	1829.9	41.8%	500	
DK-New Kattegat-6		DK	11.267652	56.993486	10.533780	57.222456	10.089206	57.062732	Vester Hassing 400 kV Substation	-10 to -20	1	9.3	10.65	2.4356	2357609.8	2051120.526	51.1	32.2	5%	3%	1891.3	2.5%	1844.34	1%	1825.9	41.7%	500	
DK-New Hesseloe Bugt-1		DK	11.465058	56.025051	11.462552	55.959632	12.199505	55.894735	Gørløsegård 400 kV Substation	-10 to -20	1	9.2	10.56	2.4583	2340087.3	2035875.951	7.3	46.5	5%	3%	1877.3	2.5%	1830.63	1%	1812.3	41.4%	500	
DK-New Hesseloe Bugt-2		DK	11.531185	56.020998	11.582046	55.960018	12.199505	55.894735	Gørløsegård 400 kV Substation	-10 to -20	1	9.2	10.56	2.4583	2325342.2	2023047.714	7.5	39.1	5%	3%	1865.5	2.5%	1819.10	1%	1800.9	41.1%	500	1500
DK-New Hesseloe Bugt-3		DK	11.641074	56.025952	11.591513	55.961138	12.199505	55.894735	Gørløsegård 400 kV Substation	-10 to -20	1	9.1	10.56	2.4583	2310597.1	2010219.477	7.8	38.6	5%	3%	1853.6	2.5%	1807.56	1%	1789.5	40.9%	500	
DK-New Samsoe		DK	11.027935	55.788889	10.988468	55.745421	12.006513	55.451960	Bjæverskov 400 kV Substation	-10 to -20	1	9.1	10.39	2.4907	2297326.2	1998673.794	5.4	71.8	5%	3%	1843.0	2.5%	1797.18	1%	1779.2	40.6%	500	500
DK-New Aeroe-1		DK	10.428629	54.725706	10.423213	54.817143	10.505859	55.365976	Fraugde 400 kV Substation	-10 to -20	1	9.1	10.44	2.6059	2337475.8	2033603.946	10.2	61.3	5%	3%	1875.2	2.5%	1828.59	1%	1810.3	41.3%	500	1000
DK-New Aeroe-2		DK	10.515827	54.703234	10.669330	54.739766	10.505859	55.365976	Fraugde 400 kV Substation	-10 to -20	1	9.1	10.44	2.6059	2337475.8	2033603.946	10.7	70.4	5%	3%	1875.2	2.5%	1828.59	1%	1810.3	41.3%	500	
DK-New Hjelms Bugt-1		DK	12.107509	54.678915	12.013845	54.722923	12.006513	55.451960	Bjæverskov 400 kV Substation	-10 to -20	1	9.1	10.37	2.4520	2289703.7	1992042.219	7.8	81.1	5%	3%	1836.9	2.5%	1791.22	1%	1773.3	40.5%	500	1000
DK-New Hjelms Bugt-2		DK	12.272585	54.803301	12.163422	54.834489	12.006513	55.451960	Bjæverskov 400 kV Substation	-10 to -20	1	9.1	10.37	2.4520	2278915.4	1982656.398	7.8	69.4	5%	3%	1828.2	2.5%	1782.78	1%	1765.0	40.3%	500	
DK-New Faxe Bugt-1		DK	12.413970	55.128797	12.386605	55.026076	12.006513	55.451960	Bjæverskov 400 kV Substation	-10 to -20	1	9.1	10.30	2.4361	2279299	1982990.13	11.6	53.1	5%	3%	1828.5	2.5%	1783.08	1%	1765.2	40.3%	500	1000
DK-New Faxe Bugt-2		DK	12.442010	55.142577	12.353519	55.237394	12.006513	55.451960	Bjæverskov 400 kV Substation	-10 to -20	1	9.1	10.30	2.4361	2279299	1982990.13	11.9	32.4	5%	3%	1828.5	2.5%	1783.08	1%	1765.2	40.3%	500	
DE-New Baltic (South KF)		DE	13.162930	54.860651	13.287687	54.670865	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.78	2.4348	2380054.7	2070647.589	22.6	64.4	5%	3%	1909.3	2.5%	1861.90	1%	1843.3	42.1%	500	500
DE-New Mecklenburg 2		DE	12.776774	54.508836	12.776696	54.431609	12.214814	54.100135	Bentwisch 400 kV Substation	-10 to -20	1	9.2	10.44	2.4008	2277264.6	1981220.202	8.7	52.3	5%	3%	1826.9	2.5%	1781.49	1%	1763.7	40.3%	500	500
DE-New Mecklenburg-1-1		DE	14.004777	54.072436	13.988886	54.056937	13.683875	54.139149	Lubmin 400 kV Substation	-10 to -20	1	8.6	9.84	2.4989	2117208.2	1841971.134	2.0	21.9	5%	3%	1698.5	2.5%	1656.28	1%	1639.7	37.4%	500	1000
DE-New Mecklenburg-1-2		DE	14.055794	54.053001	14.023120	54.038253	13.683875	54.139149	Lubmin 400 kV Substation	-10 to -20	1	8.6	9.84	2.4989	2117208.2	1841971.134	2.7	24.9	5%	3%	1698.5	2.5%	1656.28	1%	1639.7	37.4%	500	
DE-New Baltic (East of KF)-1-1		DE	13.566589	54.948295	13.420099	54.671452	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.82	2.4184	2390289.5	2079551.865	32.3	61.7	5%	3%	1917.6	2.5%	1869.91	1%	1851.2	42.3%	500	
DE-New Baltic (East of KF)-1-2		DE	13.674549	54.953514	13.420099	54.671452	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.82	2.4184	2390289.5	2079551.865	35.7	61.7	5%	3%	1917.6	2.5%	1869.91	1%	1851.2	42.3%	500	1500
DE-New Baltic (East of KF)-1-3		DE	13.791877	54.941996	13.420099	54.671452	13.683875	54.139149	Lubmin 400 kV Substation	-40 to -50	1	9.5	10.82	2.4184	2390289.5	2079551.865	38.7	61.7	5%	3%	1917.6	2.5%	1869.91	1%	1851.2	42.3%	500	
SE-New Laholmsbukten-1		SE	12.569964	56.652700	12.684946	56.681628	13.349109	56.509491	Knäred 400 kV Substation	-20 to -30	1	8.7	9.95	2.3354	2113428.1	1838682.447	7.7	44.9	5%	3%	1695.5	2.5%	1653.32	1%	1636.8	37.4%	500	1000

Wind Farm ID	Name	Country	Coordinates, [deg]		Coordinates		Coordinates		Name of Point of Connection	Depth	Ice	10 s	Weibull Parameters		Gross Production	Prod. - 13 %	Dist to Shore	Substation	Availability Loss	Cable losses	Farm	Cable factor	Prod. with m...	Transmission losses	Output	Capacity Factor	Capacity	Wind Capacity
SE-New Laholmsbukten 2		SE	12.537710	56.736735	12.626916	56.743654	13.349109	56.509491	Knäred 400 kV Substation	-20 to -30	1	8.7	9.95	2.3354	2113428.1	1838682.447	5.5	51.3	5%	3%	1695.5	2.5%	1653.32	1%	1636.8	37.4%	500	
SE-New Hanoebukten		SE	14.427282	55.799552	14.220098	55.840359	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-20 to -30	1	8.6	9.78	2.4645	2113094.5	1838392.215	13.7	52.1	5%	3%	1695.2	2.5%	1653.06	1%	1636.5	37.4%	500	500
SE-New Pukaviksbukten-1		SE	15.134588	55.950959	14.720914	56.000552	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-30 to -40	1	9.1	10.40	2.4982	2305176.2	2005503.294	26.3	18.6	5%	3%	1849.3	2.5%	1803.32	1%	1785.3	40.8%	500	
SE-New Pukaviksbukten-2		SE	15.042933	55.916598	14.720914	56.000552	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-30 to -40	1	9.1	10.40	2.4982	2279866.4	1983483.768	22.1	18.6	5%	3%	1829.0	2.5%	1783.52	1%	1765.7	40.3%	500	1500
SE-New Pukaviksbukten-3		SE	14.942850	55.949023	14.720914	56.000552	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-30 to -40	1	9	10.40	2.4982	2254556.6	1961464.242	15.0	18.6	5%	3%	1808.7	2.5%	1763.72	1%	1746.1	39.9%	500	
SE-New Oelands Soedra-1		SE	16.999147	56.003474	16.045158	56.252390	15.861571	56.767812	Nybro 400 kV Substation	-30 to -40	1	9.5	10.87	2.3947	2420329.5	2105686.665	65.3	58.4	5%	3%	1941.7	2.5%	1893.41	1%	1874.5	42.8%	500	1000
SE-New Oelands Soedra-2		SE	16.996554	56.074269	16.045158	56.252390	15.861571	56.767812	Nybro 400 kV Substation	-30 to -40	1	9.5	10.87	2.3947	2420329.5	2105686.665	62.1	58.4	5%	3%	1941.7	2.5%	1893.41	1%	1874.5	42.8%	500	
SE-New Gulf of Bothnia-1		SE	18.704050	61.903643	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2273784.8	1978192.776	66.1	65.9	5%	3%	1824.1	2.5%	1778.77	1%	1761.0	40.2%	500	
SE-New Gulf of Bothnia-2		SE	18.696595	61.906705	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2277377.8	1981318.643	65.7	65.9	5%	3%	1827.0	2.5%	1781.58	1%	1763.8	40.3%	500	
SE-New Gulf of Bothnia-3		SE	18.687599	61.840954	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2277377.8	1981318.643	66.9	65.9	5%	3%	1827.0	2.5%	1781.58	1%	1763.8	40.3%	500	
SE-New Gulf of Bothnia-4		SE	18.682737	61.774843	17.521092	61.700454	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2280970.7	1984444.509	61.7	98.4	5%	3%	1829.9	2.5%	1784.39	1%	1766.5	40.3%	500	
SE-New Gulf of Bothnia-5		SE	18.821313	61.938800	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2273784.8	1978192.776	71.6	65.9	5%	3%	1824.1	2.5%	1778.77	1%	1761.0	40.2%	500	5000
SE-New Gulf of Bothnia-6		SE	18.819368	61.875301	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2277377.8	1981318.643	72.7	65.9	5%	3%	1827.0	2.5%	1781.58	1%	1763.8	40.3%	500	
SE-New Gulf of Bothnia-7		SE	18.806402	61.808694	17.521092	61.700454	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2277377.8	1981318.643	68.7	98.4	5%	3%	1827.0	2.5%	1781.58	1%	1763.8	40.3%	500	
SE-New Gulf of Bothnia-8		SE	18.803971	61.740152	17.521092	61.700454	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2280970.7	1984444.509	67.7	98.4	5%	3%	1829.9	2.5%	1784.39	1%	1766.5	40.3%	500	
SE-New Gulf of Bothnia-9		SE	18.954622	61.932900	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2273784.8	1978192.776	78.7	65.9	5%	3%	1824.1	2.5%	1778.77	1%	1761.0	40.2%	500	
SE-New Gulf of Bothnia-10		SE	18.956081	61.864538	17.456645	62.001648	16.932982	62.541560	Nyland 400 kV Substation	-30 to -40	2	9.1	10.40	2.3652	2273784.8	1978192.776	79.9	65.9	5%	3%	1824.1	2.5%	1778.77	1%	1761.0	40.2%	500	
SE Floating	Example of Floating WF in High Wind Speed Region	SE	16.332760	55.765226	15.847199	56.074314	14.843479	56.153071	Starnö Power Plant 400 kV Substation	-60 to -70	1	9.6	10.90	2.4080	2433524.6	2117166.402	45.8	62.8	5%	3%	1952.2	2.5%	1903.73	1%	1884.7	43.0%	500	500
PL-New POL#2-1		PL	14.992638	54.433571	15.199674	54.121512	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.2	10.55	2.3919	2325136.9	2022869.103	37.2	58.4	5%	3%	1865.3	2.5%	1818.94	1%	1800.7	41.1%	500	
PL-New POL#2-2		PL	15.211605	54.402587	15.291469	54.144947	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.2	10.55	2.3919	2325136.9	2022869.103	29.1	52.4	5%	3%	1865.3	2.5%	1818.94	1%	1800.7	41.1%	500	1500
PL-New POL#2-3		PL	15.103418	54.419835	15.294736	54.145539	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.2	10.55	2.3919	2325136.9	2022869.103	32.9	52.2	5%	3%	1865.3	2.5%	1818.94	1%	1800.7	41.1%	500	
PL-New POL#1-1		PL	15.722068	54.429337	15.839498	54.236722	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9	10.29	2.3584	2242980.9	1951393.383	22.7	20.7	5%	3%	1799.4	2.5%	1754.67	1%	1737.1	39.7%	500	
PL-New POL#1-2		PL	15.826121	54.448612	15.874064	54.242200	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.1	10.29	2.3584	2255280.7	1962094.209	23.2	19.3	5%	3%	1809.3	2.5%	1764.29	1%	1746.6	39.9%	500	2000
PL-New POL#1-3		PL	15.910888	54.455187	15.981722	54.250938	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.1	10.29	2.3584	2255280.7	1962094.209	23.2	15.7	5%	3%	1809.3	2.5%	1764.29	1%	1746.6	39.9%	500	
PL-New POL#1-4		PL	16.004082	54.520217	16.319690	54.382868	16.095274	54.126565	Dunowo 400 kV Substation	-30 to -40	1	9.1	10.29	2.3584	2267580.5	1972795.035	25.5	32.0	5%	3%	1819.1	2.5%	1773.91	1%	1756.2	40.1%	500	
PL-New POL#3		PL	16.571840	55.017190	17.051717	54.664501	16.891359	54.501814	Slupsk 400 kV Substation	-30 to -40	1	9.4	10.69	2.3509	2363447.9	2056199.673	49.8	20.8	5%	3%	1896.0	2.5%	1848.91	1%	1830.4	41.8%	500	500
PL-New POL#4-1		PL	17.725021	55.118068	17.897620	54.818738	18.111377	54.719302	Zarnowiec 400 kV Substation	-40 to -50	1	9.3	10.60	2.3092	2332240.2	2029048.974	35.1	17.6	5%	3%	1871.0	2.5%	1824.50	1%	1806.3	41.2%	500	1000
PL-New POL#4-2		PL	17.610919	55.116177	17.764777	54.799300	18.111377	54.719302	Zarnowiec 400 kV Substation	-40 to -50	1	9.3	10.60	2.3092	2332240.2	2029048.974	36.6	24.0	5%	3%	1871.0	2.5%	1824.50	1%	1806.3	41.2%	500	
LT-New #3		LT	20.702547	55.403813	21.016479	55.344146	21.257782	55.681893	Klaipeda 300-330 kV Substation	-30 to -40	2	8.9	10.15	2.3600	2166207.2	1884600.264	20.9	40.5	5%	3%	1737.8	2.5%	1694.61	1%	1677.7	38.3%	500	500

Wind Farm ID	Name	Country	Coordinates, Geo [d		Coordinates, G		Coordinates, G		Name of Point of Connection	Depth	lc e	S 10	Weibull Param et		Gross Prod	od. 13 %	S S to	Substatio	Availability Lo	y cables	nd Farm	or t cabl	m po oli	es (trans mi	Output	Capacity Fa	Capacity	Capacity in wind
LT-New #1-1		LT	20.901740	55.516805	21.095790	55.503575	21.257782	55.681893	Klaipeda 300-330 kV Substation	-10 to -20	2	8.9	10.05	2.3824	2182202.0	1898515.697	12.3	22.3	5%	3%	1750.6	2.5%	1707.12	1%	1690.1	38.6%	500	1000
LT-New #1-2		LT	20.896878	55.469429	21.073541	55.443709	21.257782	55.681893	Klaipeda 300-330 kV Substation	-10 to -20	2	8.8	10.05	2.3824	2198196.7	1912431.129	11.5	28.9	5%	3%	1763.5	2.5%	1719.63	1%	1702.4	38.9%	500	
LT-New #2		LT	20.862355	55.980393	21.077877	55.974917	21.257782	55.681893	Klaipeda 300-330 kV Substation	-20 to -30	2	8.8	10.07	2.3804	2160962.5	1880037.375	13.4	34.5	5%	3%	1733.6	2.5%	1690.51	1%	1673.6	38.2%	500	500
LT-New #4-1		LT	20.326689	55.933106	21.052276	55.919159	21.257782	55.681893	Klaipeda 300-330 kV Substation	-30 to -40	1	9.2	10.42	2.3227	2279350.8	1983035.196	45.2	29.3	5%	3%	1828.6	2.5%	1783.12	1%	1765.3	40.3%	500	1000
LT-New #4-2		LT	20.442088	55.901402	21.052276	55.919159	21.257782	55.681893	Klaipeda 300-330 kV Substation	-30 to -40	1	9.2	10.42	2.3227	2279350.8	1983035.196	38.1	29.3	5%	3%	1828.6	2.5%	1783.12	1%	1765.3	40.3%	500	
LT-New #5		LT	20.754736	55.797732	21.067988	55.808064	21.257782	55.681893	Klaipeda 300-330 kV Substation	-20 to -30	2	9	10.24	2.3620	2222340.0	1933435.8	19.6	18.4	5%	3%	1782.8	2.5%	1738.52	1%	1721.1	39.3%	500	500
LV-New Interest Zone-1		LV	20.579854	56.136663	20.989373	56.217497	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.1	10.37	2.3432	2264647.9	1970243.673	26.9	38.4	5%	3%	1816.8	2.5%	1771.62	1%	1753.9	40.0%	500	2500
LV-New Interest Zone-2		LV	20.476773	56.103878	20.989373	56.217497	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.1	10.37	2.3432	2264647.9	1970243.673	34.2	38.4	5%	3%	1816.8	2.5%	1771.62	1%	1753.9	40.0%	500	
LV-New Interest Zone-3		LV	20.569967	56.202774	20.989373	56.217497	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.1	10.37	2.3432	2263797.2	1969503.564	26.0	38.4	5%	3%	1816.1	2.5%	1770.95	1%	1753.2	40.0%	500	
LV-New Interest Zone-4		LV	20.472883	56.168998	20.989373	56.217497	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.1	10.37	2.3432	2264647.9	1970243.673	32.4	38.4	5%	3%	1816.8	2.5%	1771.62	1%	1753.9	40.0%	500	
LV-New Interest Zone-5		LV	20.554084	56.237721	20.986807	56.238509	21.201358	56.542021	Grobina 300-330 kV Substation	-30 to -40	1	9.1	10.37	2.3432	2262946.5	1968763.455	26.7	36.2	5%	3%	1815.4	2.5%	1770.29	1%	1752.6	40.0%	500	
LV-New Ventspils South Coast #1		LV	21.301261	57.207048	21.412841	57.197392	21.637629	57.417886	Ventspils 300-330 kV Substation	-20 to -30	2	8.7	9.91	2.4001	2120111.1	1844496.657	6.8	28.0	5%	3%	1700.8	2.5%	1658.55	1%	1642.0	37.5%	500	500
LV-New Ventspils South Coast #2		LV	21.281163	57.154357	21.410431	57.158975	21.637629	57.417886	Ventspils 300-330 kV Substation	-10 to -20	2	8.7	9.91	2.4001	2120111.1	1844496.657	7.8	31.9	5%	3%	1700.8	2.5%	1658.55	1%	1642.0	37.5%	500	500
LV-New Ventspils South Coast #3-1		LV	21.028809	57.143279	21.410431	57.158975	21.637629	57.417886	Ventspils 300-330 kV Substation	-10 to -20	2	9.1	10.38	2.4031	2273352.5	1977816.675	23.1	31.9	5%	3%	1823.7	2.5%	1778.43	1%	1760.6	40.2%	500	1000
LV-New Ventspils South Coast #3-2		LV	21.131080	57.124364	21.415771	57.138255	21.637629	57.417886	Ventspils 300-330 kV Substation	-10 to -20	2	9.1	10.38	2.4031	2273352.5	1977816.675	17.2	33.8	5%	3%	1823.7	2.5%	1778.43	1%	1760.6	40.2%	500	
LV-New Gulf of Riga #2-1		LV	23.852178	57.419469	24.389250	57.449766	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-40 to -50	2	8.6	9.85	2.5031	2125080.5	1848820.035	32.3	48.7	5%	3%	1704.8	2.5%	1662.44	1%	1645.8	37.6%	500	2500
LV-New Gulf of Riga #2-2		LV	23.838058	57.354844	24.403844	57.356123	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-40 to -50	2	8.5	9.85	2.5031	2092164	1820182.68	33.9	39.5	5%	3%	1678.4	2.5%	1636.69	1%	1620.3	37.0%	500	
LV-New Gulf of Riga #2-3		LV	23.945286	57.352232	24.403844	57.356123	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-40 to -50	2	8.5	9.85	2.5031	2092164	1820182.68	27.5	39.5	5%	3%	1678.4	2.5%	1636.69	1%	1620.3	37.0%	500	
LV-New Gulf of Riga #2-4		LV	23.944437	57.354754	24.403844	57.356123	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-40 to -50	2	8.5	9.85	2.5031	2092164	1820182.68	27.6	39.5	5%	3%	1678.4	2.5%	1636.69	1%	1620.3	37.0%	500	
LV-New Gulf of Riga #2-5		LV	23.927238	57.289094	24.262357	57.154922	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-40 to -50	2	8.4	9.85	2.5031	2059247.5	1791545.325	25.1	15.9	5%	3%	1652.0	2.5%	1610.94	1%	1594.8	36.4%	500	
LV-New Gulf of Riga #1-1		LV	23.897124	57.811510	24.337836	57.818963	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.8	10.10	2.4287	2189468	1904837.16	26.1	87.8	5%	3%	1756.5	2.5%	1712.81	1%	1695.7	38.7%	500	4000
LV-New Gulf of Riga #1-2		LV	23.903281	57.754856	24.335673	57.823940	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	26.8	88.3	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
LV-New Gulf of Riga #1-3		LV	23.909439	57.686313	24.345846	57.700142	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	26.0	74.8	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
LV-New Gulf of Riga #1-4		LV	23.914429	57.622634	24.345846	57.700142	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.7	10.10	2.4287	2170789.6	1888586.952	27.1	74.8	5%	3%	1741.5	2.5%	1698.19	1%	1681.2	38.4%	500	
LV-New Gulf of Riga #1-5		LV	24.031211	57.625832	24.345846	57.700142	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	20.5	74.8	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
LV-New Gulf of Riga #1-6		LV	24.024841	57.682260	24.345846	57.700142	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	19.2	74.8	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
LV-New Gulf of Riga #1-7		LV	24.017622	57.744903	24.350178	57.741507	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	19.7	79.4	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
LV-New Gulf of Riga #1-8		LV	24.011040	57.814167	24.335878	57.823530	24.108055	57.039421	Rigas Tec1 300-330 kV Substation	-30 to -40	2	8.75	10.10	2.4287	2180128.8	1896712.056	19.3	88.2	5%	3%	1749.0	2.5%	1705.50	1%	1688.4	38.5%	500	
EE-New Kihnu Saar-1		EE	23.634469	58.228126	23.759350	58.335981	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2205072.9	1918413.423	14.0	54.1	5%	3%	1769.0	2.5%	1725.01	1%	1707.8	39.0%	500	3000

Wi nd Fa rm ID	Name	C ou nt ry	oo rdi na te s, G eo [d		C oo rdi na te s, G		C oo rdi na te s, G		Name of Point of Connection	a De pt	lc e	S 10	bu ll Pa ra m et		os s Pr od	od . 13 %	S S to	Su bs tat io	y Lo	ab ilit y ca bl es	nd Fa rm	or t ca bl	m po oli	es (tr an s mi	O ut pu	cit y Fa	pa cit y	y in wi nd Ca
EE-New Kihnu Saar-2		EE	23.645723	58.166068	23.762181	58.335171	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2208779.2	1921637.861	20.0	54.0	5%	3%	1771.9	2.5%	1727.91	1%	1710.6	39.1%	500	
EE-New Kihnu Saar-3		EE	23.656127	58.102929	23.762181	58.335171	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2208779.2	1921637.861	26.6	54.0	5%	3%	1771.9	2.5%	1727.91	1%	1710.6	39.1%	500	
EE-New Kihnu Saar-4		EE	23.780129	58.066091	24.080063	58.253890	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2212485.4	1924862.298	27.3	39.6	5%	3%	1774.9	2.5%	1730.81	1%	1713.5	39.1%	500	
EE-New Kihnu Saar-5		EE	23.770786	58.122745	23.904632	58.315647	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2208779.2	1921637.861	22.8	46.4	5%	3%	1771.9	2.5%	1727.91	1%	1710.6	39.1%	500	
EE-New Kihnu Saar-6		EE	23.758259	58.191918	23.762181	58.335171	24.670257	58.429102	Sindi 300-330 kV Substation	-20 to -30	2	8.9	10.17	2.4444	2208779.2	1921637.861	15.9	54.0	5%	3%	1771.9	2.5%	1727.91	1%	1710.6	39.1%	500	
EE-New Saarema-1		EE	21.274827	58.174805	21.851842	58.273197	24.670257	58.429102	Sindi 300-330 kV Substation	-30 to -40	1	9.2	10.44	2.2993	2281122.1	1984576.227	35.5	172.0	5%	3%	1830.0	2.5%	1784.51	1%	1766.7	40.3%	500	1000
EE-New Saarema-2		EE	21.371013	58.101578	21.862158	58.267337	24.670257	58.429102	Sindi 300-330 kV Substation	-30 to -40	1	9.2	10.44	2.2993	2281122.1	1984576.227	34.2	171.0	5%	3%	1830.0	2.5%	1784.51	1%	1766.7	40.3%	500	
FI-New Aalands Hav-1		FI	20.486369	59.673200	20.179962	59.970002	22.500023	60.523366	Lieto 400 kV Substation	-20 to -30	2	9.2	10.51	2.3795	2311761.9	2011232.853	37.2	142.0	5%	3%	1854.6	2.5%	1808.48	1%	1790.4	40.9%	500	1000
FI-New Aalands Hav-2		FI	20.291661	59.671578	20.179962	59.970002	22.500023	60.523366	Lieto 400 kV Substation	-20 to -30	2	9.2	10.51	2.3795	2311761.9	2011232.853	33.8	142.0	5%	3%	1854.6	2.5%	1808.48	1%	1790.4	40.9%	500	
FI-New Selkameri #1-1		FI	20.231358	60.671484	19.915572	60.420319	22.500023	60.523366	Lieto 400 kV Substation	-30 to -40	2	9	10.27	2.3585	2241097.9	1949755.173	32.8	142.1	5%	3%	1797.9	2.5%	1753.20	1%	1735.7	39.6%	500	1000
FI-New Selkameri #1-2		FI	20.354511	60.701522	19.915572	60.420319	22.500023	60.523366	Lieto 400 kV Substation	-30 to -40	2	9	10.27	2.3585	2241097.9	1949755.173	39.4	142.1	5%	3%	1797.9	2.5%	1753.20	1%	1735.7	39.6%	500	
FI-New Selkameri #2-1		FI	21.229211	61.839129	21.466987	61.852345	21.535463	61.581833	Tahkoluoto 400 kV Substation	-20 to -30	2	8.7	9.94	2.3409	2122902	1846924.74	12.6	30.3	5%	3%	1703.1	2.5%	1660.73	1%	1644.1	37.5%	500	1000
FI-New Selkameri #2-2		FI	21.188231	61.956129	21.291985	61.978916	21.376322	62.293102	Kristinestad 400 kV Substation	-20 to -30	2	8.7	9.94	2.3409	2122902	1846924.74	6.0	35.2	5%	3%	1703.1	2.5%	1660.73	1%	1644.1	37.5%	500	
FI-New Etelainen Merkenkurkku #1		FI	21.029124	62.303257	21.216459	62.340150	21.376322	62.293102	Kristinestad 400 kV Substation	-30 to -40	2	8.7	9.99	2.3090	2132071.7	1854902.379	10.5	9.8	5%	3%	1710.4	2.5%	1667.91	1%	1651.2	37.7%	500	500
FI-New Etelainen Merkenkurkku #2-1		FI	20.964009	62.505552	21.114199	62.523560	21.376322	62.293102	Kristinestad 400 kV Substation	-20 to -30	2	8.7	10.03	2.3127	2139734.4	1861568.928	8.0	29.0	5%	3%	1716.6	2.5%	1673.90	1%	1657.2	37.8%	500	1000
FI-New Etelainen Merkenkurkku #2-2		FI	20.915173	62.613005	21.062066	62.619461	21.376322	62.293102	Kristinestad 400 kV Substation	-20 to -30	2	8.8	10.03	2.3127	2139734.4	1861568.928	7.5	39.7	5%	3%	1716.6	2.5%	1673.90	1%	1657.2	37.8%	500	
FI-New Kokkola North		FI	23.239285	64.095308	23.411351	64.078418	23.095367	63.813273	Kokkola 400 kV Substation	-20 to -30	3	8.2	9.39	2.3244	1949208.2	1695811.134	8.6	33.3	10%	3%	1480.8	2.5%	1443.99	1%	1429.5	32.6%	500	500

Appendix B Ranked list for wind farms in existing areas

Wind farm ID	Name	Country	Net Output [GWh/y]	Capacity Factor [%]
DE91	DE Baltic 2, Baltic 2 area	DE	1865.8	42.6%
DE84	DE Windanker, Wikinger, Arkona - 1	DE	1864.6	42.6%
SE11-4	Södra Midsjöbanken	SE	1864.4	42.6%
DE86	DE ArcadisOst, ArkonaSee Sud, ArkonaSee West - 1	DE	1860.4	42.5%
DK54-1	Rønne Banke Reserved Area	DK	1859.9	42.5%
DK54-2	Rønne Banke Reserved Area	DK	1859.9	42.5%
DK54-3	Rønne Banke Reserved Area	DK	1859.9	42.5%
DK54-7	Rønne Banke Reserved Area	DK	1859.9	42.5%
PL16-1	Baltyk Pólnocny - Phase 1	PL	1858.0	42.4%
PL16-2	Baltyk Pólnocny - Phase 1	PL	1858.0	42.4%
DK53-6	Kriegers Flak Reserved Area	DK	1857.8	42.4%
DE85	DE Windanker, Wikinger, Arkona - 2	DE	1854.4	42.3%
DE87	DE ArcadisOst, ArkonaSee Sud, ArkonaSee West - 2	DE	1852.5	42.3%
DK53-5	Kriegers Flak Reserved Area	DK	1851.9	42.3%
PL61-1	Baltex-5	PL	1851.8	42.3%
PL61-2	Baltex-5	PL	1851.8	42.3%
DK53-4	Kriegers Flak Reserved Area	DK	1851.1	42.3%
PL19	Baltica 1	PL	1849.0	42.2%
DK54-12	Rønne Banke Reserved Area	DK	1847.5	42.2%
DK54-8	Rønne Banke Reserved Area	DK	1844.3	42.1%
DK54-9	Rønne Banke Reserved Area	DK	1844.3	42.1%
DE83	Baltic Eagle	DE	1840.5	42.0%
DE88	DE Hiddensee Area	DE	1838.4	42.0%
DK54-11	Rønne Banke Reserved Area	DK	1837.9	42.0%
DK54-4	Rønne Banke Reserved Area	DK	1835.0	41.9%
DK54-5	Rønne Banke Reserved Area	DK	1835.0	41.9%
DK54-6	Rønne Banke Reserved Area	DK	1835.0	41.9%
DK54-10	Rønne Banke Reserved Area	DK	1835.0	41.9%
SE11-3	Södra Midsjöbanken	SE	1826.5	41.7%
DE89	DE Gennaker, Baltic 1 - 1	DE	1820.5	41.6%
DE90	DE Gennaker, Baltic 1 - 2	DE	1818.5	41.5%
DK53-1	Kriegers Flak Reserved Area	DK	1817.9	41.5%
DK53-2	Kriegers Flak Reserved Area	DK	1817.9	41.5%
DK53-3	Kriegers Flak Reserved Area	DK	1817.2	41.5%
SE42	Sydkustens Vind	SE	1814.4	41.4%
PL62	AEGIR 4	PL	1807.7	41.3%
PL20-1	Baltica 2	PL	1807.5	41.3%
PL20-2	Baltica 2	PL	1807.5	41.3%
SE33	Svenska Björn Offshore	SE	1797.1	41.0%
DK-52-1	Store Middelgrund Reserved Area 1	DK	1796.9	41.0%
DK-52-2	Store Middelgrund Reserved Area 2	DK	1796.9	41.0%

Wind farm ID	Name	Country	Net Output [GWh/y]	Capacity Factor [%]
PL21-1	Baltica 3	PL	1794.1	41.0%
PL21-2	Baltica 3	PL	1794.1	41.0%
SE11-1	Södra Midsjöbanken	SE	1788.6	40.8%
SE11-2	Södra Midsjöbanken	SE	1788.6	40.8%
PL23-1	Baltic Power	PL	1785.6	40.8%
PL23-2	Baltic Power	PL	1785.6	40.8%
DK73	Omø Syd	DK	1782.0	40.7%
PL63	A-Wind	PL	1781.6	40.7%
PL27	B-Wind	PL	1777.7	40.6%
LV07-2	Baltic Wind Park - Phase 1	LV	1773.2	40.5%
LV07-4	Baltic Wind Park - Phase 1	LV	1755.3	40.1%
LV07-5	Baltic Wind Park - Phase 1	LV	1755.3	40.1%
LT06	Baltic Energy Group	LT	1751.0	40.0%
LT10	AVEC - 2	LT	1746.6	39.9%
LV07-1	Baltic Wind Park - Phase 1	LV	1739.3	39.7%
SE07-1	Finngrunden	SE	1738.8	39.7%
SE07-2	Finngrunden	SE	1738.8	39.7%
EE LB-2	Liivi Bay-1-2	EE	1721.8	39.3%
LV07-3	Baltic Wind Park - Phase 1	LV	1717.2	39.2%
EE LB-1	Liivi Bay-1-1	EE	1711.6	39.1%
EE LE-1	Loode Eesti 1	EE	1705.0	38.9%
EE05-1	Liivi laht	EE	1700.6	38.8%
EE05-2	Liivi laht	EE	1700.6	38.8%
SE51-1	Långgrund	SE	1694.2	38.7%
SE51-2	Långgrund	SE	1694.2	38.7%
SE07-3	Finngrunden	SE	1684.1	38.5%
LV06-2	JK ENERGY Offshore Wind Park	LV	1679.0	38.3%
EE LE-2	Loode Eesti 2	EE	1678.1	38.3%
SE52-1	Långgrund II	SE	1659.0	37.9%
SE52-2	Långgrund II	SE	1659.0	37.9%
DK58	Sæby (Nearshore Tender Area)	DK	1653.9	37.8%
DK83	Lillebælt Syd (Lillegrund)	DK	1652.5	37.7%
FI12	Inkoo-Raaseporin	FI	1651.7	37.7%
SE55-1	Utknallen	SE	1639.5	37.4%
SE55-2	Utknallen	SE	1639.5	37.4%
FI23	Tahkoluoto + Tahkoluoto Extension	FI	1613.9	36.8%
SE53	Gretas Klackar	SE	1609.7	36.8%
LV06-1	JK ENERGY Offshore Wind Park	LV	1602.8	36.6%
FI06	Korsnäs	FI	1600.3	36.5%
SE55-3	Utknallen	SE	1594.9	36.4%
SE54	Utposten II	SE	1544.8	35.3%
FI21	Ulkonahkiainen	FI	1494.3	34.1%
SE38	Marakallen	SE	1493.0	34.1%
FI05	Suurhiekka	FI	1467.0	33.5%
SE37	Stopparen	SE	1466.6	33.5%

Wind farm ID	Name	Country	Net Output [GWh/y]	Capacity Factor [%]
SE15	Klocktärnan	SE	1449.1	33.1%
FI22	Maanahkiainen	FI	1411.4	32.2%
SE31	Oskarshamn	SE	1399.9	32.0%

Appendix C Ranked list for wind farms in new identified areas

Wind farm ID/Name	Country	Net Output [GWh/y]	Capacity Factor [%]
SE-New Oelands Soedra-1	SE	1874.5	42.8%
SE-New Oelands Soedra-2	SE	1874.5	42.8%
DE-New Baltic (East of KF)-1-1	DE	1851.2	42.3%
DE-New Baltic (East of KF)-1-2	DE	1851.2	42.3%
DE-New Baltic (East of KF)-1-3	DE	1851.2	42.3%
DE-New Baltic (South KF)	DE	1843.3	42.1%
DK-New Kattegat-1	DK	1834.0	41.9%
DK-New Kattegat-4	DK	1834.0	41.9%
PL-New POL#3	PL	1830.4	41.8%
DK-New Kattegat-2	DK	1829.9	41.8%
DK-New Kattegat-5	DK	1829.9	41.8%
DK-New Kattegat-3	DK	1825.9	41.7%
DK-New Kattegat-6	DK	1825.9	41.7%
DK-New Hesseloe Bugt-1	DK	1812.3	41.4%
DK-New Aeroe-1	DK	1810.3	41.3%
DK-New Aeroe-2	DK	1810.3	41.3%
PL-New POL#4-1	PL	1806.3	41.2%
PL-New POL#4-2	PL	1806.3	41.2%
DK-New Hesseloe Bugt-2	DK	1800.9	41.1%
PL-New POL#2-1	PL	1800.7	41.1%
PL-New POL#2-2	PL	1800.7	41.1%
PL-New POL#2-3	PL	1800.7	41.1%
FI-New Aalands Hav-1	FI	1790.4	40.9%
FI-New Aalands Hav-2	FI	1790.4	40.9%
DK-New Hesseloe Bugt-3	DK	1789.5	40.9%
SE-New Pukaviksbukten-1	SE	1785.3	40.8%
DK-New Samsoe	DK	1779.2	40.6%
DK-New Hjelms Bugt-1	DK	1773.3	40.5%
EE-New Saarema-1	EE	1766.7	40.3%
EE-New Saarema-2	EE	1766.7	40.3%
SE-New Gulf of Bothnia-4	SE	1766.5	40.3%
SE-New Gulf of Bothnia-8	SE	1766.5	40.3%
SE-New Pukaviksbukten-2	SE	1765.7	40.3%
LT-New #4-1	LT	1765.3	40.3%
LT-New #4-2	LT	1765.3	40.3%
DK-New Faxe Bugt-1	DK	1765.2	40.3%
DK-New Faxe Bugt-2	DK	1765.2	40.3%
DK-New Hjelms Bugt-2	DK	1765.0	40.3%
SE-New Gulf of Bothnia-2	SE	1763.8	40.3%
SE-New Gulf of Bothnia-3	SE	1763.8	40.3%
SE-New Gulf of Bothnia-6	SE	1763.8	40.3%
SE-New Gulf of Bothnia-7	SE	1763.8	40.3%
DE-New Mecklenburg 2	DE	1763.7	40.3%

Wind farm ID/Name	Country	Net Output [GWh/y]	Capacity Factor [%]
SE-New Gulf of Bothnia-1	SE	1761.0	40.2%
SE-New Gulf of Bothnia-5	SE	1761.0	40.2%
SE-New Gulf of Bothnia-9	SE	1761.0	40.2%
SE-New Gulf of Bothnia-10	SE	1761.0	40.2%
LV-New Ventspils South Coast #3-1	LV	1760.6	40.2%
LV-New Ventspils South Coast #3-2	LV	1760.6	40.2%
PL-New POL#1-4	PL	1756.2	40.1%
LV-New Interest Zone-1	LV	1753.9	40.0%
LV-New Interest Zone-2	LV	1753.9	40.0%
LV-New Interest Zone-4	LV	1753.9	40.0%
LV-New Interest Zone-3	LV	1753.2	40.0%
LV-New Interest Zone-5	LV	1752.6	40.0%
PL-New POL#1-2	PL	1746.6	39.9%
PL-New POL#1-3	PL	1746.6	39.9%
SE-New Pukaviksbukten-3	SE	1746.1	39.9%
PL-New POL#1-1	PL	1737.1	39.7%
FI-New Selkameri #1-1	FI	1735.7	39.6%
FI-New Selkameri #1-2	FI	1735.7	39.6%
LT-New #5	LT	1721.1	39.3%
EE-New Kihnu Saar-4	EE	1713.5	39.1%
EE-New Kihnu Saar-2	EE	1710.6	39.1%
EE-New Kihnu Saar-3	EE	1710.6	39.1%
EE-New Kihnu Saar-5	EE	1710.6	39.1%
EE-New Kihnu Saar-6	EE	1710.6	39.1%
EE-New Kihnu Saar-1	EE	1707.8	39.0%
LT-New #1-2	LT	1702.4	38.9%
LV-New Gulf of Riga #1-1	LV	1695.7	38.7%
LT-New #1-1	LT	1690.1	38.6%
LV-New Gulf of Riga #1-2	LV	1688.4	38.5%
LV-New Gulf of Riga #1-3	LV	1688.4	38.5%
LV-New Gulf of Riga #1-5	LV	1688.4	38.5%
LV-New Gulf of Riga #1-6	LV	1688.4	38.5%
LV-New Gulf of Riga #1-7	LV	1688.4	38.5%
LV-New Gulf of Riga #1-8	LV	1688.4	38.5%
LV-New Gulf of Riga #1-4	LV	1681.2	38.4%
LT-New #3	LT	1677.7	38.3%
LT-New #2	LT	1673.6	38.2%
FI-New Etelainen Merkenkurkku #2-1	FI	1657.2	37.8%
FI-New Etelainen Merkenkurkku #2-2	FI	1657.2	37.8%
FI-New Etelainen Merkenkurkku #1	FI	1651.2	37.7%
LV-New Gulf of Riga #2-1	LV	1645.8	37.6%
FI-New Selkameri #2-1	FI	1644.1	37.5%
FI-New Selkameri #2-2	FI	1644.1	37.5%
LV-New Ventspils South Coast #1	LV	1642.0	37.5%
LV-New Ventspils South Coast #2	LV	1642.0	37.5%
DE-New Mecklenburg-1-1	DE	1639.7	37.4%

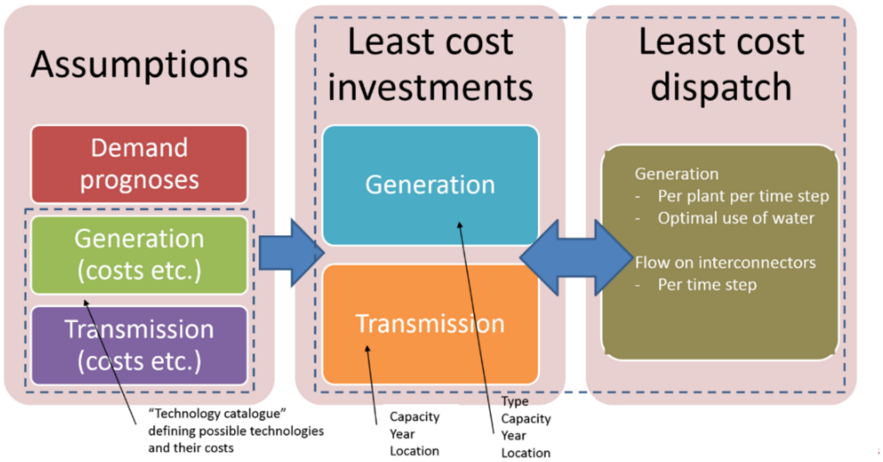
Wind farm ID/Name	Country	Net Output [GWh/y]	Capacity Factor [%]
DE-New Mecklenburg-1-2	DE	1639.7	37.4%
SE-New Laholmsbukten-1	SE	1636.8	37.4%
SE-New Laholmsbukten 2	SE	1636.8	37.4%
SE-New Hanoebukten	SE	1636.5	37.4%
LV-New Gulf of Riga #2-2	LV	1620.3	37.0%
LV-New Gulf of Riga #2-3	LV	1620.3	37.0%
LV-New Gulf of Riga #2-4	LV	1620.3	37.0%
LV-New Gulf of Riga #2-5	LV	1594.8	36.4%
FI-New Kokkola North	FI	1429.5	32.6%

Appendix D Modelling appendix

D.1 The Balmorel model

Balmorel is a detailed techno-economical partial equilibrium model suited for analyses of electricity as well as combined heat and power markets. It is capable of both, investment and dispatch optimisation. In investment mode, it is able to simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies as well as transmission capacity between predefined regions.
In dispatch optimisation mode, it determines the market optimal utilisation of available generation and transmission capacity. It is capable of both time aggregated as well as hourly modelling, which allows for a high level of geographical, technical and temporal detail. It is particularly strong in addressing the interdependency between heat and electricity production of combined heat and power (CHP) generators.
The mathematical principle behind Balmorel is based on finding a least cost solution for the dispatch and investments within the regarded interrelated electricity and district heating markets. Doing so, Balmorel takes into account developments of electricity and heat demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, spatial and temporal availability of primary renewable energy, etc.

Figure 11-1:Inforgraphic on the concept of the Balmorel model



Both societal and stakeholder perspectives can be analysed based on the models results.

D.1.1 The representation of the transmission grid

Transmission lines are represented by the total capacity available to the market between bidding areas (net transfer capacity).

D.1.2 Detailed representation of heat markets and combined heat and power

The model allows for detailed simulation of heat market, which is particularly important in countries and regions, where combined heat and power is noticeable.
Two technology types represent CPH units; extraction units and backpressure units. The capacities in the model are given as net capacities for either electricity or heat. For extraction units, the capacity is given as the electrical capacity in condensing mode; while for backpressure units it is given as the electricity capacity in co-generation mode. In full cogeneration mode at CHP units, the Cb-value specifies the ratio between electricity and heat. For extraction units, the Cv-value specifies the loss in electricity when producing heat for maintained fuel consumption. The fuel efficiencies in the model are for CHP units given as the fuel efficiency in condensing mode for extraction units and the total fuel efficiency in CHP mode for back-pressure units.
The model also includes heat only generation technologies without simultaneous electricity generation, for example heat only boilers and electricity-to-heat units (heat pumps, electric boilers). With increasing shares of renewable in power systems, electricity to heat technologies become important for system integration.

D.1.3 Investment module

The model has a technology catalogue with a set of new power generation technologies that it can invest in according to the input data. The investment module allows the model to invest in a range of different technologies including coal power, gas power (combined cycle plants and gas engines), straw and wood-based power plants, wind power (on and off-shore) and solar PV. The model is also able to rebuild existing thermal power plants from the existing fuel to another. At a lower cost than building a new power station, the model can choose to rebuild a coal-fired plant to a wood pellets or wood chips, and convert natural gas fired plant to biogas.
The technology assumptions develop from now to 2050, that meaning costs and efficiencies develop according to learning curves for the specific technology. Technology assumptions are largely based on the Danish Energy Agency's technology catalogues (https://ens.dk/en/our-services/projections-and-models/technology-data)

D.1.4 Decommissioning of power plants

The decommissioning of thermal power plants can happen both exogenously and endogenously in the model. The exogenous approach is based on data about the year of commissioning of power plants and assumptions about typical technical lifetime. Moreover, the model can decide to decommission a power plant when it is no longer economical profitable to operate (endogenous decommissioning).

D.2 General assumptions

D.2.1 Geographical scope

The Balmorel simulations are carried out over a model area which comprises the Baltic countries, the Nordic countries, Poland, Germany, the Benelux, Great Britain, Ireland, France, Switzerland, Austria, Czech Republic and Italy.

D.2.2 Power demand

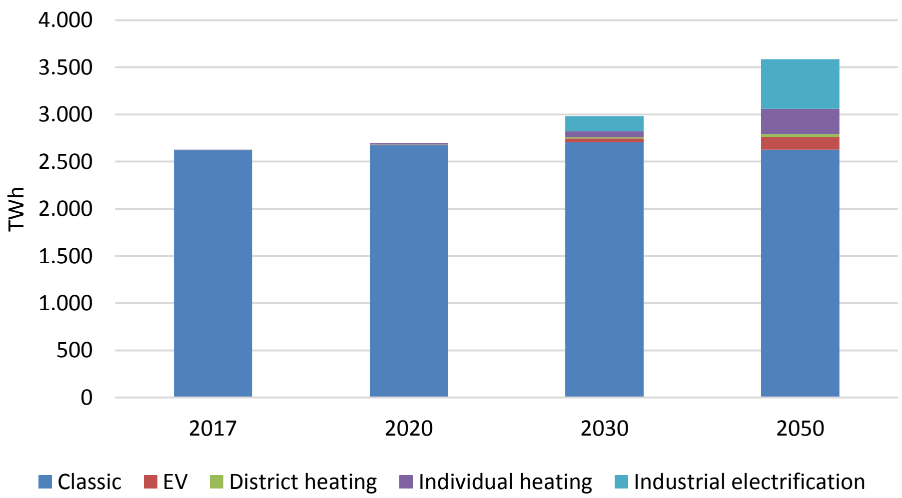
Development of electricity demand is based on the ENTSO-E scenarios in the TYNDP 2018. For 2020 and 2025, the Best Estimates (BE) are used. For 2030, demand is based on the Sustainable Transition (ST) 2030 scenario. For 2050, the demand is further extrapolated from the ST 2040 scenario. As for the RE developments, the ST scenario is more in line with the BE scenarios compared to the EUCO (European Commission) scenario.

The electricity demands for future years also includes:

- Individual heating,
- Electric vehicles,
- Electricity for district heating,
- Electricity for process heat (industry)

Electricity used in district heating, for industrial heat and production and for hydrogen is determined endogenously in the model simulations.

Figure 11-2 Power demand by type in the modelled area. Part of the demand projection is subject to model optimisation and therefore a result rather than an exogenous assumption



D.2.3 Demand flexibility

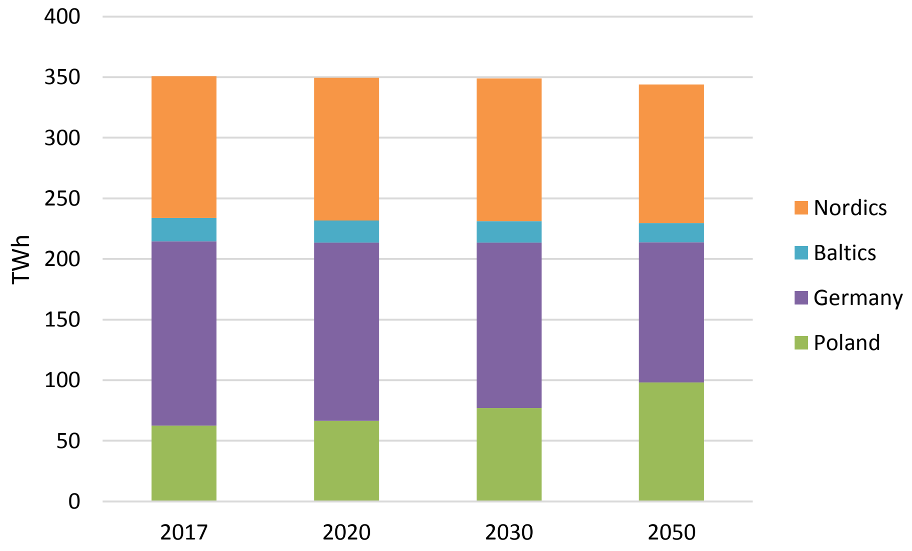
Demand flexibility (demand response) can be an important measure for integration of renewable energy in the power system. However, current experiences with demand flexibility are limited and projections are highly uncertain.

As a cautious assumption, it is assumed here, that 10% of the average nominal demand throughout the year is flexible and can be shifted in time by up to 4 hours. This leads to a demand response capacity of 27 GW by 2050 and the option to “store” 108 GWh. Additional demand flexibility related to electric vehicles is also included.

D.2.4 Heat demand

District heating areas with related heat demand is modelled for selected countries: the Baltic countries, the Nordic countries, Poland and Germany.

Figure 11-3 District heating demand in the modelled area



D.2.5 Exogenous capacity

Development of the existing generation capacity is subject to uncertainty. The reason is that similar to new investment, the lifetime of existing capacities is subject to economic optimisation and thus dependent on the development of electricity prices. However, other factors also play a role, and these can be harder to reflect in the model optimisation. They include: Environmental legislation on emissions effectively ruling out older power plants; various national subsidies to support certain power plants or type of power plants due to either concerns about the security of supply or national priorities (e.g. importance of power plants for regional economy and labour), optimisation of fixed cost as a result of changing operational patterns.

The overall approach to the development of existing capacities is that known and certain phase-outs are implemented exogenously, while the remaining capacity is held constant, and the lifetime is subject to economic optimisation (power plants have to recover fixed cost). Wind and solar capacity have relatively low fixed operational cost and are therefore assumed to be decommissioned after the end of the technical lifetime.

D.2.6 Endogenous investments and decommissioning

The capacity in the power system develops according to the least cost optimisation of the Balmorel model. The model invests in generation capacity if it is profitable, and decommissions capacity if it is not, from a power system perspective. The model both invests and decommissions myopically, i.e. only based on the information of the given year, not taking into account estimates for the future. This applies to parameters such as fuel and CO_2 prices.

- **Investments:** The model invests in a technology when its projected annual revenue can cover all costs including capital costs, fixed O&M. The model investments have been allowed after 2017, the base year of the model runs.
- **Decommissioning:** The model decommissions a technology when the revenue can no longer recover fixed O&M. Exogenous capacity is kept constant (except if better data for expected decommissioning year is available) unless it is decommissioned by the model. The model has been allowed to decommission capacity after 2020.

D.2.7 Technology costs for new investments

Table 11-1 shows the cost and efficiency assumptions for new technologies. Technology assumptions are mainly based on the Technology Catalogue, published by Danish Transmission System operator Energinet and the Danish Energy Agency[63].

[63] https://ens.dk/en/our-services/projections-and-models/technology-data

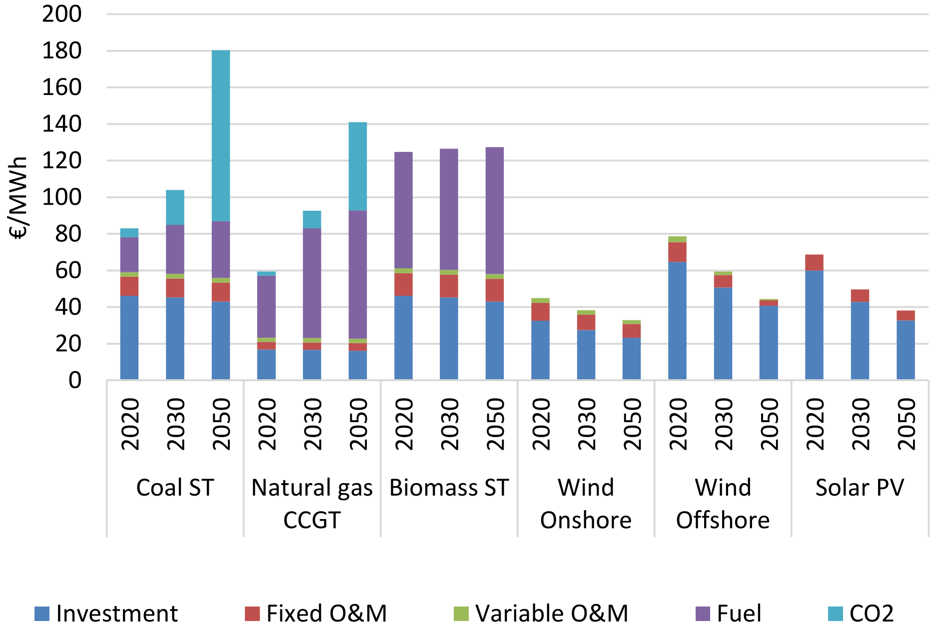
Table 11-1 Costs and efficiency for model-optimised investments.

	First year	Last year	Efficiency	Investment	Fixed O&M	Variable O&M
			%	€/kW	€/kW	€/MWh
Coal steam turbine	**2020**	**2029**	49%	2.300	41,75	2,49
	2030	**2049**	52%	2.255	41,75	2,49
	2050	**-**	54%	2.142	41,75	2,49
Natural gas CCGT	**2020**	**2029**	60%	836	16,70	2,41
	2030	**2049**	62%	826	16,70	2,41
	2050	**-**	62%	806	16,70	2,41
Wood pellet steam turbine	**2020**	**2029**	49%	2.300	50,10	2,49
	2030	**2049**	52%	2.255	50,10	2,49
	2050	**-**	54%	2.142	50,10	2,49
Wood steam turbine	**2020**	**2029**	47%	2.334	66,80	2,49
	2030	**2049**	49%	2.244	66,80	2,49
	2050	**-**	49%	2.244	66,80	2,49
Wind Onshore	**2020**	**2024**	-	1.016	24,65	2,58
	2030	**2049**	-	935	23,00	2,37
	2050	**-**	-	860	21,86	2,17
Wind Offshore	**2020**	**2024**	-	2.740	54,06	4,05
	2030	**2049**	-	2.172	41,37	2,99
	2050	**-**	-	1.793	33,68	2,31
Solar PV	**2020**	**2024**	-	745	8,79	-
	2030	**2039**	-	547	6,99	-
	2050	**-**	-	433	5,77	-

LCOE for selected technologies

For selected technologies, Figure 11-4 shows the development of the levelised costs of electricity. In the comparison, 4000 FLHs are assumed for thermal capacity. The full load hours for onshore wind is from Mid-Sweden, the offshore FLHs are from the Baltic Sea and Polish solar FLHs are used.

Figure 11-4 *LCOE for selected technologies, assumed FLHs for thermal capacity: 4000. Mid-Sweden used for onshore wind FLHs, Baltic FLHs for offshore and Polish solar full-load hours used.*



D.2.8 Minimum RE roll-out

A minimum level of RE roll-out towards 2030 in all modelled European countries is required in all scenarios to reflect the expected impact of national climate and energy policies and expected contributions to EU targets. The model will be able to exceed these minimums where it is profitable to do so.

The levels for 2030 ENTSO-E's 2030 Sustainable Transition scenario (ST 2030), as a starting point for determining the minimum roll-outs per country. The table below shows the RE capacities by 2030 per country according the Sustainable Transition scenario. Offshore wind capacities will be adjusted to reflect the assumptions of the different scenarios.

Table 11-2 Renewable energy capacities (MW) by 2030 in ENTSO-E's Sustainable Transition scenario.

	Biofuels	Hydro-pump	Hydro	Other RES	Solar-PV	Wind-onshore	Wind-offshore
Germany	0	8.378	12.794	6.631	66.300	58.500	15.000
Denmark	1.185	0	7	700	2.939	5.596	2.905
Estonia	0	0	10	127	100	1.500	0
Finland	685	0	3.200	2.200	1.200	2.300	700
Lithuania	0	950	1.263	199	80	750	0
Latvia	0	0	1.619	295	10	300	150
Norway	0	1.115	35.817	76	400	3.330	0
Poland	0	1.488	2.446	1.756	2.430	9.200	2.250
Sweden	330	0	16.184	4.203	1.740	10.780	190
Total	**2.200**	**11.930**	**73.340**	**16.187**	**75.199**	**92.256**	**21.195**

Beyond 2030 no further minimum roll-out is assumed within the modelling framework and RE-investments will instead be driven by market conditions, including an increasing CO_2 price.

D.2.9 RE subsidies

Until 2020, RE technologies receive subsidies for power generation. The different subsidy levels per technology type are shown in Table 11-3.

Table 11-3 Subsidy level until 2020 for RE technologies. These levels are 50% lower in Poland and Czech Republic.

Technology	Subsidy level (€/MWh)
Onshore wind	5
Offshore wind	8
Solar power	5
Solid biomass	15
Biogas	25

D.2.10 Fossil fuel and carbon prices

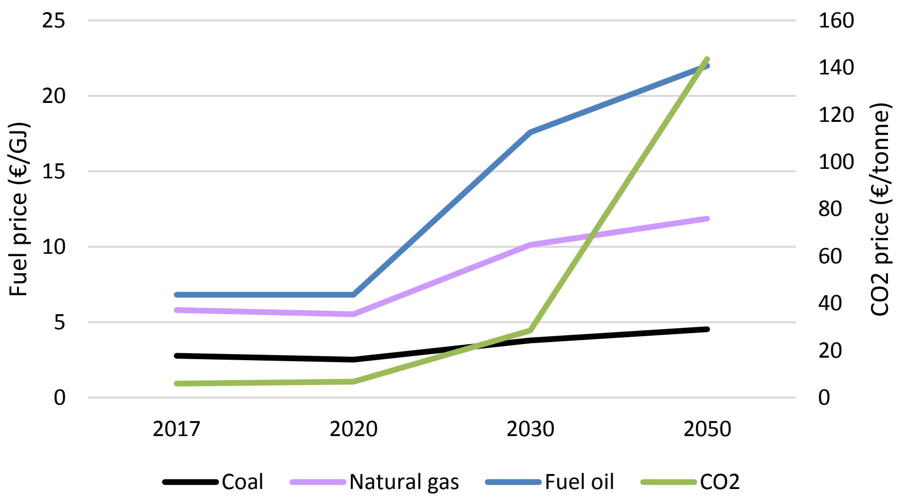
The value of offshore wind power in the power system is highly dependent on expected future fuel prices and the cost of emitting CO_2.

The current (autumn 2018) price of EU emission allowances is around 20 €. The price of CO_2 allowances does, however, not necessarily represent the actual socio-economic cost of abating CO_2 emissions within the EU ETS because other measures, including policies to support renewable energy technologies and energy efficiency measures, have considerable associated cost attached to them.

The most precise approach to value offshore wind deployment in the Baltic Sea region is by internalising the actual socio-economic cost of CO_2 in the electricity market prices.

Fossil fuel and CO_2 prices are therefore based on the European Commission (PRIMES data) for a scenario compliant with current EU climate and energy objectives for 2030 and decarbonisation of heat and power sector by 2050.

Figure 11-5 Fuel price projections for Coal, Natural gas and Fuel oil and CO_2 price

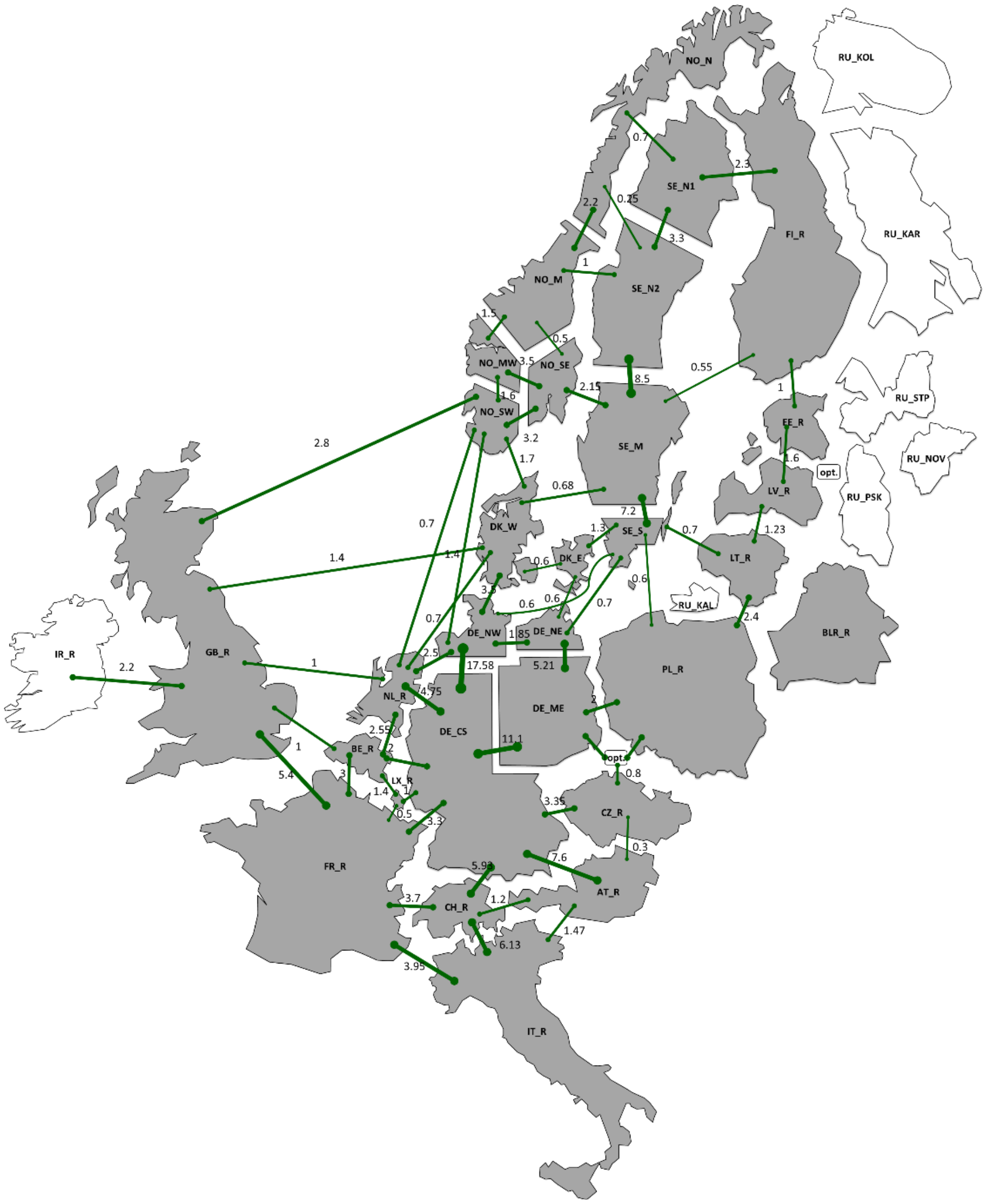


D.2.11 Transmission system

Transmission Grid developments are based on the Ten-Year Network Development Plan 2016, developed by the transmission system operators within ENTSO-E. Where updated information is available, this has been used. Mid-term and Long-term projects were included, while Future projects were excluded since they are more uncertain and with longer time horizon.

The German internal grid is based on the TSOs' latest grid development plan (NEP2014), scenario B. Data until 2020 was directly implemented; expansion beyond 2020 appeared optimistic with regards to the controversial ongoing discussions. Therefore, the most controversial expansion corridors were assumed to be delayed to 2025. Transmission capacity between North West DE and Southern DE increases significantly between 2020 and 2025. Further expansion beyond 2025 between South and North DE are added. Beyond 2030, all transmission capacities are expected to be further strengthened, and by 2050, they reach a capacity, which is 50% higher than in 2030.

Figure 11-6 Transmission capacity in 2030 in the modelled region



D.3 Detailed scenario assumptions

D.3.1 Choices for offshore deployment levels

At the end of 2017, installed offshore wind capacity in the Baltic Sea equalled approximately 1.4 GW.

Table 11-4 Offshore wind deployment (including North Sea for Denmark and Germany) by BEMIP country at the end of 2017

	No. of farms	No. of turbines connected	Installed capacity (MW)	Installed capacity Baltic Sea (MW)
Germany	23	1,169	5,355	690
Denmark	12	506	1,266	423
Estonia	-	-	-	-
Finland	3	28	92	92
Lithuania	-	-	-	-
Latvia	-	-	-	-
Poland	-	-	-	-
Sweden	5	86	202	202
Total	43	1,789	6,915	1,407

Source WindEurope for total installed capacity. Energinet and Deutsche Windguard for Baltic capacity in Germany and Denmark

As an input to determine realistic and appropriate levels of future offshore wind deployment in the Baltic Sea for the different scenarios, projections from a variety of relevant sources have been examined. These include:

- TYNDP scenarios 2018
- Wind Europe, 2017: Offshore Wind in Europe Key trends and statistics 2017
- Bundesnetzagentur Entwurf Szenariorahmen 2030
- Energinet.dk, Analyseforudsætninger

The table below depicts expected offshore wind deployment in the Baltic Sea region according to the scenarios from ENTSO-E and Wind Europe. Today, there is approximately 1.4 GW of offshore wind capacity in the Baltic Sea Region, but this figure is expected to increase to about 3 GW by 2020 and 5 GW by 2025 according the ENTSO-E's Best Estimate projection. These numbers represent an average annual buildout of 400-500 MW per year.

By 2030, ENTSO-E's EUCO scenario exhibits the lowest level of offshore deployment, namely 4 GW, compared to the highest case with 14 GW in Wind Europe's high case. By 2040, deployment ranges between 14 and 20 GW in ENTSO-E scenarios, whereas extrapolating the Wind Europe's high case to 2040 yields more than 30 GW.

Table 11-5: Total capacities for offshore wind power in the Baltic Sea in different scenarios

	ENTSO-E,	ENTSO-E,	ENTSO-E,	Wind	Wind	Wind

	Distributed generation	Sustainable transition	Global climate action	Europe, Low	Europe, Central	Europe, High
2017	1,369	1,369	1,369	1,369	1,369	1,369
2020	2,997	2,997	2,997	2,997	2,997	2,997
2025	4,992	4,992	4,992	4,992	4,992	4,992
2030	7,545	7,581	4,288	6,768	8,720	13,990
2040	13,551	13,644	20,359			

Looking closer at the geographical distribution of offshore deployment by 2030 in the depicted scenarios, we see that most of the capacity is expected in Poland and Germany.

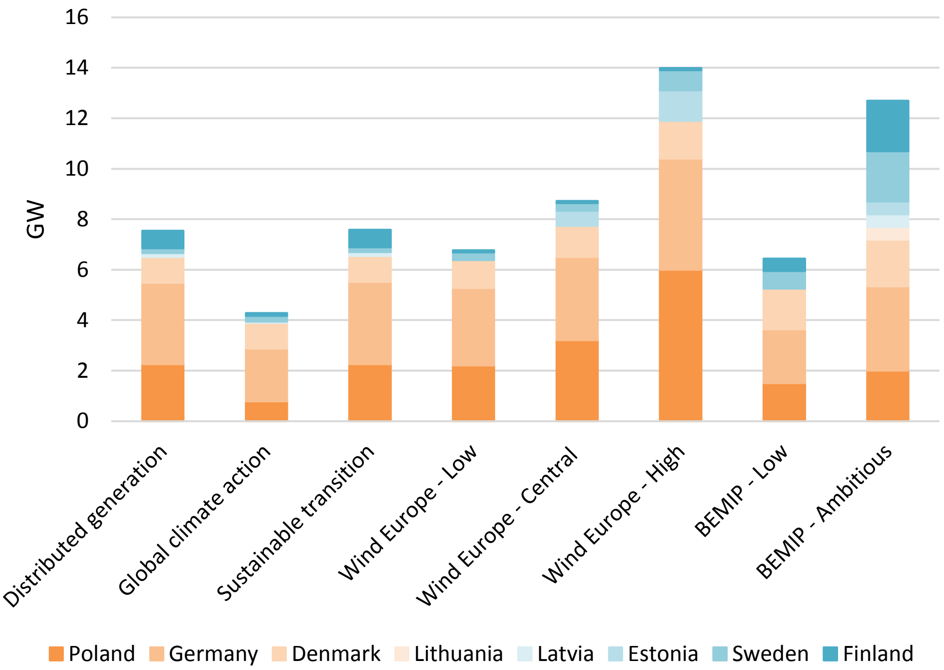
It is also interesting to note that ENTSO-E expects no or very limited offshore deployment in Sweden and Estonia in all three scenarios, but considerable capacity in Finland in two of the scenarios. In Wind Europe's high scenario, the picture is the opposite.

Table 11-6: Projected deployment of offshore wind by 2030 according to ENTSO and the Wind Europe scenarios. For Germany and Denmark, only wind farms in the Baltic Sea Region have been included

	ENTSO-E, DG	ENTSO- E, ST	ENTSO-E, EUCO	Wind Europe, Low	Wind Europe, Central	Wind Europe, High
Denmark	1,029	1,029	1,016	1,101	1,234	1,503
Sweden	190	190	227	300	300	800
Finland	700	700	119	87	87	87
Estonia	0	0	0	0	600	1,200
Latvia	150	150	49	0	0	0
Lithuania	0	0	0	0	0	0
Poland	2,250	2,250	777	2,200	3,200	6,000
Germany	3,226	3,262	2,100	3,080	3,300	4,400
Total	**7,545**	**7,581**	**4,288**	**6,768**	**8,720**	**13,990**

Figure 20 shows the total offshore wind deployment in the Baltic Sea for different scenario analyses by 2030. The Baseline scenario reaches levels close to Wind Europe's Low scenario, while being a little below ENTSO-Es highest scenario. The deployment level in the ambitious scenario is well above ENTSO-E scenarios but does not quite reach the level shown in Wind Europe's High scenario. Since the analyses in this project extend to 2050, the total deployment by that time of 33 GW in the ambitious scenario is far beyond any of the scenarios shown here.

Figure 11-7 Offshore wind capacities in the Baltic Sea in different Scenario analyses for 2030.



D.3.2 Choices for offshore hub configuration in grid cooperation scenarios and grid and policy cooperation scenarios

For the set-up of the advanced connections in the Grid Cooperation and Grid and Policy Cooperation scenarios, 4 hubs were implemented. The hub configurations were decided based on

- InteGrid case studies
- Market simulations and indications of value of additional connection capacity
- Initial estimates on possible grid congestions
- Potentials for offshore wind power

Four areas for advanced options are identified:

- **Hub 1: SE-DE**
  Casestudy in the InteGrid project. Shows potential in market simulations
- **Hub 2: SE-PL-LT**
  Casestudy in the InteGrid project. Shows potential in market simulations
- **Hub 3: EE-LV**
  Potential onshore grid congestions. Shows potential in market simulations
- **Hub 4: FI-SE**
  Shows potential in market simulations

Table 11-7 Wind capacity (MW) related to the four hub configurations in the grid cooperation scenarios and the grid and policy scenarios

Hub	Country	Wind farm	Low scenarios 2030	Low scenarios 2050	Ambitious scenarios 2030	Ambitious scenarios 2050
Hub 1	Germany	Windanker	1000	1000	600	1000
	Germany	BalticEagle	0	500	0	500
	Germany	NewBal_East	0	0	0	1500
	Denmark	RoenneB	0	500	400	1500
Hub 2	Poland	Baltex	0	0	0	1000
	Poland	Baltica1	0	500	500	500
	Poland	Baltyk	1000	1000	1000	1000
	Sweden	SoedraM	0	1500	1000	2000
	Sweden	OelandsSoedra	0	0	0	1000
Hub 3	Latvia	GulfRiga1	0	500	500	1000
	Estonia[64]	LiiviBay	0	500	500	1000
Hub 4	Sweden	SvenskaBjoern	490	500	500	500
	Finland	AalandsHav	467	1000	1000	1000
			2957	**7500**	**6000**	**13500**

Table 11-8 Onshore interconnection capacity (MW) related to the four hub configurations in the grid cooperation scenarios and the grid and policy scenarios

Hub	Country	Low scenarios 2030	Low scenarios 2050	Ambitious scenarios 2030	Ambitious scenarios 2050
Hub 1	Germany	500	1000	500	2500
	Sweden	500	1000	500	2500
Hub 2	Sweden	500	1500	1500	3500
	Poland	500	1500	1500	3500
	Lithuania	0	500	500	1500
Hub 3	Estonia[65]	0	500	500	1000
	Lithuania	0	500	500	1000
Hub 4	Finland	500	750	750	750
	Sweden	500	750	750	750
		3000	**8000**	**7000**	**17000**

[64] Estonia plans deployment that is more ambitious, as follows: Low Scenario – 500 MW by 2030 and 1000 MW by 2050; Ambitious Scenario – 1000 MW by 2030 and 1000 MW by 2050.
[65] See previous footnote.

Figure 11-8 Configuration of the four advanced offshore hub configurations. Capacities indicated represent the ambitious scenarios.

D.3.3 Hub costs calculations

For the cost calculations of the offshore hub, input from COWI on HVDC offshore platform is used, which is based on the Dogger Bank Analysis report and includes substations and converters

The onshore-to-hub connection costs were calculated by estimating the offshore cable distance in km from the shore to the hub and using representative offshore wind projects provided by COWI to determine an onshore cable distance (from the pooling station to the point of connection). The costs assumptions provided by COWI with learning curves from the Danish Technology catalogue are applied on these cables.

D.4 Detailed results

D.4.1 Generation by fuel and by country

See Excel file "Annual generation"

Annual generation by fuel, TWh/year

Scenario	Country	Fuel	2020	2030	2050
Low national policies	Austria	Natural gas	9,38	3,69	3,57
		Coal + other fossil	6,13		
		Biomass	2,95	3,15	2,72
		Hydro	40,68	40,68	40,68
		Onshore wind	8,03	11,96	21,03
		Solar	2,05	33,67	53,49
	Austria Total		69,23	93,15	121,50
	Belgium	Nuclear	29,50		
		Natural gas	24,44	9,04	5,45
		Coal + other fossil	10,16		
		Biomass	1,58	7,26	4,28
		Hydro	1,67	1,67	1,67
		Onshore wind	4,71	8,04	18,36
		Offshore wind	7,56	8,42	26,70
		Solar	3,66	13,69	13,69
	Belgium Total		83,27	48,11	70,16
	Czech	Nuclear	29,05	29,05	24,97
		Natural gas	2,88	2,09	2,84
		Coal + other fossil	40,10	31,71	
		Biomass	3,78	6,25	7,21
		Hydro	2,86	2,86	2,86
		Onshore wind	1,05	7,32	21,05
		Solar	2,17	5,97	20,57
	Czech Total		81,90	85,24	79,49
	Denmark	Natural gas	1,45	0,44	
		Coal + other fossil	6,69		
		Waste	2,09	2,06	2,55
		Biomass	8,52	11,38	8,16
		Onshore wind	11,41	20,23	30,28
		Offshore wind	9,02	20,72	30,49
		Solar	1,02	2,81	2,81
	Denmark Total		40,20	57,64	74,29
	Estonia	Natural gas	0,01		
		Coal + other fossil	10,46	3,14	0,14
		Waste	0,13	0,13	
		Biomass	0,77	0,70	0,66
		Hydro	0,03	0,03	
		Onshore wind	1,04	10,70	16,38
		Offshore wind			2,16
		Solar	0,03	0,10	0,10
	Estonia Total		12,47	14,80	19,44

D.4.2 Demand supply balance by country

See Excel file “Annual generation”

System balances, TWh/year

Minor deviation in balances mainly due to transmission losses.
Finland has additional import from Russia of 4,5 TWh in 2020 and 2030.

		Total demand			Total generation			Net imports			RES-E share		
		2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
Low natio	Austria	73	82	103	69	93	122	4	-10	-17	73%	109%	114%
	Belgium	87	95	117	83	48	70	3	47	47	22%	41%	55%
	Czech	69	74	91	82	85	79	-13	-11	12	14%	30%	57%
	Denmark	43	52	65	40	58	74	3	-6	-9	70%	106%	111%
	Estonia	9	11	14	12	15	19	-3	-4	-5	21%	108%	138%
	Finland	91	105	124	83	91	121	4	10	4	35%	41%	81%
	France	483	491	530	473	536	631	11	-42	-92	25%	63%	99%
	Germany	537	604	724	608	614	672	-70	-7	64	42%	66%	90%
	Great_Bri	329	344	384	305	337	414	24	7	-22	29%	66%	93%
	Italy	326	379	491	305	341	485	23	41	17	32%	77%	95%
	Latvia	8	9	12	7	8	12	0	0	0	64%	86%	100%
	Lithuania	12	13	18	4	10	23	8	4	-5	26%	68%	130%
	Luxembou	7	11	13	4	2	2	4	9	11	6%	9%	11%
	Netherlan	115	130	167	89	94	114	26	36	53	23%	56%	63%
	Norway	137	155	154	147	178	195	-9	-23	-41	105%	113%	126%
	Poland	163	214	323	165	217	302	-1	-3	26	11%	46%	83%
	Sweden	145	151	162	154	188	202	-9	-37	-38	70%	94%	123%
	Switzerlar	62	63	75	68	77	87	-6	-13	-11	71%	85%	90%
Ambitious	Austria	73	82	103	69	93	122	4	-10	-17	73%	109%	114%
	Belgium	87	95	117	83	48	70	3	46	47	22%	41%	55%
	Czech	69	74	91	82	85	78	-13	-11	13	14%	30%	55%
	Denmark	43	52	65	40	57	73	3	-5	-8	70%	106%	108%
	Estonia	9	11	14	12	15	21	-3	-4	-7	21%	111%	151%
	Finland	91	105	124	83	91	120	4	9	6	35%	42%	80%
	France	483	491	530	473	536	629	11	-42	-90	25%	63%	99%
	Germany	537	604	725	608	615	680	-70	-8	58	42%	67%	91%
	Great_Bri	329	344	384	305	337	414	24	8	-22	29%	66%	93%
	Italy	326	379	491	305	341	484	23	41	17	32%	77%	95%
	Latvia	8	9	12	7	9	11	0	-0	1	64%	92%	91%
	Lithuania	12	13	18	4	11	25	8	3	-7	26%	75%	140%
	Luxembou	7	11	13	4	2	2	4	9	11	6%	9%	11%
	Netherlan	115	130	167	89	94	116	26	36	51	23%	56%	64%
	Norway	137	155	154	147	178	195	-9	-23	-40	105%	113%	125%
	Poland	163	214	324	165	216	302	-1	-1	27	11%	46%	83%
	Sweden	145	151	162	154	189	205	-9	-38	-41	70%	94%	124%
	Switzerlar	62	63	75	68	77	87	-6	-13	-11	71%	85%	91%

D.4.3 Total cost by country

See Excel file “Total costs per country”

Total costs, Million EUR/year

Including annualised investment costs of generation capacity (WACC of 5% over 20 year) and transmission capacity

caseName	Country	2020	2030	2050
Low national policies	Austria	1.668	3.024	5.011
	Belgium	3.143	6.902	8.939
	Czech	1.849	3.321	5.727
	Denmark	2.303	3.121	4.045
	Estonia	502	628	837
	Finland	2.724	3.456	5.162
	France	14.764	19.575	27.194
	Germany	70.158	87.740	104.291
	Great_Britain	17.820	20.959	20.818
	Italy	12.925	21.389	29.631
	Latvia	319	390	510
	Lithuania	534	788	801
	Luxembourg	295	747	826
	Netherlands	4.854	9.269	13.711
	Norway	1.294	1.295	669
	Poland	67.746	74.887	88.839
	Sweden	3.793	3.810	5.043
	Switzerland	1.344	1.497	1.880
Ambitious national pol	Austria	1.668	3.025	5.022
	Belgium	3.143	6.901	8.938
	Czech	1.849	3.323	5.715
	Denmark	2.303	3.117	3.995
	Estonia	502	672	896
	Finland	2.724	3.569	5.318
	France	14.764	19.572	27.199
	Germany	70.158	87.744	104.288
	Great_Britain	17.820	20.961	20.824
	Italy	12.925	21.389	29.624
	Latvia	319	399	512
	Lithuania	534	791	809
	Luxembourg	295	747	825
	Netherlands	4.854	9.271	13.700
	Norway	1.294	1.295	668
	Poland	67.746	74.881	88.201
	Sweden	3.793	3.934	5.314
	Switzerland	1.344	1.497	1.886

D.4.4 Detailed total cost per category

See Excel file "Total costs per category"

	Total costs																	
	CAPEX Baltic Offshore		CAPEX All, but Baltic Offshore		OPEX Baltic Offshore		OPEX All, but Baltic Offshore		Fuel cost		CO2 Tax		Total		Hub cost		Total	
Scenarios	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Low NP	782	2.725	48.580	94.167	168	344	153.211	161.607	46.012	44.132	13.814	20.948	262.568	323.924	-	-	262.568	323.924
Ambitious NP	1.941	5.426	47.976	92.504	399	717	152.950	161.097	45.861	43.238	13.732	20.727	262.859	323.710	-	-	262.859	323.710
Low GC	843	2.732	48.604	94.088	169	344	153.222	161.566	45.976	43.898	13.790	20.897	262.605	323.525	85	210	262.690	323.735
Ambitious GC	1.960	5.481	48.018	92.349	400	718	152.962	161.109	45.737	42.490	13.587	20.443	262.663	322.590	206	454	262.870	323.043
Low GPC	825	2.894	48.539	94.113	169	344	153.236	161.723	46.037	43.126	13.789	20.684	262.595	322.883	85	210	262.680	323.094
Ambitious GPC	1.963	5.471	47.876	91.981	401	722	152.939	161.021	45.745	42.216	13.640	20.483	262.565	321.894	206	454	262.772	322.348

D.5 Detailed wind farm evaluation

D.5.1 List of wind farms showing capacity factor, LCOE and market value for 2030 and 2050.

See Excel file "CF, MV, LCOE". Note that the capacity factors shown here account for technological progress over time and so are different from those in Appendix B.

			Capacity factors		Market value							
					Low national policies		Ambitious national policies		Low grid cooperation		Ambitious grid cooperation	
			[%]	[%]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]	[EUR17/MWh]
Region Balmorel	Area Balmorel	Connected Region	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
DE_BalticEagle_x	DE83	DE	49,68%	51,47%	52,80	51,06	52,20	48,51	-	-	-	-
DE_Windanker_x	DE84	DE	49,89%	51,68%	52,04	50,28	51,45	47,75	-	-	-	-
DE_Windanker_x	DE85	DE	49,59%	51,38%	51,71	49,56	51,12	47,02	-	-	-	-
DE_ArkonaSee_x	DE86	DE	49,73%	51,53%	51,29	49,43	50,70	46,90	51,31	50,78	50,49	46,77
DE_ArkonaSee_x	DE87	DE	49,48%	51,28%	51,39	49,28	50,80	46,74	51,41	50,65	50,59	46,63
DE_HiddenSee_x	DE88	DE	48,84%	50,64%	50,36	47,39	49,80	44,83	50,41	48,74	49,60	44,66
DE_Gennaker_x	DE89	DE	48,32%	50,13%	49,84	46,35	49,30	43,76	49,91	47,72	49,10	43,57
DE_Gennaker_x	DE90	DE	48,31%	50,11%	49,72	46,17	49,18	43,57	49,79	47,54	48,99	43,35
DE_Baltic_2_x	DE91	DE	49,94%	51,75%	51,86	50,99	51,29	48,54	51,86	52,27	51,04	48,30
DK_StoreMiddelG_x	DK-52-1	DK_2	47,66%	49,44%	47,57	46,64	47,27	46,58	47,40	46,78	46,87	46,92
DK_StoreMiddelG_x	DK-52-2	DK_2	47,66%	49,44%	47,57	46,64	47,27	46,58	47,40	46,78	46,87	46,92
DK_KF_x	DK53-1	DK_2	48,12%	50,00%	48,81	47,79	48,39	46,43	48,73	48,08	47,94	46,51
DK_KF_x	DK53-2	DK_2	48,10%	49,98%	48,83	47,86	48,41	46,52	48,75	48,14	47,97	46,61
DK_KF_x	DK53-3	DK_2	47,57%	49,41%	47,23	45,45	46,82	44,38	47,17	45,75	46,41	44,28
DK_KF_x	DK53-4	DK_2	48,45%	50,34%	48,75	47,01	48,29	45,50	48,66	47,40	47,79	45,62
DK_KF_x	DK53-5	DK_2	48,39%	50,28%	48,86	47,35	48,41	45,87	48,77	47,71	47,92	45,97
DK_KF_x	DK53-6	DK_2	48,49%	50,39%	49,14	47,77	48,68	46,36	49,04	48,12	48,20	46,49
DK_RoenneB_x	DK54-1	DK_2	49,86%	51,72%	50,50	48,58	50,00	47,13	-	-	-	-
DK_RoenneB_x	DK54-2	DK_2	49,85%	51,70%	50,62	48,72	50,11	47,27	50,51	49,11	-	-
DK_RoenneB_x	DK54-3	DK_2	49,83%	51,68%	50,72	48,85	50,21	47,41	50,61	49,24	-	-
DK_RoenneB_x	DK54-4	DK_2	49,80%	51,65%	50,77	48,95	50,26	47,51	50,65	49,33	49,77	47,66
DK_RoenneB_x	DK54-5	DK_2	49,77%	51,63%	50,83	49,04	50,31	47,60	50,71	49,42	49,82	47,73
DK_RoenneB_x	DK54-6	DK_2	49,74%	51,59%	50,89	49,24	50,38	47,82	50,77	49,62	49,89	47,92
DK_RoenneB_x	DK54-7	DK_2	49,82%	51,67%	50,68	49,01	50,18	47,60	50,57	49,38	49,70	47,77
DK_RoenneB_x	DK54-8	DK_2	49,80%	51,65%	50,77	49,11	50,27	47,71	50,66	49,48	49,78	47,86
DK_RoenneB_x	DK54-9	DK_2	49,78%	51,63%	50,83	49,19	50,32	47,79	50,72	49,56	49,84	47,92
DK_RoenneB_x	DK54-10	DK_2	49,76%	51,61%	50,88	49,29	50,38	47,88	50,77	49,66	49,89	47,99
DK_RoenneB_x	DK54-11	DK_2	49,75%	51,60%	50,83	49,38	50,33	48,01	50,72	49,73	49,86	48,12
DK_RoenneB_x	DK54-12	DK_2	49,82%	51,67%	50,69	48,66	50,17	47,18	50,56	49,07	49,67	47,36
DK_Saeby_x	DK58	DK_1	43,16%	44,95%	48,87	44,72	48,84	44,76	48,86	44,76	48,87	44,93
DK_Omoe_x	DK73	DK_2	46,95%	48,81%	47,22	44,49	46,79	42,85	47,16	44,94	46,29	42,74
DK_LilleBaelt_x	DK83	DK_1	42,58%	44,47%	48,02	43,60	47,88	43,11	47,97	43,57	47,74	42,62
EE_Liivi_x	EE05-1	EE_R	44,13%	45,93%	37,90	36,29	37,15	33,34	37,91	36,21	37,11	33,36
EE_Liivi_x	EE05-2	EE_R	44,09%	45,90%	37,92	36,48	37,21	33,55	37,93	36,43	37,16	33,55
EE_LiiviBay_x	EE-LB-1	EE_R	44,41%	46,21%	38,05	36,35	37,25	33,42	-	-	-	-
EE_LiiviBay_x	EE-LB-2	EE_R	44,64%	46,43%	38,05	36,56	37,25	33,58	38,07	36,42	-	-
EE_Loode1_x	EE-LE-1	EE_R	43,86%	45,54%	37,46	36,91	36,67	33,63	37,47	36,49	36,74	33,48
EE_Loode2_x	EE-LE-2	EE_R	42,90%	44,61%	37,36	36,05	36,55	32,93	37,37	35,74	36,64	32,87
FI_Suurhiekka_x	FI05	FI_R	39,46%	41,11%	38,71	35,89	38,08	34,93	38,56	35,75	38,08	35,32

D.5.2 List of Hubs, average capacity factors, LCOE and market value

See Excel file "Hub MV, LCOE"

Hub market value and LCOE

* LCOE incl. hubs - MV including congestion rent

Scenario	Year	Hub	LCOE excl. hubs	LCOE incl. hub	MV excl cong.	MV incl. cong	LCOE – MV*
Low grid cooperation	2030	Hub 1	48,94	55,21	39,06	53,76	1,45
		Hub 2	43,46	69,49	34,95	55,43	14,06
		Hub 3	-	-	-	-	-
		Hub 4	49,85	60,49	32,68	38,43	22,05
	2050	Hub 1	43,31	48,84	35,53	52,57	-3,73
		Hub 2	39,38	58,06	34,01	82,6	-24,54
		Hub 3	41,11	52,71	36,01	37,3	15,41
		Hub 4	45,05	51,07	29,38	39,92	11,15
Ambitious grid cooperation	2030	Hub 1	45,65	51,91	39,8	52,45	-0,53
		Hub 2	44,4	54,8	35,82	62,74	-7,94
		Hub 3	51,66	58,36	37,19	39,94	18,42
		Hub 4	49,26	56,05	32,54	38,56	17,49
	2050	Hub 1	40,67	46,73	34,99	49,9	-3,17
		Hub 2	42,62	52,85	33,13	89,36	-36,51
		Hub 3	45,9	51,81	33,24	33,48	18,34
		Hub 4	48,38	54,49	29,72	39,54	14,94
Low grid and policy cooperation	2030	Hub 1	48,94	55,21	39,1	53,64	1,57
		Hub 2	43,46	69,49	34,93	55,56	13,93
		Hub 3	-	-	-	-	-
		Hub 4	49,85	60,49	32,68	38,41	22,08
	2050	Hub 1	43,31	48,84	35,61	54,47	-5,63
		Hub 2	39,38	58,06	34,22	81,38	-23,32
		Hub 3	41,11	52,71	36,11	37,75	14,96
		Hub 4	45,05	51,07	29,27	40,74	10,33
Ambitious grid and policy cooperation	2030	Hub 1	45,65	51,91	39,92	52,8	-0,89
		Hub 2	44,4	54,8	35,78	62,95	-8,15
		Hub 3	51,66	58,36	37,26	40,04	18,32
		Hub 4	49,26	56,05	32,53	38,63	17,42
	2050	Hub 1	40,67	46,73	35,29	49,14	-2,41
		Hub 2	42,62	52,85	33,77	86,87	-34,02
		Hub 3	45,9	51,81	33,01	33,31	18,5
		Hub 4	48,38	54,49	29,9	40,88	13,61

D.5.3 Detailed list of offshore deployment on site level for all six scenarios

See Excel file “Capacity”

		CAPACITIES												
		Max capacity Region	Capacity built Low national policies		Capacity built bitious national poli		Capacity built Low grid cooperation		Capacity built bitious grid cooperat		Capacity built rid and policy coope		Capacity built s grid and policy coo	
		[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]
Region Balmorel	**Area Balmorel**		**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
DE_BalticEagle_x	DE83	500	-	-	-	500	-	-	-	-	-	-	-	-
DE_Windanker_x	DE84	500	-	-	-	500	-	-	-	-	-	-	-	-
DE_Windanker_x	DE85	500	-	500	290	500	-	-	-	-	-	-	-	-
DE_ArkonaSee_x	DE86	500	-	-	-	64	-	-	-	64	-	-	-	-
DE_ArkonaSee_x	DE87	500	-	-	-	-	-	-	-	-	-	-	-	-
DE_HiddenSee_x	DE88	500	500	500	500	500	500	500	500	500	500	-	500	500
DE_Gennaker_x	DE89	500	500	500	500	500	-	500	500	500	-	-	7	500
DE_Gennaker_x	DE90	500	500	500	500	500	90	500	500	500	27	0	500	500
DE_Baltic_2_x	DE91	500	-	500	500	500	-	500	190	500	-	-	-	500
DK_StoreMiddelG_x	DK-52-1	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_StoreMiddelG_x	DK-52-2	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-1	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-2	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-3	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-4	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-5	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_KF_x	DK53-6	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-1	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-2	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-3	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-4	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-5	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-6	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-7	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-8	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-9	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-10	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_RoenneB_x	DK54-11	500	-	-	-	-	-	-	-	-	-	-	-	249
DK_RoenneB_x	DK54-12	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_Saeby_x	DK58	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_Omoe_x	DK73	500	-	-	-	-	-	-	-	-	-	-	-	-
DK_LilleBaelt_x	DK83	500	-	-	-	-	-	-	-	-	-	-	-	-
EE_Liivi_x	EE05-1	500	-	-	-	-	-	-	-	-	-	-	-	-
EE_Liivi_x	EE05-2	500	-	-	-	-	-	-	-	-	-	-	-	-
EE_LiiviBay_x	EE-LB-1	500	-	-	-	5	-	-	-	-	-	-	-	-
EE_LiiviBay_x	EE-LB-2	500	-	500	500	500	-	-	-	-	-	-	-	-
EE_Loode1_x	EE-LE-1	500	-	-	-	-	-	-	-	-	-	-	-	-
EE_Loode2_x	EE-LE-2	500	-	-	-	-	-	-	-	-	-	-	-	-

Appendix E Task 4 and 5 factsheets

EU Regulations

Task 4

Market design

In late 2016, the European Commission introduced the Clean Energy for All Europeans Package, which consisted of a set of legislative proposals on renewable energy, energy efficiency and electricity market design. The proposal for a regulation on the internal market for electricity (COM(2016)0861) aims to make the market fit for flexibility, decarbonisation and innovation. As of November 2018, the negotiations on the legislative proposals on Electricity Regulation, the Electricity Directive and ACER are ongoing.

Priority dispatch

The Commission proposal advocates a market-based approach to the dispatching of power plants and limits priority dispatch for renewables and high efficiency cogeneration to small installations, pre-existing installation that received support and demonstration projects. The rules for priority dispatch are currently up for debate under the trilogue negotiations.

Day-ahead, intraday and balancing markets

The proposed legislation aims to enable trading in the market to be as close to real time as possible. Wholesale price caps will be removed, to allow scarcity pricing to drive investments towards flexible assets.

The Internal Electricity Market Directive defines rules for the organisation and functioning of an integrated and competitive electricity market in the EU.

Network regulation

Network codes

In order to implement and harmonise EU law, the European Commission introduced legally binding network codes that supplement the electricity regulation. Network codes are a set of rules drafted by ENTSO-E, with guidance from ACER, to bolster the harmonisation, integration and efficiency of the European electricity market.

The Network Code on Requirements for Generators, which entered into force in May 2016, harmonises the rules for grid connection, including for offshore power park modules. The network code for HVDC connections, which entered into force in September 2016, regulates the requirements for grid connections of DC-connected power park modules, such as offshore wind farms.

With respect to offshore grids, the network codes on Capacity Allocation and Congestion Management (CACM) and Forward Capacity Allocation (FCA) are relevant for the allocation of interconnector capacity. CACM, which entered into force in 2015, governs the establishment of cross-border EU electricity markets in the day-ahead and intraday markets, as well as methods for the calculation of interconnection capacity. Furthermore, CACM introduced a new procedure for reviewing the configurations of existing bidding zones. The Network Code on forward capacity allocation (FCA) entered into force on 17 October 2016 and provides guidelines for long-term cross-zonal capacity allocation.

Interconnection targets

In 2014, the EU set a target for cross-border interconnection capacity to be at least 10% of Member States' installed electricity production capacity by 2020. In 2017, the Commission proposed to increase the target to 15% by 2030.

Use of congestion revenues

The use of congestion revenues is regulated in Regulation (EC) No. 714/2009 Article 16 (6):

> "Any revenues resulting from the allocation of interconnection shall be used for the following purposes:
> (a) guaranteeing the actual availability of the allocated capacity; and/or
> (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.
> If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) of the first subparagraph, they may be used, subject to approval by the regulatory authorities of the Member States concerned, up to a maximum amount to be decided by those regulatory authorities, as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs."

Exemptions can be made upon application and approval by the European Commission.

Support mechanisms

In late 2016, the European Commission introduced the Clean Energy for All Europeans Package, which consisted of a set of legislative proposals on renewable energy, energy efficiency and electricity market design. Through the Renewable Energy Directive (RED II), the EU introduced a binding target to increase the share of renewable energy in EU energy consumption to at least 32% by 2030. RED II does not translate the EU target into binding national targets. However, the previous national targets for 2020 will serve as baseline levels, which Member States are not allowed to go below. The proposed Regulation requires Member States to develop Integrated National Energy and Climate Plans that cover the five dimensions[66] of the Energy Union.

The proposals also enable national support mechanisms for renewable energy to remunerate electricity generated in other Member States. At least 10% of newly supported capacity must annually be opened up to RES installations in other Member States for the period 2021 to 2025, and at least 15% between 2026 and 2030. The energy generated under these support mechanisms will count towards the Member States funding the installation.

The EU does not interfere in the energy mix of Member States. However, the regulation leaves flexibility for Member States to be exempted from the prohibition of state aid under Art. 107 TFEU when providing economic incentives to renewable energy. Such exemptions may be granted if the funding contributes to the fulfilment of the EU's climate and energy targets without having undue negative effects on competition and trade.

The RES Directive established a framework for the development of renewable energy sources in the EU.
Its replacement, RED II, introduced a shift to market-based support mechanisms for renewable electricity.

[66] The dimensions are: (i) security, solidarity and trust; (ii) a fully-integrated internal energy market; (iii) energy efficiency; (iv) climate action – decarbonising the economy; and (v) research, innovation and competitiveness.

CEF Funding

The regulation on guidelines for trans-European energy infrastructure (TEN-E) supports the development of priority corridors, including those projects of common interest (PCIs) within the scope of the BEMIP initiative. The European Commission makes a list of Projects of Common Interest (PCIs) every two years (see Appendix - Task 5 – Projects of Common Interest). PCI Projects may apply for the Connecting Europe Facility (CEF) funding. According to the new proposal from 6 June 2018, the Connecting Europe Facility will be renewed for 2021-2027 with a budget of €42.3 billion to support investments in infrastructure networks, of which €8.7 billion will be allocated for energy infrastructure. CEF will help foster cooperation on cross-border renewable energy projects and support trans-European energy network infrastructure.

Task 5

EU Directive on Maritime Spatial Planning

The EU Directive on maritime spatial planning (Directive 2014/89/EU) was adopted in 2014, with a deadline for its transposition and the designation of competent authorities by 2016. The Directive seeks to ensure the more coherent use of maritime areas by establishing a common framework for maritime spatial planning across Member States. This includes a common timeframe for the completion of plans and common minimum requirements for the planning process.

Minimum requirements

- Member States must draw up maritime spatial plans no later than 31 March 2021. These should both map existing human activities in their marine waters and identify their most effective future use.
- The plans must take into account land-sea interactions, as well as environmental, economic, social and safety aspects.
- Member States must aim to promote coherence between these plans and other related processes, such as integrated coastal management.
- Member States must ensure the involvement of stakeholders and establish a means of public participation in the plans’ development by informing all interested parties and by consulting the relevant stakeholders, authorities, and the public at an early stage of the plans’ development.
- Member States bordering the same marine waters must cooperate so as to ensure that maritime spatial plans are coherent and coordinated across the marine region concerned. Where EU countries share a maritime border with a non-EU country, they should seek to cooperate.
- The plans shall be reviewed at least every ten years.

Network development plans

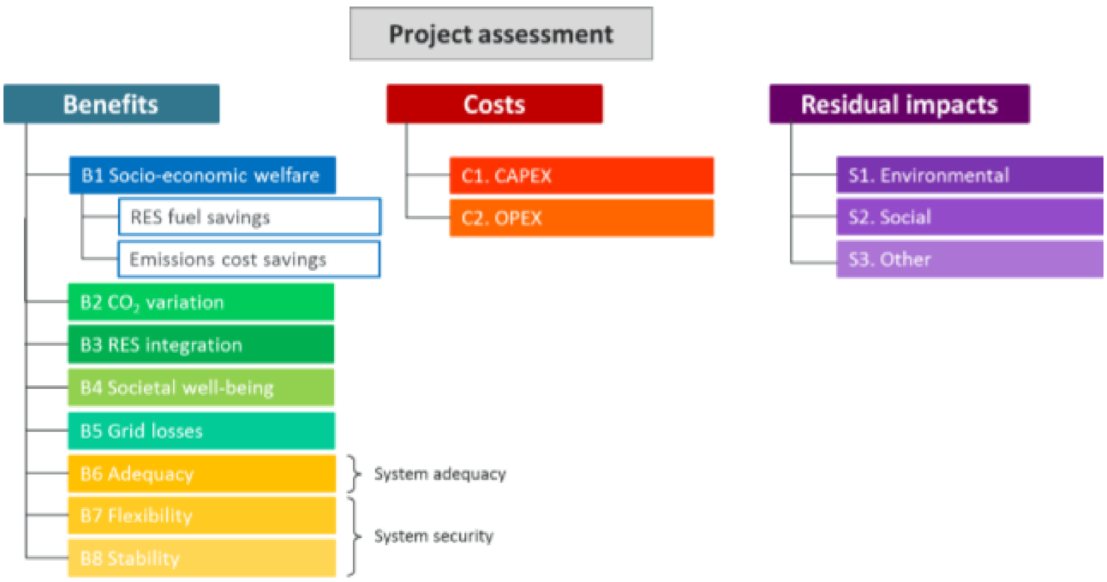
Regulation (EC) 714/2009 established the European Network of Transmission System Operators for Electricity (ENTSO-E) and required that it “draw up, publish and regularly update a non-binding Community-wide ten-year network development plan (Community-wide network development plan). Viable electricity transmission networks and necessary regional interconnections, relevant from a commercial or security of supply point of view, should be included in that network development plan.” These studies are conducted by around 200 experts spread across Europe’s TSOs and Member States. The studies use a common set of methodologies and tools to assess the power flows implied by scenarios developed as part of the Plan, identify bottlenecks and consider the infrastructure projects needed to resolve future constraints.

Broadly speaking the development of each ten-year network development plan (TYNDP) consists of four steps:

1. Scenario development – High-level scenarios are developed to allow exploration of a variety of potential future developments. This allows uncertainties to be captured and considered. These scenarios cover issues like different patterns of investment in generation, different patterns of final consumption, and different policy arrangements for pursuing decarbonisation.
2. System needs identification – In order to develop the necessary infrastructure, the European system is mapped against the EU energy pillars and any necessary capacity increase is identified, especially at the borders between the countries.
3. Project Collection – This step is based on the EC Commission Recommendation of 24 July 2018 establishing Guidelines on equal treatment and transparency criteria to be applied by ENTSO-E and ENTSOG when developing their TYNDPs as set out in Annex III 2(5) of Regulation (EU) No 347/2013 of the European Parliament and of the Council.
4. Project assessments – The projects identified through the collection process above are assessed using an approved method of multi-criteria assessment described below.

Multi-criteria assessment framework

The assessment framework, illustrated below, incorporates a monetised cost benefit analysis, but also considers a number of additional factors that cannot be readily monetised.



- CO_2 variation – Impact on CO_2 emissions
- RES integration – Ability of the power system to connect RES plants while minimising curtailments
- Socio-economic welfare / market integration – Ability of the power system to reduce congestion and thus provide adequate transfer capacity so that electricity markets can trade power in an economically efficient manner
- Grid losses – Impact on transmission losses
- Security of supply – Ability of the power system to provide an adequate and secure supply of electricity under ordinary conditions
- Flexibility – Ability of the project to be appropriate under a variety of different possible future development paths or scenarios
- Stability – Ability of the system to withstand increasingly extreme system conditions (exceptional contingencies)

- Costs – Total project expenditures
- Environmental impact – Environmental effects of the project as assessed through preliminary studies
- Social impact – Effect on the (local) population as assessed through preliminary studies

Projects of Common Interest

Projects of Common Interest (PCIs) are energy infrastructure projects designated by the European Commission owing to their importance in supporting the EU's policy objectives, notably the further integration of the European energy market. The legislative foundation for PCIs is Regulation (EU) No 347/2013 on the development of trans-European energy infrastructure.

PCIs benefit from accelerated planning and permit granting, a single national authority to facilitate and coordinate permitting with a time limit of 3.5 years, streamlined environmental assessment procedures, improved regulatory conditions, enhanced public participation via consultations, and increased visibility to investors. They also have the right to apply for funding from the Connecting Europe Facility (CEF), with up to €5.35 billion available.

Designation process

The European Commission draws up a list of PCIs every two years. In order for a project to be eligible for PCI designation it must be part of the TYNDP. It must also have a significant cross-border impact and:

- enhance market integration and contribute to the integration of EU countries' networks;
- increase competition in energy markets by offering alternatives to consumers;
- enhance security of supply; or,
- contribute to the EU's energy and climate goals.

A comprehensive list of the criteria for the selection of PCIs can be found in Article 4 of Regulation (EU) No 347/2013.

The process by which a project is designated a PCI is broadly as follows. The project must have a 'promoter' that submits an application for the project to be selected. These proposed projects are then assessed by one of twelve Regional Groups structured around priority corridors and thematic areas. One of these groups is 'BEMIP Electricity'.

The Groups include representatives from the relevant EU countries, the Commission, transmission system operators and their European networks, project promoters, regulatory authorities, as well as from the Agency for the Cooperation of Energy Regulators (ACER). In the case of electricity and gas projects, it is ACER that is responsible for assessing projects' compliance with the PCI criteria and their European added value.

Based on the assessment of these Groups, a comprehensive list of PCIs is compiled by the Commission, which then adopts the list via a delegated act procedure. The list is submitted to the European Parliament and Council, which have two months to oppose the list and which may ask for an extension of two months to finalise their position. If neither the Parliament nor the Council rejects the list, it enters into force.

Denmark

Task 4

Market design

Day-ahead market

- **Market coupling:** Denmark participates in the Nord Pool wholesale market for electricity together with Sweden, Norway, Finland, Estonia, Lithuania and Latvia. Through Nord Pool, Denmark is also part of Multi-Regional Coupling (MCR), which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 59.6 TWh in DK (33.0 TWh Buy and 26.6 TWh Sell) in 2017. 0.8 % growth in yearly traded volume for DK from 2016. By bidding zone: 36.3 TWh (61%) in DK1 and 23.3 TWh (39%) in DK2
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh (common price cap/floor for the Nord Pool region)

Intraday market

- **Liquidity/traded volumes:** National: 3.2 TWh (1.5 TWh Buy and 1.7 TWh Sell) in DK in 2017. By bidding zone: 2 TWh (63 %) in DK1 and 1.2 TWh (37 %) in DK2.
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate closure:** One hour before real-time (in the Nordic countries, Lithuania and Latvia).

Network regulation

TSO revenue regulation

The Danish TSO Energinet is fully state-owned and has historically been regulated through a non-profit principle which has enabled Energinet to fully recover operational costs and interest and amortisation of loans related to new investments. The regulation of Energinet is currently under revision with the intent of introducing a revenue cap regulation. Under this regulation, new investments will be added to the regulatory asset base at historical cost (with a time lag) and remunerated under a WACC model.

Network tariffs and connection charges

Danish generators are obliged to pay a tariff of 0.3 DKK øre/kWh, which amounts to a total of 3 per cent of Energinet's revenues (ENTSO-E, 2018). Some renewable generators are exempt from the tariff. The average tariff is capped at 1.2 EUR/MWh according to EU Regulation 838/2010.**Super shallow to partially shallow**: In Denmark, investors bidding into the offshore wind auctions have not historically needed to pay for grid connection or transmission reinforcement, as these costs were covered by the TSO. [67] Energinet was responsible for transformer substations, cabling and necessary reinforcement onshore. The owner of the concession was responsible for the internal grid in the wind farm from the individual turbines to the transformer substation. Costs incurred by Energinet.dk for the substation, the export cable and onshore cabling are passed on to electricity consumers and will not be imposed on the owner of the concession.[68] However, for the upcoming tender for the Thor offshore wind farm, the offshore substation and connection cable to the onshore grid will be part of the tender and will be financed through subsidies for the wind farm.[69]

Support mechanisms

Denmark has two different procedures for obtaining permits for the construction and operation of offshore wind farms: tenders announced by the State and the so-called open-door procedures. [70]In the general government tender procedure, the Danish Energy Agency (DEA) announces a tender for an offshore wind power project of a specific size, within a specific geographic area, on behalf of the Danish State. The Danish Energy Agency then invites applicants to submit a bid for the price they are willing to accept as a fixed feed-in tariff for a given volume. Selected projects receive a floating premium that is specific for each project and determined through auctions.[71]

Support under the Danish scheme is capped at 50,000 full load hours (equivalent to approximately 12 years assuming a load factor of 47 %).[72] The volume cap effectively removes most of the volume upside from the project, as more load hours in the early years would shorten the duration of the support.

Prioritised access applies to offshore wind farms, which can only be curtailed under special circumstances and must then be compensation for any operational losses, in accordance with the Danish RE Act. [73]

Task 5

Policy and legal framework

Offshore planning

The Danish government has a history of developing explicit cross-sectoral maritime strategies, most recently through the 2016 Maritime Strategy Team, which presented 52 recommendations to the government in 2017. Among many others, these included the development of a maritime spatial plan that supports testing of new generation technologies and the streamlining of guidelines and regulation affecting offshore wind development across the North and Baltic Seas.

As regards planning, a dedicated offshore wind spatial planning committee was established in 1995, led by the Danish Energy Agency and comprising all government authorities responsible for the natural

67 http://www.nera.com/content/dam/nera/publications/2016/PUB_Offshore_Wind_A4_0916.pdf
68 http://www.windpower.org/download/1811/energistyrelsen_udbud_af_havmoelleparkerpdf
69 https://ens.dk/sites/ens.dk/files/Vindenergi/brief_tender_for_thor_offshore_wind_farm_30march2019.pdf
70 https://eguides.cmslegal.com/offshore#denmark
71 https://www.energiforetagen.se/globalassets/energiforetagen/press/remisser/remissunderlag-2018-009.pdf?v=fQnzC_i9JwrHpZcGz2taBe6wFBY
72 http://www.nera.com/content/dam/nera/publications/2016/PUB_Offshore_Wind_A4_0916.pdf
73 Danish Energy Regulatory Authority (2017). National Report Denmark – Status for 2016.

environment, safety at sea, navigation, offshore resource extraction, visual interests and grid transmission conditions. The committee also included technical experts on offshore wind generation. It proactively identifies the most promising areas for offshore wind development given conflicts with other interests and the economic desirability of the location. Suggested sites are then discussed with the remaining maritime authorities and affected municipalities. Following public consultation, the recommended sites are then zoned for offshore wind development. This process was carried out in 1997, 2007, 2011 and 2012, with the committee lying dormant in-between planning rounds. The 2007 process examined 23 locations, each of 44 km^2. The 2012 process identified 15 nearshore sites.

The Danish Government recently committed to tender for the development of three offshore wind farms, with a cumulative capacity of 2.4GW, in the period to 2030. It is not clear how this capacity will be split between the North and Baltic Seas. However, a tender round for a 800-1000 MW offshore wind farm in the North Sea is already being planned.

Grid infrastructure

EnergiNet.dk, the state-owned monopoly national TSO, is responsible for the development of grid infrastructure. It has previous experience with the development of advanced grid connection options as part of the Krieger's Flak initiative, in which Danish and German offshore farms will be linked to provide interconnection capacity.

Permitting and licensing

Legislation and process

The requirements for developing offshore wind generation in Denmark's Exclusive Economic Zone are outlined in the Danish Act for the Promotion of Renewables, which entered into force on 1 January 2009.

Offshore wind development occurs through one of two processes:

1. Central tendering – the sites earmarked for offshore wind exploitation are generally tendered for development by the Danish Energy Agency
2. Open-door procedure – alternatively, developers may proactively apply to develop another site

Developers require four distinct licenses for an offshore generation project. Additional licenses are required for grid connection. Offshore grid works are usually carried out separately for tendered projects.

- License to carry out preliminary investigations
- License to establish offshore wind turbines. Before this license can be granted, an Environmental Impact Assessment (EIA) must be carried out.
- License to exploit wind power for 25 years. This license may be prolonged.
- Approval for electricity production in compliance with general electricity legislation.
- Any permits needed for grid connection. Construction or modification of lines requires the approval of the Energy Minister.

Relevant authorities

The Danish Energy Agency is mandated to issue the licenses necessary to plan and commission wind farms and attempts to act as a 'one-stop shop', coordinating procedures across other relevant authorities. Relevant authorities include the Danish Maritime Authority, the Danish Maritime Safety Administration, the Danish Environmental Protection Agency (Miljøstyrelsen), the Danish Forest and Nature Agency (Naturstyrelsen), the Cultural Heritage Authority, and the Fisheries Inspectorate etc.

Stakeholder consultation

Planning regulations require that there is a public consultation lasting no less than eight weeks. For offshore wind farms this consultation occurs once the EIA and final offshore wind farm application are received by the Danish Energy Agency. The consultation is announced on the Danish Energy Agency's website and in national and local newspapers. Key interested stakeholders include:

- Shipping and navigation bodies, including ship owner organisations, the Danish Maritime Authority and the Danish Maritime Safety Administration,
- The Danish Civil Aviation Administration (CAA-DK),
- The Danish Fishermen's Association and local fisheries organisations such as Bønnerup Fiskeriforening and Grenaa Fiskeriforening,
- Nature conservation agencies including the Agency for Spatial and Environmental Planning and the National Environmental Research Institute,
- The Heritage Agency of Denmark,
- The National IT and Telecom Agency, and
- Others including local communities, the oil and gas industry and the military.

Sector conflict management

Conflict management is handled proactively through use of a dedicated Committee for Future Offshore Wind Turbine Locations, as described in the 'Offshore planning' section above.

The work of this committee includes a hearing process that invites objections from other government bodies before a development application is made.

As discussed above, public consultation is required as part of the EIA process. In addition, the consenting process for all types of offshore and nearshore planning allows for appeal to the Energy Board of Appeal within four weeks of the publication of the decision. Onshore infrastructure planning decisions may similarly be appealed to the Environmental Board of Appeal. However, in the case of offshore wind projects, the groundwork laid by the Committee for Future Offshore Wind Turbine Locations means that these processes are rarely used.

Compensation measures exist and fishermen are expected to be compensated for the potential impact on commercial fishing. Losses are calculated based on a 500m protection line around the offshore wind farm.

Data and information management

Topographic information is held by the National Survey and Cadastre, which produces both national charts and specifications for ensuring safety at sea. It was also the agency responsible for transposing the INSPIRE Directive into national law.

Ecological data is provided by the Agency for Spatial and Environmental Planning, the Ministry of Environment and the Danish Energy Agency.

Socio-economic data is provided by the National Survey and Cadastre, the Danish Maritime Authority, the Danish Maritime Safety Administration and the Danish Directorate for Fisheries.

Geotechnical data is provided by Risø DTU's Wind Power Meteorology Programme and Energy and Environmental Data (EMD).

In 2015, the Danish Geodata Agency initiated work to implement a common Danish Marine Spatial Data Infrastructure (MSDI) alongside ten other agencies. The initiative promotes the sharing and coordination of marine geospatial data among Danish authorities. See msdi.dk

Cross-border and regional cooperation

Denmark is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- OSPAR – The Convention for the Protection of the Marine Environment of the North-East Atlantic
- Common Wadden Sea Secretariat – Supporting environmental protection of the Wadden Sea along with Germany and the Netherlands
- North Seas Energy Cooperation (NSEC) – Supporting integrated offshore network planning in the North Sea
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

It is a signatory of:

- A joint declaration in the field of research on offshore wind energy deployment together with Germany, Sweden and Norway

Estonia

Task 4

Market design

Day-ahead market

- **Market coupling:** Estonia participates in the Nord Pool wholesale market for electricity together with Denmark, Sweden, Norway, Finland, Lithuania and Latvia. Through Nord Pool, Estonia is also part of Multi-Regional Coupling (MCR), which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 17.5 TWh (7.4 TWh Buy and 10.2 TWh Sell) in EE in 2017. 3.2 % growth in yearly traded volumes from 2016.
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh (common price cap/floor for the Nord Pool region)

Intraday market

- **Liquidity/traded volumes:** 0.3 TWh (0.2 Buy and 0.1 Sell) in EE in 2017
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate Closure:** 30 minutes before real-time (for XBID Contracts in Estonia, Finland and Germany).

Network regulation

TSO revenue regulation

The Estonian TSO Elering is fully state-owned and is subject to a rate of return regulation (CEER, 2017). New investments are remunerated at a nominal pre-tax WACC and included in the regulatory asset base at historical cost.

Network tariffs and connection charges:

Estonian generators do not pay G tariffs.

Deep: Network connection charges, including necessary reinforcements in the grid, are paid by the project developer.[74] The connection charges are based on actual costs.

Support mechanisms

In 2018, the Estonian Parliament voted to amend the Electricity Market Act, which regulates incentives for renewable energy. As part of the system of revised support mechanisms established through these amendments, technology-neutral tenders will be held to procure renewable electricity generation. The tenders planned for larger-scale installations (>1 MW), and those therefore relevant to offshore wind, will provide winning bidders with monthly payments for renewable generation based on a sliding premium on top

[74] https://docstore.entsoe.eu/Documents/MC%20documents/TTO_Synthesis_2018.pdf

of the market price for electricity. Support payments will last for 12 years, with bids possible from wind, solar, geothermal, hydropower, biogas and biomass projects. The current timeline and volume to be procured in these large-scale tenders is as follows: 2021 (450 GWh); 2023 (650 GWh). Additional tender rounds may follow. The Electricity Market Act allows the government to organise such tenders in order to meet obligations stemming from any statistical transfers of renewable energy established under the EU flexible collaboration mechanism and / or to meet any renewable generation targets established by the government beyond 2020.

There is no system of priority dispatch for renewable sources of generation.

Task 5

Policy and legal framework

Offshore planning

Estonia has no recent offshore wind-specific targets. Its National Renewable Action Plan (2010) envisaged 250 MW of offshore capacity in 2020, but actual deployment to date has lagged behind the associated projections. The National Development Plan of the Energy Sector until 2030 includes a 2030 renewable target of 50%, calculated as a share of final energy consumption and based on an assumption that joint projects with other Member States are used, as well as a 2030 target of >10% for the share of final electricity consumption from fuel-free sources (solar, wind, hydropower). It also suggests a strategy of future deployment based on effective European mechanisms, rather than the development of national subsidy mechanisms. Despite this, and as noted above, national support is to be made available through tendering rounds as described in the ‘Support mechanism’ section above.

The National Development Plan notes that, with an effective carbon price, the share of electricity generation from renewable sources could reach 30% by 2030. The plan adds that, “The share of electricity generated from renewable sources could be increased to 50% of final electricity consumption in Estonia, subject to successful implementation of the flexible cooperation mechanisms with other EU Member States.” This level of generation would imply offshore wind development.

There are six offshore wind projects currently seeking consent: Loode-Eesti (~1000 MW), Liivi Lath (~1000 MW), Saare (600 MW), Loode-Eesti 2 (~1000 MW), Neugrund (228 MW) and Tuuletraal OÜ (476 MW).

Estonia’s national spatial plan ‘Estonia 2030+’ envisages that more detailed spatial planning for wind farms will be conducted through county-level planning and the aim is to have a Maritime Spatial Plan for each county by 2021.

Grid infrastructure

AS Elering, the state-owned monopoly national TSO, is responsible for the development of grid infrastructure. Grid development plans are focused on strengthening interconnection with the Nordic and European markets to make it possible to disconnect the Baltic electricity system from the North-East Russia synchronous grid and synchronise it with the Continental Europe synchronous grid over the period 2025-2030. There is currently congested interconnection capacity between Estonia and Latvia, but this is expected to be eliminated by the completion of the third trans-boundary transmission line in 2019. Internal grid reinforcement is likely to be required to enable offshore development.

Permitting and licensing

Legislation and process

Planning procedures relevant to the development of offshore wind are established in the Planning Act (amended on 1 July 2015), the Water Act and the Environmental Impact Assessment and Environmental Management System Act.

Under the revised Planning Act, planning authority for high voltage transmission and generators with a capacity of 150MW or more has been centralised under the Ministry of Finance, which manages the process of spatial planning, and under Ministry of Environment, which is responsible for Strategic Environmental Assessments (SEA). Previously this work was conducted by regional governments.

The elements required by an offshore wind developer include:

- A state special plan, through which the Government provides planning consent,
- A permit for the special use of water under the Water Act,
- A construction permit, and
- Authorisation to generate under the Electricity Market Act

These processes are distinct and run in parallel, resulting in a somewhat complicated licensing procedure. They also mean that the same conflict may be raised in multiple processes.

Note that an Environmental Impact Assessment (EIA) is obligatory for offshore wind farm development under the Environmental Impact Assessment and Environmental Management System Act.

No specific grid connection regulations or procedures apply to grid connection for offshore wind. In general, connection permits are issued by the TSO, Elering.

Relevant authorities

The Ministry of the Interior is responsible for issuing the state special plan. In doing so, it consults with the Ministry of the Environment, the Ministry and Defence and the Maritime Administration, among others.

Stakeholder consultation

The Planning Act and Environmental Impact Assessment and Environmental Management System Act establish the requirements for consultation. The Planning Act requires that initial and completed spatial plans are made available for public consultation. In general, the public has the right to submit proposals, objections and questions regarding the plan. In the case of the EIA, notification of the consultation must appear in the official publication, Ametlikud Teadaanded, in one national newspaper or one local or county newspaper, and in at least one public building or place near the location of the proposed activity (e.g. shop, library, school, bus stop). Immediately affected stakeholders and NGOs are also contacted by letter.

Sector conflict management

No mechanisms exist for addressing sector conflict beyond those inherent in the planning and consultation processes above. The Ministry of the Interior seeks to coordinate across various departmental interests. Other interests participate through the public consultation process.

Data and information management

Detailed Maritime Spatial Planning is currently piecemeal, with two regional plans having been developed since 2016 (notably covering the waters around Hiiumaa, and those in Pärnu and Liivi Bay). Additional areas are expected to be added in the future, with the aim to have a plan for each county by 2021. Potential offshore wind sites that have been identified include: Liivi Laht (1000 MW), Loode-Eesti (1000 MW), Saare (600 MW).

Sketch of the Estonian Maritime Spatial Plan (best offshore wind locations shown in light blue)

The national government has also developed a high-level nationwide spatial plan, which also covers maritime waters, called 'Estonia 2030+'.

Attempts to improve Maritime Spatial Planning are being undertaken as part of the BaltSeaPlan project, within the Interreg BSR Programme.

Cross-border and regional cooperation

Estonia is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

It should be noted that the EIA process implies the need to consult with neighbouring countries.

Finland

Task 4

Market design

Day-ahead market

- **Market coupling:** Finland participates in the Nord Pool wholesale market for electricity together with Sweden, Norway, Finland, Estonia, Lithuania and Latvia. Through Nord Pool, Finland is also part of Multi-Regional Coupling (MCR), which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 104.5 TWh (60.1 TWh Buy and 44.4 TWh Sell) in FI in 2017. -1.3 % reduction in yearly traded volume from 2016.
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh (common price cap/floor for the Nord Pool region).

Intraday market

- **Liquidity/traded volumes:** 2.0 TWh (1.0 TWh Buy and 0.9 TWh Sell) in FI in 2017
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate Closure:** 30 minutes before real-time (for XBID Contracts in Estonia, Finland and Germany).

Network regulation

TSO revenue regulation

The Finnish TSO Fingrid has majority state ownership, with significant co-ownership by financial investors. Fingrid is subject to a revenue cap regulation. New investments are added to the regulatory asset base according to standard netwok component prices and remunerated at a nominal pre-tax WACC.

Network tariffs and connection charges

Finnish generators pay a G tariff based on available generator capacity per month plus an energy charge. The average G tariff is capped at 1.2 EUR/MWh according to EU Regulation 838/2010.

Shallow: Project developer must pay standard connection charge based on average costs of connection infrastructure.[75] [76] The connection fees for 2018 are two million Euros for connection to an existing 400 kV substation, 1.2 million Euros for an existing 220 kV substation and 0,6 million Euros for an existing 110 kV substation. If a new substation is built for a connection in the transmission grid, the project developer bears the full construction costs of the substation. However, if new connections to the same substation are built for a third party or Fingrid within ten years after the substation is commissioned, the primary customer is

[75] https://docstore.entsoe.eu/Documents/MC%20documents/ENTSO-E_Transmission%20Tariffs%20Overview_Synthesis2016_UPDATED_Final.pdf
[76] https://www.fingrid.fi/en/services/power-transmission/fees/#grid-connection-fees

compensated for the main grid connection fee. The valid main grid connection fee is deducted from the compensation. [77]

The TSO selects the connection point and the project developer must cover all the costs to the grid connection point, though not the costs of reinforcements in the transmission grid.

Support mechanisms

To date, **no new support mechanism for offshore wind** has been planned since the government granted €20 million to a demonstration project in 2015.

On June 25th, 2018, amendments to the Act on Production Subsidy for Electricity Produced from Renewable Energy Sources entered into force, introducing a new technology-neutral tender process. Under the new subsidy scheme, a successful generator will be paid a premium (on top of the market price) corresponding to the price offered into an auction process.[78] The subsidy is limited to a maximum period of 12 years. Finland is planning two technology-neutral auctions for 1 TWh renewable energy each (excluding hydropower) between 2018 and 2020. However, offshore wind is unlikely to win at auction due its cost disadvantage relative to more mature renewable technologies.

In addition, the Ministry of Employment and the Economy can grant energy subsidies on a case-by-case basis to companies, municipalities or organisations to support climate- and environmentally-friendly investments that promote (among others) the generation or use of renewable energy.

Finland does not provide priority dispatch for RES connections.

[77] https://www.fingrid.fi/globalassets/dokumentit/fi/palvelut/kulutuksen-ja-tuotannon-liittaminen-kantaverkkoon/main-grid-connection-fees-2018.pdf

[78] https://uk.practicallaw.thomsonreuters.com/7-629-2923?transitionType=Default&contextData=(sc.Default)&firstPage=true&comp=pluk&bhcp=1

Task 5

Policy and legal framework

Offshore planning

Finland has no explicit target for offshore wind deployment. Offshore wind projects are eligible for support under the general measures provided to renewable sources of electricity generation, but offshore wind projects are not expected to be cost competitive relative to other renewable options and may therefore choose not to submit bids. 'Innovative projects', for example that pioneer offshore wind deployment in artic conditions, have previously received investment aid. Future projects are expected to be supported through technology-neutral tendering for renewable generation and through investment subsidies for innovative projects. A total of eight offshore windfarms (2,490 MW) are in the planning pipeline. Spatial plans have been approved for 800 MW.

No maritime spatial plans exist for Finland, but three spatial plans, split geographically, will be developed to cover Finland's Exclusive Economic Zone. These will be drafted by the eight coastal regional councils and should be completed by March 2021. A national maritime spatial planning coordination group has been established to help coordinate the process across the regional councils, autonomous Åland Islands region and the Ministry of the Environment.

Grid infrastructure

Fingrid, the majority state-owned monopoly national TSO, is responsible for the development of grid infrastructure. The development of offshore wind is not specifically considered in its ten-year development plan, although network reinforcements are considered in relation to the continued deployment of onshore wind. Finland has existing submarine cables to Sweden (Fenno-Skan 1 and 2) and Estonia (Estlink 1 and 2). Major future works include the construction of a third AC link to Sweden, due to be operational by 2025, and the replacement of the Fenno-Skan 1 cable to Sweden, which will reach the end of its lifespan in the late 2020s. Stronger interconnection between Finland and Estonia is also desirable and could conceivably be realised as part of an offshore grid.

Offshore wind developers in Finland are directly responsible for the construction of the submarine cables, transformers and transmission infrastructure needed to connect them to the existing grid. This implies the need to build network infrastructure to connection points that are 20-30 km inland, adding about 10-15 €/MWh to developers' costs.

Permitting and licensing

Legislation and process

The relevant legislation for the territorial sea is the Land Use and Building Act (132/1999) and it is this process that is described below. The UN Law of the Seas is implemented in national legislation for the Exclusive Economic Zone.

An offshore wind installation will in general require an Environmental Impact Assessment (EIA), a municipality-led spatial plan, a building permit, a water permit, a defence force statement, and a grid connection, which are separately applied for. It will also require an aviation obstacle permit if the turbines exceed 60 meters in height.

The spatial plan is conducted by the relevant municipality. The developer usually pays the costs of developing the plan.

The obligation to conduct an EIA, where relevant, stems from the Environment Protection Act (527/2014). The process itself consists of two stages. In the first, the EIA program, a report containing a description of the project and a plan of the impact assessment is drafted. In the second, the EIA report, the relevant impact assessments are made and their results reported.

The building permit is issued by the relevant municipality. The municipality may also require an environmental permit under the Environment Protection Act (527/2014), which allows the authority to restrict the operations of a wind farm and to obligate the operator to monitor and report on the environmental impacts of the operations, if the farm disturbs its neighbours with noise or flickering. Offshore wind farms also require a so-called water permit in accordance with the Water Act (587/2011).

The defence force statement effectively seeks approval for the project from the Finnish Defence Force, who will consider the project's impact on surveillance sensors and radar systems, as well as on their general operations.

Finally, a connection permit is required from the Finnish Energy Authority. Producers have a right to connect to the grid, on the condition that reasonable compensation is paid to Fingrid. The Ministry of Employment and the Economy grants permits for the construction of grid cables and new transmission lines.

Relevant authorities

The relevant authorities involved in the planning process include the regional and municipal councils, the relevant municipality, the Ministry of the Environment, the Finnish Energy Authority, the Ministry of Employment and the Economy, the Finnish Defence Force, the air traffic service provider (Finavia) and the Finnish Transport Safety Agency (Trafi).
Metsähallitus (a government-owned body, www.metsa.fi) decides to whom and where the sea area is rented for offshore wind farms and how much the developer has to pay as a rent.

Stakeholder consultation

The Land Use and Building Act requires a participatory process and therefore stakeholder consultation is expected as part of the ongoing work to develop maritime spatial plans for Finland.
The EIA and building permitting processes require that consultation occurs with the sectoral stakeholders affected.
The municipality-led spatial plan requires consultation with the sectoral stakeholders affected.

Sector conflict management

No mechanisms exist for addressing sector conflict beyond those inherent in the spatial planning and approval processes described above.

Data and information management

Data is held by a variety of different institutions. Biological data is held by SYKE and VELMU. Geo-technical data is available through the Finnish Wind Atlas, the National Spatial Data Network of Finland and the National Council for Geographic Information.

Cross-border and regional cooperation

The legislation on maritime spatial planning makes clear that the Ministry of the Environment will be responsible for working with neighbouring countries to ensure that maritime spatial plans are coherent and coordinated across the region.

Finland is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

Germany

Task 4

Market design

Day-ahead market

- **Market coupling:** Germany, Belgium, France, the Netherlands and Luxembourg form a regional wholesale electricity market (i.e. the Central-Western European (CWE) market region). Germany is also part of Multi-Regional Coupling (MCR), which covers 19 countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 241.7 TWh for the previous German-Austrian bidding zone DE/AT (233 TWh at EPEX Spot and 8.4 TWh at EXAA) in 2017. Total volumes fell by 0.3 % from 2016. Austria has now been separated into its own zone, as explained further below.
- **Minimum size of bids:** The minimum volume increment is 0.1 MW for individual hours and 0.1 MW for blocks.[79]
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh at EPEX Spot.

Intraday market

- **Liquidity/traded volumes:** 47 TWh for DE/AT in 2017. [80]
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate closure:** 30 minutes before real-time (for XBID Contracts in Estonia, Finland and Germany). EPEX spot offers both a continuous market and a discrete auction while Nord Pool offers a continuous platform. The auction clears at 3pm, before the opening of intraday continuous trading.

Network regulation

TSO revenue regulation

For the Baltic Sea the relevant German TSO is 50Hertz, which is owned by the Belgian TSO Elia (80 per cent) and the German government-owned development bank KfW (20 per cent). 50Hertz is subject to a revenue cap regulation where new investments are added to the regulatory asset base at historical cost and remunerated at a cost of capital determined by the regulatory authority.Network tariffs and connection charges

German generators do not pay a G tariff.

Shallow to super shallow: Offshore projects are entitled to grid connection, which is financed through the network charges that the TSOs pass on to electricity consumers. [81] BNetZa (Bundesnetzagentur) oversees the level of charges and ensures that it gives an adequate rate of return to the TSOs. German offshore projects only bear the cost of the grid from the offshore wind park to the offshore transformer station.

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[79] https://www.epexspot.com/en/product-info/auction/germany-austria
[80] https://www.epexspot.com/document/39308/Annual%20Report%20-%202017
[81] https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2017/13042017_WindSeeG.html

Support mechanisms

The Offshore Wind Act (WindSeeG) in **Germany**, which entered into force on January 1, 2017, contains the details of future tenders for offshore wind projects. A transitional regime applies to offshore wind installations commissioned between 2021 and 2025 while the WindSeeG's new "central" auctioning scheme will apply to plants commissioned from 2026 onwards. [82] In the central model, the government authorities will select sites and conduct a preliminary investigation of these sites. Development rights to selected sites will then be auctioned. Only successful bidders will receive funding based on the auction results. The duration of the market premium payments received has been set at 20 years from commissioning, although the associated permit for operation will be valid for 25 years. The first call for tenders are scheduled in 2021.

Renewable electricity has priority dispatch on the German grid.

Task 5

Policy and legal framework

Offshore planning

Under the revised Renewable Energy Sources Act (EEG 2017) Germany will introduce the 'central model' for offshore wind development. Under this model, offshore wind sites are identified and investigated in advance and then auctioned to developers. The new system will apply to wind farms commissioning from 2026, with the first call for tenders scheduled in 2021. Auctions in 2017 and 2018 were run on a transitional basis among those wind farms that had already independently advanced through the planning process without government-led identification and investigation of the relevant sites. Under this transitional scheme, a "Baltic Sea quota" of 500 MW was auctioned.

The EEG establishes a clear deployment trajectory for offshore wind in Germany. A total capacity of 15 GW will be installed by 2030. Between 2021-2022, 500 MW of capacity will be added annually; between 2023-2025, 700 MW will be added annually, and thereafter an average of 840 MW will be added annually. The table below shows the anticipated trajectory of offshore wind deployment in the Baltic Sea.

Anticipated offshore wind capacity in the German Baltic Sea

Approximate timing	Cumulative scheduled deployment
Mid-2018	700 MW
2020	1,070 MW
2025	1,800 MW

The Federal Maritime and Hydrographic Agency (BSH) is the process of developing an Offshore Area Development Plan (Flächenentwicklungsplan, FEP). This plan is an integral part of the new 'central model'. It will both identify the specific offshore wind sites that will be tendered for development and set out the years in which these planned sites and the necessary transmission infrastructure should be brought into operation.

[82] WFW

Grid infrastructure

Under the German Offshore Wind Act (WindSeeG), the Federal Maritime and Hydrographic Agency (BSH) will collaborate with the Federal Network Agency (BNetzA) to establish an Offshore Area Development Plan. This plan will set out the sites to be auctioned, when the sites should be developed and the associated grid development plan, including the location of converter platforms and substations, as well as the cable routes for the associated grid. Onshore grid planning occurs on a biennial basis among Germany's four TSOs and culminates in the publication of the Grid Development Plan for Germany. The most recent plan (2017), covers the period to 2030.

The latest available offshore grid planning is included in the second draft of the Offshore Grid Development Plan 2030. This foresees an extension of the Baltic offshore grid by 750km and 2.4 GW in the period to 2030. This implies network investment of around €4.8 billion.

Permitting and licensing

Legislation and process

The relevant permitting and licensing regime depends on whether the installation is within Germany's territorial waters, in which case approval rests with the relevant German coastal state, or outside territorial waters but within the EEZ (as will be true of most sites), in which case the BSH is the relevant authority. In the latter case, the approval procedure for wind farms and the corresponding network is set out in the Offshore Wind Energy Act (WindSeeG 2017). The approval process relevant to the windfarms successful in the transitional auctions consists of the following elements:

1. Key authorities (the Waterways and Shipping Directorate-General, mining authority, Federal Environmental Agency, Federal Agency for Nature Conservation) are invited to comment.
2. After this initial consultation, a wider consultation process is conducted involving the public and major stakeholders (e.g. associations for the protection of nature, affected commercial interests, small craft shipping, fisheries, and the development of wind energy). The coastal state is also consulted. These parties are given the opportunity to inspect the relevant planning documents.
3. An application conference is then held, at which the project and conflicting interests or uses are presented and discussed.
4. Following the conference, the BSH sets out the framework for further investigation and the applicant obtains and necessary assessments. These may include a risk analysis on ship collisions, an FFH (Flora Fauna Habitat) impact assessment and – for projects with more than 20 turbines – an environmental impact assessment. These elements are also consulted on.
5. In a public hearing, the findings and observations are discussed by all stakeholders. The BSH then reviews the documents and statements and considers whether approval should be granted. In parallel, the Waterways and Shipping Directorate-General determines whether final approval should be given with respect to the safety and efficiency of maritime navigation.

Relevant authorities

The BSH is the principal planning authority for installations outside of territorial waters. The Waterways and Shipping Directorate-General has specific responsibility for considering the impact on navigation. Other relevant authorities include the mining authority, Federal Environmental Agency, and Federal Agency for Nature Conservation. Where the installation is in territorial waters, the coastal state is the relevant approving authority, and even for projects outside territorial waters, the state is likely to be involved in connection with the planning of onshore infrastructure.

Stakeholder consultation

There was broad public participation in the creation of Germany's federal spatial plan for its Baltic EEZ, achieved through stakeholder consultations and a public hearing. These covered agencies and NGOs with an interest in the marine environment and nature conservation, fisheries, energy, sand and gravel extraction, shipping, the military, tourism, leisure boating, and research. Neighbouring countries were also consulted.

The process for stakeholder consultation is legally defined as part of the licensing process and involves all of the relevant government authorities, stakeholder organisations and the general public. Planning documents are made available and comments collected for a period of a month. Public hearings are also carried out.

Sector conflict management

No mechanisms exist for addressing sector conflict beyond those inherent in the spatial planning and approval processes described above.

Data and information management

The BSH maintains GeoSeaPortal, which provides a central online access point for geographic data on the sea and its coasts. Data is provided in the form of online interactive maps (WebGIS) and covers subjects including the Offshore Grid Plan, bathymetry, shipping, model forecasts, remote sensing, oceanography, pollution, geology, biology and the marine environment.

The BSH also maintains the CONTIS database, which covers the current and planned use of the marine environment. CONTIS geodata covers information on shipping, the exploitation of resources, planned offshore wind farms and environmentally sensitive areas, which is made available through thematic maps.

Cross-border and regional cooperation

Germany is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- OSPAR – The Convention for the Protection of the Marine Environment of the North-East Atlantic
- Common Wadden Sea Secretariat – Supporting environmental protection of the Wadden Sea along with Denmark and the Netherlands
- North Seas Energy Cooperation (NSEC) – Supporting integrated offshore network planning in the North Sea
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

It is a signatory of:

- A joint declaration in the field of research on offshore wind energy deployment together with Denmark, Sweden and Norway.

Latvia

Task 4

Market design

Day-ahead market

- **Market coupling:** Latvia participates in the Nord Pool wholesale market for electricity together with Denmark, Sweden, Norway, Finland, Estonia and Lithuania. Through Nord Pool, Latvia is also part of Multi-Regional Coupling (MCR), which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 14.4 TWh (7.3 TWh Buy and 7.1 TWh Sell) in LV in 2017.
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh (common price cap/floor for the Nord Pool region)

Intraday market

- **Liquidity/traded volumes:** 0.2 TWh (0.02 TWh Buy and 0.16 TWh Sell) in LV in 2017.
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate Closure:** One hour before real-time (in the Nordic countries, Lithuania and Latvia).

Network regulation

TSO revenue regulation

Augstsprieguma tīkls is the independent transmission system operator in Latvia and 100 per cent owned by the state. The company is subject to a rate-of-return regulation. New investments are included in the regulatory asset base at historical cost remunerated at a nominal pre-tax WACC.Network tariffs and connection charges:

Latvian generators do not pay G tariffs.

Deep: Producers pay a connection fee that includes all connection equipment and reinforcement of the grid. The connection fee is completely based on the actual costs.

Support mechanisms

No support mechanism for offshore wind. No priority dispatch for RES or other technologies.[83]

[83] http://www.tuuleenergia.ee/en/2018/08/nelja-energia-latvian-renewable-subsidies-have-failed-to-develop-sector/

Task 5

Policy and legal framework

Offshore planning

Latvia has no recent offshore wind-specific targets. It's National Renewable Action Plan (2010) envisaged 180 MW of offshore wind capacity in 2020. However, its only wind project under development, the 200 MW Baltic Wind Park, is on hold following the suspension of Latvia's renewable support mechanism, due to concerns over corruption. The Government is currently focused on realising lower cost onshore renewables.

The Sustainable Development Strategy of Latvia until 2030 (also from 2010) set a target to provide half of the total final energy consumption in the country from RES in 2030.

As discussed below, a partial Maritime Spatial Plan has recently been developed.

Grid infrastructure

AST, the state-owned monopoly national TSO, is responsible for the development of grid infrastructure. Major ongoing projects include strengthening interconnection with Estonia, as part of efforts to enable synchronisation with a European grid, as well as significant internal grid development. This includes completion of the 330 kV Kurzeme Ring, which involves the construction of a 330kV line along the coast east of Riga. Work is due to be completed in 2019 and will support the potential deployment of wind capacity in western Latvia.

Permitting and licensing

Legislation and process

The legislative basis for Marine Spatial Planning is the Spatial Development Planning Law, issued on the 1st of December 2011. Permitting and licensing is governed by the Marine Environment Protection and Management Law. Under this Law, the Cabinet itself issues licenses in accordance with the Marine Spatial Plan. In practice, this responsibility is delegated to the Ministry of Economics.

Although an administrative framework technically exists, it remains untested and uncoordinated, with the relevant competencies divided across several ministries, and no clear mechanism to coordinate activity.

Relevant authorities

Authorities with an interest include the Ministry of Economics, the Ministry of Environmental Protection and Regional Development, the Latvian Maritime Authority, and the Building Administration (which issues the building permit).

Stakeholder consultation

An extensive stakeholder consultation process was followed in the development of the Marine Spatial Plan for Latvia's westernmost coast, described below. This included representatives from of all major sea uses and interests including maritime transport, fishery, tourism, energy, cultural heritage, environment and nature.

Specific requirements for public consultation are established in the Law on Territorial Planning and in Resolution No. 1079 of the Government of Lithuania on Approval of Regulations for Public Information, Consultation and Participation in Decision-Making on Spatial Planning. These require the planning body to make a public presentation on the proposals and to contact directly-affected parties by mail. Anyone is free to submit alternative proposals to the planning body and, in the case of a Strategic Environmental

Assessment, the SEA must document how these proposals have been accounted for.

Sector conflict management

No formal mechanisms or guiding documents exist for addressing sector conflict.

Data and information management

A Maritime Spatial Plan for Latvia's westernmost coast, the area most relevant for offshore wind development, was developed in 2015-16 under the Ministry of Environmental Protection and Regional Development (MoEPRD). The proposed plan covers both the territorial sea and Latvia's Exclusive Economic Zone. It also explicitly accounts for offshore wind development and identifies two areas as suitable for offshore wind development.

The draft plan was produced by the 'Baltic Environmental Forum-Latvia', which led a consortium including the Latvian Institute of Aquatic Ecology (LIAE), the Maritime Administration of Latvia (MAL), and the Lithuanian Coastal Research and Planning Institute CORPI.

Cross-border and regional cooperation

Latvia is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

Lithuania

Task 4

Market design

Day-ahead market

- **Market coupling:** Lithuania participates in the Nord Pool wholesale market for electricity together with Denmark, Sweden, Norway, Finland, Estonia and Latvia. Through Nord Pool, Lithuania is also part of Multi-Regional Coupling (MCR), which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 19.7 TWh (13.1 TWh Buy and 6.6 TWh Sell) in LT in 2017.
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 €/MWh and price cap of 3000 €/MWh (common price cap/floor for the Nord Pool region)

Intraday market

- **Liquidity/traded volumes:** 0.4 TWh (0.2 TWh Buy and 0.2 TWh Sell) in LT in 2017.
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate Closure:** One hour before real-time (in the Nordic countries, Lithuania and Latvia).

Network regulation

TSO revenue regulation

The Lithuanian TSO Litgrid is 97 per cent state-owned and subject to a hybrid regulatory model with 50/50 price and revenue cap (CEER, 2017). New investments are remunerated at a nominal pre-tax WACC and included in the asset base at an estimated market value.

Network tariffs and connection charges

Lithuanian generators do not pay G tariffs.

Deep: The draft law on Energy from Renewable Sources, which was submitted by the Ministry of Energy on August 10th, 2018, stipulates that renewable energy producers must cover all connection-related costs. [84] Until then, renewable energy generators with a capacity above 350 kW only had to bear 40 % of the connection costs, including necessary grid developments costs.[85] Other generators bear 100% of all actual connection costs.

[84] https://enmin.lrv.lt/en/news/government-to-consider-a-new-model-for-development-of-renewable-energy
[85] http://www.res-legal.eu/search-by-country/lithuania/single/s/res-e/t/gridaccess/aid/grid-development-15/lastp/159/

Support mechanisms

There is currently no national support scheme for offshore wind development in Lithuania.

In 2017, the Lithuanian government decided to centralise the development of offshore wind park sites. A decision on the sites and capacities to be tendered is expected by 2021. Then the fully permitted sites will be tendered to potential investors. [86] [87]

Renewable plant operators are entitled to priority dispatch.

Task 5

Policy and legal framework

Offshore planning

In 2017, the Lithuanian government approved an updated National Energy Independence Strategy, which establishes Lithuania's long-term goals with respect to renewable energy and offshore wind development. The Strategy aims to source 30% of final electricity consumption from renewables by 2020, 45% by 2030 and 100% by 2050. Wind power is expected to be the largest source of renewable electricity generation – contributing no less than 55% of renewable generation in 2030 and 65% in 2050 – though much of this will be onshore.

The Law on Renewable Energy Sources foresees a government tendering process for the development of offshore wind sites, similar to the Danish model, and the first tendering round will follow the completion of exploratory studies, which Ministry of Energy is responsible for organising. A decision on the sites and capacities to be tendered is expected by 2021. However, production is not anticipated until after 2030.

Grid infrastructure

Litgrid, the publicly-traded but state-controlled monopoly national TSO, is responsible for the development of grid infrastructure. As with the other Baltic States, grid development is focused on efforts to enable synchronisation with a European grid. In Lithuania's case, this requires the increase of transmission capacity on the LitPol link through construction of a second 500 MW converter and internal reinforcements. Uncertainty regarding the impact of re-synchronisation on flows may act as a barrier to offshore wind deployment. Increased domestic generation capacity is anticipated in Litgrid's planning, in line with national policy objectives, and implies the need for internal grid reinforcement. However, offshore wind development is not explicitly mentioned.

Permitting and licensing

Legislation and process

Until the planned tendering process is developed, the current legislative framework effectively prevents the development of offshore wind in Lithuania. Although planning procedures have been in place for some time and offshore wind projects are currently in development, there is no legislation that allows independent developers to survey the state-controlled seabed. As a result, these projects have no means by which they

[86] Nelja Energia AS (2018). Annual Report of the Consolidation Group for the financial year ended on 31 December 2017.
[87] http://www.rechargenews.com/wind/1390597/lithuania-plans-wind-auctions-from-2019?utm_medium=email&utm_source=free_article_access&utm_content=229573180

can obtain the right to conduct surveys of the seabed and therefore no practical means to progress the projects.

Under the earlier planning process, developers could initiate their own Environmental Impact Assessment, for which they could gain approval, and after which they could apply for a construction permit.

Relevant authorities

Authorities with an interest include the Ministry of Energy, the Ministry of the Environment (in charge of spatial planning), the fishery sector, the port authority, the State Department of Tourism and the Navy.

Stakeholder consultation

Information about the planning process was made available throughout the development of Lithuania's comprehensive spatial plan, and planning materials were publicly available on the Ministry of the Environment website. The plan was also presented publicly at national and international conferences and specific public hearings were organised to inform the public about the plan. Information was also made public via the mass media.

It is expected that specific consultations will also be held as part of the process used to identify the offshore sites to be tendered under Lithuania's new offshore wind development model, but the details of this process are not yet known. Under standard Environmental Impact Assessment (EIA) procedures, the public must be informed about the planning process, a public presentation must be held and the public must have the ability to make their own proposals.

Sector conflict management

No mechanisms exist for addressing sector conflict beyond those inherent in the planning and consultation processes above. Solutions designed to address sectoral conflicts are expected to be developed as part of the EIA process.

Data and information management

A legally-binding and comprehensive spatial plan for all of Lithuania including its maritime territory was adopted by the Seimas, or Parliament, in 2015. As part of this work, areas were investigated for potential use by offshore wind. The legal basis for this plan is the revised Law on Territorial Planning (2013) and it is available from the Ministry of Environment.

Cross-border and regional cooperation

Lithuania is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

Poland

Task 4

Market design

Day-ahead market

- **Market coupling:** The Polish day-ahead market is part of Multi-Regional Coupling, which covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 25.2 TWh in 2017. The trading volume fell by 8.6 % from 2016.[88]
- **Minimum size of bids:** The minimum order volume is 0.1 MW.[89]
- **Price caps:** Maximum price of 3000 €/MWh and minimum price of -500 €/MWh since July 1st 2018.

Intraday market

- Liquidity/traded volumes: 0.0714 TWh in 2016.
- **Regional scope/market coupling:** Poland is part of the second wave of XBID countries, with an expected go-live date of Summer 2019. At this point the intraday market will be coupled with most of the rest of Europe and all of the BEMIP member states.
- **Gate Closure:** Three hours before real-time delivery.

Network regulation

TSO revenue regulation

The Polish TSO Polskie Sieci Elektroenergetyczne (PSE) is fully state-owned. The TSO is subject to a cost-of-service regulation with incentive elements, inter alia through efficiency requirements for operating costs. New investments are remunerated at a nominal pre-tax WACC and included in the asset base at historical cost.Network tariffs and connection charges:

Polish generators do not pay G tariffs.

Shallow: Electricity producers pay for the direct line and any extension or rebuilding costs for the substation. The TSO covers reinforcement and development of the existing network. Generators with an installed capacity above 5 MW pay 100% of connection costs, while smaller units are subject to rebates in the connection charge.[90]

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[88] https://www.tge.pl/fm/upload/Raporty-Miesiczne/2017/RR_TGE_2017_interactive_EN_final.pdf
[89] https://tge.pl/en/39/day-ahead-market-dam
[90] https://docstore.entsoe.eu/Documents/MC%20documents/ENTSO-E_Transmission%20Tariffs%20Overview_Synthesis2016_UPDATED_Final.pdf
https://www.energiforetagen.se/globalassets/energiforetagen/press/remisser/remissunderlag-2018-009.pdf?v=fQnzC_i9JwrHpZcGz2taBe6wFBY

Support mechanisms

The Renewable Energy Act, which entered into force in July 2016, replaced the former green certificate system with an auction scheme.[91] Following an amendment in June 2018, offshore wind is now placed in the same auction pot as hydropower, biofuels and geothermal energy (Basket II). The 2018 amendment also removed the requirement for offshore wind farms to have valid building permits before entering the auction. Offshore wind farms will be able to bid for up to PLN 450 (EUR 121.3) per MWh.[92]

Producers of electricity from renewable sources are exempt from the tax on the sale and consumption of electricity. [93]

Poland provides priority dispatch for renewable energy sources.

Task 5

Policy and legal framework

Offshore planning

Poland's NREAP (2010) estimated that there would be 500 MW of offshore wind capacity in 2020. This remains Poland's only explicit target for the sector. Under renewable support mechanisms established in 2016, offshore wind can receive support through tenders for renewable electricity generation capacity. Successful bids receive support for 15 years in the form of a fixed feed-in-tariff or a contract-for-difference style premium.

No maritime spatial plan has been officially adopted in Poland. Three pilot, non-binding plans exist, each covering a subset of Polish waters.

A legally-binding maritime plan for all Polish sea areas, except port areas, the Szczecin Lagoon and the Vistula Lagoon, is currently being developed by the Maritime Office in Gdynia. Public consultation and the publication of a draft version is expected in 2018. In 2019, a final version is due to be submitted to Minister of Economy for approval.

Grid infrastructure

Polskie Sieci Elektroenergetyczne, the state-owned monopoly national TSO, is responsible for the development of grid infrastructure. Its network development plan for 2016-2025 explicitly considers the development of an offshore grid within Poland's Exclusive Economic Zone for the purpose of enabling offshore wind connections, a project it refers to as 'Baltic Grid'. However, PSE notes that the capacity of windfarms scheduled for connection to the network (2,250 MW under connection agreements) is currently insufficient to justify investment in an offshore network. It adds that constructing an offshore network would probably require offshore wind development to be an explicit national policy objective.

Permitting and licensing

Legislation and process

The main legal act regarding maritime spatial planning is the "Act on sea areas of the Republic of Poland and

[91] https://www.iea.org/policiesandmeasures/pams/poland/name-145058-en.php
[92] https://www.4coffshore.com/windfarms/project-dates-for-baltica-1-pl19.html
[93] http://www.res-legal.eu/search-by-country/poland/tools-list/c/poland/s/res-e/t/promotion/sum/176/lpid/175/

the maritime administration” of March 21st 1991 (ustawa z dnia 21 marca 1991 r. o obszarach morskich Rzeczypospolitej Polskiej i administracji morskie). Under this law, spatial plans determine the areas for producing renewable energy and the conditions imposed on their use.

It is supported by “Ministerial Regulation on MSP of 17th of May 2017”(Rozporządzenie Ministra Gospodarki Morskiej i Żeglugi Śródlądowej oraz Ministra Infrastruktury i Budownictwa z dnia 17 maja 2017 r. w sprawie wymaganego zakresu planów zagospodarowania przestrzennego morskich wód wewnętrznych, morza terytorialnego i wyłącznej strefy ekonomicznej). This stipulates that a Strategic Environmental Assessment must be carried out when developing any spatial plan.

Construction of an offshore windfarm, as well as the laying of offshore cables, requires that permission be obtained either from the Minister responsible for maritime economy or the territorially competent Director of the Maritime Office at the outset of the project. The responsible authority depends on the area’s legal status (EEZ, territorial sea, internal sea waters etc.) and the status of spatial planning for the area.

After this authorisation is received, an Environmental Impact Assessment must be performed and a construction permit obtained.

Relevant authorities

Maritime spatial plans are adopted by ministerial regulation from the minister responsible for maritime economy and the minister responsible for regional development in consultation with the ministers responsible for environment, water management, culture and national heritage, agriculture, fisheries, transport, internal affairs and the Minister of National Defence The draft plans are prepared by the territorially competent Directors of the Maritime Offices.

The head (marshal) of the province (województwa), health inspector of the province (województwa), the Ministry of the Environment, and the Director of the Maritime Office all have a role in specifying the EIA’s scope and evaluating the EIA report. The Regional Directorate of Environmental Protection is responsible for issuing a decision on environmental conditions at the conclusion of the EIA process and for issuing a construction permit.

Stakeholder consultation

The law on maritime spatial planning gives any stakeholder the right to express an opinion in writing to the planning authorities and expects the authorities preparing the plan to state how these opinions have been accounted for in their planning decision. Public consultation forms a part of the current plans to develop a legally-binding spatial plan for Poland’s Exclusive Economic Zone.

Public consultation also occurs as part of the EIA process. The Regional Directorate of Environmental Protection is obliged to publish information on the project as part of the process and anyone may submit comments, orally or on writing, within 21 days of the relevant publication. The relevant authority is obliged to take these comments into account and to prepare a report explaining how this has been done. Public consultations are run and managed by the authority issuing the environmental decision.

The means of notifying the public is not specified in legislation. Typically, a notification is published on the authority’s website and in the local press.

Sector conflict management

No mechanisms exist for addressing sector conflict beyond those inherent in the spatial planning and EIA processes described above.

Data and information management

Data on geology, maritime traffic, fisheries, NATURA 2000 sites, military areas, and dumping areas etc. is available from the Maritime Institute in Gdansk. Most of the data covers either Poland's territorial sea or EEZ and is available in GIS format on request. However, information on geology, biology, currents and dynamics of the deep-sea seafloor is limited or not available.

Cross-border and regional cooperation

Poland is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation

Sweden

Task 4

Market design

Day-ahead market

- **Market Coupling:** Sweden participates in the Nord Pool wholesale market for electricity together with Denmark, Norway, Finland, Estonia, Lithuania and Latvia. Through Nord Pool, Sweden is also part of the Multi-Regional Coupling that covers 19 European countries and 85 % of European electricity consumption.
- **Liquidity/traded volumes:** 291.4 TWh (138.3 TWh Buy and 153.1 TWh Sell) in SE in 2017. 2.9 % growth in yearly traded volume from 2016.
- Minimum size of bids: 0.1 MW
- **Price caps:** Price floor of -500 EUR/MWh and price cap of 3000 EUR/MWh (common price cap/floor for the Nord Pool region).

Intraday market

- **Liquidity/traded volumes:** 4.2 TWh (2.2 TWh Buy and 2 TWh Sell) in SE in 2017.
- **Regional scope/market coupling:** The European Cross-Border Intraday Market (XBID) solution couples 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden).
- **Gate Closure:** One hour before real-time.

Network regulation

TSO revenue regulation

The Swedish TSO Svenska kraftnät is a fully state-owned enterprise subject to a revenue cap regulation. New network assets are added to the regulatory asset base on a half-yearly basis according to historical costs, that are adjusted for inflation and depreciation and remunerated with a regulatory WACC denominated in real terms.Network tariffs and connection charges

Swedish generators pay a G tariff based on subscribed capacity plus an energy charge based on marginal nodal losses. The average G tariff is capped at 1.2 EUR/MWh according to EU Regulation 838/2010.

Deep: At present, generators connecting to the grid pay the costs related to this (lines, sub stations etc.). The general principle is that the producer shall bear the costs incurred from the connection, including necessary grid reinforcements. The wind developer can therefore be charged an additional fee for the onshore transmission investment, on top of the cost for connection to shore.

In February 2018, at the request of the government, the Swedish Energy Agency published proposals for how to remove the grid connection charge for offshore wind power. The agency proposed two models where the connection costs would either i) be financed through an increase in grid tariffs or ii) through a separate fee levied on all electricity consumers.[94] Following criticism from various market players, including the Swedish Energy Markets Inspectorate (EI), the agency was tasked to further analyse the compatibility of the proposals with EU state aid regulations. In the supplementary report from June 2018, the Swedish Energy Agency concluded that abolishing the connection charges would most likely be incompatible with state aid regulation and could have distortive effects on the electricity market.[95]

Support mechanisms

Sweden does not have a separate support mechanism for offshore wind.

Offshore wind installations are eligible, but unlikely to be competitive, for electricity certificates (Elcertificates), which are a technology-neutral and market-based support scheme. The expected combined revenues from the spot market and the Elcertificate market have been insufficient to support new offshore wind capacity since the last offshore wind park, Kårehamn, was completed in 2013. The two other projects developed in Sweden in the last decade, Lillgrund (2007) and Vanern (2009), received pilot support from Energimyndigheten.[96]

Even if offshore wind would become cost competitive under this regime, it is unlikely that an offshore wind farm could be developed in time to receive support from the electricity certificate system. Although the Swedish government decided in 2017 to prolong the Elcertificate system to 2030 and increase its part of the target, the final target of 46.4 TWh of annual renewable energy in Sweden and Norway may be met as early as 2021 due to the rapid build-out under the system (THEMA Consulting, 2018)[97]. The Swedish government is expected to implement a stop rule for the system by 2021, upon which no new projects would be accepted into the system

There is no priority dispatch of renewable energy sources.

Task 5

Policy and legal framework

Offshore planning

The Swedish Parliament has a planning target of 10 TWh of offshore wind generation for 2020. The 'Agreement on Swedish energy policy', agreed among five of the eight parties in parliament and supported by the government, also includes a target of achieving 100% renewable electricity generation by 2040, though this explicitly does not require a banning of nuclear power or the closure of existing nuclear plants. The Agreement also commits to the abolition of connection fees for offshore wind, and this is now under investigation.

Renewable generation is supported through a common elcertificate scheme with Norway, in which renewable generators are provided certificates linked to their output and retailers are obliged to source a

[94] http://www.energimyndigheten.se/nyhetsarkiv/2018/tva-modeller-for-slopade-anslutningskostnader-for-havsbaserad-vindkraft/

[95] http://www.energimyndigheten.se/nyhetsarkiv/2018/redovisning-av-kompletterande-analys-av-slopade-anslutningsavgifter-for-havsbaserad-vindkraft/

96 https://www.energimyndigheten.se/globalassets/nyheter/2015/rapport-havsbaserad-vindkraft.pdf

[97] THEMA Consulting Group (2018). *ElCertificate Price Forecast.*

number of certificates sufficient to cover their sales. 190 MW of offshore wind capacity is currently in operation. There is almost 3,000 MW of permitted offshore capacity and as much again in the permitting process.

Draft marine spatial plans for Sweden's Exclusive Economic Zone were published in 2018 and are currently being consulted on. These plans identify areas to be used for power generation, notably offshore wind, and are being developed by the Swedish Agency for Marine and Water Management. The Swedish Environmental Code (EC, 1998:808) and the Plan and Building Act (2010:900) constitute the legal base for marine spatial planning in Sweden. An addition to the environmental code from 2014 calls for the preparation of the plans currently under consultation. The resultant plans are intended to be adopted by the Government. The Government may also choose to adopt regulations prohibiting or limiting activities in designated geographical areas, but without further regulation, these plans will be for guidance only.

Grid infrastructure

Svenska Kraftnät, the state-owned monopoly national TSO, is responsible for the development of grid infrastructure. It's System Development Plan 2018-2027 does not foresee significant offshore wind development unless significant public subsidy is introduced, but notes that offshore projects are likely to require internal reinforcement of the grid, and that the associated investment cost may fall to the offshore developer. Major planned projects include the reinforcement of the North-South grid boundary, investment in the Hansa PowerBridge (a 700 MW HVDC cable to Germany) and the construction of a new 400 kV line to Finland.

Permitting and licensing

Legislation and process

The permitting and licensing process varies depending on whether or not the proposed windfarm is located within Sweden's territorial waters. A separate construction permit is also required for any work that takes place on land, for example in association with landing the export cable.

Within Sweden's territorial waters, two permits are required, one covering environmentally hazardous activities (issued under the Environmental Act), the other governing operations on the water (issued in accordance with the Water Act).

The environmental permit is issued using the same rules as pertain to onshore wind. Although Sweden's marine spatial plans may set out the intended purpose of different areas, the significance of this designation for planning purposes is not yet clear. The distinct water operations permit is issued on the basis of a cost benefit analysis, with only net beneficial activities awarded a permit.

Wind farm projects in areas beyond Sweden's territorial waters need a single permit issued in accordance with the Act on the Swedish EEZ. The permit application requires that an EIA be conducted and is awarded by the Swedish government or the nominated authority.

The military effectively has the right to veto projects on the grounds that they conflict with the country's defence needs. This veto can be exercised inefficiently late in the permitting process.

Relevant authorities

Relevant authorities include the Environmental Authority (in relation to the EIAs), the Swedish Energy Agency (for grid consenting), the Energy Markets Inspectorate (for a license to operate offshore grid infrastructure), the municipalities and the Swedish Agency for Marine and Water Management (on issues of spatial planning), and the Ministry of Enterprise, Energy and Communication (for permitting related to the EEZ).

Stakeholder consultation

Consultation on Sweden's draft maritime spatial plans is ongoing with trade organisations, NGOs, central government agencies, regional government bodies (County Administrative Boards), regions, municipalities, academia and neighbouring countries. Draft plans have been published and are open for comment, and a number of public presentations have been planned.

Consultation also forms a part of the permitting process relevant to each specific farm. Initially, any affected parties and the relevant municipal and county planning authorities are invited to respond to detailed plans and a consultation report is published reflecting the information and opinions gathered. A public exhibition then takes place ahead of a final decision. There is at least a three-week window in which to submit a written response to this exhibition and this latter process is open to all.

Sector conflict management

Sector conflict management is intended to be resolved through the development of maritime spatial plans and, failing this, through the consultation phases included within the detailed permitting process. No mechanisms exist for addressing sector conflict beyond those inherent in these processes.

Data and information management

Some data is held by the Swedish Agency for Marine and Water Management in connection with its spatial planning functions. The Swedish Meteorological and hydrological Institute (SMHI) also holds some of the following types of data: biological, ecological, state of the sea, and wind statistics. However, this data is not available in a GIS format.

Cross-border and regional cooperation

Sweden is a member of the following initiatives:

- HELCOM – the Baltic Marine Environment Protection Commission
- OSPAR – The Convention for the Protection of the Marine Environment of the North-East Atlantic
- North Seas Energy Cooperation (NSEC) – Supporting integrated offshore network planning in the North Sea
- VASAB – the Committee on Spatial Planning and Development in the Baltic Sea
- BASREC – Baltic Sea Region Energy Cooperation
- Joint renewable certificate scheme with Norway

It is a signatory of

- A joint declaration in the field of research on offshore wind energy deployment together with Germany, Denmark and Norway